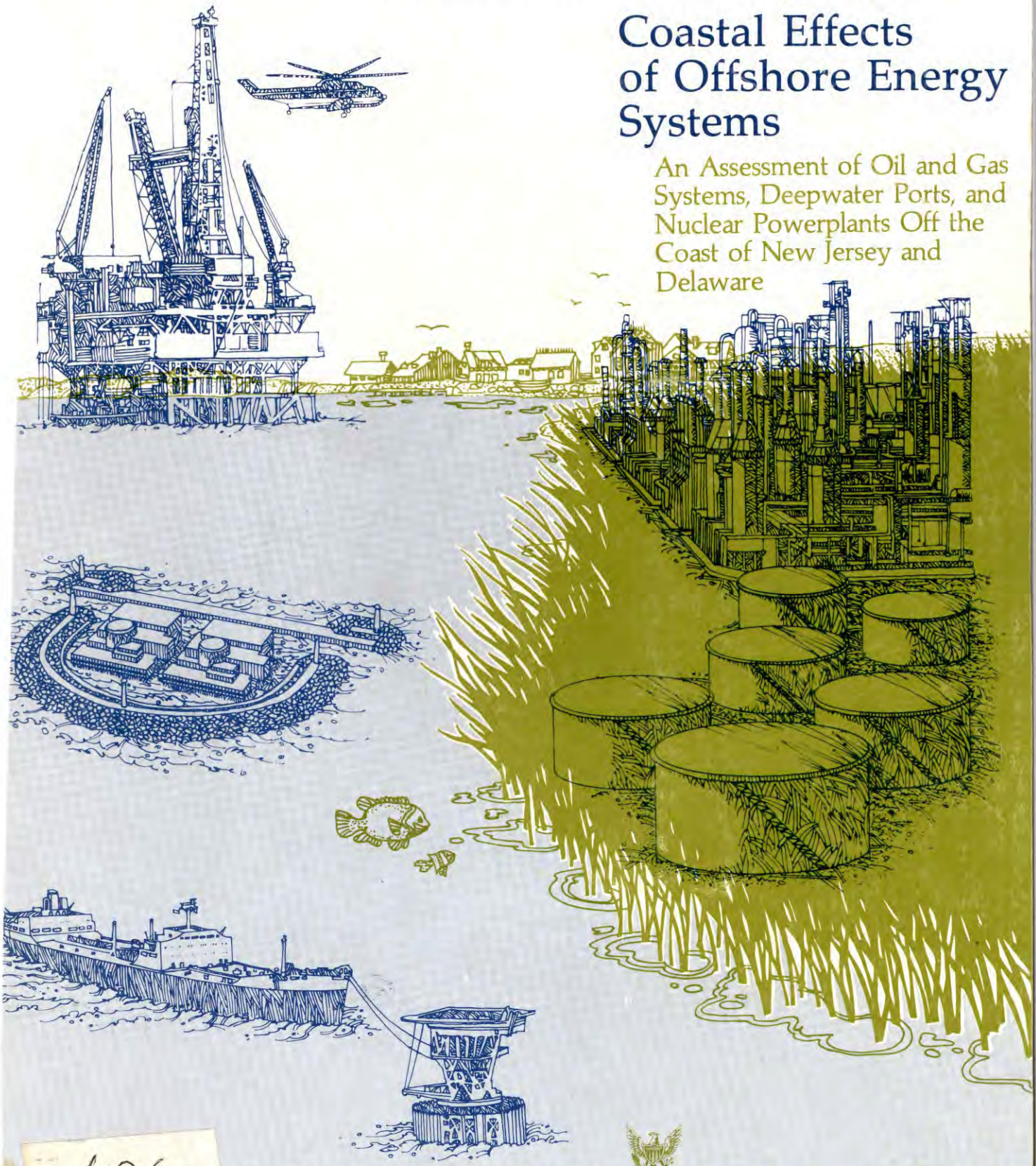
Volume II: Working Papers

Coastal Effects of Offshore Energy Systems

An Assessment of Oil and Gas Systems, Deepwater Ports, and Nuclear Powerplants Off the Coast of New Jersey and Delaware



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November 1976

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Working Papers for
Coastal Effects of Offshore Energy Systems:

Oil and Gas
Deepwater Ports
Floating Nuclear Powerplants

Congress of the United States
Office of Technology Assessment

November 1976

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LIST OF WORKING PAPERS

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Working Paper #2	Biological Impacts of Three Offshore Enerby Technologies By Ecological Analysts, Inc.
Working Paper #3	Oil Spill Risk Assessment for OCS Oil and Gas Processing Facilities and Deepwater Ports. By The BDM Corp.
Working Paper #4	Air and Water Quality Impacts of Oil and Gas Processing Facilities By Energy and Environmental Analysis, Inc.
Working Paper #5	Regional Energy Supply and Demand Considerations By Energy and Environmental Analysis, Inc.
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Working Paper #7	Environmental Studies for OCS Oil and Gas Development By Michael J. Canoy, William Barbee, Andre LaBonte, and OTA
Working Paper #8	Safety Analysis for Floating Nuclear Powerplants By P.R. Davis
Working Paper #9	Analysis of Fuel and Waste Handling and Decommissioning for Floating Nuclear Powerplants By Nuclear Energy Services, Inc.
Working Paper #10	Economic Considerations for Floating Nuclear Powerplants By Irvin C. Bupp Jr.

FOREWORD

The ten working papers included in this document contain background data and detailed analysis prepared for the Office of Technology Assessment in the course of its study of the Coastal Effects of Offshore Energy Systems.

The OTA team which conducted the assessment identified issues, information gaps, and the need for analysis of data during the study and commissioned professionals in appropriate fields to prepare the reports contained in this document.

The working papers, along with interviews, workshops, published data, and other sources of information, provided the basis for specific findings about the development of offshore oil and gas, the siting of deepwater ports, and the siting of floating nuclear power plants, particularly off the coast of New Jersey and Delaware. These findings are discussed in a report by the OTA Ocean Assessment Program which is being published simultaneously with these working papers.

The working papers do not represent a complete bibliography used during the course of the assessment of the three technologies. Many other published works are cited in footnotes to the report. No attempt has been made here to reproduce such material, which should be available to the reader through established information channels.

Working Paper #1

Federal and State Regulation of the Three Offshore Energy Technologies

Prepared by OTA,
House Ad Hoc Committee on the OCS,
and the BDM Corp.

September 1976

Working Paper #1

FEDERAL AND STATE REGULATION OF THREE OFFSHORE ENERGY TECHNOLOGIES

INTRODUCTION

This working paper identifies and discusses the laws and regulations which apply to deepwater ports and Outer Continental Shelf oil and gas development. The emphasis is on major Federal laws and applicable laws of the States of New Jersey and Delaware. Laws and regulations which apply to floating nuclear powerplants are discussed fully in the published report, Coastal Effects of Offshore Energy Systems.

The paper also includes a discussion of the Federal government's operating orders and management practices concerning OCS oil and gas production and a comparison of House and Senate versions of proposed changes to major Federal legislation dealing with the OCS.

A summary of the major Federal laws which are relevant to offshore energy systems is included.

Much of the information in this working paper comes from appendices prepared by BDM Corporation.
Other information comes from two congressional reports: Outer Continental Shelf Oil and Gas Leasing Off Southern California: Analysis of Issues, a November 1974 staff report for the Senate Committee on Commerce; and Effects of Offshore Oil and Natural Gas Development on the Coastal Zone, a March 1976 report prepared by the Congressional Research Service for the House Ad Hoc Select Committee on the Outer Continental Shelf. The comparison of House and Senate amendments to the OCS Lands Act is taken from material prepared by the Select Committee. Use of these materials is gratefully acknowledged.

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I. REGULATION OF DEEPWATER PORTS

Introduction

Under the Deepwater Port Act of 1974, the Secretary of Transportation issues licenses for deepwater ports beyond the three-mile limit and the Coast Guard writes and enforces regulations for building and operating the ports. TABLE I-1 summarizes the federal procedures.

No such precise authority exists for ports inside the three-mile limit where authority is shared by Federal, State and regional authorities under laws which were written primarily for activities other than deepwater ports.

In neither case are there guidelines for determining, as a matter of national policy, where deepwater ports should be located and in what numbers.

Offshore Facilities

The Coast Guard published detailed regulations covering all aspects of deepwater port operations from weather-forecasting techniques to standards for spill clean-up equipment in the November 10, 1975, Federal Register (33 CRF 148-150). An environmental impact statement accompanying the regulations was published October 3, 1975.[1] The Coast Guard has said it will require an applicant to file an environmental analysis for any offshore deepwater port.

Under procedures set forth in the Act, the Governor of a State "adjacent" to a deepwater port may veto a license without showing

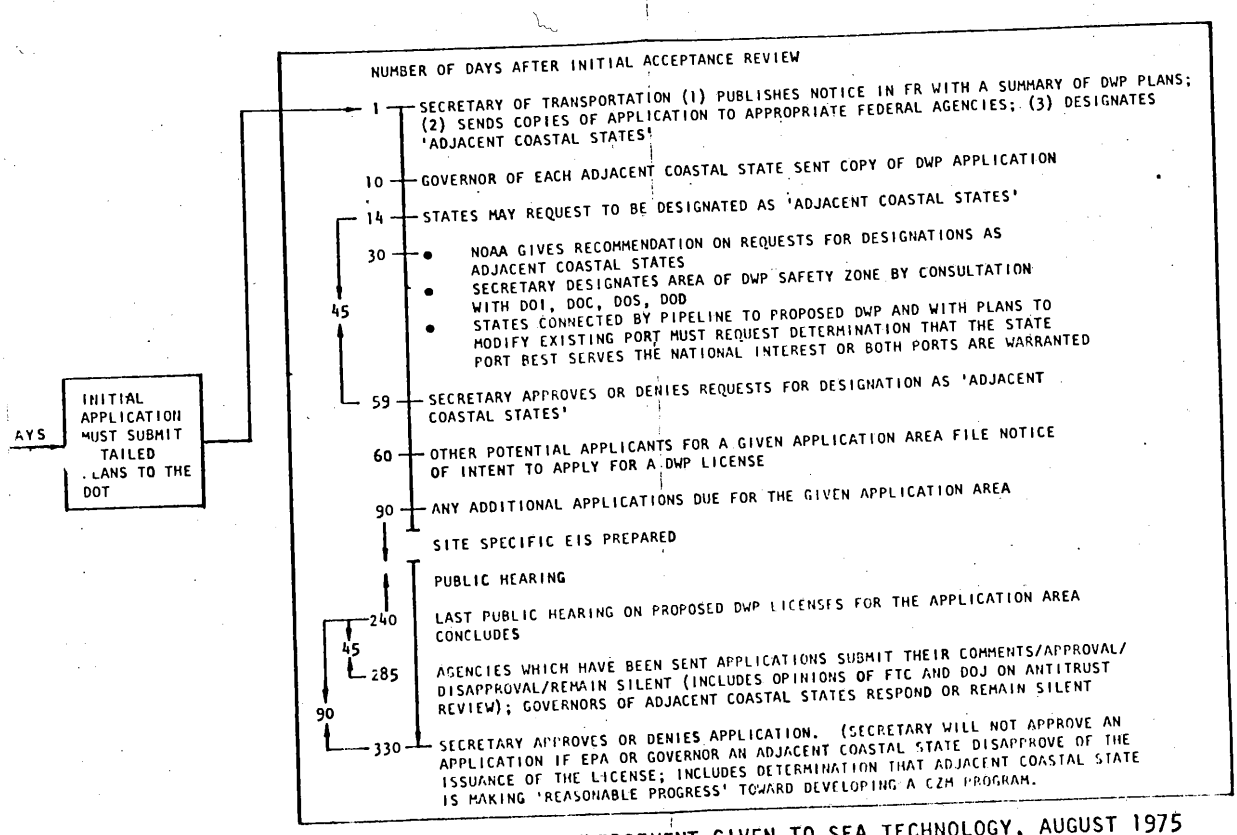
1/ U.S. Department of Transportation, Deepwater Ports Project, Office of Marine Environment and Systems, U.S. Coast Guard, Environment al Impact Statement: Deepwater Port Regulations, October 3, 1975.

PREPARATION OF DWP APPLICATION (INCLUDING ENVIRONMENTAL ANALYSIS AND PRECONSTRUCTION SITE EVALUATION AND TESTING)

- FINANCIAL INFORMATION.
- GENERAL TECHNICAL INFORMATION ON AN APPLICANT'S EXPERIENCE IN OFFSHORE OPERATIONS.
- A STATE WATER QUALITY CERTIFICATE.
- COMPLIANCE WITH ALL OF THE FEDERAL REGULATIONS RELATING TO DEEPWATER PORT OPERATIONS.
- IDENTIFICATION OF SEABED AREAS UNDER LEASE FOR MINERAL EXPLORATION IN OR ADJACENT TO PORT AREAS, AND AGREEMENT NOT TO INTERFERE WITH PORT OPERATIONS.
- COMPLETE SITE PLAN INCLUDING HYDROGRAPHIC SURVEY AND LOCATION OF EQUIPMENT.
- ANALYSIS OF DATA ON SEABED AND SUB-BOTTOM CONDITIONS RELATIVE TO SUPPORTING STRUCTURES.
- PHYSICAL DATA ON ALL TANKERS THAT WILL USE THE PORT TO PERMIT THE DESIGN TO ALLOW FIVE FEET OF UNDERKEEL CLEARANCE.
- MAXIMUM WIND, WAVE AND CURRENT CONDITIONS FOR USE AS DESIGN CRITERIA.
- COMPLETE DESCRIPTION AND PRELIMINARY DESIGN DRAWINGS FOR ALL OFFSHORE AND ONSHORE PIPELINE COMPONENTS AND STORAGE FACILITIES.
- PROCEDURES FOR CONSTRUCTING THE OFFSHORE PORT
- DRAFT OF AN OPERATIONS MANUAL.
- AN ENVIRONMENTAL ANALYSIS OF THE PORT TO BE USED IN PREPARING AN ENVIRONMENTAL IMPACT STATEMENT.
- EXACT LOCATION OF ALL AIDS TO NAVIGATION SUCH AS LIGHTS, RADAR, ETC.
- TELECOMMUNICATIONS EQUIPMENT.
- DETAILED LISTING OF ALL POLLUTION CONTROL EQUIPMENT.
- COMPLETED FORMS FOR DREDGE AND FILL OPERATIONS.
- ANTITRUST REVIEW INFORMATION.
- OWNERSHIP AND PRODUCTION OF CRUDE BY APPLICANT.
- OWNERSHIP AND OPERATIONS OF REFINERIES BY APPLICANT.
- OWNERSHIP OF PIPELINE BY APPLICANT.

1 1/2 - 2 YEARS ASSUMED

→ APPLICATION SUBMITTED TO DOT → 21 DAYS → INITIAL APPLICATION MUST SUBMIT DETAILED PLANS TO THE DOT →



ACKNOWLEDGEMENT GIVEN TO SEA TECHNOLOGY, AUGUST 1975

TABLE I-1 Preparation and Review of Application for DWP License

cause and may require the Secretary of Transportation to make observance of State environmental, land use and coastal zone management programs a condition of any license he issues. An "adjacent" state is defined in the Act as one within 15 miles of a deepwater port terminal or one through which a pipeline would run linking the terminal with shore facilities. The Secretary also is authorized under the Act to designate any State an "adjacent" State upon request of its Governor "if he determines that there is a risk of damage to the coastal environment of such state equal to or greater than the risk posed to a state directly connected by pipeline to the proposed deepwater port."

There are four major advantages to official status as an adjacent State:

1. In addition to the fact that the Secretary of Transportation may not approve an application for a deepwater port unless the Governor of an adjacent coastal state approves, an adjacent state also can impose stipulations on the license.

2. The Secretary must give public notice of a deepwater port application in each adjacent coastal state and hold a public hearing on the application.

3. Any adjacent coastal state may set reasonable fees for use of a deepwater port and such land-based facilities as tank farms to compensate that state for environmental or administrative costs that result from the construction and operation of the port.

4. Any adjacent state may, upon request, secure certain types of proprietary information which it requires in order to deal with the impact of the port.

The Act designates the Secretary of Transportation coordinator of all 21 Federal agencies which share responsibility for environmental, legal, economic or other aspects of a deepwater port. The Department's Office of Deepwater Ports is responsible for implementing the requirements of the Act. And the Coast Guard has been designated certain operational responsibilities in the administration of the Act. The Act specifies that a license cannot be issued if the Environmental Protection Agency does not certify that the port would conform with the Clean Air Act, the Federal Water Pollution Act and the Marine Protection, Research and Sanctuaries Act.

Part 149 and 150 of the Department of Transportation's regulations for implementation of the deepwater ports legislation contain most of the existing Federal standards set out for construction and operation of ports. The sections describe design standards, construction requirements, requirements for pollution prevention equipment, safety equipment and aids to navigation, including emergency power equipment, means of escape, personnel landings, fire detection, alarm and extinguishing systems, and lifesaving equipment. It also requires that the port meet the design, construction and equipment requirements of existing Coast Guard regulations, the American Bureau of Shipping, the National Fire Protection Association's code, the American Petroleum Institute recommended practices for offshore platforms, the American Society of Mechanical Engineers boiler and pressure vessel code and the American National Standards Institute standards. Sections on operational procedures set minimum qualifications for personnel, require a vessel navigation system, set net bottom

clearance, impose minimum standards for tests and inspections, require cleanup capability to handle a 10,000 gallon discharge, and require the filing of certain reports on operational activities.

The Coast Guard has supplemented these regulations with several guides on how the applicant should prepare his application and operational plans. Three of these guides are:

-- Recommended Procedure for Developing Deepwater Port Design Criteria (1975). This manual describes the factors -- waves, currents, wind, tides, design loads -- that the applicant should consider when designing the proposed deepwater port.

-- Guide to Preparation of Environmental Analyses for Deepwater Ports (1975). This manual discusses what should be included in the environmental reports that accompany each application.

-- Guidelines for Preparation of a Deepwater Port Operations Manual (1975). These guidelines are for use by an applicant in developing a draft Operations Manual for the proposed deepwater port.

The regulations cover only the building and operation of the port itself. They do not extend to onshore activities associated with a port. An applicant for a license, however, is required under the regulations to describe the pipelines, tank farms, and refineries that would be part of a total deepwater port system.

Coast Guard permits would be valid for 20 years.

The regulations require that the "best available" cleanup equipment must be stationed either at a pumping platform or on a

ship within the port zone at all times when oil is being transferred from a tanker to the terminal network. The equipment is not specified in the regulations. It requires only that the equipment be capable of containing and removing from the water spills of up to 10,000 gallons in cases where the port is being used to unload tankers and 40,000 gallons in cases where the port is being used to pump oil onto tankers.

The Act and the Coast Guard regulations both require an applicant to specify the existing or new refineries that would be served by a deepwater port. The regulations also require an applicant to submit an environmental analysis with an application which would cover both onshore and offshore impacts of a port.

In addition to complying with the provisions of the Deepwater Port Act, an applicant for a permit to build a terminal offshore is required to certify that the activity would conform to the coastal zone management program of any state that would be involved.

Nearshore Facilities

Construction of a port inside Delaware Bay such as one proposed by the Delaware Bay Transportation Co. would be covered by a series of zoning and licensing decisions involving the U.S. Army Corps of Engineers, the U.S. Environmental Protection Agency, the Delaware River Basin Commission and state and local governments.

The Corps of Engineers draws its authority from the Rivers and Harbors Act of 1899 which prohibits obstructions to navigation in U.S. waters and requires approval from the Chief of Engineers, and in some cases, the Secretary of the Army for dredging or other

modifications to the course of navigable waters. The Corps also shares with the Environmental Protection Agency responsibility for enforcing section 404 of the Federal Water Pollution Control Act Amendments of 1972, which requires a permit to discharge dredged material or fill into navigable waters.

Because pipelines would be used to transport crude oil from a deepwater port to refineries in the Philadelphia and Wilmington areas, the Delaware River Basin Commission would have to approve plans for pipeline construction.

Other state jurisdiction over a port inside the bay would be similar to its authority over pipelines, storage facilities and refineries that would be associated with an offshore oil terminal.

Approval by the Corps of Engineers of plans for deepwater port inside the bay would not necessarily prevail over state objections. The Corps would be obliged to deny a permit for construction if a state objected to a project unless the Secretary of the Army were to intervene.

Corps of Engineers administrative procedures for permits are described in interim final regulations promulgated July 25, 1975. The regulations are less precise in their descriptions of acceptable technology and operating procedures than are the Coast Guard regulations covering offshore ports. One study of the Corps' procedures concluded in 1975: "The Corps evaluation of (a) project will be based on an extremely vaguely defined 'all-the-circumstances' balancing process."[2]

2/ University of Delaware College of Marine Studies, "Legal Considerations for the Construction of a Deepwater Terminal in the Delaware Bay," September, 1975.

An application for a construction grant is filed with the District Engineer and prepared in accordance with Corps guidelines outlined in a publication, "Applications for Activities in Waterways". Applications must include: a description of the proposed activity, its location, purpose and construction schedule; and a description of materials and methods that would be involved in any dredging operations.

The District Engineer solicits comment on a project form interested public officials and agencies and determines whether an environmental impact statement is required.

In July 1975, the Corps set out general policies for evaluating permit applications. According to those policies, a permit shall be granted or denied based on an evaluation of the proposed structure and its intended use, on the public interest, the balance of benefits and detriments, and the consideration of all relevant factors including conservation, environment, economic, fish and wildlife, flood-damage prevention, navigation, recreation, water quality, land use classifications, needs and welfare of the people and state and local views. Also to be considered are the public and private need for the structure or work, alternative locations and methods, extent and permanence of good or bad effects on the area, and the cumulative effect in relation to other structures in the area.

As with an offshore terminal application, an applicant for a permit to build a terminal inside Delaware Bay will be required to certify that the activity would conform to the coastal zone management program of any state that would be involved.

Onshore Facilities

For facilities in the New Jersey coastal zone, onshore systems require approval under the Coastal Area Facilities Review Act, the Wetland Act, riparian law and State air and water quality regulations. Coastal facilities in Delaware require approval under the Subaqueous Lands Act, the Wetlands Act, the Coastal Zone Act and the Beach Preservation Act, as well as conformity with State air and water quality regulations.

Facilities located outside the coastal zones come under county laws in Delaware and municipal zoning laws in New Jersey.

Delaware's Coastal Zone Act prohibits construction of tank farms, refineries or pipeline landfalls in the State's coastal area. New Jersey law requires case-by-case review of applications to locate industrial facilities in its coastal zone.

Oil Spill Liability and Insurance

The oil spill liability provisions of the Deepwater Port Act cover clean-up costs and damages that may result from oil spills associated with a deepwater port. Damages are broadly defined in the Act as those suffered by any person or involving property, or the natural resources of the marine or coastal environment.

If the source of the discharge is vessel within any "safety zone" associated with the port, the vessel owner or operator is strictly liable without regard to fault up to a limit of the lesser amount of $20 million or $150 per gross ton. For spills from any component of a port, including pipelines, or from vessels moored at the port, the port's licensee is liable up to $50 million.

Dischargers are liable for the full costs of clean-up and damages if a spill results from gross negligence or willful misconduct on the part of the spiller. The only defenses to liability are acts of war, negligence on the part of the Federal government in establishing or maintaining aids to navigation, or, with respect to a damaged party, if that party's negligence was solely responsible for the spill.

Evidence of financial responsibility is required of vessel owners or operators of vessels using deepwater ports, or port licensees.

A Deepwater Port Liability Fund, administered by the Secretary of Transportation, is liable without regard to fault, for the actual costs compensated in excess of the limits for which the discharger is liable. The Liability Fund collects a 2¢-a-barrel fee on oil loaded or unloaded at a deepwater port until the Fund totals $100 million after which the tax is suspended until claims reduce the Fund below $100 million. The Fund may borrow money if the costs of clean-up or damages exceeds the amount in the Fund.

The Act provides for class action suits, and for claims by the Secretary as trustee of natural resources. Claims must be brought within three years of the spill.

The Act does not preempt the field of liability nor does it preclude a state from imposing additional liability requirements.

Provisions for liability for damages within the three miles of the coast is presumably not covered by the Act.

Liability for foreign vessels would have to be provided either through bilateral agreements with each nation using a deepwater port or through international conventions.

II. FEDERAL REGULATION OF THE OUTER CONTINENTAL SHELF

Coastal Zone Management Act and Possible Changes in the Present OCS Leasing System

Under present procedures, the major decisions on when and where to lease OCS tracts are made by the Federal government, specifically the Department of the Interior. There is only one point at which the States and the general public formally participate in the decision-making. This is after the draft environmental impact statement is released, and when comments on it can be made and testimony presented at public hearings on the draft. Besides offering such comments and testimony, the States or public can take the Interior Department to court, but only the procedures by which the decision was made can be challenged, and not the substance of the decision itself.

The Coastal Zone Management Act of 1972, as amended by the Coastal Zone Management Act Amendments of 1976, could effect two major changes in OCS leasing procedures.

First, the Act provides a mechanism for helping the States plan for onshore impacts, and cope with them when they occur. Section 305 of the Act authorizes the Secretary of Commerce to make grants to coastal States (including those on the Great Lakes) to help them develop State coastal plans. The grants are made on a matching basis, with the federal government paying up to eighty percent of the cost. Among other things, such plans include a process for locating energy facilities, such as terminals and refineries related to OCS development. The Commerce Department's

Office of Coastal Zone Management has the responsibility for making such grants.

Section 306 authorizes the Commerce Department to make administrative grants to States whose coastal plans have been formally approved by the Secretary of Commerce. Plans are to be approved if the State has approved its plan formally, if the State has established ways to coordinate State and local agencies and to implement the plan, if it provides "adequate consideration of the national interest," and if certain procedural requirements have been met, such as public hearings.

And a new Section 308 establishes a "coastal energy impact program," which will provide loans and some grants "to meet the needs of coastal States and local governments in such States resulting from specified activities involving energy development." Much of Section 308 deals with the impacts of OCS development.

Second, Section 307 of the Act, as amended, alters the OCS decision-making process. It does so by requiring Federal activities, including plans for the exploration and development of OCS lands, to be "consistent" with those state coastal plans which have been approved by the Secretary of Commerce. In cases where a state with an approved plan says that a given proposed activity is inconsistent with that plan, the Secretary will attempt to mediate the dispute between the state and the Federal agency involved. If mediation does not work, the final decision is up to the Commerce Secretary, who may approve the project, e.g., OCS development, if he finds "that the activity is consistent with the objectives of this title (of the

Act) or is otherwise necessary in the interest of national security."

The term "consistency" has not yet been defined clearly, largely because the Office of Coastal Zone Management is only now beginning to formally approve State coastal plans. But the new mechanism established by the Act certainly will alter the OCS decision-making process, and by giving the States a larger role in the decisions.

Proposed Changes in the OCS Lands Act of 1953

Two bills now before the Congress could alter the present OCS leasing procedures considerably. One bill is S.521, which passed the Senate in 1975 and which would amend the Outer Continental Shelf Lands Act of 1953. H.R.6218, different in content but dealing with the same subject, passed the House in July 1976.

The passage of these bills reflects a general desire to amend the 1953 Act. Both bills seek to do several major things: improve the U.S. leasing program by requiring the Secretary of the Interior to develop a comprehensive leasing plan, one which would be submitted to both the States and the Congress; require improved OCS safety and environmental regulations; and provide a new framework for oil spill liability and compensation.

Details of the two bills are compared in the following analysis by the House Ad Hoc Select Committee on the OCS. This comparison was made prior to the House/Senate conference on the bills in September 1976.

DIFFERENCES BETWEEN S. 521 - SENATE VERSION (S) AND HOUSE VERSION - (H) (FORMERLY H.R. 6218)

TITLE I

1. Title -- S. calls the bill "Outer Continental Shelf Management Act of 1975"; H. calls the bill "Outer Continental Shelf Lands Act Amendments of 1976".

2. Findings -- Both versions have many of the same findings.

However, S. also has findings that it is a "national policy" to develop coastal zone resources and provide for energy facility siting; and that the Coastal Zone Management Act provides procedures to anticipate and prevent adverse impacts.

H. alone has findings requiring an updating of environmental and safety regulations; that states should be given timely access to information relating to the outer continental shelf; that states should have an opportunity to review and comment on decisions; that states should receive financial assistance to plan for and ameliorate OCS impacts; that funds should be made available to pay for the removal of oil spills and damages from oil spills; and that the federal government should minimize or eliminate conflicts between OCS exploitation and other uses, such as fishing and recreation.

3. Purposes -- Both versions contain many of the same purposes.

However, H. alone provides that states should have timely access to information regarding OCS activities; that states should have an opportunity to review and comment on decisions; that conflicts between OCS and other resource recoveries should be minimized or eliminated; that states should receive financial assistance to plan for and ameliorate OCS impacts; that an oil spill liability fund should be established to pay for the prompt removal of oil spills and damages from oil spills; and that the resources of the OCS should be assessed at the earliest practicable time.

4. Sunshine in Government -- (Should really be in Miscellaneous Section -- Title IV) -- H. alone contains a provision providing for filing of statements concerning the financial interests of employees of the Interior Department and reports to Congress on such statements.

TITLE II

5. National Policy -- (Amending Section 3)

H. restates first two provisions of Section 3 of the OCSLA (maintained without change in S), providing for control of the subsoil and seabed of the OCS of the United States and preservation of the right to navigation and fishing of the waters above the OCS's high seas.

S. recognizes development of OCS resources will have significant impact on coastal zones, and H. states that such OCS activities will have significant impact on not just coastal areas, but on other affected areas of all states.

H. contains a provision for insuring safe operations in this section, while S. places the policy for safe operations in the section on safety regulations.

6. Leasing Programs (New section) -- Both versions establish an OCS leasing program.

* H. limits as factors to be included in consideration and establishment of such program the laws, goals and policies of affected states and the policies and plans established pursuant to the Coastal Zone Management Act required to be considered as those specifically identified by the governors of the states.

H. also alone provides, as a consideration, recommendations and advice given by regional OCS boards and whether there will be sufficient resources, including equipment and capital, to provide for expeditious exploitation.

* S. provides that the timing and location of leasing should occur so that areas with the greatest potential for discovery of oil and gas are leased first, taking into account environmental and coastal zone impacts and national needs, while H. provides that timing and location should be based on a proper balance between environmental damage, discovery of oil and gas, and adverse impacts on the coastal zone.

S. version provides for estimates to be prepared in the leasing program for the $500 million exploration program authorized by that bill and H., not having that program, does not so provide.

S. alone includes detailed considerations of what is to be included in the EIS for the leasing program.

H. requires that the procedures to be established by regulation, in addition to those provided in S. version, include periodic consultation with governments, lessees and permittees, representatives of individuals or organizations involved in OCS activities, including fishing, recreation.

S. requires proposed leasing programs to be submitted to Congress and published in the Federal Register, while H. requires that it be submitted to Congress, the Attorney General, state and local governments and regional advisory boards, and other persons, and provides that the Attorney General is to submit comments on competitive aspects of the program and other organizations and states and local governments are to submit recommendations as to any aspect of the program within ninety days of publication.

H. alone specifically requires in addition that during the preparation of any program, the Secretary is to invite and consider suggestions from the governors and to submit the proposed program sixty days prior to formal proposal by publication in the Federal Register to the governors.

S. provides for approval by June 30, 1977 and no leasing unless in accordance with that program after that date, while H. provides for approval within 18 months of enactment and allows leasing to continue until the program is approved and/or under judicial or administrative review.

S. requires the program to be revised and reapproved at least annually, while H. requires review annually and reapproval as seen fit by the Secretary of the Interior.

Both H. and S. provide for the obtaining of information and reports from public sources, or by purchase from private sources, but S. provides that confidentiality is to remain for such period of time as agreed by the parties, while H. provides confidentiality for such period of time as provided specifically in the OCS Act, established by regulation, or agreed to by the parties.

7. Exploration/Information Program (Amended Section 11 and new Section)

* Exploration -- S. alone authorizes any type of exploration and alone establishes a comprehensive "information-gathering program" concerning OCS resources, including government drilling, purchasing results of permitted drilling activities in a $500 million drilling program; S. alone also contains a provision for keeping and publishing a detailed set of maps and submitting to Congress a report on the information-gathering program.

* H. adopts, in an amended Section 11, the original language of the OCSLA giving the authority of any agency of the United States, or any person authorized by the Secretary, to conduct any type of geological or geophysical exploration; and adds a subsection requiring the Secretary to "seek qualified applicants to conduct geological explorations in areas of greatest likelihood of resources (on-structure drilling)."

Information -- S. provides that all lessees or permittees are to provide all data and interpretations to the Secretary of the Interior while H. provides a lessee or permittee is to provide all information and interpretations as the Secretary requests.

H. alone adds provisions providing that an interpretation made in good faith eliminates any liability by the lessee or permittee based on reliance on that interpretation, and providing for processing and reproduction expenses to be paid by the Secretary.

*S. provides that the Secretary and any other person coming into possession of information is to insure confidentiality until the Secretary determines release would not "damage the competitive position of the lessee," while H. provides for the Secretary only to establish regulations to assure the confidentiality of information.

*H. limits transmittal of information to states to other persons unless the permittee or lessee agrees, but provides specifically that the governor of the state can designate an appropriate official to see any privileged or confidential information after a lease sale, that the state shall keep such information confidential and any provision of state law to the contrary is overruled, and that a state could be deprived of the right of access and transmittal if it violates confidentiality standards. S., on the other hand, provides for the Secretary to make available to the public and to various states all information that the Secretary himself obtains, or obtains by services contracts; and all other information which the Secretary obtains, provided that confidentiality is secured.

H. alone adds a provision that a copy of all relevant documents, reports, plans, EIS's, nominations are to be submitted to the states; that a summary of the data prepared by the Secretary and any other data processed or analyzed by the Secretary is to be submitted to the states, provided that it does not unduly damage the competitive position of the lessee or permittee.

S. has a provision that once an entire geological structure or trap is leased, the Secretary is to publish estimates of the amount of oil and gas contained therein, and also a separate section providing for certain planning information for the states to be supplied as soon as practicable after each lease sale, while H. provides for planning information to be prepared by the Secretary for the states to include estimates of reserves, size and timing of development, etc., and to be periodically transmitted to the states as soon as practicable after <u>any</u> information is received.

8. <u>Safety Regulations</u> -- (New section) -- S. contains a policy for safe operations, which H. puts in its amended section and establishing national policy.

S. provides for promulgation of all "safety regulations," while H. provides for the promulgation of safety regulations as to the construction andoperation of any fixed structure and artificial island on the outer continental shelf.

* S. provides for the safety regulations to be prepared by the Secretary of the Interior with concurrence and advice of the EPA and Coast Guard; H. provides for the separation of responsibility -- regulations are to be developed by the Secretary (1) for protection of the environment with the EPA or the Secretary of Commerce (NOAA), (2) for the avoidance of navigational hazards, with the Army or Coast Guard, (3) for occupational safety and health with the Secretary of Labor (OSHA) or Coast Guard. Both provisions provide for a complete promulgation of new regulations within one year after enactment and the continuation of existing regulations until that time (language has to be cleared up to make this explicit).

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H. alone contains a provision providing for interim regulations to be prepared within sixty days by OSHA as to diving activities and any other unregulated hazardous working conditions.

* S. contains a provision requiring the best available technology, while H. provides for the best available and safest technology economically achievable.

H. alone contains provisions indicating that nothing should affect or duplicate the authority of the Secretary of Transportation as to pipelines, and providing for a compilation of all safety regulations to be prepared by the Secretary available to any person.

9. Research and Development -- (New section) -- S. contains an extensive provision for research and development programs, and H. does not. /Committee on Science and Technology of the House has passed an Outer Continental Shelf Research and Development Act, which is presently pending in the House Interior Committee, providing for a detailed R&D program as to the OCS, H.R. 11333./

10. Safety Enforcement -- (New section) -- *S. provides for the Secretary of the Interior and the Coast Guard to enforce all regulations, while H. provides for the Secretary of the Interior and the Coast Guard to enforce safety and environmental regulations, and the Secretary of Interior and Secretary of Labor (OSHA) to enforce occupational and public health regulations.

H. alone also provides that enforcement shall be "strict".

* H. provides for joint responsibility by holders of leases or permits with an employer or subcontractor for all safeguards in accordance with regulations.

S. provides for physical observation once a year, while H. provides for it twice a year.

Both versions provide for periodic on-site surprise inspection, but requires on-site inspections as to permittees, and not just as to lessees, as limited in S.

H. alone requires an investigation and report on any death or serious injury by the Secretary of Labor (OSHA).

Both versions provide that the relevant agencies are to consider any allegation as to safety violations, but S. requires the Secretary to answer an allegation within ninety days.

H. alone contains a provision requiring the annual report to contain a listing of the number of safety regulations violations reported or alleged, investigations undertaken, the results of the investigations, and any other action taken in response.

H. alone has a provision providing that after notice and hearing, the Secretary is to cancel a lease, without compensation, where there has been a failure to comply with safety regulations in a repeated course of conduct, or there is an overall pattern of failure to comply with regulations to assure maximum efficient and safe development of leases.

*11. Oil Spill Fund -- S. contains a new but limited section on oil spill liability, while H. contains a very extensive Title establishing liability and a pollution fund.

Specifically, H. applies to OCS facilities and vessels transporting OCS oil, while S. is limited to OCS facilities.

H. alone contains a provision prohibiting the discharge of oil in quantities determined to be harmful under the Federal Water Pollution Control Act.

Both versions contain provisions for the person in charge to report a spill, penalties for failure to report, and limitations on the effects of notification on any subsequent criminal prosecution.

S. provides for liability for all clean-up and damages up to $22 million and a fund thereafter, while H. provides for liability for damages up to $35 million and unlimited clean-up.

* H. alone specifically provides that liability limits do not apply to damages resulting from gross negligence, willful misconduct, or violation of applicable standards or regulations. S. provides that liability is not to be imposed for spills as a result of acts of war, negligence by a government agency, or the negligence or intentional act of the claimant, while H. provides that liability does not apply to spills as a result of acts of war, negligence or intentional acts of the damaged, or any third party, including the government, or an act of God (a natural phenomenon, of an exceptional, inevitable and irresistable character).

Both versions provide for subrogation, but H. specifically provides for the right to go against the person who damages or injures. H. contains a provision providing for the limitation of liability to a citizen of a foreign country unless there is a treaty or executive agreement or the Secretary of State, or the Attorney General certifies that there is a similar remedy in that country.

H. also alone provides for interests upon claims.

S's fund is to be within the Department of the Interior, to be financed by 2½ cents per barrel charge, until $200 million has been accumulated, while H's fund is to be administered by the Department of Transportation, on the basis of a three cent per barrel fee, until $100 to $200 million is established in the fund, and H. provides for the ability to borrow up to $500 million in addition.

H. specifically details the duties and powers of the fund, the recoverable damages, the specific disbursements available from the fund and its revolving account, the claims procedure, none of which are specifically detailed in S.

S. provides for removal of discharged oil by the Coast Guard; while H. provides for arrangements to be established by the President.

H. alone provides that claims can be brought directly against the Fund or Spiller, allows the President to adjust the requirements of liability, and provides that states cannot require additional evidences of financial responsibility in addition to those required.

H. alone provides that the President or his representative is to act as a trustee of the natural resources so as to recover for damages to the natural resources from a spill, and alone specifically provides procedures for judicial review; for class actions; for representation of the class by the Attorney General, or if he does not act, by the Secretary of Transportation; for access to records by the Secretary; for limited public access to information; and for an annual report.

H. specifically provides for appropriations of $10 million for 1977, $5 million for 1978, and $5 million for 1979, in accordance with appropriation acts each year, while S. contains a general authorization provision.

While Both S. and H. provide that this act should not preempt a state from imposing additional requirements or liability for discharge, H. provides that a person who receives compensation from one fund should not be able to receive compensation from another fund.

12. Citizens Suits -- (New section) -- *S. provides that any person having interest which "is or may be" adversely affected can sue, while H. provides that any person having interest "which is or can be " adversely affected can sue.

S. alone provides specifically that one can sue a government instrumentality, "to the extent permitted by the Eleventh Amendment."

S. provides for suits against the Secretary, while H. provides for suits against any federal official involved in safety regulation and enforcement. Similarly, S. precludes suits if the Secretary is diligently prosecuting a civil suit on the same matter, while H. provides a limitation if the relevant official or the Attorney General is undertaking such litigation.

S. provides for sixty day notice unless there is an imminent threat to the health or safety "of the plaintiff" while H. provides sixty-day notice unless there is an imminent threat to the "public health or safety."

*S. provides that the citizens suits provision does not in any way limit the ability to sue under any other law while H. provides that some of the judical review procedures as to certain activities do limit the way one can sue under other laws, except for NEPA.

Both versions provide for a right of judical review to the D.C. court of appeals of a leasing program, providing challengers participate in relevant administrative procedures, but H. provides that this is the exclusive method of review, and is excluded from citizens suits.

Both versions provide that review of a development and production plan is to be in a court of appeals where an affected state is located, after suitable administrative proc-edings, but H. provides this should be the exclusive way to review a development and production plan.

H. also provides for judicial review in a court of appeals of an affected state of an exploration plan (an exploration plan is not included as part of the requirements of the Senate bill).

*S. provides that judicial review of the holding of a specific lease sale is to be reviewed by a United States Court of Appeals, while H. specifically excludes a lease sale from judicial review, thus including it as an event that can be challenged in a citizens suit in the district court.

H. specifically provides, as in the original OCS Act but in a different section (and thus retained in S.), for jurisdiction in the district courts as to court actions, also alone provides for expedited consideration and specifically that this section not to affect any procedures or actions under NEPA.

13. Annual Reports/Promotion of Competition (amended section 15, and a new S. section) -- Both versions provide for an annual report, which H. alone including in the report a list of all shut-in wells, and S. alone including a summary of grants made from the impact fund.

Both versions require a report on competition. S. provides in a separate section for a report within one year after enactment, via the Secretary, while H. provides for it to be included in the annual report by the Secretary after consultation with the Attorney General and includes within the report an evaluation of restrictions on joint bidding and their effectiveness.

14. Enforcement/Remedies (New Section) -- Both versions provide for the relevant agencies to sue to enjoin or restrain activities, while discretion is granted to do so in S. for violations or implementation while H. provides "it shall be done."

S. provides for penalties of $5,000 for each and every day while H. provides for $10,000 each and every day, and there are minor differences between H. and S. in the criminal provisions.

15. Baseline and Monitoring Studies -- Both versions provide for baseline studies to be undertaken by NOAA, in cooperation with the Secretary of the Interior.

H. alone specifically provides that the study is to be commenced within six months for any area where there has already been a lease sale, and no later than six months prior to the holding of a lease sale for any area to be included in a lease sale, and that the Secretary of Commerce is to complete such study and submit it to the Secretary prior to final approval of a D&P plan, that failure to complete a study should not ordinarily be a basis to preclude approval unless the Secretary finds it necessary to do so.

Both versions provide for monitoring after a baseline study, but H. alone provides that additional studies can be undertaken after the development and production is approved to establish baseline information.

H. alone specifically provides that existing information from other agencies as to EIS's or other studies are to be utilized and not repeated, that the Secretary of Commerce is to submit to the Secretary of the Interior and to Commerce and make available to the general public, an assessment of the cumulative effect of activities on the environment.

16. Environmental Impact Statement -- S. specifically details what is to be included in any environmental impact statement, while H. did not include it, as it did not want to interfere with the discretion granted in NEPA.

17. Regional Boards (New Section) -- Both versions provide for Regional Boards to be established, to include representatives from the relevant federal agencies (H. adds as a relevant agency, OSHA) and provides recommendations are to be accepted, if submitted within 60 days, from a state or a Regional Board, unless overridden in the national interest.

*H. specifically defines national interest as consistent with obtaining oil and gas supplies in a balanced manner, and provides procedures if recommendations from different governors or boards conflict.

S. alone specifically provides that the Secretary's determination, after receiving such recommendations, shall be final unless determined to be arbitrary or capricious (this may be in conflict with S's general provision providing that on judicial review the standard is to be substantial evidence based on the record considered as a whole).

18. Planning Information (New Section - separate for S; in H's information section) -- Both versions provide for planning information to be prepared, S. provides it to be forwarded to the States after each lease sale while H provides that the summary of data is to be available as soon as information is received periodically.

19. Limitations on Export -- Both provisions provide for limitations on export in the same manner.

*20. Restrictions on Employment -- H. alone contains a provision that limits the ability of an employee or an officer of the Department of the Interior, above GS-16, to work within two years for any company subject to regulation by the Interior Department.

21. Lease Terms (amended Section 5) -- Both bills revise the various bidding systems with certain minor differences. S. provides minimum royalty of 16 2/3, while H. provides a minimum royalty of 12 1/2 percent; S. provides a minimum net profit share of 60 percent while H. provides a minimum net profit share of 30 percent; for percentage leasing systems, S. provides for bids on the basis of highest price per share, while H. provides for averaging of bid shares; S. provides for a work program bid, based on specific activities to be undertaken, while H. does not include such a bidding option; S. provides for a bidding system with matching exploration grants to accompany bids on the cash bonus system where H. does not contain this provision.

Both versions allow deferment of any cash bonus, but S. allows deferring to be for three years while H. allows it to be for five years. H. alone allows decreasing royalty or net profit share to promote increased production.

Both S. and H. provide for an evaluation of net profit share, but S. requires that a net profit share be determined individually for each lease area, while H. allows it to be done generally by regulation.

As to the percentage leasing system, both provide that the United States is a non-voting party to any joint working group, but H. alone describes detailed procedures for averaging out the bids, and offering additional percentages.

S. provides generally that the systems are to be used to accomplish the objectives of the Act, while H. provides detailed considerations for use of bidding systems.

H. alone allows more than one bidding system to be used in a particular lease area.

S. provides for 50 percent of new leasing systems to be utilized in frontier areas unless the Secretary decides not to use 50 percent and neither House disapproves that decision while H. provides for 33 1/3 percentage use of new systems which can only be overridden by the Secretary if one House approves, pursuant to an expedited procedure.

*S. also alone contains a specific provision requiring that one of the percentage leasing systems, and one other new system, must be utilized in sales in undeveloped areas in the next two years.

H. specifically requires a report to be prepared by the Secretary as to the use of the bidding systems, detailing all the information to be required and evaluation of effectiveness.

*S. does not allow joint bids under the percentage leasing while H. has a more detailed procedure as to limitations on all joint bidding, of 1.6 million barrels or less a year, pursuant to regulation.

*S. provides for leases to cover whole areas containing geological structures or traps to the maximum extent practicable, or a reasonable economic unit while H. provids for tracts of 5,760 acres, unless the Secretary wants a larger area so as to comprise a reasonable economic and production unit.

S. provides for a lease of five years, or to encourage exploration in deep water adverse weather conditions, for ten years, while H. provides for a lease of five years, and capabiity, if a provision is in the original lease, to extend for five additional years in areas of unusually deep water or adverse weather conditions.

S. specifically requires a provision in the lease describing the ability of the Secretary to require increased production, while H. does not contain such provisions (as is this is already authorized by Energy Act).

*H. alone provides that the lease shall contain a provision detailing that it can be suspended or cancelled in appropriate circumstances as detailed in the Act, and that a lease is conditioned upon satisfaction of due diligence requirements.

*H. provides that a lease is not to be issued or extended for five additional years until notification is given to the Attorney General or the FTC who can say that granting the lease or extension would maintain a situation inconsistent with the antitrust laws. In such a situation, the Secretary is to held a hearing to balance the infringement on competition against the overall benefit to the public.

*H. also alone contains a provision, providing that no lease is to be issued or extended if there is a finding that a lessee is not meeting due diligence requirements on other leases.

*H. alone contains a provision providing for joint leasing in areas within three miles of a seaward boundary of a coastal state and for resolutions of disputes as to resources that might be in both federal and state waters.

22. Royalty Oil and Gas (New Section) -- Both versions allow oil and gas to be taken in kind, as a royalty, but H. specifically states that net profit share can be taken in oil and gas.

Both allow 16 2/3 percent by volume of hydrocarbons to be purchased by the United States, but H. provides that the government can only purchase that amount if the, and to the extent that, the royalty or net profit share is not 16 2/3.

H. specifically provides that title to the royalty or net profit share purchased oil and gas can be transferred to other federal agencies.

Both versions provide for disposition of federal royalty oil on the basis of competitive bidding, but H. alone specifically provides that if there is a regulated price, or a required allocation, it is to be in accordance with those regulatory provisions.

*S. provides that participation in sales can be limited to an "independent refiners", while H. provides that participation can be limited to "small refiners" defined in the section as those companies so designated by the Small Business Administration.

Both provisions provide for disposition of federal royalty gas to the highest bidder and allow limitations so as to have it to needy regional geographic areas, but H. specifically provides that this is to be in accordance with, and not in conflict with, the regulated price or allocation procedures established by the FTC and other agencies.

23. Development of Production Plans (New Section) -- Both versions provide for development and production plans.

S. provides for plans to be prepared by all lessees prior to development and production, while H. requires to be prepared by lessess only in those regions where there is no development prior to January 1, 1975.

S. provides for the plan itself to contain information about offshore activities and onshore impact, while H. provides for the plan only to involve offshore activities and a statement of information to be prepared as onshore impact. H. alone specifically provides that the Secretary is to forward, within 10 days of receipt, the plan and statement to the governor and make it available to the public.

S. provides that the plan is to contain a commitment to produce at a maximum efficient rate, with the ability to secure a waiver from the Secretary; while H. provides that production is to be in accordance with rules and orders as established by law, and if no rule or order is established at a rate to be set by the Secretary to assure "maximum rate of production which is efficient and safe."

*H. alone specifically requires a finding by the Secretary as to whether the development and production in an area is a major federal action, requiring NEPA procedures, and requires the Secretary to declare that a lease sale, at least once prior to major development in any area where there has not been development, to be a major federal action.

S. provides that the Secretary determine and tentatively approve a plan and transmit it to states with all other information and that a lessee can proceed with development based on such tentative approval. H. provides for no such tentative approval.

If NEPA does not apply, H. provides for comments to be forwarded within 90 days by a governor or any other person to the Secretary and for the Secretary to approve or disapprove a plan within 120 days after receiving all the comments. While S. provides for public hearings 60 days prior to approval or disapproval of a plan with sufficient opportunity to participate, and states no particular time period for decision.

H. specifically details that if development is a major federal action, a draft EIS is to be sent to the governors, regional boards, and other affected persons for review and comment and that after the final environmental impact statement is prepared the Secretary must act within 60 days, while S. provides merely that the plan is to be made available to the general public not less than 60 days prior to any public hearing.

Both versions allow the Secretary to require modifications of a plan if they don't insure safe operations but S. provides that no modification is to be included if it is inconsistent with the valid exercise of authority by the state or subdivision while H. did not contain such a provision because the H. D&P plan, by definition, has only to do with offshore operations.

Both versions detail procedures for disapproval of a plan and H. contains a provision that disapproval can be had without compensation, if it is not consistent with the Coastal Zone Management Act.

H. alone specifically contains a provision that disapproval means that a lease is to be extended for five years, that new plans can be requested and that if disapproval occurs, and five years later there is still no action on the lease, and no new plan approved, the lease is to be cancelled and a certain stipulated cancellation compensation is to be paid.

Both provisions provide for periodic review of a plan and possible revisions. S. specifically provides the situations where revisions will be allowed when requested by the lessee, while H. provides so long as the revision is not inconsistent with the Act it should be accepted.

Both versions provide that failure to comply with the approved plan shall terminate the lease, but H. alone provides that failure to submit a plan in accordance with regulations shall also terminate the lease, and specifically provides the right to a hearing and judicial review, and states that failure to comply with the plan would not entitle a lessee to compensation.

S. provides that lessees are to design and implement a program to obtain maximum efficient rates of production; while H. does not contain such a provision as the requirement is in the Energy Act.

H. alone contains a provision that allows a development and production plan to be submitted to not just the Secretary of the Interior but also to the FPC and the FPC to approve those portions having to do with transportation of natural gas.

24. Exploration (amended Section 11) -- S. provides for a $500,000,000 exploration program, and does not allow any type of exploration unless there is a permit issued by the Secretary. H. provides for no such program, but does require applicants to be sought for on structure drilling, and allows any agency of the United States and any person to conduct exploration either by permit or pursuant to regulation.

S. separates out the confidentiality requirements as to permittees and provides that all information is to be given to the Secretary and confidentiality is to be maintained until there is a lease sale, or until it would not effect the competitive position of the permittee, while H. provides for the same procedures as to confidentiality for lessees and permittees, grants access after a lease sale to any information by a state representative and precludes transmission unless consented to by the permittee or lessee.

H. contains a provision requiring an exploration plan to be prepared by the lessee which would detail work to be done and also have attached a statement of information as to onshore impact. Such plan would be reviewed by the Secretary and could be modified. Disapproval could only occur under certain circumstances which would allow cancellation under a newly amended section 5.

25. Administration (amended Section 5) -- S. retains the original language of the OCS Lands Act as to authority to issue regulations, while H. grants broader authority to prescribe regulations, including as part, the original language of the OCS Lands Act.

*H. alone provides that regulations are to be applicable to any lease issued or maintained under the Act, requires such regulations to be prepared in cooperation with relevant agencies, and as to competition, requires consultation with the Attorney General.

H. also alone specifically provides procedures for the suspension and temporary prohibition of an activity; for cancellation of a lease or permit for environmental reasons, after a five year suspension and with compensation, and details regulations to be included to implement certain requirements of the Act.

H. also includes provisions noting that issuance or continuance of a lease is to be dependent upon compliance with the regulations (as in the original OCS Lands Act and thus retaining in S.); provides that a lease can be cancelled for failure to comply with the Act, if a lease is producing, or if the lease is nonproducing, reincludes the provisions as to rights of way through submerged lands (all as in the original OCSLA and thus retained in S.).

26. Definitions (amended Section 2) -- Both versions include many new definitions, but H. alone includes a new definition of lease to include "any form of authorization;" does not include "coastal state", but does add a definition for "affected state" which is to comment on particular activities and programs. S. and H. both provide definitions for marine and coastal environment but H. alone adds a definition of human environment relating to the social infrastructure and adds definitions for governor, antitrust law, fair market value, and major federal action, while S. alone defines "maximum efficient rate of production".

27. Laws Applicable (amended section 4) -- H. contains a provision changing certain terms to be consistent with the Geneva Convention, providing for an updating of applicable state criminal law as they are enacted and state civil laws every five years, requiring the President to determine within one year boundaries between states and to seek to resolve international boundary disputes, and requiring the Coast Guard to mark navigational hazards when the owner has failed to so mark, rather than as an existing law (and thus in S.) merely authorizing it to so mark.

TITLE III

28. Miscellaneous Provisions -- S. contains and H. does not, a provision for a pipeline safety and operations, study and report within one year.

Both versions contain provisions for review of shut-in or flaring wells, and for a review and revision of delinquent royalty payments. H. alone

contains a new provision providing for the ability of a natural gas distributing company to have any gas found on a lease which it owns to be sent back to its service area, adds provisions prohibiting discrimination and requiring affirmative action, and requiring all rules and regulations to be submitted to Congress and to be capable of being disapproved by either House of Congress within 60 days. Both versions indicate that the Act is not to repeal any provisions above the laws, unless expressly provided, and S. alone has a severability clause.

29. Funding -- S. contains a provision amending the Mining and Mineral Policy Act giving 22 1/2 percent more money to the states, and amending the Coastal Zone Management Act providing for a coastal facility impact program to pay for OCS and energy facility siting impact -- both of which are not contained in the House version.

30. Other Miscellaneous Provisions -- S. alone contains provisions limiting the ability of the FEA to stop new retail gas outlets, limiting the ability of the Administrator of the FEA to reduce the allocation of retail gasoline sales, requiring the FEA to submit reports about its oil entitlement program and the regional impact of such program, requiring the Secretary of the Interior to submit a comprehensive plan for effective and efficient use of royalty natural gas to meet emergency shortages of natural gas.

FEDERAL REGULATION OF OPERATING PROCEDURES

Introduction

The Interior Department's U.S. Geological Survey is the primary agency regulating OCS development and production activities.

USGS regulations for each phase of exploration, development, production, and transportation of oil and gas on the OCS are set forth in "orders"; there is a set of orders for each area supervised by the agency. For instance, there is a detailed set of twelve orders for the Gulf of Mexico area.[3] These regulations set forth requirements on what technologies and operating procedures companies are to use; the idea behind the regulations is to promote safety and minimize pollution. Seven similar orders for the mid-Atlantic region have been issued recently, and more will follow.[4]

In the past such orders were rarely controversial. However, in recent years--and especially since the 1969 oil spill in California's Santa Barbara Channel--there has been considerable debate over (1) the safety and environmental soundness of OCS technology and operating procedures, (2) the adequacy of USGS management practices by which these orders are prepared, enforced, and updated.

3/ U.S. Department of the Interior, Geological Survey, Conservation Division, OCS Orders 1 thru 12 Governing Oil, Gas, and Sulphur Leases in the Outer Continental Shelf, Gulf of Mexico Area.

4/ U.S. Department of the Interior, Geological Survey, "Mid-Atlantic Area Final Orders; (1 through 5, 7, and 12)," Federal Register, Vol. 41, No. 134--Monday, July 12, 1976.

Largely as a result of this concern, six major studies were done in the early 1970's on OCS technology, regulations, and management practices. These produced numerous recommendations, many of them directed toward the Department of the Interior. In addition, recommendations also have come from a USGS working group which reviewed three of the studies, and from a National Research Council Marine Review Board.

This section of the working paper describes these various studies and recommendations: the actions taken by the Interior Department, other Federal agencies, and the petroleum industry since these studies were published; and the main points about the new USGS orders for OCS operations in the mid-Atlantic region.

Six Studies

Six studies have been conducted in the 1970's which focus on the improvement of offshore petroleum technologies and regulations. This section generally describes and compares the six studies in terms of their objectives, how they were conducted, and their conclusions. TABLE II-1 presents a summary of this information.

1. NASA Study Applicability of NASA Contract Quality Management and Failure Mode Effect Analysis Procedures to the USGS Outer Continental Shelf Oil and Gas Lease Management Program - (November, 1971)

a. General Information

The National Aeronautics and Space Administration study was funded by the U.S. Geological Survey in accordance with an agreement between the Director, USGS, and the NASA George C. Marshall Space Flight Center. The study was designed to satisfy the need for identification and recommendation of steps to improve the

	NASA STUDY	LMS STUDY	NAE STUDY
SCOPE OR PURPOSE	APPLICABILITY OF NASA PROCEDURES TO OCS OIL AND GAS MANAGEMENT	DESCRIBE OCS LEASE MANAGEMENT PROGRAM OF THE USGS AND GIVE RECOMMENDATIONS FOR INCREASING EFFECTIVENESS OF SAFETY AND POLLUTION PREVENTION	REVIEW OF OCS OPERATIONS TO MINIMIZE OIL SPILLS
DURATION	2 MONTHS	UNKNOWN	16 MONTHS
TEAM COMPOSITION	(5) ENGINEERS-AEROSPACE (1) LIAISON-USGS	(7) MEMBERS OF THE SYSTEMS LAB GROUP, WATER RESOURCES DIVISION USGS	(5) EXECUTIVES-INDUSTRIAL, (2) ENGINEERS-MARINE, (1) ENGINEER-PETROLEUM, (1) LIAISON-COAST GUARD (1) INTERIOR
REQUESTED BY	USGS	USGS	DEPARTMENT OF INTERIOR
CONCLUSIONS	1. TECHNOLOGIES CHARACTERIZED BY AN ABSENCE OF FORMAL QUALITY CONTROL ORGANIZATIONS AND PROCEDURES. 2. SIGNIFICANT PROGRESS HAS BEEN MADE IN THE PAST TWO YEARS IN ACHIEVING SAFER OPERATIONS. 3. "PRODUCTION FIRST" PHILOSOPHY HAS DELAYED PROBLEM RESOLUTION. 4. BASIC NASA CONTRACT APPROACHES ARE APPLICABLE TO OCS OPERATIONS. 5. HAZARDS ANALYSIS IS APPLICABLE TO OCS OPERATIONS. CURRENT DESIGN DOCUMENTATION IS INADEQUATE. 6. NO CHANGES IN LAW REQUIRED TO IMPLEMENT NASA PROCEDURES. 7. OCS ORDERS ARE DEVELOPING IN THE RIGHT DIRECTION TO PROVIDE ESSENTIAL GUIDANCE TO INDUSTRY. HOWEVER, GREATER STANDARDIZATION IS NEEDED, AND ORDERS REQUIRE FURTHER REVISION.	1. THE INSPECTION PROGRAM AND [2] THE PRESENT ENFORCEMENT POLICY APPEAR TO HAVE BEEN PARTIALLY EFFECTIVE. 2. RE-INSPECTIONS APPARENTLY HAVE LITTLE EFFECT ON THE BEHAVIOR OF THE OPERATOR OR OF THE COMPANY. 3. A STRONGER ENFORCEMENT POLICY AND NEW METHODS OF INC REDUCTION ARE NEEDED TO KEEP THE RISKS ASSOCIATED WITH PRODUCTION OPERATIONS WITHIN BOUNDS ACCEPTABLE TO THE PUBLIC INTEREST.	1. PRESENT TECHNOLOGY IS ADEQUATE TO SUPPORT CURRENT OPERATIONS. 2. IMPROVEMENTS ARE POSSIBLE IN DAMAGE CONTROL AND FIRE FIGHTING. 3. NUISANCE SPILLS CAN BE ALMOST ELIMINATED WITH PRESENT METHODS. 4. MOST OIL RELEASES ARE CAUSED BY ACCIDENTS OF ERROR AND EQUIPMENT. 5. OIL SPILLS HAVE TEMPORARY EFFECTS, BUT LITTLE AGREEMENT EXISTS ON LONG-TERM EFFECTS. 6. OCS ORDERS HAVE BEEN EFFECTIVE BUT THE CRITERIA OF EFFECTIVENESS ARE VAGUE. 7. GOVERNMENT INSPECTORS LACK STANDARDS, RESULTING IN REQUIREMENTS FOR AD HOC JUDGMENTS. 8. THE OCS INDUSTRY SUFFERS FROM A LACK OF PUBLICLY RECOGNIZED STANDARDS. 9. INDIVIDUAL COMPANIES OFTEN HAVE COMPLETE AND HIGH-QUALITY STANDARDS. 10. INDUSTRY/GOVERNMENT RELATIONS ARE CLOSED TO PUBLIC VIEW; INDUSTRY RESEARCH IS HELD PRIVATE. 11. ACCIDENT DATA ARE GENERALLY UNAVAILABLE. 12. ALTHOUGH SKILLED PERSONNEL ARE REQUIRED, TRAINING IS LIMITED IN SCOPE.

[1] ACKNOWLEDGEMENT IS GIVEN TO TABLES 39 AND 40, ENERGY UNDER THE OCEANS, PP. 350 AND 353. ADDITIONAL INFORMATION PROVIDED BY THE BDM CORPORATION

[2] SELECTED CONCLUSIONS

[3] SELECTED CONCLUSIONS

[4] "STATEMENT OF PRINCIPLES," OCS OIL AND GAS (CEQ), P. 2

TABLE II-1 Summary of OCS Studies[1]

OU STUDY	GAO STUDY	CEQ STUDY
ASSESSMENT OF TECHNOLOGIES AND IN OCS OIL AND GAS OPERATIONS	OBTAIN DATA ON CERTAIN OCS OIL SPILLS AND REVIEW INTERIOR'S INSPECTION AND REGULATION OF OCS OIL OPERATIONS	STUDY ENVIRONMENTAL IMPACT OF OIL AND GAS PRODUCTION ON ATLANTIC OCS AND IN THE GULF OF ALASKA
20 MONTHS	UNKNOWN	12 MONTHS
(1) BIOLOGIST, (2) ENGINEERS-AEROSPACE, (1) ENGINEER-INDUSTRIAL, (1) LAWYER, (1) PHYSICIST, (2) POLITICAL SCIENTISTS	GAO	CEQ + FEDERAL INTRA-AGENCY GROUPS AS MONITORS
RANN DIVISION OF THE NATIONAL SCIENCE FOUNDATION	CONSERVATION & NATURAL RESOURCES SUBCOMMITTEE OF THE COMMITTEE ON GOVERNMENT OPERATIONS - HOUSE OF REPS.	APRIL 18, 1973, PRESIDENTIAL MESSAGE
1. OCS OPERATIONS ARE NOT TECHNOLOGY DRIVEN. TECHNOLOGICAL CHANGES HAVE BEEN EVOLUTIONARY AND INCREMENTAL. 2. UNTIL RECENTLY, THE GOVERNING CRITERION OF TECHNOLOGICAL DEVELOPMENT HAS BEEN ECONOMICS. 3. RECENT SAFETY AND ENVIRONMENTAL DEMANDS SERIOUSLY CHALLENGE THE PRESENT SYSTEM FOR MANAGING OCS DEVELOPMENT. PARTICIPATION HAS BEEN LIMITED TO INTERIOR AND THE PETROLEUM INDUSTRY. 4. SELECTED PHYSICAL TECHNOLOGIES PRESENTLY BEING USED ON THE OCS NEED TO BE IMPROVED OR MORE WIDELY UTILIZED. HOWEVER, INDUSTRY'S STATE OF THE ART TECHNOLOGICAL CAPABILITIES ARE ADEQUATE TO MEET NEW SAFETY AND ENVIRONMENTAL REQUIREMENTS. 5. THE MAJOR PROBLEMS TO BE RESOLVED FOR OPTIMAL OCS DEVELOPMENT ARE MANAGERIAL. 6. EFFECTIVE MANAGEMENT REQUIRES MORE ADEQUATE RESOURCE AND IMPACT DATA, MORE EFFECTIVE COOPERATION AND COORDINATION BY RESPONSIBLE AGENCIES IN PLANNING AND POLICY-MAKING - AND A SPECIFIC STATEMENT OF THE PORTION OF ENERGY DEMAND TO BE SUPPLIED BY THE OCS. 7. OCS DEVELOPMENT IS SOCIALLY PREFERABLE TO INCREASED IMPORTS AND TAPS.	1. INSPECTIONS IN THE GULF COAST[3] REGION DID NOT ALWAYS FOLLOW PRESCRIBED REGIONAL ENFORCEMENT ACTIONS. CONSISTED OF ONLY WRITTEN WARNINGS AND WERE NOT ALWAYS EFFECTIVE IN OBTAINING PROMPT CORRECTION AND DEFICIENCIES. 2. EXCEPT FOR INSPECTIONS OF PRODUCTION OPERATIONS, THE SURVEY HAD NO WRITTEN POLICIES ON HOW FREQUENTLY OCS OPERATIONS WERE TO BE INSPECTED. 3. THE SPECIAL WORK GROUP ASSIGNED BY THE SURVEY TO EVALUATE THE RECOMMENDATIONS OF THREE STUDIES OF OFFSHORE OIL OPERATIONS HAS PROPOSED IMPLEMENTING ACTIONS. SUCH ACTIONS SHOULD IMPROVE THE SURVEY'S REGULATION AND INSPECTION FUNCTION.	1. EXPLORATION AND DEVELOPMENT OF THE OCS[4] MUST TAKE PLACE UNDER A POLICY WHICH PUTS VERY HIGH PRIORITY ON ENVIRONMENTAL PROTECTION. 2. THE LOCATION AND PHASING OF OCS LEASING SHOULD BE DESIGNED TO ACHIEVE THE ENERGY SUPPLY OBJECTIVES OF THE LEASING PROGRAM AT MINIMUM ENVIRONMENTAL RISK. 3. THE BEST COMMERCIALLY AVAILABLE TECHNOLOGY MUST BE USED TO MINIMIZE ENVIRONMENTAL RISKS IN NEW OCS AREAS. 4. REGULATORY AUTHORITIES AVAILABLE TO FEDERAL AGENCIES MUST BE FULLY IMPLEMENTED AND REQUIREMENTS STRICTLY ENFORCED TO MINIMIZE ENVIRONMENTAL RISKS IN NEW OCS AREAS. 5. PLANNING AT ALL PHASES OF OCS OIL AND GAS OPERATIONS MUST RESPECT THE DYNAMIC RELATIONSHIP BETWEEN INITIAL FEDERAL LEASING DECISIONS AND SUBSEQUENT STATE AND LOCAL COMMUNITY ACTION. THE STATES AND THE COMMUNITIES AFFECTED MUST BE GIVEN COMPLETE INFORMATION AS EARLY AS POSSIBLE SO THAT PLANNING CAN PRECEDE AND CHANNEL THE INEVITABLE DEVELOPMENT PRESSURES. EXPERIENCE MUST BE CONTINUOUSLY INTEGRATED INTO THE MANAGEMENT PROCESS. 6. THE INTERESTED PUBLIC MUST BE GIVEN THE OPPORTUNITY TO PARTICIPATE AND PLAY A MAJOR ADVISORY ROLE IN THE FEDERAL MANAGEMENT AND REGULATION OF THE OCS.

ABREVIATIONS

INC = INCIDENT OF NON-COMPLIANCE
TAPS = TRANS-ALASKA PIPELINE SYSTEM

TABLE II-1 Summary of OCS Studies[1] (Continued)

safety and pollution control of offshore oil recovery operations. The duration was two months, from August 16, 1971 to October 8, 1971.

b. Objectives & Conduct of the Study

The broad objective of the study was to examine the feasibility of improving the reliability of safety and antipollution equipment used in offshore oil operations through the use of NASA advanced engineering techniques. The specific objectives as outlined in the study[5] were to determine:

(1) The practicality of adopting NASA contractual quality management (QC) techniques to the USGS/OCS lease management functions

(2) The applicability of Failure Mode and Effect Analysis (FMEA), to the drilling, production, and delivery systems in use offshore

(3) The impact on industrial offshore operations and onshore management operations required to carry out a full-scale investigation and systems design for either QC or FMEA programs

(4) The probable changes in law or regulation required for either the full-scale investigation or implementation of either program to offshore operations.

5/ Morris Dyer, et. a., Applicability of NASA Contract Quality Management and Failure Mode Effect Analysis Procedures to the USGS Outer Continental Shelf Oil and Gas Lease Management Program, (NASA, Washington, 1971, p.1.

The study team was composed of five NASA engineers with extensive backgrounds in aerospace technology and systems safety and a USGS representative.

The study team interviewed personnel and viewed operations in managerial, manufacturing, and oil production facilities, concentrating on 16 subject areas. These included, for example, enforcement, specifications, organization, inspections, analysis, and procurement. The applicability of established NASA procedures was considered. Finally, the NASA team observed the extent to which formal quality control organizations and procedures are used in the OCS and how inspection is used in quality control. The progress that has been made in achieving safe operations was noted as was the general philosophy of production operations. Specific hazards, such as with fuels and corrosion, for example, were identified. The 30-page report containing recommended changes in USGS and operator activities has been widely disseminated throughout the industry and has been generally well-received.[6]

2. LMS Study - Outer Continental Shelf Lease Management Study, USGS (May, 1972)

a. General Information

The Lease Management Study was proposed by the Office of Management and Budget (OMB) and authorized by the Director of USGS in August, 1970. The study group convened in September, 1970.

6/ Don Kash, et.al., Energy Under the Oceans, (Norman: 1973), pp. 350-353.

b. Objectives and Conduct of the Study

The study was conducted by the Systems Laboratory Group, Water Resources Division, USGS, which consisted of seven members assisted intermittently by three additional members.

The report describes the OCS Lease Management Program of the USGS and sets forth recommendations for increasing the effectiveness of the program in achieving the objectives of safety and pollution prevention. The major part of the program is concerned with exploration and development operations for oil and gas in the Conservation Division's Gulf Coast Region. While the study dealt with the management of Federal leases in this region, the study's findings are generally applicable to the management of Federal leases on other Outer Continental Shelf Lands. The range of possible alternatives considered includes those which might require changes in the legislation governing oil and gas operations on OCS lands.[7]

3. NAE Study - Outer Continental Shelf Resource Development Safety: A Review of Technology and Regulation for the Systematic Minimization of Environmental Intrusion from Petroleum Products, National Academy of Engineering (December, 1972)

a. General Information

The National Academy of Engineering study was initiated in response to a request from the Department of the Interior for a special study on operational safety in offshore resources development. The duration was 16 months, from May, 1971 to August, 1972.

7/ OCS Lease Management Study: Safety and Pollution Control, May 1972, pp. i, 1-1.

b. Objectives and Conduct of the Study

The purpose of the NAE study was to recommend reasonable technical and regulatory procedures to minimize petroleum intrusions into the marine environment. Utilizing the NASA study as an element of its data base, the NAE review dealt with certain problems of management of technology but did not address itself to the broader issues of the management and control of OCS resource development.[8]

An eight-man panel of experts in offshore oil operations and technology, marine technology, government, and industry safety was convened by the NAE Marine Board. It included three presidents of marine engineering companies and vice presidents from Westinghouse Electric Corporation and Esso Production Research Company. The U.S. Coast Guard and the Department of the Interior provided liason members of the panel who participated in most of the sessions. The panel met in ten working sessions which combined field trips and meetings with government agency and industry spokesmen. The panel co-sponsored (with the U.S. Department of the Interior) an all-day technical session at the 1972 Offshore Technology Conference. Members were exposed to a broad range of opinions, data, and conclusions about the necessity of offshore oil recovery, the degree of biological and aesthetic degradation of the environment that has been produced or that can be tolerated, the adequacy of present offshore oil technology and regulations, the cost-benefit relationships of alternative energy sources, the magnitude and effects of other sources of oceanic

8/ Op.cit., Energy Under the Oceans, pp. 350-353.

environmental intrusions, and even the actual social benefit likely to result from putting various recommendations into effect.[9]

Petroleum (oil and natural gas) extracted under the jurisdiction of the Outer Continental Shelf Lands Act is the only resource that the panel considered. The 197-page report published by the NAE Maring Board in December, 1972 has been widely circulated.

4. OU Study - Energy Under the Oceans, A Technology Assessment of OCS Oil and Gas Operations, University of Oklahoma, April, 1973.

a. General Information

The University of Oklahoma Technology Assessment was supported by a grant from the Research Applied to National Needs (RANN) Division of National Science Foundation. The duration of the study was 20 months, beginning September, 1971 and ending April, 1973.

b. Objectives & Conduct of the Study

The stated objective of the study was to impartially "assess the adequacy and impacts of OCS petroleum technology and to recommend new equipment, procedures, and policies for optimal development of OCS oil and gas resources."[10]

The core research team was drawn entirely from the University of Oklahoma. The eight-man team was composed of experts in the social, physical, and life sciences as well as engineering and law, representing

9/ Outer Continental Shelf Resource Development Safety, (National Academy of Engineering: 1972), pp. v, vi.

10/ Op.cit., Energy Under the Oceans, pp. 349-350.

one of the first attempts at technology assessment as a means of providing a broad, interdisciplinary overview of problem areas.[11]

Background data for the study were collected following a series of briefings by government and industry representatives, field trips to offshore drilling and production facilities, and interviews with petroleum company personnel. The team also participated in a five-day Engineering Foundation Conference, taking the opportunity to discuss OCS technologies and their impacts, the consequences of alternatives were examined and a general management system was defined. The NASA study was an element of the data and the NAE Review was examined during the final portion of the study. The final publication, Energy Under the Oceans, has been widely circulated.

5. GAO Study - Improved Inspection and Regulation Could Reduce the Possibility of Oil Spills on the Outer Continental Shelf, USGS (June, 1973)

a. General Information

The study by Congress' General Accounting Office was initiated by a request of the Conservation and Natural Resources Subcommittee of the Committee on Government Operations, U.S. House of Representatives.

b. Objectives and Conduct of the Study

The objectives as defined by the Subcommittee Chairman required GAO to:

(1) Obtain data on certain oil spills on the OCS, including that on the responsibility for cleanup, damage, and enforcement actions

11/ Ibid, p. 352.

(2) Review the adequacy of Interior's inspection and regulation of OCS oil operations.

At the direction of the Chairman's office, GAO did not obtain formal comments from Interior; however, it did discuss these matters with Department officials.[12] The study presents a critical review of OCS regulatory and inspection procedures and includes recommendations designed to achieve more effective capability and procedures.[13]

6. CEQ Study - OCS Oil & Gas: An Environmental Assessment--A Report to the President by the Council on Environmental Quality (April, 1974)

a. General Information

The Council on Environmental Quality study was initiated in response to the President's Energy Message of April 18, 1973 in which the President announced his decision to defer any drilling on the Atlantic OCS and in the Gulf of Alaska until a study of the environmental impact of oil and gas production in these areas could be carried out. CEQ's report was completed in April, 1974.

b. Objectives and Conduct of the Study

CEQ worked with the Environmental Protection Agency, the National Academy of Sciences, other Federal agencies, governors, legislators, and citizens of the Atlantic States and Gulf of Alaska area in assessing the impact of oil and gas production on the OCS. Federal interagency working groups were formed to develop the scope of work and to monitor the progress of the study.

12/ Improved Inspection and Regulation Could Reduce the Possibility of Oil Spills on the OCS, (Geological Survey: June, 1973), p. 1.

13/ Ibid, p. iv.

In carrying out the President's directive, CEQ reviewed the environmental impacts in broad terms. The study focuses on a number of hypothetical drilling sites in areas considered by geologists to be particularly promising for oil and gas discovery. The potential impact on the marine environment of developing these sites, as well as the likely onshore impacts of industrialization and growth related to processing oil and gas were anlayzed. The report includes chapters assessing the technology of oil and gas production and the institutional and legal mechanisms for managing OCS development.[14]

In conducting the study, CEQ held public hearings in Washington, D.C., Alaska, and various cities on the Atlantic Coast. Representatives of environmental groups and of industry were consulted and kept advised of the study's progress. An advisory committee representing the Governor of each Atlantic coast State and Alaska was established and on three occasions met with the Council to review progress. Much of the research and information contained in the report was developed through contracts with universities and private consulting firms working with the Council and a number of Federal interagency working groups. A special panel of the National Academy of Sciences (NAS) performed a critique of the study.[15]

Two Working Groups

1. Recommendations of the Work Group on OCS Safety and Pollution Control

14/ OCS Oil and Gas: An Environmental Assessment, (Council on Environmental Quality: April 1974), p. iii.

15/ Ibid, p. iv.

The six studies made several recommendations, most of which were directed at the Department of Interior.

The Director, U.S. Geological Survey, appointed a Work Group to review the findings of the three studies conducted at the request of the Geological Survey on improving safety and pollution control in the management of Outer Continental Shelf Oil and Gas Operations and to recommend appropriate implementation actions. Their first report (May, 1973) was not only responsive to the specific recommendations of these three studies, but also reflected findings from meetings with personnel from the American Petroleum Institute, the Offshore Operators Committee, the Western Oil and Gas Association, a panel of the Marine Board, National Academy of Engineering, NASA, Occupational Safety and Health Administration, the Department of Interior's Office of the Solicitor, and others.[16]

Two supplements to the first report have been issued in response to recommendations of two of the studies: Energy Under the Oceans, Technology Assessment of Outer Continental Shelf Oil and Gas Operations, published in November 1973; and OCS Oil and Gas - An Environmental Assessment, published in April, 1974. For these studies, Work Group responses were only made to those recommendations which pertained to safety and pollution control and over which the U.S. Geological Survey had some control or responsibility.

16/ Report of the Work Group on OCS Safety and Pollution Control, (USGS: May, 1973), p. 3.

2. Recommendations of the Marine Board of Review Committee on Safety of OCS Petroleum Operations

The Review Committee on Safety of Outer Continental Shelf Petroleum Operations operates under the auspices of the Assembly of Engineering of the National Research Council.[17] It was established in July 1973 at the request of the U.S. Geological Survey on matters relating to safety and pollution control in petroleum operations on the outer continental shelf.[18]

In its first report to the United States Geological Survey (USGS), issued in March 1974, the Review Committee on Safety of Outer Continental Shelf Petroleum Operations addressed five areas:

(1) Standards and specifications;

(2) Applicability of systems analysis techniques to offshore gas and oil operations;

(3) The safety alert system of the USGS;

(4) A proposed revision to OCS Order No. 8 (Approval Procedure for Installation and Operation of Platforms, Fixed and Mobile Structures, and Artificial Islands) to include caisson-like structures; and

(5) A preliminary look at environmental baseline studies in support of offshore oil and gas operations.[19]

17/ Prior to 1 July 1974, the Marine Board's affiliation was within the National Academy of Engineering.

18/ First Report of the Review Committee on Safety of Outer Continental Shelf Petroleum Operations to the United States Geological Survey, (Marine Board of the National Academy of Engineering: January, 1974), Appendix A.

19/ Third Report of the Review Committee on Safety of Outer Continental Shelf Petroleum Operations to the United States Geological Survey, (Marine Board, National Research Council: March, 1975)

The second report, issued in June 1974, focused on three issues:

(1) Policy and program planning by the USGS for the assurance of safety and pollution control in OCS petroleum operations;

(2) Implementation actions and priorities established by the USGS on the basis of safety study recommendations; and

(3) Application of system analysis techniques to offshore oil and gas operations.[20]

The third report, issued in March 1975, concerned three topics:

(1) Standards development for OCS operations;

(2) Inspection strategies for use in the OCS; and

(3) Methods for determining the condition of existing pipelines.[21]

Summary of Recommendations

Summary tables have been made of the relevant recommendations of the six studies cited earlier and those of the USGS Work Group and Marine Board. To facilitate presentation, eleven categories have been chosen to designate areas of concern. These categories represent a combination of categories used in Energy Under the Oceans, and those of the USGS Work Group on Safety and Pollution Control.[22] Additional categories were chosen to reflect current socio-political concerns. In several cases, a recommendation did not fit any one of the

20/ Ibid.

21/ Ibid.

22/ Memorandum from the Chief of the Conservation Division to the Director of the Geological Survey on the subject of Implementation of the Recommendations of the Work Group on OCS Safety and Pollution Control, 9 June 1973 as cited in the Second Report of the Review Committee on Safety of Outer Continental Shelf Petroleum Operations to the United States Geological Survey, January, 1974.

eleven categories exclusively, so subjective decisions for placement within categories were made. It is noted that the initial 15 recommendations of the Work Group were revised to reflect responses to the University of Oklahoma and the CEQ studies. In these cases, the Work Group revisions are dated (5/73, 5/74, or 11/74) and/or only the revisions are given. There is no particular pattern to the Marine Board recommendations. Summaries of the recommendations appear as Tables II-2 through II-13 for the eleven categories.

Actions Taken Since the Studies

1. Priorities Assignments of U.S.G.S. on Study Recommendations

Even a cursory glance at the recommendations presented in Tables II-2 through II-13 will show that a great number of the recommendations make specific reference to the Department of Interior, especially the U.S. Geological Survey. Recognizing this, the Director of the Survey placed priorities on the areas of concern expressed in the earlier NASA, Lease Management, and NAE studies.[23]

The U.S. Geological Survey, Gulf of Mexico Area, is taking the lead responsibility for implementation of several of the recommendations. Pacific Area, USGS, personnel are also developing portions of the recommendations and are in the process of developing and revising OCS Orders. The U.S. Geological Survey implementation schedule indicates that all of the 15 recommendations resulting from the initial studies should be fully implemented by late 1975.[24]

23/ Ibid.

24/ Draft Environmental Statement Oil and Gas Development in the Santa Barbara Channel Outer Continental Shelf Off California, (USGS: June, 1975), Vol. 3, p. IV-55.

FUNCTIONAL CATEGORY SAFETY AND ADVISORY

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
LMS: • Establish Offshore Operators Subcommittee on Safety --- Subcommittee and the Survey should periodically review the performance of the Safety Program and exchange information on potential hazards and review program specifications. • A hazard review committee should periodically review reports of accidents, unusual operating conditions, equipment malfunctions, and inspection results, assess the adequacy of the current OCS Orders, and recommend changes in regulations or procedures which would reduce risks of accidents and associated losses to both industry and government. OTHER: The Director, USGS, recommended a review committee be established on safety of OCS petroleum operations to serve as an independent audit of the effectiveness of USGS operations and procedures.	5/73: • Encourage the Offshore Operators Committee (OOC), as well as the Western Oil and Gas Association (WOGA), to establish a committee on safety. This committee can serve as a vehicle for communication between the operators and the Survey in discussions of general problems that arise. • Establish a Systems Review Committee in each area with OCS operations, to be composed of key USGS field personnel. This committee should meet regularly to review accidents, unusual conditions, equipment failures, inspection results, and the adequacy of OCS Orders, and recommend appropriate changes in regulations, orders, and procedures Reports of findings and recommendations should be submitted in writing to the Supervisor, with copies, through channels, to the Director, USGS. Implementation Action Required: The Conservation Division should communicate with the safety committees of OOC and WOGA to maximize their effectiveness. The Systems Review Committees should be established by the Conservation Division. The Director, USGS, should propose items to the review committee for consideration. These would, of course, be additional to items which the committee would determine to consider on its own.	
UO: Industry Cooperation - USGS should actively promote greater industry cooperation in the development of safety, accident prevention, and environmental protection technologies. Industry should be assured that cooperation in these designated areas will not be subject to anti-trust action. This could be accomplished by having the Anti-Trust Division of the Department of Justice issue guidelines for cooperative efforts or by having the Division give opinions on specific proposals. Review Technology - USGS should appoint an independent and representative committee of experts to review state-of-the-art in OCS technologies periodically and recommend desirable changes in equipment and performance standards.	NAR: NO ADDITIONAL RESPONSE	

TABLE II-2 Safety and Advisory Committees

FUNCTIONAL CATEGORY FAILURE REPORTS, ACCIDENT INVESTIGATIONS, AND TESTING

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: It is therefore recommended that USGS lay the groundwork for the type of activity, described above (a closed-loop, failure reporting and corrective-action program), in the drilling and production phase of the oil industry by requiring monthly summaries from each operator of failure causes and corrective action taken for all safety equipment specified by OCS Orders. All accidents and oil spills should follow similar procedures. For the procedure to be effective, its object should be recurrence prevention, with emphasis placed on the determination of causes, preventive action, and follow-up. This recommendation, if adopted, will have a significant impact, primarily due to the change in policy made necessary by the majority of offshore operators. The statement is often made by offshore people that "the only real test of equipment is to place it in service in the Gulf." Whether this is a valid assumption or not, the data from this "test" should be utilized to maximum advantage. The basic philosophy to be followed is that every failure has a cause, every cause can be understood, and every failure can be corrected or alternate procedures provided.	5/73: It is recommended that the USGS require all operators to establish an internal failure-reporting, corrective-action program, to include: (1) an operator's report to the USGS on incidents, problems, and failures which result in fires or reportable oil spills or reportable accidents; (2) the factual circumstances surrounding the incident; and (3) the corrective actions taken. The operator's report to the USGS should be required on a scheduled basis. Data from the reports should be computerized to facilitate analyses and corrective actions. Implementation of this recommendation should not preclude compliance with the existing requirements for immediate reporting of serious accidents, all fires, and spills as specified in 30 CFR 250.43 and 250.45, and pertinent OCS Orders. Implementation Action Required - The Conservation Division should determine the requirements for reporting and include them in OCS Orders. For those cases where the OCS Orders cannot be issued within a reasonable period of time, notices, as appropriate, should be issued to all operators.	
UO: Failure Reporting- USGS should establish improved reporting and systematic analysis procedures for failures, malfunctions, and equipment defects, as well as issue appropriate notices and warnings.		
NAE: The official reports stemming from investigation of major accidents should receive prompt and full public disclosure, and should be available in a readily accessible form. The U.S. Government should directly sponsor, encourage, and provide the means for a public exchange of information on the causes and effects of accidents, and on the performance of specific items of safety-related	5/73: The Work Group agrees with all four recommendations of the NAE Study, i.e.: • Reports of major accidents stemming from the current USGS procedure for investigation of accidents should be made available to the public promptly. • Work Group Recommendation No. 3, calling for a system for disseminating information concerning equipment failures and accidents, should include a means for the public to have access to the information.	

TABLE II-3 Failure Reports, Accident Investigations and Testing Actions

FUNCTIONAL CATEGORY FAILURE REPORTS, ACCIDENT INVESTIGATIONS, AND TESTING

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
equipment in the offshore industry. A careful analysis should be carried out after every major offshore oil spill to determine the precise manner in which the spill occurred--taking into account any equipment failures, personnel errors, or design inadequacies, their causes and what can be done to prevent such future occurrences. The information resulting from accident investigation and evaluation of component performance should be analyzed by a competent organization (similar to the National Transportation Safety Board or the Marine Safety Council), and its conclusions should be made public promptly. CEQ: The Council recommends that the Departments of the Interior and Transportation and the Environmental Protection Agency develop and implement a common reporting system for all accidents associated with OCS operations. This improved system should provide complete unambiguous reporting, with special attention to the analysis of cause-effect relationships.	• Analyses of causes of major oil spills should be made as part of the accident investigation procedure and, if required, by additional follow-up studies. Results of all such analyses should be provided to the Review Committee. • Results of accident investigations, in addition to being made available to the public, should be provided to the Review Committee for possible further analyses. 11/74: The USGS accident reporting system should be modified in conjunction with DOT and EPA to insure compatible formats so that statistical analyses of composite figures may be performed. Implementation Action Required - The Conservation Division should begin immediately to implement the above recommendations. They will need to determine the format and means of disseminating reports to the public and consult with the Solicitor's Office prior to release. Referral of appropriate items to the Review Committee should be done by the Director, USGS. Implementation Action Required (additional to those in May 1973 report) - Liaison should be established with the DOT and EPA to determine what modifications to the systems used by the agencies will be necessary to provide a comprehensive basis for adequate analyses.	3/75: Methods of Inspection of Pipelines- The USGS should set forth a list of the various methods which can be used for partial or complete verifications of integrity of older pipelines and permit the Operator to select from this list that test or group of tests which can be practicably applied and which will reasonably assure the USGS that the line will not be in imminent danger of developing a serious leak within the next two-year period. • Periodic inspection of submarine pipelines should be required. • The USGS should list procedures and equipment which are acceptable in whole or in part and allow the operator to propose, for USGS approval, the use and conditions under which he will make the test.

TABLE II-3 Failure Reports, Accident Investigations and Testing Actions (Continued)

FUNCTIONAL CATEGORY FAILURE REPORTS, ACCIDENT INVESTIGATIONS, AND TESTING

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
		Inspection should require that any submarine oil or gas line have • a leakage rate below a stated level • a high reliability factor against the probability of leakage for a specific period based on the best technology available. . Non-destructive testing and inspection of risers, and particularly cross-platform lines connecting risers on platforms, should be conducted at periodic intervals, dependent upon system design, type and rate of flow, and other pertinent factors. Each operator should be required (if not included in present requirements) to prepare a "response plan" that sets forth ways of dealing positively and effectively with any possible leakage or rupture. While considerable progress has been made in preventing external corrosion, more effort now needs to be devoted to the prevention of internal corrosion, especially under conditions in which crude oils are aggressive. The committee urges that the USGS consider the foregoing in the next revision to OCS Order No. 9, "Approval Procedures for Oil and Gas Pipelines." In addition, the Committee recommends that: • The USGS encourage the development of various sensor devices for leak detection and corrosion measurement and be prepared to support R&D programs for a number of such devices, since it is recognized that no one device or method will have universal use. Emphasis should be placed on the development of devices that will be designed to negotiate sharp bends and minor buckles. • The USGS encourage or sponsor test applications of the various sensor devices for pipelines whose characteristics, degree of corrosion, etc. are already known or can be determined, in order that the accuracy and dependability of the devices can be ascer-ascertained.

TABLE II-3 Failure Reports, Accident Investigations and Testing Actions (Continued)

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FUNCTIONAL CATEGORY FAILURE REPORTS, ACCIDENT INVESTIGATIONS, AND TESTING

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
		• The USGS initiate a study into ways of reducing pipeline accidents caused by ship anchors. While there are no easy solutions to this problem, possible approaches include indicating the pipelines on navigational charts, establishing pipeline corridors for new lines, and providing buoys or navigational markers to warn ships. It is noted, however, that subaqueous vehicular tunnels (tubes) are often protected against ship's anchors by sand and crushed rock backfill heaped on top, by deeper burial (Or cover), or by precast concrete slabs. Lines in the North Sea have been protected by composite concrete encasement (structural, not just weight coating) and by deep burial using more powerful jet-sled and bury-barge equipment. The three feet of burial, now specified, may be inadequate for larger lines.

TABLE II-3 Failure Reports, Accident Investigations and Tesing Actions (Continued)

- WEAROUT PREVENTION
- SUBSEA
- SYSTEMS ANALYSIS
- PIPELINE INTEGRITY
- DOWNHOLE PRESSURE

FUNCTIONAL CATEGORY PHYSICAL TECHNOLOGIES IMPROVEMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: • Development of a reliable sand erosion probe under USGS sponsorship (including a specification). • USGS revision of OCS No. 8 specifying method of implementation of sand erosion probe. • Requirement for rigorous test and inspection (X-Ray/sonic) of wells upon sand detection. At a later date, when data on failed equipment are available, an evaluation of the necessary inspection frequency and/or periodic replacement of selected safety equipment should be undertaken.	5/73: • Include the development of a reliable sand erosion detector in the research and development program. • Develop rigorous test and inspection procedures for detection and control of sand erosion. • Using data from a failure reporting and corrective action system and other sources, specify the requirements for the frequency of inspection and the frequency of replacement for equipment susceptible to failure, and include them in OCS Orders. Implementation Action Required - The Conservation Division should incorporate the requirement of Recommendation No. 8a in the Research and Development program, and those of Recommendation No. 8b and No. 8c in its Inspection Procedures program. OCS Orders should be revised accordingly.	
UO: Subsea Production Systems - USGS should encourage early development and use of subsea production systems. Parallel to this, efforts should be made to formulate those specifications and regulations necessary to insure safe operation of subsea production systems. CEQ: The Council recommends that subsea production equipment be used in new OCS areas where it would provide a higher degree of environmental protection and reduce conflict between oil and gas operations and competing uses of the ocean.	• The USGS should make a special effort to become acquainted with all subsea production systems under development and in use. • Industry should be encouraged to speed up development and testing of such systems. USGS personnel should be observers of such tests. • If it is determined that subsea production systems are preferable from an environmental standpoint, their use should be encouraged. • The cooperative USGS-API committee on standards should sponsor the preparation of standards and specifications of the safety and pollution control aspects of subsea production systems at the earliest appropriate time. • Concurrent with development and testing, USGS should begin the preparation of OCS Orders covering the use of subsea production systems.	

TABLE II-4 Physical Technology Improvement

FUNCTIONAL CATEGORY PHYSICAL TECHNOLOGIES IMPROVEMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: • The team recommends that USGS request identification of operations and equipment critical to safety of personnel and pollution prevention. Data to complete this "Critical Items List" could be derived from two sources. One, from compilation of accident history and problem/failure reports, is the topic of another recommendation. The second source could result from analysis of the systems utilized to perform a given function. Two types of design/system analysis most commonly used in industry today are the Failure Mode, Effect Analysis (FMEA) and the Hazard Analysis (HA). • The USGS Gulf Coast Regional Office should be authorized to implement the the proposed "design review" group. • The region should require submission from offshore operators a list of critical operations to be performed during drilling at time of permit request. List of critical systems should also be obtained at the time of well completion, and appropriate reviews conducted with the operator. • The requirement for submission of complete Hazard Analysis should be phased into system starting with new work, with time limits on existing wells. • The analysis group should work with operators to eliminate (reduce) hazardous operations by recommending redesign of hardware or operations. • Inspection criteria should be revised to include any additional critical equipment identified by Hazard Analysis. LMS: • Systematic procedures should be established to identify potential hazards associated with various OCS operations and provide risk assessments. • Design specifications for a safety program to be implemented by industry as a means of further reducing risk of accidents and losses on the OCS.	The USGS should require lessees to submit a systems analysis prior to granting approval for platforms, pipelines, drilling operations, and production operations. Operators should provide with each analysis, an identification of operations and equipment critical to safety of personnel and pollution prevention. The latter information should be incorporated into a "Critical Items List." A phased program requiring systems analysis on existing platforms and pipelines should also be developed. Implementation Action Required - Implementation of the recommendation will require study of the findings of the recently completed contracts for hazards analysis. Assuming satisfactory results the requirements for systems analysis should be incorporated in OCS Orders and the necessary staffing for review of analyses should be developed by the Conservation Division. The reorganization of the Conservation Division provides for an operational unit to accomplish this work.	1/74: The Review Committee finds merit in the application of the general method of systems analysis, and recommends continued effort by the USGS to adapt this technique to the requirements of offshore operations. 6/74: The Committee concurs with the conclusion of the Subpanel on Systems Analyses that adaptations of advanced safety and reliability analysis techniques can be quite valuable in enhancing the safety, reliability, and overall economy of offshore petroleum operations. It further recommends that the USGS identify and initiate additional studies, similar to that which resulted in API RP 14C (Analyses, Design Installation, and Testing Basic Surface Systems on Offshore Production Platforms) for other operations and equipment used in offshore petroleum activities and that the work be undertaken by the appropriate technical associations on a priority basis.

TABLE II-4 Physical Technology Improvement (Continued)

FUNCTIONAL CATEGORY PHYSICAL TECHNOLOGIES IMPROVEMENTS

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
Industry and the U.S. Government should establish a working relationship for the joint development of standards for advanced deep water technology. Industry consensus standards for completion and workover safety procedures should be developed. Special consideration should be given hazard control and damage limiting methods.		
The U. S. Government should develop a policy regarding the testing of offshore equipment, including the establishment of criteria for selection of test sites for such equipment in the marine environment.		
UO: Industry should undertake a self-conscious program aimed at increased use of the systems approach in designing its technologies. Specific efforts should focus on increased redundancy and fail-safe designs.		
CEQ: Rapid, accurate measurement of downhole pressure appears important in improving the ability to maintain well control and to reduce the possibility of blowouts. The Council recommends that the Department of the Interior determine which technologies could improve the measurement of the formation pressure near the drill bit and incorporate them into the OCS orders.	11/74: Will be one of the items included in the list of items for R&D	
CEQ: The Council recommends that the Department of the Interior and Transportation develop detailed performance requirements for OCS pipeline protection and undertake the development of pipeline integrity monitors to detect incipient failures in OCS pipelines.	11/74: Considered under 0100 for pipelines.	

TABLE II-4 Physical Technology Improvement (Continued)

FUNCTIONAL CATEGORY SAFETY AND TRAINING 1

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: It is recommended that USGS require, through revision or addition of OCS Orders, that: • Operators develop methods to ensure that company or contract personnel performing inspection and test of safety or anti-pollution equipment are properly trained in USGS requirements, the equipment functions, test methods, etc., prior to performing these services and that training is periodically updated as equipment is modified or new types of equipment are utilized. Operator or outside-source certification of personnel following demonstration of skill should be required. • Operators provide USGS with a description of the methods to be employed in accomplishing the above, and that these methods be approved in advance by USGS. NAE: Since operator training programs are essential to safety in offshore resource development, the U.S. Government should: • Actively encourage and support such training programs; including the objective of safe and reliable operation, installation, maintenance and repair of equipment systems and components; • Sponsor industry-government standardization of training criteria; • Give weighted consideration to the existence and quality of job qualification requirements and corresponding personnel training in permit procedures; • Ensure the participation of U.S. Government personnel involved in standard setting, regulation and inspection or permit procedures in such training programs.	The USGS, working with industry through API, should set standards and requirements for training of personnel, to include, but not be limited to, the following: 5/74: A requirement that all operator or third party personnel, who perform inspection and test functions related to safety and pollution control, be formally trained and qualified. 5/73: A requirement of minimum training in safety and pollution prevention and control for all company and contractor personnel, including identification and proper use of safety equipment, emergency procedures, and first aid. 5/73: A requirement for minimum training in safety and pollution prevention and control for all company and contractor personnel, including identification and proper use of safety equipment, emergency procedures, and first aid. 5/73: A requirement that appropriate company and contractor field personnel be briefed on USGS regulations and orders. 5/73 and 5/74: Standards and requirements for such training should be specified in OCS Orders and a certification, by the operator, of compliance should become a prerequisite for inspecting, testing, and for certain permits and operational work. A system for updating and auditing such training should be developed. Appropriate credit should be given for pertinent experience. 5/74: The expertise of organizations and individuals who specialize in training should be utilized in the development of standards and requirements for training. 5/73 and 5/74: USGS field supervisory and inspection personnel should be required to participate in training courses appropriate to their responsibilities. (The "third party" inspectors referred to above could be someone in the employ of the operator who is not responsible for the operations he is inspecting and who reports directly to management or someone who is an employee of an outside firm with which the operator or group of operators contract for inspection services.)	6/74: With respect to accident prevention and control, the Committee believes that training aspects are equally as important as materials and recommends that increased priority be given to this.

TABLE II-5 Personnel Safety and Training

FUNCTIONAL CATEGORY SAFETY AND TRAINING 2

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: It is recommended that USGS initiate an OCS-wide safety and anti-pollution motivation program. Such a program could be effective in terms of obtaining industry response and favorable publicity. A program consisting of at least the following elements is suggested. • Visual aid package consisting of dramatic evidence of the results of carelessness and human error (pictures of platform fires, etc.) accompanied by analysis of typical events leading to accidents and pollution. • Periodic review of accident (safety and pollution) records, from available statistics, with appropriate awards for top performance. The awards should be public ceremonies with maximum possible publicity. The government program could be put together by an outside company specializing in the field, but should be conducted by USGS. Additional elements recommended to be implemented by offshore operating companies, with some USGS participation, are: • Safety training for all field personnel to include identification and proper use of all safety equipment. Review of all emergency procedures with periodic drills. Instructions concerning daily operations to avoid pollution and minimize hazards. • Periodic review of accident and pollution history to field employee level with recognition for good performance. Recognition would assist in obtaining cooperation for better reports of incidents.	5/73: The USGS should ask API to take the lead in promoting safety and anti-pollution motivation programs for all personnel involved in offshore operations. API should be encouraged to obtain descriptions of the various motivation ideas and programs now practiced by several companies and publish the best in a brochure for others to consider for adoption.	6/74: See Training and Certification

TABLE II-5 Personnel Safety and Training (Continued)

FUNCTIONAL CATEGORY SAFETY AND TRAINING 2

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
• Employee suggestion program regarding safety improvements for both equipment and operations. Again, a recognition system is recommended for accepted suggestions.		
UO: Industry should focus specific attention on the rise of human factors criteria in equipment design aimed at minimizing human - error accidents.		
CEQ: Training programs may not be required for all types of jobs, but certainly for the most critical, curriculum standardization and personnel certification should be required. The Council recommends that the Department of the Interior establish minimum Federal standards for critical OCS operation personnel and certify or provide for appropriate accreditation of the training programs.	NO ADDITIONAL RESPONSE	
CEQ: The continuing search for better technology must build upon an improved understanding of the role of human factors in equipment design and must be coupled with thorough training of the equipment operators. The Council recommends that human factors engineering be employed to the fullest extent in the design of OCS oil and gas equipment. The Department of Interior should review proposed designs for facilities to be used in new OCS areas and encourage the incorporation of man-machine engineering principles.	RECOMMENDATION ALREADY IMPLEMENTED IN PROGRESS	
GAO: Sec. of Interior should consider establishing a formal training program for the inspection staff.	NO RESPONSE	
UO: Personnel Standards. - USGS should develop uniform standards and certification requirements for personnel who perform inspection and test functions. Personnel Training. - USGS should develop a program to establish improved and standardized training and procedures for operating personnel. This program should utilize the expertise of organizations and individuals such as behavioral scientists who specialize in training.		

TABLE II-5 Personnel Safety and Training (Continued)

FUNCTIONAL CATEGORY STANDARDS AND SPECIFICATIONS

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: That USGS seek API cooperation in establishing a committee to function under USGS guidance for the purpose of determining specific needs, and to write, review and approve standards/specifications for safety and anti-pollution equipment. The committee must function under the guidance of USGS. That specifications developed by the committee contain requirements for a basic quality control system and, where equipment is to be used in a deleterious environment, an environmental test program. The committee should use, as a quality system guideline, the quality control provisions of the Bureau of Mines specification covering fuses for trailing cables used in coal mines, and in NASA Publication NPC 200-3, "Inspection System Provisions for Suppliers of Space Materials, Parts, Components and Services." That the USGS, through OCS Orders, require the use of approved standards/specifications. As an alternate recommendation, if the USGS cannot obtain API participation, it is recommended that USGS establish a committee, comprised of appropriate members from the industry, for the purpose of developing these standards/specifications for equipment and methods used in OCS operations. NAE: The U. S. Government should encourage and support the development of a comprehensive system of industry consensus standards and should make use of the resulting standards system in the regulation and inspection of the offshore industry, and make adherence to such standards a consideration in the issuance of permits. The American National Standards Institute (ANSI) should be used jointly by government and industry to integrate the efforts of government,	5/73: Remarks - NASA has noted the need for the development of new and more meaningful standards. It was also noted that many standards had been written in to general terms, insufficient to adequately describe a specific situation. Although equipment quality is of the utmost concern to oil operators, no requirements have been placed on manufacturers for a quality control system. Organizations already in existence, such as the American National Standards Institute, American Petroleum Institute, American Society for Testing Materials, American Society of Mechanical Engineers, etc., are best qualified to develop the necessary standards. Recommendation - The USGS, in cooperation with API, should identify needs for additional or more specific standards for safety and anti-pollution equipment. The standards should include performance requirements for the operational testing of the equipment in the marine environment. Arrangements should be made with ANSI for the development of needed standards. API, ASTM, ASME, and other organizations should be requested to prepare proposed standards as appropriate, with USGS participation. Standards adopted by the USGS should be published and incorporated in OCS Orders.	1/74: Based on the technical review by selected Committee members, the Review Committee recommends to the USGS that it utilize API Spec. 14A and RP 14B on an appropriately time-phased basis, in the implementation of OCS Order No. 5. The Review Committee further suggests that the USGS investigate the feasibility of carrying API-developed standards through American National Standards Institute procedures to provide wider credibility and acceptance. Review Committee members consider the field performance reporting features of API Spec. 14A a significant factor in the evolutionary refining of the specification. 6/74: Standards and Specifications - As recommended in its First Report, the Committee suggests that the USGS investigate the feasibility of carrying API-developed standards through the procedures of the American National Standards Institute, in order to provide wider credibility and acceptance.

TABLE II-6 Standards and Specifications

FUNCTIONAL CATEGORY STANDARDS AND SPECIFICATIONS

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
industry, and the professional societies for the development of industry consensus standards for personnel, equipment, and operating procedures.		
U. S. Government personnel associated with offshore resource development should participate in the standards preparation procedures and there should be means of assuring that such government personnel can participate as equals.		
Industry and the U. S. Government should establish a working relationship for the joint development of standards for advanced deep water technology. Industry consensus standards for completion and workover safety procedures should be developed. Special consideration should be given hazard control and damage limiting methods.		
The U. S. Government should develop a policy regarding the testing of offshore equipment, including the establishment of criteria for selection of test sites for such equipment in the marine environment.		
UO: Standards - USGS should establish equipment requirements in terms of the objectives to be achieved. While these requirements should include detailed performance standards for all pieces of equipment affecting safety and environment, design specifications should not be allowed to act as a deterrent to technological development. The presently used fines and orders for suspension of operations are generally adequate. Detailed standards will require equipment suppliers to establish quality-control procedures.	5/74: NAR	
UO: Certification of Drill Rigs. In addition to its present responsibilities for safety, the Coast Guard should establish formal certification and inspection requirements for jack-up drilling rigs.	NO RESPONSE	

TABLE II-6 Standards and Specifications (Continued)

FUNCTIONAL CATEGORY STANDARDS AND SPECIFICATIONS

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
CEQ: The Council recommends that the Department of the Interior develop detailed performance requirements for safety practices for well workover and servicing operations on production platofrms and incorporate them in OCS orders for the new areas. The Department should consider regulations encouraging the use of improved technology to minimize the threat of blowouts during workover and service operations.		
CEQ: The Council recommends that the Department of the Interior develop detailed performance requirements for surface-actuated subsurface safety valves and require their use on all production wells in new OCS areas where technically feasible. The Department should encourage the development of such valves with higher pressure ratings and with improved reliability of operation over the life of the devices.	11/74: Additionally, in the development of OCS orders for different areas, attention should be directed to environmental hazards and problems that are characteristic of the specific OCS area. The Work Group believes that the USGS should adopt new procedures that would formalize the participation of all interested parties in the development of standards. This does not preclude the continuation of work on the part of API for the development of "industry consensus standards." Recommendation (Revised) - The USGS should identify needs for additional or more specific standards for safety and antipollution equipment and for hazardous operations such as well workovers, servicing, and completions. The standards should include performance requirements for hazardous operations and for the operational testing of the equipment in the marine environment. The USGS should establish the in-house capability to develop standards but should make use of recognized standards organization such as ANSI, ASME, ASTM, and API, as appropriate. Interested labor, environmental, governmental, and industrial organizations, as well as the general public should be given the opportunity to assist in the preparation, to review, and to comment on proposed standards before they are adopted. Standards adopted by the USGS should be published and incorporated in OCS Orders. Specific environmental hazards and problems that are characteristic of different areas of the OCS should be taken into account when incorporating standards into OCS Orders. Implementation Action Required (Additional to those in the May 1973 report) - The Conservation Division should adopt the following procedures for the development of standards:	

TABLE II-6 Standards and Specifications (Continued)

FUNCTIONAL CATEGORY STANDARDS AND SPECIFICATIONS

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS

	• Identify needs for new or modified standards, and establish priorities.
	• Publish a notice in the Federal Register of intent to prepare specific standards, requesting input and assistance.
	• Prepare drafts of new, updated, or revised standards by one or a combination of the following methods:
	  • By use of input derived from step 2 above
	  • By use of available in-house expertise.
	  • By arrangement with ANSI, ASME, ASTM, API, or other organizations who prepare standards.
	• Publish draft standards in the Federal Register for comments.
	• Consider the comments received, publish the final standards in the Federal Register, and incorporate them in an appropriate OCS Order by reference.
	
	The necessary staff to accomplish this program should be requested. Additionally, the Conservation Division should negotiate arrangements with ANSI for an ongoing program of standards development that would involve organizations which prepare standards and permit public and other participation and publish a notification of these arrangements in the Federal Register.	

TABLE II-6 Standards and Specifications (Continued)

FUNCTIONAL CATEGORY INFORMATION AND DATA

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: It is recommended that the USGS revise the Pollution Report form, presently being utilized in the District offices, and require its use by the operators for those spills presently requiring written confirmation. The form should include as a minimum the following: • More detailed information, especially in the area of cause and and corrective action. For example, if equipment malfunctions is the cause, the reason should be recorded in detail. • The "corrective action taken" remarks should include, in detail the repair, if any, that was accomplished to correct the immediate problem. • Information should be provided as to action taken to prevent recurrence.	5/73: Remarks - A revised Pollution Report form is needed to derive necessary information for corrective actions. Recommendation - The Work Group agrees with the NASA recommendation above. Implementation Action Required - The Conservation Division should revise the form and require its use.	NO RESPONSE
NASA: It is recommended that USGS require certain minimum engineering documentation be available at the operator's lowest level onshore engineering office. This recommendation is made in pursuit of the USGS stated objectives of reviewing process equipment designs more closely. The following list is recommended as minimum requirements: • Structural layout and details. • Piping runs. • Schematic diagrams (mechanical and electrical). • Engineering parts list (complete to value and power supply level, including part number, name and manufacturer). • Specifications for all actively functioning components.	5/73: Remarks - The availability of complete documentation at the working level is essential for immediate analysis of problems or malfunctions that could lead to accidents. OCS Orders should include requirements for certain minimum engineering documentation such as wiring diagrams, structural layouts, piping layouts etc., to be readily available at the operator's lowest level onshore engineering office, with copies to the USGS. A Conservation Division task force should identify which documentation is required. Implementation Action Required -The Conservation Division should organize a task force to identify the required documentation, consult with operator groups to determine that particular items can be provided meaningfully, and include appropriate requirements in OCS Orders.	NO RESPONSE
NASA: It is recommended that USGS investigate the legal question of a possible anti-trust law violation regarding formal exchange of hardware and method problem information within the oil and gas industry. If a favorable ruling is obtained, USGS should encourage and participate in the development and operation of the system.	5/73: The USGS should establish and operate a system for disseminating information concerning equipment failures and accidents, utilizing data obtained through a failure and accident reporting and corrective action program, operator reports, and investigation conducted by the USGS. Such information should be made readily available to the public.	1/74: The Committee concludes that the "Safety Alert" Notices are a welcome innovation providing useful information, and recommends that their use be continued and expanded. The Committee recommends that, as appropriate, each Notice make reference to specific OCS Orders, API

TABLE II-7 Information and Data

FUNCTIONAL CATEGORY INFORMATION AND DATA

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
As an alternative, USGS could become the focal point for this information and disseminate it to all concerned parties.	A system should also be established for immediate notification to all operators of a potential failure or accident as a result of specific incidents prior to a full investigation and final dissemination of information.	Specifications, or other documents which discuss the system or component whose failure led to the Alert Notice, as well as actions recommended to correct the problem. If no documentation can be cited, the question of preparing a new standard or revising an existing standard should be addressed. In the latter case, the Notice should state what action the USGS intends to take in order to prevent recurrence of the problem.
NAE: In addition to, and separate from the inspection procedures, there should be a government-sponsored system of reporting safety-related information for the purpose of improving the safety of offshore operations and the inspection system by additions and eliminations. This system, in order to be effective, must take into consideration and allow for the problems of self-incrimination.	Implementation Action Required - In view of the mass of data to be handled, and the intricacies of a system for evaluating, cataloging, and dissemination of information, the USGS should contract for the design by data-blank specialists. Due consideration should be given to the possible adaption to USGS needs of dissemination systems used by other agencies such as NASA, AEC, FAA, and others.	
UO: Based on the inclusion of areas on the five-year lease schedule, USGS should initiate its own data-collection program for each area to the extent required to prepare a lease sale impact statement. Collection procedures should assure that the data is public and available for inclusion in the statement. The data collection should be broad and include, among other things, geological and geophysical information as well as information on environmental and land use impacts.	NO RESPONSE	
UO: USGS should actively promote greater industry cooperation in the development of safety, accident prevention, and environmental protection technologies. Industry should be assured that cooperation in these designated areas will not be subject to anti-trust action. This could be accomplished by having the Anti-Trust Division of the Department of Justice issue guidelines for cooperative efforts or by having the Division give opinions on specific proposals.	NO RESPONSE	
CEQ: The Council recommends that the Department of the Interior consider the competitive consequences of requiring disclosure of certain industry data and analyses. The Department should weigh those consequences against the benefits to be obtained and develop standards for governing such disclosures. In	NO RESPONSE	

TABLE II-7 Information and Data (Continued)

FUNCTIONAL CATEGORY INFORMATION AND DATA

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
making the balance, it should consider particularly the need for informed public participation in the NEPA process. CEQ: The Council recommends that the Department of Interior, in consultation with other appropriate Federal agencies, determine the kinds of information and analyses necessary for adequate assessment of environmental factors at all stages of leasing and development. The Department should take measures to obtain such information, including acquisition and analysis of high-resolution, near-surface seismic reflection data for the purpose of determining the nature and magnitude of geologic hazards prior to tract selection.		

TABLE II-7 Information and Data (Continued)

FUNCTIONAL CATEGORY MANAGEMENT AND REGULATION

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: It is recommended that USGS regional office extend the current effort by staffing, at the earliest possible time, with personnel experienced in quality management and capable of developing, documenting and assisting the Regional Supervisor in implementing this type program. It is recommended that NASA documents NPC 200-1A, "Quality Assurance Provisions for Government Agencies", and NHB 5330.7, "Management of Government Quality Assurance Functions for Supplier Operations", be used as guidelines. USGS should require that all data generated from this planned quality effort be assembled at the regional and Washington offices to be analyzed and evaluated to determine the effectiveness of the district operations. LMS: The major elements of the OCS Lease Management Program, the Production Program and the Revenue Program need to be coordinated and directed to avoid conflicts over available resources. • Designate an OCS Lease Management Program Coordinator. • The Survey should hold a formal annual review of the performance of the program components. • Survey management should delineate specific operational policies for both programs. • The Survey should encourage personnel, especially field technicians, to participate in industry training programs. • A paperwork management study should be conducted in order to streamline procedures for processing documents related to oil and gas operations. • All routine procedures, decision rules, policies, and operating criteria pertaining to OCS operations should be documented in a set of Branch of Oil and Gas Operations' Manuals.	The NASA recommendations listed above should be implemented to provide the needed quality management capability. Most of the items given as a minimum for the program plan are in existence, but they need to be reviewed, updated, consolidated, and systematically documented. The LMS recommendations listed above should also be impelmented, with the exception of item 1. Instead of an OCS Lease Management Program Coordinator, necessary staff capability should be added for program coordination. Implementation Action Required: The Conservation Division should add personnel to implement these recommendations. The Director's Office should develop the guidelines for a formal annual review and prepare the recommended operational policies. A contract will probably be required for the paperwork management study. The recommended operations manuals should be developed by the Conservation Division as soon as possible.	

TABLE II-8 Management and Regulation

FUNCTIONAL CATEGORY MANAGEMENT AND REGULATION (CONTINUED)

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
UO: Environmental Administrations - USGS should be responsible for enforcing all environmental quality standards applicable to OCS oil and gas operations. Where necessary, agency responsibilities should be clearly defined in inter-agency agreements between Interior, Transportation, and EPA.	Enforcement authorities are usually assigned by statutes. However, various inspection and monitoring activities upon which enforcement actions are based can sometimes be shared or delegated. Accordingly, current efforts towards finalizing various Memoranda of Understanding to clearly define the respective functions, scope of activities and responsibilities among the agencies involved in various aspects of environmental protection on the OCS should be expedited, and the results publicized for the guidance of all concerned.	
UO: Promotion-Regulation- Promotion and regulation functions should remain divided divided within Interior, between the Bureau of Land Management (BLM) and the United States Geological Survey (USGS). The planning process inevitably requires coordination and interaction between these two components as do subsequent management actions. This need for coordination stems from the practical inability to separate fully promotion from regulation. Nonetheless, assigning separate responsibilities provides a continuous checking mechanism.	NO RESPONSE	
UO: Bonus Bid- BLM should continue to administer the lease sale using present procedures including the bonus bid system. Selected experimentation with the staggered bonus system should be considered. The bonus bid system has the dual attractions of raising substantial revenue for government and being easily administered.	NO RESPONSE	
UO: Platform Location- The present Corps of Engineers responsibilities concerning platforms should remain unchanged. The responsibility for maintaining unimpeded navigation requires management by a single agency.	NO RESPONSE	
UO: Ten Year Schedule - BLM should formulate a ten-year development schedule for OCS oil and gas resources. A long lead-time is essential for an effective planning process.	The Work Group agrees that the USGS should continue to administer all of its present post-lease activities.	

TABLE II-8 . Management and Regulation (Continued)

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FUNCTIONAL CATEGORY MANAGEMENT AND REGULATION (CONTINUED)

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
UO: USGS Management - With limited exceptions post-lease sale management of OCS oil and gas operations should be concentrated in USGS. The objective of this concentration of management is to eliminate gaps and overlaps and establish clear-cut responsibility. Such concentration will also assure that management decisions conform to the development plan laid out in the hierarchy of impact statements. Any impact statements triggered by post-lease sale activities should be the responsibility of USGS and be subsidiary to the lease sale statement. Where necessary, transfer of operational responsibility to USGS should be accomplished by inter-agency agreements. In summary, USGS should continue to administer all of its present post-lease activities plus the following: OSHA - By agreement between Labor and Interior, OCS responsibilities assigned to the Department of Labor by the Occupational Safety and Health Act (OSHA) should be administered by USGS. The standards themselves should be developed by Labor with the advice of USGS and the Department of Health, Education and Welfare (HEW). Such an arrangement will increase the effective day-to-day administration of the OSHA standards since USGS is already equipped to inspect OCS facilities. Further, these safety and health concerns are intimately tied to equipment design and operational procedures that are already a USGS responsibility. As a final advantage, this approach relieves industry of an additional layer of inspectors.	The Conservation Division should continue to take the lead in negotiating a Memorandum of Understanding between OSHA and the USGS.	
UO: Rights-of-Way - By formal agreement between BLM and USGS, BLM should issue rights-of-way for common carrier pipelines only upon recommendation of the USGS. This will assure that coordination exists between common carrier lines and the gathering lines presently regulated by USGS. Such authority will allow USGS to insure that pipeline development conforms to the plans developed in the impact statements. Present responsibility for pipelines is fragmented, and some agencies are incapable of	5/74: A Memorandum of Understanding between USGS and BLM should be developed whereby BLM approval of pipeline rights-of-way applications will require a determination by USGS of the adequacy of the application with respect to design, installation, maintenance and operation. A Memorandum of Understanding between USGS, BLM, and OPS should be formulated whereby the USGS will enforce OPS safety standards, jointly developed by OPS and USGS, for OCS pipelines.	3/75: The problem of regulating these pipelines so as to reduce their pollution potential appears to be additionally complicated by questions of regulatory authority. Despite growing cooperation among the three affected agencies (BLM, OPS, USGS), the Review Committee believes that a clearcut delegation of authority to a single agency would help to achieve the necessary improved regulation.

TABLE II-8 Management and Regulation (Continued)

FUNCTIONAL CATEGORY MANAGEMENT AND REGULATION (CONTINUED)

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
of meeting their regulatory responsibilities. Pipelines - By formal agreement between the Office of Pipeline Safety (OPS) and Interior, USGS should be designated as responsible for enforcing design and performance standards for offshore pipelines which are now under OPS jurisdiction. The standards, however, should be jointly formulated by OPS and USGS. USGS presently exercises such authority over gathering lines.		
UO: Gas Reserves - By formal agreement between the Federal Power Commission (FPC) and Interior, USGS should be required to provide estimates of recoverable gas reserves to be served by proposed new gas lines. Attached to the estimates should be an assessment of how the line will fit into the development plan established in the impact statements. Additionally, USGS should be available to FPC for consultation on all questions concerning lines. The puppose is to assist FPC in approving new pipelines so that they conform to the development plan established in the impact statements.	Estimates of recoverable gas reserves to be served by proposed new gas lines are the responsibility of FPC, but the USGS has cooperated with the FPC when requested and is available for assistance and consultation.	
UO: Apply FWPCA to OCS. The FWPCA Amendments of 1972 should be amended specifically to apply discharge provisions to the OCS. Under this arrangement, EPA would establish the standards, but as recommended earlier, USGS would have enforcement responsibility. There is no apparent reason why the general principle of a separate agency to set environmental standards should not be applicable to the OCS. Such a separation provides an additional check and increased public credibility in this sensitive area.	The USGS and EPA should continue to pursue their discussions leading to the joint development of discharge standards for the OCS and a Memorandum of Understanding calling for enforcement by the USGS.	6/74: The Committee, therefore, believes that the time is opportune for the development and promulgation of a basic overall program plan by the USGS. Other Federal agencies have developed such program policies in the past, and have in all cases tailored their plans to particular situations of concern, with attention directed toward fundamental issues such as program goals and purposes, and toward the responsibilities of the issuing agency, other agencies, the public, and the industry.
CEQ: The Council recommends that the Department of the Interior in coordination with the Environmental Protection Agency, develop more detailed guidelines for the disposal of drilling muds, drill cuttings, and other materials, considering fully the results of the Bureau of Land Management monitoring studies of ocean disposal of these materials in the new OCS area.	RECOMMENDATION ALREADY IMPLEMENTED IN PROGRESS	Recommendation - The Committee recommends that the USGS undertake immediate and concerted action to develop and promulgate a basic program plan for the assurance of safety and pollution control in OCS petroleum operations.

TABLE II-8 Management and Regulation (Continued)

FUNCTIONAL CATEGORY MANAGEMENT AND REGULATION (CONTINUED)

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
CEQ: In undeveloped areas like the Atlantic and Gulf of Alaska OCS, environmental loadings of oil and other materials should be kept at the lowest levels possible at least until environmental baseline studies such as those recently initiated by the Bureau of Land Management determine the environmental risk from such materials. The Council recommends that the Department of the Interior and the Environmental Protection Agency, in cooperation, establish effluent standards for waste water discharge from OCS drilling, production, and associated operations. Strong consideration should be given to requiring installation of the best commercially available control technology for oil-water separation in new OCS areas.	RECOMMENDATION ALREADY IMPLEMENTED	
CEQ: Citizen suit provisions, which allow interested persons to sue to remedy violations of Federal regulations or permit conditions, can provide a useful compliance mechanism. The Council recommends that the Secretary of Interior seek the establishment of such a right under the OCS Lands Act.	NO RESPONSE	
CEQ: The Federal Government should carefully consider the full economic and environmental implications of various types of liability - fault or no fault - and various means of ensuring adequate compensation such as liability insurance for operators or a revolving fund financed through charges on operators. The Council recommends that a comprehensive Federal liability system for OCS - related oil spill cleanup and damages be established through new legislation.	NO RESPONSE	

TABLE II-8 Management and Regulation (Continued)

FUNCTIONAL CATEGORY OCS ORDER DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: In order to remain abreast of the ever-changing needs, the following recommendation is made: The USGS Regional Office should organize an OCS Order development and implementation function. This function, technical in nature, involves many hours of research, investigation, and discussion, and should be assigned to a small committee of qualified people selected by the Supervisor. This committee should: • Schedule meetings periodically to review current needs and evaluate existing Orders. • Meet with USGS Region management to determine their overall reaction to the proposed order and/or change. • Schedule meetings with the Offshore Operators Committee and/or subcommittee and discuss the change and the impact it will have on the operators and other companies operating in the OCS and document their comments and/or suggestions. • Schedule meetings with the USGS District engineers and chief technicians, discuss the proposed changes and document their comments. • If needed, consult with or solicit advice from field officials of other Government agencies and document their comments. • If needed, consult with or solicit advice from field officials of other Government agencies and document their comments. • Assemble and consolidate the comments into a report for USGS Region management review and evaluation. • Coordinate for approval with the Washington level. • After the new Order and/or change has been agreed to by all concerned, develop the final draft to submit to Washington for signature. • After the Order is approved, serve in an advisory and assistance capacity to USGS management in assuring that concerned USGS and operator personnel thoroughly understand requirements prior to implementation and during implementation.	5/73: The development of OCS Orders is of utmost importance in achieving and maintaining safety and pollution control in OCS operations. More formalized organization and procedures are needed to develop new orders and to revise existing orders as new and improved technology and operating procedures are developed. Recommendations: • Formalized procedures of the type outlined in the NASA recommendation should be established for development and revision of OCS Orders. • In general, OCS Orders should specify the objectives to be achieved, with standards for achievement included by reference. • The Work Group agrees with the NAE recommendations that (1) there should be continuation and refinement of the current practice of requiring submission of plans of applicants in terms of equipment and including personnel qualifications and training procedures; and (2) that regulations should take into account on a continuing basis the results of the analysis of information resulting from accident evaluation as well as consideration of natural environmental hazards. Implementation Action Required - The Conservation Division should prepare written procedures outlining the step-by-step actions to be followed in the formulation of OCS Orders for all areas, in keeping with the NASA and NAE recommendations.	1/74: A Review Committee member reviewed the USGS draft revision of OCS Order No. 8 in order to extend the Order to caisson-type structures, and noted that API RP2A ("API Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms"), developed both within industry and with help from outside engineers, represents a sound and objective approach being followed by industry worldwide.

TABLE II-9 OCS Order Development

FUNCTIONAL CATEGORY OCS ORDER DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NAE: In order to avoid inhibition of technical development and to take maximum advantage of advances made in equipment and methodology, the U.S. Government policy should be to establish regulations in terms of the objectives to be achieved and not in terms of specific methods of achieving them. In permit procedures, there should be continuation and refinement of the current practice of requiring submission of plans of applicants in terms of equipment and including personnel qualification and training procedures which will be used to control hazards. The government should continue to make granting and continuance of permits contingent upon adherence to regulation and submitted plans. Regulations established for the control of offshore oil operations should take into account on a continuing basis the results of the analysis recommended above (information resulting from accident evaluation), as well as consideration of the natural environmental hazards (such as hurricanes, earthquakes, or large waves, and the state of the art of working in the marine environment).		
UO: OCS Orders: Coverage - All design specifications and regulations for which USGS has administrative responsibility, including those resulting from interagency agreements, should be detailed in OCS orders for each USGS area. OCS orders should be detailed composite of the regulations and criteria under which oil and gas operations are to be carried out. Such a composite would inform both industry and the interested public of operational standards. OCS Orders: Preparation - All OCS orders should be reviewed in advance by committees representing both industry and other interested parties selected by the Chief of the Conservation Division of USGS. At present, preparation of OCS orders involves industry participation. For example, in the Gulf Coast area, proposed orders are reviewed by	5/74: All memoranda of understanding and interagency agreements concerning management of OCS petroleum activities should be made available in a single document, and appropriate references made in OCS Orders. The Conservation Division should adopt the following procedures for the development of new and revised OCS Orders: • Announce in the Federal Register its intention to prepare a new or revised Order and solicit comments and recommendations. • Prepare a draft of the Order and publish it in the Federal Register for comment. Steps 1 and 2 may in some cases be concurrent. • After receipt of comments, Division personnel may meet with interested organizations or consult with individual experts on the various requirements of the Order. • Revise the draft Order, if appropriate, to take	

TABLE II-9 OCS Order Development (Continued)

FUNCTIONAL CATEGORY OCS ORDER DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
the Offshore Operators Committee. Broadening the range of reviewers should assure sensitivity to a wide set of social concerns at the immediate management level. Placing selection in the Conservation Division in Washington should provide access to the best informed people in organizations such as the national environmental interest groups.	into account the information developed from steps (2) and (3). • If the revision is extensive or significant, republish the Order in the Federal Register as a redraft for further comment. Otherwise, publish it in the Federal Register as a final Order with an effective date. Implementation Action Required - The Conservation Division should prepare written procedures outlining the step-by-step actions to be followed in the formulation of OCS Orders for all areas and should assemble and make available all applicable memoranda of understanding and interagency agreements.	
CEQ: The Council recommends that the Department of the Interior develop and incorporate in OCS orders detailed performance requirements for production platforms and associated equipment to be used in new OCS areas, with full consideration of natural hazards. The Department should develop in-house capability, or should contract with a qualified independent firm, to evaluate the adequacy of the proposed designs to guarantee structural integrity subject to natural and manmade forces. Decisions on offshore oil storage in the Atlantic and Gulf of Alaska OCS must fully consider the potential impacts of severe storm and seismic conditions The Council recommends that the Departments of the Interior and Transportation develop detailed performance standards for offshore storage facilities and incorporate them into OCS orders for the new areas. Serious consideration must be given to postponing leasing in an OCS region where oil cannot be safely produced and safely transported to markets because of significant threats of earthquakes, tsunamis, and severe storms. The Council recommends that the Departments of the Interior and Transportation coordinate their evaluation and approval procedures for drilling platforms for new OCS areas. They should prepare detailed performance requirements for such platforms, considering fully the natural hazards in these areas.	11/74: The USGS, in coordination with DOT and other Federal agencies having pertinent expertise or jurisdiction, should develop detailed performance requirements for fixed and mobile platforms and fixed and mobile offshore storage facilities, taking into account specific environmental hazards and problems that are characteristic of different regions of the OCS. Implementation Action Required (additional to those in the May 1973 report and in Supplement No. 1, May 1974) - The Division should strengthen its in-house and contract capability for the development of platform performance requirements and design review, and coordinate as appropriate with DOT and other Federal agencies having pertinent expertise or jurisdiction. The Division should also coordinate its evaluation and approval procedures for such platforms and storage facilities with DOT.	

TABLE II-9 OCS Order Development (Continued)

FUNCTIONAL CATEGORY OCS ORDER DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
GAO: Sec. of Interior should issue regulatory orders to: • Control erosion of pipes and other equipment • govern workover and wireline operations • govern concurrent drilling, production, and remedial operations on a single structure	NO RESPONSE	

TABLE II-9 OCS Order Development (Continued)

FUNCTIONAL CATEGORY COASTAL CONCERNS

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
CEQ: The Council recommends that states affected by new OCS development strengthen their coastal zone management programs by developing special technical expertise on all phases of OCS development and its onshore and offshore impacts. Such augmented state coastal zone management agencies should attempt to ensure that state interests and regulatory authorities are fully coordinated with Federal OCS technical and management activities. Federal agencies should make every effort to cooperate with state coastal zone management agencies on an ongoing basis and at all stages of the management process.	RECOMMENDATION ALREADY IMPLEMENTED	
CEQ: The Coastal Zone Management Act provides a framework for Federal/State cooperation in planning for onshore development induced by OCS operations, particularly siting of pipelines, refineries, and other facilities in the coastal zone. The Council recommends that the Secretary of Commerce require that state coastal zone plans consider refineries, transfer and conversion facilities, pipelines, and related development as a condition of approval. State coastal zone management agencies and concerned Federal agencies should jointly participate in developing these portions of the plans.	NO RESPONSE	
CEQ: The Council recommends that the Department of the Interior, in cooperation with other Federal agencies and the affected states, undertake advanced planning for pipeline corridor siting as soon as the location of potentially producing OCS areas is known and designate corridors which avoid or minimize, to the maximum extent possible, intrusion into environmentally sensitive areas in the marine and coastal regions of new OCS areas.	RECOMMENDATION ALREADY IMPLEMENTED	

TABLE II-10 Coastal Zone Concerns

FUNCTIONAL CATEGORY ENVIRONMENTAL IMPACT STATEMENTS

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
UO: The OCS management process should include preparation of a hierarchy of impact statements that starts with a general programmatic statement.	NO RESPONSE	
UO: USGS should lead with the close co-operation of Commerce, in preparing programmatic impact statements for each of the regions included in the ten year development schedule.	NO RESPONSE	
UO: Based on the programmatic statement and nominations from industry, BLM in cooperation with USGS, should prepare a lease sale draft impact statement to be available at least fifteen months prior to the sale and three months prior to the public hearing. EPA approval on impact statements.	NO RESPONSE	
UO: The Department of Commerce should be designated as having special responsibilities for providing the coastal-zone planning component in OCS impact statements. The objective is to use the statements as a mechanism for integrating energy, land use, and environmental planning. Existing legislation assigns responsiblity to Commerce for land use planning in the coastal zone. Under the proposed management plan, Interior and Commerce would have primary responsibility for these three planning elements.	NO RESPONSE	
UO: The Department of the Interior should be assigned lead agency responsibility for all 102 statements prepared for the OCS. Preparation of these statements should be coordinated with all agencies having responsibilities on the OCS. The rationale for assigning the lead agency role to Interior is in part linked to later recommendations which concentrate additional OCS administrative responsibilities in that Department.	NO RESPONSE	
UO: Using programmatic statements as a base, BLM should in consultation with USGS select areas (not tracts) defined by	NO RESPONSE	

TABLE II-11 Environmental Impact Statements

FUNCTIONAL CATEGORY ENVIRONMENTAL IMPACT STATEMENTS

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
coordinates for inclusion on its five-year lease schedule. Specific designation of the areas to be leased is necessary to facilitate detailed data collection.		
UO: An ad hoc committee should be constituted by the Council on Environmental Quality (CEQ) to review draft impact statements for lease sales. The committee should represent a broad range of interests and expertise. The review and a report of the review should be open to the public. This review could provide additional assurance that the impact statements and actions being planned are both adequate and consistent with the regional plan.	NO RESPONSE	
CEQ: The NEPA process can be an important focus of Federal state coordination concerning OCS development. The council recommends that state coastal zone management agencies be given the opportunity to cooperate with Federal Agencies in designing and preparing environmental studies used as input to the environmental review process in addition to commenting on draft environmental impact statements	NO RESPONSE	
CEQ: The Council recommends that impact statements on environmentally significant OCS activities include in the discussion of "the range of potential uses of the environment" analyses of possible alternative uses of specific OCS, nearshore and onshore areas. In addition, the statements should include discussion of onshore impacts. In commenting on draft statements, Federal agencies, states, and interested parties should give particular emphasis to those issues.	NO RESPONSE	
CEQ: OCS decision making could also be enhanced through regional, programmatic impact statements. The Council recommends that programmatic statements be prepared on a regional basis by all Federal agencies proposing environmentally significant activities on the OCS. Comprehensive OCS planning could be approached through reconciling various agency statements in the circulation and comment process.	NO RESPONSE	

TABLE II-11 Environmental Impact Statements (Continued)

- CLEAN-UP R&D
- GOVERNMENT R&D UTILIZATION
- ENVIRONMENTAL R&D
- OTHER

FUNCTIONAL CATEGORY RESEARCH AND DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
NASA: It is recommended that USGS establish a method to determine needs and conduct or direct the research, testing and development necessary to improve equipment and methods for an increasingly safe and pollution-free operation on the OCS. An alternate recommendation is that USGS work with the industry in establishing an organization such as the American Petroleum Institute (API) to serve as the R&D focal point, with all comapnies contributing toward resolution of problems. NAE: The U. S. Government should encourage and utilize industry research and development programs by means of promotion of industry consensus standards on offshore technology so that it can act to ensure that information on improvements in safety technologies becomes available to participants in offshore resource development. The U. S. Government should sponsor a coordinated program to specify reasonable limits of crude oil intrusion in accordance with biological and aesthetic standards. These standards should be set in a manner that will take full account of site variables. The effort should be carried out on a continuing basis in order to take advantage of improvements in the technology of offshore petroleum operations. The program should be specifically directed to provide a basis for engineering design and standards for components and systems to be used in offshore petroleum operations. The U. S. Government should make quantitative studies of the effectiveness of the various present and potential methods of cleaning up oil from the marine environment, and of their potential marine environmental impact. The U. S. Government should actively encourage and sponsor the development and testing of damage-limiting and fail-safe systems and techniques in the areas of damage control, fire-fighting, and well control.	5/73 and 5/74: The USGS, in cooperation with the API or other appropriate organizations, should establish a program to encourage and promote research and development in safety and anti-pollution equipment and systems. Current and completed research and development should be taken into account in the determination of specific needs. Such needs should be communicated to industry through API or other appropriate organizations, and issued by USGS as an annual summary report. For those needs where there is no response from industry, or the response is unsatisfactory, the USGS should contract for the required work, utilizing, when appropriate, organizations outside the usual petroleum industry R&D establishments to perform such research. 5/73: With specific reference to the NAE recommendations, the Work Group recommends: • The promotion of industry consensus standards should be effected through a cooperative arrangement with API. • Requests should be made to NOAA, USCG, and EPA to sponsor programs to study the effects of various amounts of crude oil intrusion into the marine environment, taking into account site variables. • The recommendation to undertake quantative studies of the effectiveness of methods for cleaning up oil from the marine environment should be referred to the U.S. Coast Guard. • The development and testing of damage limiting and fail-safe systems in the area of damage control, fire-fighting, and well control should be an item for follow-up under cooperative arrangements with API, or other appropriate organizations. 5/74: Industry should be encouraged to grant reasonable access to patented safety and pollution control devices and systems to offshore operators.	6/74: Research and Development (R & D)- This area requires further consideration by the Committee before commenting R&D will be addressed in a subsequent report of the Review Committee.

TABLE II-12 Research and Development

FUNCTIONAL CATEGORY RESEARCH AND DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
UO: Government R&D- USGS should undertake an expanded research, development, and testing program as necessary to insure optimal regulation and rapid development of new equipment and procedures. So far as possible, this work should be contracted. with organizations outside the R&D system of the petroleum industry. This will help to insure that USGS and OCS operators maintain continuing effective communications with other technological communities. Inadequate Components - USGS should immediately compile a list and each year publish a summary review of the progress achieved in correcting weaknesses. This review should continue until the indentification system previously recommended is operational. The physical technologies with weaknesses fall into three categories: need to be developed, need to be improved, and need to be deployed. • Surface actuated, fail-safe valves that can be substituted for existing velocity actuated downhole safety devices with out pulling the production tubing The objective is to provide more reliable protection against loss of control in producing wells. • Downhole instrumentation for measuring pressure at the bit face. Such a capability would give immediate warning of potential blowouts. • Event recorders designed to survive accidents, similar to the "black boses" in airplanes. These would provide a record of equipment malfunctions. • A device for identifying which wells on a burning multi-well platform are out of control. Presently efforts to re-establish control over wells are slowed by the difficulty in identifying the wells that are out of control. UO: Hydrocarbon Studies - The National Oceanic and Atmospheric Administration (NOAA) should initiate continuous hydrocarbon baseline and toxicity tests at the point that areas are included on the five-year lease schedule. This will provide a base for anticipating the impact of later	NO RESPONSE	

TABLE II-12 Research and Development (Continued)

FUNCTIONAL CATEGORY RESEARCH AND DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
operations. To assure maximum credibility studies should be funded and carried out so as to preclude the appearance of bias. This is one rationale for having NOAA as assume responsibility for these studies.	NO RESPONSE	
Environmental Monitoring.- With the start of exploratory drilling operations in any OCS area, NOAA should assure continuous monitoring of commercially useful and sensitive marine species for sublethal effects and possible tainting. Findings of measurable changes would require immediate action by the management system.	NO RESPONSE	
Environmental R & D - A single federal agency, probably either EPA or NOAA, should assume responsibility for monitoring, coordinating, and filling gaps in environmental research. The purpose is to assure a balanced R&D program.	NO RESPONSE	
Clean-up R&D - EPA should assume responsibility for monitoring, coordinating and filling gaps in R&D aimed at improving clean-up and containment technology. The objective is to assure a balanced R&D program.	NO RESPONSE	
Industry R&D - Industry should expand its R&D programs with the objective of developing technologies that are responsive to broader criteria such as those associated with safety and environmental concerns.	NO RESPONSE	
		1/74: The Review Committee has proposed a three-phase environmental approach designed for realistic data requirements at minimum cost. The approach, outlined below, is proposed as a means of achieving the baseline study requirements. Phase one includes the compliation of a complete bibliography of studies in the proposed area, accompanied by a detailed compliation of data which will highlight areas where further knowledge is needed. The prime objective of this phase is the gathering of currently available data on the

TABLE II-12 Research and Development (Continued)

FUNCTIONAL CATEGORY RESEARCH AND DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
		area. A similar system is now used by the Bureau of Land Management. Phase Two involves a pilot study done to update data obtained in Phase One, and to fill in obvious gaps. At this stage, a decision can be made whether to proceed with offshore development or to abandon it on the basis of environmental considerations. The pilot study should be a "one-shot" survey, with consideration of seasonal and long-term changes deferred until Phase Three. The time of the year for the pilot survey should be determined by the data obtained in Phase One. That data will also determine such factors as optimal sampling methods, and will provide the framework for the longer-term study of Phase Three. As offshore development proceeds, a Phase Three dynamic study should be made on a continuing basis of the basic physiographic and biological types found in both development-affected and development-unaffected sites in the area. The three-phase approach outlined above is designed to conduct in-depth studies of selected sites, to project the data obtained to other areas which are apparently similar, and to check those projections against additional data.
CEQ: OCS technology should continue to evolve in order to ensure lower levels of risks from operations in the Atlantic and Gulf of Alaska. Research can contribute to understanding the behavior of offshore structures under storm and seismic forces, to reducing chronic pollution from OCS operations to improving the integrity of offshore pipelines, and to integrating knowledge of human factors engineering into design. Improved Federal performance standards for OCS operations should draw upon the results of such research.	NO RESPONSE	

TABLE II-12 Research and Development (Continued)

FUNCTIONAL CATEGORY RESEARCH AND DEVELOPMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
CEQ: The Council believes that further study of onshore impacts of OCS activities is needed. Studies focusing on the socioeconomic impacts of OCS development at specific sites will be needed by local decisionmakers. Availability of land for development, impacts on the quality of life, shifts in population and employment patterns-all must be evaluated on a local basis to be of use in state and local planning.	NO RESPONSE	
CEQ: The Council recommends that the Federal Government and industry continue efforts to improve oil spill containment and cleanup. The Council recommends further that the Departments of the Interior and Commerce and the Environmental Protection Agency cooperatively consider the identification of critical environmental regions in new OCS areas and the incorporation of appropriate measures into the National Oil and Hazardous Substances Pollution Contingency Plan.	11/74: The lead responsibility for improving oil spill containment and cleanup technology rests with agencies other than the USGS. The USGS does, however, participate in the identification of critical environmental areas and will continue to participate in the interagency development of Pollution Contingency Plans.	
CEQ: Research Needs: • Population life histories for many species, including identification of survivorship, fecundity, larval lifestyle, migrations, and behavior. • Community response at the species level following polluting incidents or in controlled experiments. • Adaptations of organisms to oil exposure, including genetic changes • Impacts of oil during sensitive stages of species development • Effects of oil on commercial fisheries	NO RESPONSE	

TABLE II-12 Research and Development (Continued)

FUNCTIONAL CATEGORY INSPECTION PROCEDURES AND ENFORCEMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS

NASA:
• The data processing equipment, that the team (LMS study team) was advised is being considered for location in the Regional Office, should be installed at the earliest possible time.
• The presently used Potential Incidence of Non-Compliance (PINC) list should be modified to separate the gathering of descriptive information (e.g. number of wells/platforms) from compliance information (e.g., satisfactory operation of check valves).
• A method should be established to ensure that compliance characteristics of the PINC list are maintained current as OCS Orders are revised or added.
• Conservation Division should devise a "best method" of adapting study techniques to the needs of Region operations. An operating procedure should then be developed, and implemented as soon as possible, in order to provide uniform guidance to all concerned personnel. The procedure should include the use to be made of information generated by District, Region, and Headquarters.
• The procedures referenced above should be integrated into the overall OCS Management Program Plan.
 	
LMS:
• Adopt the inspection techniques and methodology developed and utilized in the course of this study.
• Expand the scope of the inspections to include other production operations as they are specified in conjunction with the hazard review activity and as new OCS Orders are written.
• Continue the review and analysis of inspection results in order--
  • to modify inspection strategies and to allocate resources in response to changes in the level of company activity and compliance;
  • to advise the Offshore Operators Subcommittee on Safety of the inspection results.
	5/73: Remarks - USGS inspection procedures have been criticized for lack of uniformity among inspectors in the interpretation and application of OCS Orders. It is important that uniform practices be adopted.
	
	LMS Recommendation 4 advocated that required fixed periods of shut-in time for specific items of non-compliance or combinations of items be added to existing enforcement authority.
	
	While it might be argued that such a shut-in would be designed as a deterrent to a recurrence of the violation, it is difficult to consider the shut-in itself anything other than a punitive action.
	
	A further aspect is that while such a shut-in might punish the company by a temporary loss of deferment of income, the public would, likewise, have a deferment of royalty income and would suffer a loss of availability of fuel.
	
	Recommendation
	
	• The USGS should incorporate into its inspection program all of the NASA recommendations and LMS recommendations. Punitive fixed-period shut-ins are not permissible under existing legislation, nor are they considered advisable.
	• OCS Orders should include requirements for lessees to conduct inspections on a scheduled basis and report the results in a specified format to the USGS.
	• The USGS should explore the feasibility of third-party inspections as an alternative or supplement to lessee inspections.
	• The PINC system of inspection should be periodically reviewed to determine how it can be modified and improved
	• The USGS should formalize inspection strategies and policies, including optium frequencies of inspection results.
	• The USGS should continue to evaluate procedure for inspection and enforcement to insure the application of rigorous and uniform practices in light of new requirements and past experiences
	
	Implementation Action Required - While some of the recommendations have already been implemented, the Conservation Division should take the necessary steps to require standardized inspections by lessees.
		3/75: The Committee therefore recommends that the USGS further study, with a view towards initiating, the use of third-party inspection procedures in conjunction with the execution of its plans for the use of ANSI standards in the implementation of OCS Orders.

TABLE II-13 Inspection Procedures

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FUNCTIONAL CATEGORY INSPECTION PROCEDURES AND ENFORCEMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
• Augment the existing enforcement authority with the addition of required fixed periods of shut-in time for specific items of noncompliance or combinations of items. • On a periodic basis, perhaps monthly, inform upper management of actions taken against their company.	They should also determine the feasibility of third-party inspections and recommend to the Director appropriate follow-up actions. Systematic review by the Conservation Division of inspection methods and strategies should be continued. Procedures should be developed for rigorous and uniform application. Inspectors should be instructed accordingly.	
NAE: Routine inspection procedures in the offshore industry should be carried out by the specific companies involved for compliance with industry consenus standards. U.S. Government inspections should be confined to spot-checking to ascertain compliance to regulations.	Attainable inspection frequency schedules should be developed. Wherein these are less than the optimum, requirements for additional required capacity should be identified.	
CEQ: The Council recommends that the Department of the Interior determine the frequency and type of inspections necessary to verify compliance during all phases of OCS operations. It should establish inspection teams and procedures in light of those determinations and the scale of OCS development in various regions. State agencies should be invited to participate in these inspection efforts. In addition, the Department should establish a formal training program for the inspection staff. The Council recommends that, in order to deter violations of OCS orders rather than simply shortening the time that operators take to correct noncompliance, the Secretary of the Interior propose sanctions requiring fixed shutin periods and administrative fines as enforcement measures.	11/74: Remarks - The Work Group agrees, however, that in the absence of legal constraints it would be desirable to include representatives from coastal States in certain inspections. Additional Recommendations - The USGS should invite representatives from interested State agencies to become familiar with Federal inspection procedures. USGS should also request an opinion from the Solicitor on the extent of possible participation by State employees in OCS inspections, and respond accordingly with invitations to the States to participate, as appropriate. The USGS should formalize inspection strategies and policies, including optimum frequencies of inspectors, and emphasize improvement of methods for evaluating inspection results. These results should be used in determining the number of inspectors required. Implementation Action Required (additional to those in May 1973 report) - A Solicitor's opinion on the extent of State participation in OCS inspections should be requested.	
GAO: The Sec. of the Interior should require the Survey to: • Emphasize the need for inspection personnel in the Gulf Coast region to apply prescribed enforcement actions for violations of OCS orders unless deviations are authorized under circumstances specified by the region and properly documented in each case.		

TABLE II-13 Inspection Procedures (Continued)

FUNCTIONAL CATEGORY INSPECTION PROCEDURES AND ENFORCEMENT

STUDY RECOMMENDATIONS	USGS WORK GROUP RECOMMENDATIONS	MARINE REVIEW BOARD RECOMMENDATIONS
• Reexamine the Pacific region's policy of not halting operations for violations of OCS orders and consider the advisability of shutting down individual wells to encourage the operator to promptly correct deficiencies. • Establish a realistic policy on how frequently each type of OCS operation must be inspected, considering the resources available and the risks of oil spills involved. • Issue instructions covering partial inspections and inspection of remedial and abandonment operations.	NO RESPONSE	

TABLE II-13 Inspection Procedures (Continued)

2. Safety and Advisory Committees

Three cooperative committees were established by the American Petroleum Institute and the Geological Survey in September 1972 to address: Offshore Safety and Anti-Pollution Equipment Standards, Offshore Safety and Anti-Pollution Research, and Offshore Safety and Anti-Pollution Training and Motivation. The petroleum industry has established a committee on OCS Safety in both the Pacific and Gulf of Mexico areas.[25]

Secondly, the Director of the Geological Survey has formed a review committee on technologies related to safety of OCS petroleum operations. This committee is composed of experts not regularly employed by industry or the federal government and is sponsored by the Marine Board of the Assembly of Engineering of the National Research Council. The initial meeting of this committee was held in Washington, D.C., during August, 1973.

3. Failure Reports, Accident Investigations, and Testing Actions

1) Failure Reports and Corrective Action

The USGS implemented a Failure Reporting and Corrective Action System in 1974 for subsurface safety valves. OCS Order No. 5, for the Gulf of Mexico, has been revised and now requires operators to submit quarterly failure-analysis reports on subsurface safety devices. This revised order is under consideration by the USGS Office, Pacific Area, for possible adaptation to the Pacific Area. An examination of the Proposed Gulf of Alaska orders indicated that the

25/ Comptroller General of the United States, Follow-Up on Certain Matters Concerning the Inspection and Regulation of Outer Continental Shelf Oil Operations, February, 1974.

failure-analysis reports will also be required of operators. The Gulf Coast Operators' Committee is developing procedures for a closed-loop failure reporting and corrective action system which will include all critical platform safety components. The output from these systems will be computerized and will be analyzed by the Safety Review Committee.[26]

2) Accident Investigation and Reporting

The USGS Conservation Division established, on April 12, 1971, a procedure for "Notification and Investigation of Accidents." This procedure is designed to provide prompt investigation and systematic review of accidents as a basis for taking immediate corrective actions to limit the probability of recurrence.[27]

The legality of publishing investigation reports of major accidents has been affirmed by the Solicitor's Office of the Department of the Interior. However, according to the Assistant Solicitor's memorandum to the USGS of January 10, 1973, it is necessary to be careful about the content of the report published. For example, any proprietary information was to be deleted before publication. Moreover, the report was to be limited to factual statements and was not to include judgments on the conduct of companies or personnel.[28] Subsequently, the USGS Pacific and Gulf Area Oil and Gas Supervisors modified OCS Order No. 12 (Public Inspection of Records) which now makes

26/ Draft Environmental Statement, Santa Barbara Channel, Vol. 3, p. IV-56.

27/ Memorandum to Oil and Gas Supervisor, Gulf Coast Region from Chief, Conservation Division on the subject of Notification and Investigation of Accidents, USGS, April 12, 1971

28/ Op.cit., Draft Environmental Statement, Santa Barbara Channel, Vol. 3, p. IV-56.

provisions for all accident investigation reports, pollution incident reports, facilities inspection data, and records of enforcement actions, etc., to be available for public inspection.[29] This requirement is also included in the proposed Alaska Orders.

4. Physical Technology Improvement

1) Subsea

In July 1973 and January 1975, the USGS asked the petroleum industry to assess the status of subsea technology. The Survey requested information in the following areas:[30]

(1) Depths at which current and projected subsea systems are economical

(2) Costs of drilling, completing, and maintaining subsea wells

(3) Flowline connection and servicing

(4) Navigation for well location and reentry

(5) Well Maintenance and repairs

(6) Subsea separation and storage

(7) Diving limitations.

The comments received to this request have been published and are presently being evaluated by Survey personnel.

2) Wearout Prevention

"The proposed revision of the Gulf of Mexico Area OCS Order No. 8 includes an erosion control program. This is also the

29/ Final Environmental Statement Proposed Increase in Oil and Gas Leasing on the Outer Continental Shelf, Vol. 3, pp. 150-151 and Federal Register, Vol. 39, 1974, pp. 26656 and 45059.

30/ Federal Register, Vol. 40, p. 1107.

subject of one of the APIUSGS Research and Development Committee's projects. The Pacific Area will review the Gulf of Mexico Area OCS Order No. 8 when completed, for adaptation of the erosion control section to the Pacific Area."[31]

3) Systems Analysis

The results of studies performed on 13 installations in the Gulf of Mexico by General Electric and Southwest Research are being evaluated by USGS for possible adoption of system analysis into the lease management program.[32] On January 14, 1975, USGS published a notice of intention to develop a standard for and an OCS order on system design analysis.[33]

An example of the feasibility of systems analysis was given in the environmental statement recently issued for oil and gas development in the Santa Barbara Channel. Exxon contracted with General Electric to perform system analysis for the initial Santa Ynez Unit, Hondo Field Development, Santa Barbara Channel. The study found that only 28 of 2,400 functional components were in need of additional analysis and these could be improved by suggested design improvements. The study also concluded that for a facility of its size and complexity, the proposed Santa Ynez Unit facilities had minimum problems when compared to similar facilities studied by General Electric in the Gulf of Mexico.[34]

31/ Draft Environmental Statement, Santa Barbara Channel, Vol. 3, pp. 1V-61-62.

32/ Ibid, p. 1V-60.

33/ Federal Register, Vol. 40, No. 9, January 14, 1975, p. 2597.

34/ Ibid, pp. 1V-60, 1V-61.

The Marine Review Board also has investigated the application of systems analysis techniques to offshore oil and gas operations, with the purpose of deciding if documents similar to API RP 14C would be feasible.[35] After reviewing and evaluating various adaptations of advanced safety and reliability analysis techniques and oil spill data,[36] the Subpanel on Systems Analysis compiled: a) A list of the various operational systems and equipment components of offshore petroleum operations; and b) A list of presently available API specifications, standards, and recommended practices (RP) documents. Following this, additional documents or studies were suggested and priorities were assigned to the suggestions. One result of this investigation appears as TABLE II-14.

5. Personnel Safety, Training, and Motivation

A committee has been formed in conjunction with the American Petroleum Institute on Offshore Safety and Anti-Pollution Training and Motivation. The committee is outlining the training needed for personnel working offshore, establishing curricula, and establishing a time framework for implementing this. A considerable amount of vocational training and some safety training is being accomplished under the auspices of the Committee on Vocational Training of the Division of

35/ API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Subsurface Safety Systems for Offshore Production Platforms uses recognized systems analysis methods to develop requirements for a safety system and includes procedures to document the safety system and verify performance with the RP.

36/ USGS oil spill data for the Gulf of Mexico was used along with report by J.E. Ritchie, Jr., J.F. Allen, R.M. Fettes, R.G. Roote, W.A. Shortt, E.B. Bell, and J. Winn, Petroleum Systems Reliability Analysis, Vol. 1 - Engineering report and Vol. 11 - Appendices (Washington, D.C.: EPA, August, 1973) in Second Report of the Review Committee on Safety of Outer Continental Shelf Petroleum Operations.

NO. OF SPILLS	RANK	SYSTEM	SUBSYSTEM	EQUIPMENT
3309	1	GATH./DISTR.	PIPELINE	PIPE, SCRAPER TRAPS, PIPE SUPPORTS, ROAD & STORM CROSSINGS
897		GATH./DISTR.	GATHERING	PIPE, SCRAPER TRAPS, PIPE SUPPORTS, ROAD & STREAM CROSSINGS
1426		PRODUCTION	GATHERING	FLOWLINES, MANIFOLDS, (SCRAPER TRAPS, VALVES, CHOKES, HEADERS, FITTINGS)
5632				
139	2	GATH./DISTR.	STORAGE	TANK, TANK ASSOCIATED EQUIP., TANK FIRE WALLS, POWER TANK
1153		PRODUCTION	LOCAL STORAGE	TANK ASSOCIATED EQUIP., FIRE WALLS, PUMP SYSTEM, POWER
1292				
569	3	PRODUCTION	TREATER	HEATER TREATERS, ELECTRIC TREATERS, SKIMMERS (SETTLING), FREE WATER KNOCKOUTS, DESANDERS, PRECIPITATORS, GUN BARRELS, & CONTROLS FOR EACH.
530	4	PRODUCTION	SEPARATOR	H.P. SEPARATORS, I.P. SEPARATORS, L.P. SEPARATORS, 3-PHASE SEPARATORS, SCRUBBERS, & CONTROLS FOR EACH.
294	5	PRODUCTION	WELLHEAD	CASING HEAD & TUBING HEAD EQUIP., XMAS TREE (FIXED CHOKES, ADJUST. CHOKES, MANUAL VALVES, AUTO VALVES, ELECTRIC DOWNHOLE PUMP, ROD PUMP, GAS LIFT, HYDRAULIC LIFT)
224	6	GATH./DISTR.	PUMP STATION	MANIFOLDS, PUMPS, POWER, & CONTROLS FOR EACH, METERING EQUIP., COMMUNICATIONS EQUIP.
113	7	PRODUCTION	CUSTODY TRANSFER	PUMPS, METERING EQUIP., MANIFOLD, SAMPLING EQUIP., POWER, PROVER TANK, AUTO. PUMP CONTROL
75	8	DRILLING	ALL	ALL
70	9	PRODUCTION	WELL	PRODUCING ZONE, CASING STRINGS & CEMENT, PRODUCTION TUBING, DOWNHOLE ASSEMBLY.
61	10	PRODUCTION	WATER DISPOSAL	INJECTION WELL; PUMPS, TURBINES & POWER; CLARIFYING TANKS; FLOTATION CELLS; FILTERS; SETTLING PITS & TANK OXYGEN STRIPPING TANKS
6	11	GATH./DISTR.	SAFETY	ENERGY SOURCE & DISTR. EQUIP., SENSING & SIGNALING EQUIP.
54		PRODUCTION	SAFETY	MONITOR. & ALARM PANELS, SIGNAL RELAY SWITCHING EQUIP., SAFETY REACTION ACTUATOR EQUIP., MANUAL OVERIDE, SUBSURFACE SAFETY VALVE, SURFACE SAFETY VALVE, FIRE FIGHTING & OTHER EMERGENCY EQUIP.
60				
19	-	UNIDENTIFIED	-	-
21	-	GATH./DISTR.	UNIDENTIFIED	-
266	-	PRODUCTION	UNIDENTIFIED	-
9226				

TABLE II-14 Ranking Based on Number of Spills and System Descriptions Used in USGS Data and in CSC Study for EPA

Production of API through courses given in various colleges and universities in the Gulf and Pacific Coast areas. The International Association of Drilling Contractors also trains drilling personnel.[37] The API and petroleum industry are also taking the lead in developing a motivation program.

Three major publications have been recently issued by API which deal with training and motivation:

(1) API RP T-1, Recommended Practice for Orientation Program for Personnel Going Offshore for the First Time, First Edition, January 1974.

(2) API RP T-2, Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work with Anti-Pollution Safety Devices, First Edition, September 1974.

(3) API Bulletin T-5, Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations, First Edition, September 1974.

Moreover, a new subcommittee on occupational safety for drilling and well servicing operations has been formed by API, Division of Production.[38]

USGS

Evidence of implementation of training requirements is seen in the January 1975 revision of Gulf OCS Order No. 2 in the section on well control:[39]

37/ Report of the Work Group on OCS Safety and Pollution Control, (May 1973), p. 18.

38/ API Monogram, June 1975.

39/ OCS Orders 1 Thru 12 Governing Oil, Gas, and Sulphur Leases in the Outer Continental Shelf Gulf of Mexico Area, January, 1975.

Training

Company and drilling-contractor supervisory personnel shall be trained in and knowledgeable of present-day well control. The operator shall maintain a record of such training on the facility. Training shall include:

(a) Abnormal pressure detection methods

(b) Well control operations, including kicks, lost circulation, and trips.

In a letter to API of June 15, 1975, USGS stated that it plans to require minimum levels of training for offshore operating personnel and would continue to monitor the training course outlines and curricula prepared by educational institutes and operating companies, although the Solicitor had recently decided that the joint API-USGS committees would have to change their status.[40] This same letter stated that appropriate training courses established by API and other organizations, upon approval by USGS, may form the basis for these requirements.

6. Standards and Specifications

1) API-USGS Actions

A cooperative committee on offshore safety and antipollution standards has been formed in conjunction with the American Petroleum Institute, the offshore Operators Committee in the Gulf of Mexico and the Western Oil and Gas Association (WOGA). The first project undertaken by the committee was the development of a

40/ Letter from V.E. McKelvey, USGS, to Roy Carlson, API, on subject of USGS-API cooperative committees, June 15, 1975.

recommended practice for design, installation and operation of subsurface safety valve (SSSV) system (API RP 14 B) and specifications for subsurface safety valves (API Standard 14 A). These were published in 1974. Supplement 1 to 14A: Specification for Subsurface Safety Valves was issued in April, 1975. This supplement clarified requirements for a metallic materials, testing and quality assurance for subsurface safety valves. An API test facility is now available for subsurface safety valve performance testing at Southwest Research Institute, San Antonio, Texas.

2) USGS Procedure for the Development of Standards

USGS established the following interval procedures for the development of standards for OCS operations on June 20, 1974.[41]

(1) The Chief, Branch of Marine Oil and Gas Operations, Conservation Division, USGS, will be responsibile for the OCS standards development program of the U.S. Geological Survey in accordance with Recommendation No. 5, Report of the Work Group on OCS Safety and Pollution Control, May 1973.

(2) The American Petroleum Institute, the American Society for Testing Materials, the American Society of Mechanical Engineers, the National Association of Corrosion Engineers, and other similar organizations, as appropriate, will be requested by the USGS to identify, develop, and update as required, needed standards. USGS representatives will participate in these efforts.

41/ Third Report of the Review Committee on Safety of Outer Continental Shelf Petroleum Operations to the U.S. Geological Survey, March 1975, pp. 2-3.

Standards developed by these organizations, and appropriate existing standards now referenced in OCS Orders, will be submitted to the American National Standards Institute (ANSI). (Although the ANSI does not itself develop standards, it provides the organizational mechanism for coordinated development and independent determination of national recognition and acceptance.)

(3) Pending approval by ANSI, standards will be reviewed by the USGS to determine the advisability of requiring early compliance by OCS operators.

(4) All standards approved by ANSI and adopted by the USGS, andthose determined to be appropriate for adoption prior to ANSI approval, will be either (a) issued as a Notice to Lessees and Operators and later referenced in appropriate OCS Orders, or (b) initially referenced in OCS Orders, whichever is appropriate.

(5) The Review Committee on Safety of Outer Continental Shelf Petroleum Operations, Marine Board, National Academy of Engineering, will be requested to review the standards program of the USGS and provide recommendations. As appropriate, the Committee will also be requested to review draft standards. The Review Committee was of the opinion that if this procedure was well publicized and followed it would give USGS wider acceptance and credibility by those concerned with the safety of OCS operations. USGS and ANSI have begun to discuss the utilization of ANSI in developing USGS safety and pollution control standards.

3) Certification of Jack-Up Rigs

The Coast Guard is considering certification of mobile drilling units. This was a subject for discussion at the National Offshore Operations Industry Advisory Committee meeting in late August 1975.[42]

7. Information and Data

1) Standardization of Pollution Forms

The Pacific USGS Area has reviewed the Gulf of Mexico proposed pollution form and a form has been agreed upon.

2) Engineering Documentation

"This recommendation has been fully implemented in the Pacific Area to the extent that all of the recommended documentation is in each operator's field office. Similar documentation is in the U.S. Geological Survey Area and District Office except for parts lists and specifications for all functioning components. The current Pacific Area OCS Order No. 8 requires this information to a large degree, although in some cases, the particular items recommended for documentation are not specifically addressed. However, the Pacific Area will review the Gulf of Mexico revised OCS Order No. 8, when completed, for consideration and possible adaptation to the Pacific Area."[43] The Proposed Gulf of Alaska Order No. 8 does include engineering documentation requirements (wiring diagrams, piping layouts, etc.).

42/ National Offshore Operations Industry Advisory Committee, (U.S. Coast Guard, Federal Register, Vol. 40, No., 156, August 12, 1975), p. 33851.

43/ Draft Environmental Statement, Santa Barbara Channel, p. IV-61.

3) Information Exchange

A "Safety Alert" system was initiated in September 1972 in the Pacific and Gulf of Mexico Areas. With this system operators are advised of accidents occurring during OCS drilling and producing operations to let the industry know immediately of its own mistakes and malfunctions so that improvements can be made where applicable. The Marine Board Review Committee noted that the technical aspects of the notices appear to confirm the merits of applying Failure Mode Effects and Analysis and Hazards Analysis Techniques to Offshore Operations.[44]

(1) Reference is made to specific OCS Orders, where applicable

(2) Reference is made to API specifications

(3) Reference is made to other documents which discuss the system or component whose failure lead to the notice

(4) Actions recommended to correct the problem are included.

In addition to the "Safety Alert" notices, it is sometimes necessary to modify the existing set of regulations on very short notice. In this purpose, "Notices to Lessees and Operators" are used. The notices have the same effect or status as OCS operating Orders and regulations and are used when immediate clarifications or additions to existing orders and regulations are necessary. (TABLE II-15)

4) Information Needs and Data Collection

Much attention has been given to the lack of geological and geophysical data available to the Federal Government which could be

44/ First Report of the Review Committee on Safety of Outer Continental Shelf Petroleum Operations, January, 1974.

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
3-22-72	Flash fire in the production facilities of a producing platform	Overheating of heat transfer fluid (chemical circulating pumps not operating)	1. Heat transfer fluid expansion tanks should be equipped with a large secondary relief valve which should be operationally tested monthly and before each start-up. 2. Control mechanism should be installed to prevent the main burner fuel valve from operating when the chemical circulating pumps are not operating. 3. Expansion tanks should be pressure-rated vessels constructed to withstand pressures exceeding the normal operating pressure range. 4. Heat sensors should be installed immediately downstream of the firebox and be in continuous service.
12-13-72	Blowouts in wells drilling at shallow depth	Failure to detect shallow hydrocarbons	The use of gas detection equipment for continuous monitoring of the hydrocarbon content of the returning mud stream on all exploratory wells drilling on OCS leases in the Gulf of Mexico Area is recommended from the time conductor pipe is set until total depth is reached. It is recommended that all operators review 30 CFR 250.41 and OCS Order No. 2 and caution drilling personnel as to proper procedures to be followed in case of threatened loss of well control at shallow depths.

TABLE II-15 Safety Alert Notices

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
1-3-73	Flash fire in the production facilities of a gas production platform	Gas and condensate released through a crack in the threads of the glycol return line at the contact tower	1. Design piping such that pump induced vibrations and other vibrations are damped out at the source and not transmitted through the piping system. 2. Perform periodic maintenance inspections of piping systems and identify and eliminate piping vibrations whill will cause this type of failure. 3. Insulate or use double wall exhaust stacks on all hot surfaces which are a potential ignition source, especially in areas of possible release of produced hydrocarbons or other flammable liquids.
1-9-73	Two flash fires on OCS installations	Welding sparks	1. These documents should be consulted in order to establish procedures and precautions which are necessary in the performance of safe cutting and welding operations. (1) API RP 2009 "Safe Practices In Gas and Electric Cutting and Welding", (2) National Fire Protection Association Bulletin No. 51B "Cutting and Welding Processes 1971", (3) Offshore Operators Committee, "Manual of Safe Practices in Offshore Operations". 2. Prior to performing any cutting or welding outside of an approved fire safe area, a work permit should be obtained from the individual responsible for authorizing the work. Prior to issuing this permit, the work location should be inspected by the responsible individual to insure that the area is safe for cutting and welding operations. Detailed information on the scope of the area inspection may be obtained from the above listed documents.

TABLE II-15 Safety Alert Notices (Continued)

79-065 O - 76 - 8

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
1-9-73 Continued			3. All equipment used in the operation, cutting and welding apparatus, gas and vapor detection equipment, and fire extinguishing equipment, should be maintained in good operating condition. 4. A periodic review of safety precautions relating to cutting and welding operations and a review of firefighting techniques are necessary training field personnel. 5. Fire extinguishing equipment must be inspected frequently and completely to insure that it will be in working condition when needed.
6-15-73	15 flash fires reported by OCS Gulf of Mexico Area oil operators during the first 4 months of 1973	Gas engine related explosions/fires	1. Equipment availability permitting, replace fabric air intake hoses between air filter and carburetor with flexible metal or wirebraid reinforced hose. 2. Use a portable combustible gas detector to perform leak checks during scheduled gas engine inspections. 3. Install a relief valve downstream of engine sensitive regulators to prevent excessive fuel gas pressure.

TABLE II-15 Safety Alert Notices (Continued)

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
6-15-73 Continued		Glycol reboiler fires	1. Check for and correct any leaking connections, especially in the area of any direct or indirect fired vessel. Leak detection and correction in these areas are particularly important because of the ever present ignition source. 2. Maintain the integrity of insulation on those surfaces which operate at a temperature which could possibly ignite the vapors and gases handled in the area. The ignition temperature for petroleum vapors is 536°F and that for natural gas is 900°F.
		Engine exhaust fires	Each facility is somewhat unique insofar as specific maintenance requirements are concerned; however, the below listed documents generally apply to all installations and should be useful as guides in accomplishing a safer operation. 1. API RP 7C-11F. Recommended Practice for Installation, Maintenance and Operation of Internal-Combustion Engines. 2. National Fire Protection Association Bulletin No. 37, Stationary Combustion Engines and Gas Turbines, 1970. 3. API Division of Refining. Guide for Inspection of Refinery Equipment.

TABLE II-15 Safety Alert Notices (Continued)

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
9-17-73	90 barrels of poisonous cyanide adrift	Ship Collision	1. If a barrel is sighted - do not try and recover, but note the time, location, and direction of drift. 2. Notify all sightings immediately to the Commander Eighth Coast Guard District at A/C 504/527-6225.
11-16-73	Pollution	Well left unattended with subsurface safety device removed, master valve open, wing valve open, flowline disconnected	1. Establish a procedure whereby the lease operator's personnel secure each unmanned platform after or during the departure of all other personnel. 2. A night inspection procedure of unmanned platforms, assuring at least one inspection per night, with the exception of inclement weather qualification.
11-19-73	Flash Fire	Catalytic heater unit equipped with the wrong fuel gas regulator. Lack of attention to the safety features for installation of device which uses fuel gas	There are presently no standards which can be referenced for the manufacture or installation of catalytic heater units. It is essential that responsible operator personnel investigate all necessary safety provisions for heater unit installation. In the absence of any directly applicable installation standard for catalytic heaters, NFPA Bulletin No. 54, "Installation of Gas Appliances Gas Piping 1969", could be used to point out some of the safety items which must be provided. Ignition temperature considerations are necessary in determining insulation requirements for hot surfaces. The general practice is to insulate those surfaces having an operating temperature above 400°F. NFPA's Bulletin No. 325M, "Fire Hazard Properties of Flammable Liquids, Gases, Volatile Solids, 1969", contains an excellent discussion of this subject and is recommended as a reference document.

TABLE II-15 Safety Alert Notices (Continued)

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
8-1-74	Accidents on platforms resulting in fires, pollution, serious injuries to personnel, and major damage to platforms and equipment	Inadequate planning and safety control procedures	More advance analysis of the potential adverse effects of operations to be conducted; improved safety control procedures; better training of personnel involved in offshore operations.
8-15-74	Valve stems blew out while an attempt was made to close them	Excessive torque required to close the valves	Valves can be modified to correct the potentially dangerous situation. Address to write to for information was given.
10-17-74	Fire on offshore production platform	Leak in heat exchanger tubes	To prevent a recurrence of this incident the operator has: 1. Replaced the heat exchanger tubes 2. Piped the surge tank relief valves to a flare scrubber 3. Installed high-pressure shutdown controls on the surge tank to actuate an inlet shut-in valve 4. Initiated a monthly pressure test of the heat exchanger tubes
11-27-74	Offshore workboat collided with well satellite structure during the night	Aids to navigation had been rendered inoperable 2 weeks earlier by hurricane and the service contractor was unable to make repairs because of extensive damage in the area	In order to prevent recurrence of this accident, when aids to navigation are lost from service on a structure, the operator plans to install as quickly as possible temporary NAVAID equipment for use in the interim until repairs to permanent equipment can be made.

TABLE II-15 Safety Alert Notices (Continued)

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
11-20-74	Minor fire spread to a life raft which contained chlorine tablets producing chlorine gas	Heat from generator exhaust set fire to the tie down ropes of the life raft	Inspect all platforms to insure that all combustible material is a safe distance from engine exhausts.
11-27-74	Fire on offshore production platform	Overturned wireline barge punctured a gas line	To prevent recurrence of this type of accident, the operator is designating certain areas in the vicinity of structures as safe locations for jack-up rigs; and in the event a similar situation occurs where an object poses a threat of colliding with a structure, operations will be suspended and the facilities placed in a safe condition.
11-27-74	Wireline lubricator ruptured under pressure	Faulty construction of rented equipment	Exercise greater caution in the choice of 3rd party rental equipment to insure that adequate quality and strength are present to safely contain well pressures.
11-26-74	Fatal injury to a roustabout who fell off a rig onto the tie-up line of a mud transport boat	Roustabout cut the rope securing a hose to rig railing before the crane picking up the hose had removed all the slack	Rig supervisory personnel should instruct all crews in the proper hose handling procedure for the off-loading of drilling mud onto transport boats.
11-27-74	Fire on offshore production platform	Gas flowing from an open-ended line was ignited by welding operations	1. All open piping, regardless of type, is blind flanged or plugged. 2. All valves not used on a day-to-day basis are locked. 3. Proper planning with a written detail of the work plans is formulated prior to commencing operations. 4. It is ascertained that personnel have proper knowledge of piping and flow schematics before operating the facilities.

TABLE II-15 Safety Alert Notices (Continued)

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
11-27-74 Continued			5. The appropriate portion of the company operating instruction letter or manaul is reviewed. 6. All wells are shut in during welding operations, except those supplying generator gas. 7. All personnel not involved in the welding or cutting are to stay out of the work area.
2-13-75	2 men drowned	Unusually large wave swept them off a catwalk	1. Handrails have been installed on both sides of the catwalks. 2. Employees have been instructed to wear life jackets at all times when working on catwalks or boat landings near the water. 3. Employees have been instructed never to work in these areas alone, but to work in two-man teams.
2-13-75	Oil Spill	Safety system malfunction resulted in failure to shut in a well	Operator should instruct the switcher not to leave the wells on the facility producing unless there is sufficient storage tank space to permit flowing the wells until he returns the following day.
2-24-75	Falling line and ball struck a roustabout causing fatal injury	Crane operation	To attempt to prevent a recurrence of this type accident, the drilling contractor is more closely following the recommendations of the crane manufacturer in reconditioning and maintenance of the crane and is also requiring review of procedures for safe crane operations by all rig personnel. Available publications containing information for use as guidelines for safe crane operations are as follows: Offshore Operators Committee, Manual of Safe Practices in Offshore Operations, Section XII, "Crane Safety Procedures", New Orleans, LA

TABLE II-15 Safety Alert Notices (Continued)

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
2-24-75 Continued			American Petroleum Institue, API Recommended Practices on Care and Use of Oil-Field Equipment, RP 2D, Offshore Cranes, Dallas, Texas
4-16-75	Crewman killed when struck by falling equipment	Safety device installed but not in operation at the time of the accident	1. Drilling crews have been instructed to count the joints in each stand when coming out of the hole. 2. The traveling block safety device is to be readjusted and placed in service every time the drilling line is slipped and cut. 3. The traveling block safety device is to be checked weekly for proper operation. 4. All exits from the rig floor are to be kept clear, allowing quick access to a safe place in the event of an emergency.
4-30-75	Fire on a production platform	Cap of a well choke blew off	1. All choke body and cap threads will be brushed, inspected and gauged, at regular intervals, and replaced if necessary. 2. Emphasis will be placed on lubrication of threads during the regular inspection interval with a thread lubricant having corrosion and erosion inhibiting qualities.
5-6-75	Fire on offshore production platform	Gas escaping from the tope of an open sump tank ignited	1. Install seals and locking devices on the lids. 2. Install a connection for attaching bleed-off hoses. 3. Install a gas vent line and route to a safe location.

TABLE II-15 Safety Alert Notices (Continued)

DATE OF NOTICE	TYPE OF SITUATION THAT OCCURRED	CAUSE	CORRECTIVE ACTION TAKEN AND/OR RECOMMENDATIONS
6-2-75	Offshore drilling rig blowouts	Drilling into shallow gas zones	1. Use additional casing strings and/or liners in the shallow portion of the hole in order to obtain more formation competency at the casing seats. 2. Plan casing and liner points based on the location of possible shallow gas zones indicated by geophysical data. 3. Use higher mud weights when drilling into suspected shallow gas zones. 4. Redesign bottom-hole drill assembly to minimize the possibility of swabbing. 5. Use closer control of drilling rate and surveillance of drilling operations. 6. Work on elimination of mechanical problems concerning riser-diverter assembly.

TABLE II-15 Safety Alert Notices (Continued)

used in the determination of the location and value of potential oil and gas reserves and also to determine the nature and magnitude of geologic hazards prior to tract selection.

In response to this criticism, USGS proposed new regulations which define policies, procedures, and requirements for geological and geophysical exploration on the OCS.[45] An important aspect of the regulations is the provision for disclosure of the data both to the USGS and the public. The regulations would require a permittee to submit to the USGS all geological and geophysical data obtained through his explorations. In terms of public disclosure, the following time periods would apply:

(1) Geologic data would be release in 6 months

(2) Geophysical data would be made public within 10 years or whenever a lease is relinquished, whichever period is less

U.S. Geological Survey Orders for the mid-Atlantic Region

This part of the working paper covers two topics:

1. Status of the OCS orders for the mid-Atlantic region: seven of the fourteen orders for the region have been issued; the other seven will not be issued until sometime after the August 1976 lease sale in the Atlantic.

2. Discussion of how USGS OCS orders are prepared, and what level of detail they have. They are compared with Coast Guard

45/ "Oil, Gas, and Sulphur Operations: Geological and Geophysical Exploration," Federal Register, Vol. 40, No. 78, April 22, 1975, and accompanying news release of April 18, 1975.

regulations, which tend to set much more specific standards for comparable offshore facilities.

Status of the OCS Orders for the Mid-Atlantic Region

The Interior Department's U.S. Geological Survey now issues separate sets of OCS "orders" (regulations) for each area of the country in which OCS tracts are leased. Presently there is a set of orders for the Gulf of Mexico area, and a Pacific Coast set issued recently to cover petroleum development off the Southern California coast. Several orders have been issued for Alaska; others for Alaska are now being drafted.

At the present time a full set of these regulations includes twelve orders, all dealing either with equipment or OCS operating procedures. For instance, the twelve orders for the Gulf of Mexico are listed in TABLE II-16. The numbering sequence of orders for one area is consistent with those for other areas; for example, each area's #2 deals with "drilling procedures," and the numbering of other orders is similarly consistent.

In addition, the Survey now is preparing orders in three new categories, though none of these has yet been issued for any of the four major OCS regions of the country.

-- Order #13: "Production, Measurement, and Comingling." This will regulate production, including in offshore areas where two or more companies are drilling into the same oil deposit. It also will set policy on how to comingle oil and gas, and will set procedures by which USGS will measure production. This measurement activity is important because the government receives royalties based on the amounts of oil and gas produced from the offshore wells.

ORDER NO. 1-"MARKING OF WELLS, PLATFORMS, AND FIXED STRUCTURES"	COVERS THE IDENTIFICATION OF WELLS AND OTHER STRUCTURES. THIS IDENTIFICATION MUST BE OF A SIZE AND LOCATED AS TO BE LEGIBLE FROM THE AIR OR THE WATER SURFACE.
ORDER NO. 2-"DRILLING PROCEDURES"	DESCRIBES CASING AND CASING-CEMENT REQUIREMENTS, BLOWOUT PREVENTION EQUIPMENT, AND DRILLING MUD PROGRAMS. IT GOVERNS DRILLING OPERATIONS FOR ALL EXPLORATORY AND DEVELOPMENT WELLS NOT COVERED BY FIELD RULES. FIELD RULES MAY BECOME APPLICABLE UPON COMPLETION OF FIVE WELLS IN AN OIL OR GAS FIELD AND TAKE INTO CONSIDERATION SPECIFIC PROBLEMS ENCOUNTERED IN THE AREA.
ORDER NO. 3-"PLUGGING AND ABANDONMENT OF WELLS"	DESCRIBES THE PLUGGING WITH CEMENT OR MUD THAT IS REQUIRED FOR WELL ABANDONMENT OR SUSPENSION OF OPERATIONS.
ORDER NO. 4-"SUSPENSIONS AND DETERMINATION OF WELL PRODUCIBILITY"	ESTABLISHES CRITERIA FOR DETERMINING WHETHER A WELL IS CAPABLE OF PRODUCING OIL OR GAS IN PAYING QUANTITIES.
ORDER NO. 5-"INSTALLATION OF SUBSURFACE SAFETY DEVICE"	REQUIRES THE INSTALLATION OF A VALVE IN THE TUBING OF A WELL TO CLOSE THE WELL AUTOMATICALLY IF ABNORMAL CONDITIONS DEVELOP.
ORDER NO. 6-"PROCEDURE FOR COMPLETION OF OIL AND GAS WELLS"	CONTAINS REQUIREMENTS FOR TESTING OF WELLHEAD EQUIPMENT AND THE PROCEDURES FOR MULTIPLE AND TUBINGLESS WELL COMPLETIONS.
ORDER NO. 7-"POLLUTION AND WASTE DISPOSAL"	COVERS THE VARIOUS ASPECTS OF POLLUTION CONTROL FROM PREVENTION TO REMOVAL. IT CALLS FOR PERIODIC INSPECTION OF PRODUCING FACILITIES BY THE OPERATOR AND ESTABLISHES A REPORTING PROCEDURE IN CASE OF POLLUTION.
ORDER NO. 8-"APPROVAL PROCEDURE FOR INSTALLATION AND OPERATION OF PLATFORMS, FIXED AND MOBILE STRUCTURES, AND ARTIFICIAL ISLANDS"	COVERS GENERAL DESIGN AND NONDESIGN FEATURES, THE PROCEDURE FOR APPLICATIONS FOR INSTALLATION, AND THE REQUIREMENT FOR CERTIFICATION OF STRUCTURAL PLANS.
ORDER NO. 9-"APPROVAL PROCEDURES FOR PIPELINES"	INCLUDES REQUIREMENTS FOR APPROVAL OF GENERAL DESIGN AND INSTALLATION AS WELL AS TESTING PROCEDURES. IT ALSO COVERS THE INSTALLATION OF SAFETY AND POLLUTION-CONTROL DEVICES AND PROCEDURES FOR INSPECTION AND MAINTENANCE OF THE LINE THROUGHOUT ITS LIFETIME.
ORDER NO. 10-"SULPHUR DRILLING PROCEDURES OFF LOUISIANA AND TEXAS"	A LOCALIZED ORDER COVERING THE ONLY AREA IN THE WORLD WHERE SULPHUR IS PRODUCED OFFSHORE.
ORDER NO. 11-"OIL AND GAS PRODUCTION RATES, PREVENTION OF WASTE, AND PROTECTION OF CORRELATIVE RIGHTS"	ESTABLISHES CRITERIA FOR DETERMINING MAXIMUM EFFICIENT WELL PRODUCING RATES AND OTHER ACTIVITIES FOR MAXIMIZING ULTIMATE OIL AND GAS RECOVERY.
ORDER NO. 12-"PUBLIC INSPECTION OF RECORDS"	OUTLINES THE REPORTS RECEIVED BY THE AREA OFFICES WHICH ARE AVAILABLE FOR INSPECTION UNDER THE PUBLIC INFORMATION ACT.

TABLE II-16 Summary of the OCS Orders for the Gulf of Mexico Area

-- Order #14: "Approval of Suspensions of Production." Orders in this category presumably will prevent oil companies from holding back production.

-- Order #15: This category has no official title as yet, but will describe States' formal access to non-proprietary information on oil company exploration and development plans, including their plans for OCS-related onshore facilities. State officials have wanted better access to such information for some time.

Seven OCS orders for the mid-Atlantic area were issued on July 12, 1976.[46] These are Orders 1, 2, 3, 4, 5, 7, and 12, each covering the same topic as its like-numbered counterpart for the Gulf area. There appears to be little difference in content between the Gulf and Atlantic orders, though some of the Atlantic orders are more detailed than their Gulf counterparts.

No Order #10 is contemplated for the mid-Atlantic region, since category #10 deals with sulfur extraction, an activity which occurs in the Gulf but which is not contemplated for the Atlantic.

The Draft Environmental Impact Statement for the proposed mid-Atlantic OCS lease sale stated that "Orders 6, 8, 9, and 11 are still undergoing internal review and will be available for public comment before the proposed sale."[47] However, this position was not taken by USGS,

46/ 41 Federal Register 28553, July 12, 1976.

47/ U.S. Department of the Interior, Bureau of Land Management, Draft Environmental Statement, Proposed 1976 Outer Continental Shelf Oil and Gas Lease Sale Offshore the Mid-Atlantic States, Undated (but presumably 1975), Vol. 2, p. 314.

but by the Interior Department's Bureau of Land Management, the leasing agency and author of the draft statement. USGS plans to issue these four orders--which deal with production rather than early offshore operations--after the lease sale, but before oil company exploration and development plans are approved.

USGS' OCS Orders and Standards Section offers two reasons why these four mid-Atlantic orders have not been issued yet. First, Orders #6 (completion of wells), #8 (platforms), and #9 (pipelines) are being postponed until the Survey arranges a "memorandum of understanding" with the Department of Transportation; such a memorandum is valuable because both the Coast Guard and DoT's Office of Pipeline Safety have some jurisdiction over OCS facilities. Second the Survey is waiting because it is now in the process of writing one set of "National Orders," combining the present four sets of regional orders. Thus they state that they do not wish to issue any more regional orders than they have to, and mid-Atlantic production orders are not immediately necessary.

The Nature of USGS Orders[48]

There is some concern about whether specific, detailed, and well-researched standards will be set for mid-Atlantic OCS development, production, and transportation. Two factors lead to this concern.

First, USGS appears to do little original research or testing before issuing a new set of orders, even though conditions of weather, seismic activity, and so forth differ substantially from one part of the country

48/ Much of the following discussion is taken from "Multi-Agency Regulation of Similar Offshore Technology Subsystems," a 3/12/76 report submitted to OTA by Engineering Computer Optechnomics, Inc. of Arnold, Maryland.

to another. Instead, the Survey issues draft orders in the Federal Register, based on the Gulf of Mexico orders, and modifies the drafts on the basis of comments received from other agencies, industry, and environmentalists. Little USGS testing of equipment or operating procedures seems to be done.

Second, and related, existing USGS orders tend to lack specificity. That is, while they state what kinds of procedures and equipment are required, e.g., blowout preventers, they rarely set specific design criteria or standards for such procedures and equipment.

Both these factors reflect a general USGS philosophy of approving designs and technology on an individual basis, checking only to see if they meet the very general specifications set forth in the OCS orders.

This philosophy is in marked contrast to those of some other agencies. For instance, the Coast Guard often specifies precise design criteria for equipment, recommends a method to translate those criteria into quantitative instructions, and then requires compliance with specific government or industry standards for design and construction.

A recent report prepared for OTA compared the USGS regulations for offshore platforms with Coast Guard regulations for similar deep-water port platforms. The difference in specificity is significant, as TABLE II-17 shows.

Some key points from the comparison are summarized in the paragraphs below.

1. General Design. In terms of design the USGS often espouses a philosophy of approving any given design on an individual basis commen-

TABLE II-17 Comparison of OCS Orders and Deepwater Port Regulations

	Extracts From USGS Gulf of Mexico Area OCS Order No. 8 Platforms and Structures, 10/30/70	Extracts From USCG Deepwater Port Regulations in Final EIS - Deepwater Port Act of 1974, P.L. 93-627
General Design	"The design of platforms, fixed structures, and artificial islands shall include consideration of such factors as water depth, surface and subsurface soil conditions, wave and current forces, wind forces, total equipment weight and other pertinent geological, geographical, environmental, and operational conditions"	"(a) Each fixed marine and floating component of a deepwater port, except hoses, mooring lines, and aids to navigation buoys, must be designed to withstand at least the combined wind, wave, and current forces of the most severe storm that can be expected to occur in any period of 100 years at the port. (Note: 'Recommended procedure for Developing Deepwater Ports Design Criteria' describes a method to prepare the wind, wave, and current criteria for use in determining the forces of the storm described by this paragraph.) (b) Each platform must be designed in accordance with the American Petroleum Institute 'Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms' (API RP 2A) sixth edition, January 1975, and the codes and standards in API RP 2A, to the extent that the recommended practice, codes, and standards are consistent with this subchapter. (c) Each electrical installation on a platform must be designed to the extent practicable in accordance with 46 CFR 110-113. (d) Each boiler and pressure vessel on a platform must be designed in accordance with Sections I, IV, and VIII of the American Society of Mechanical Engineers 'ASME Boiler and Pressure Vessel Code' 1974 Edition, to the extent that the code is consistent with this subchapter. (e) Main oil transfer piping on a platform must be designed in accordance with the American National Standards Institute (ANSI B 31.4) Liquid Petroleum Transportation Piping System."

TABLE II-17 Comparison of OCS Orders and Deepwater Port Regulations (cont.)

Emergency Power	"(4) An auxiliary electrical power supply shall be installed to provide emergency power capable of operating all electrical equipment required to maintain safety of operation in the event the primary electrical power fails."	"(a) Each PPC must have emergency power to operate all of the following at any time: (1) Emergency lighting circuits. (2) Aids to navigation equipment. (3) Communications equipment. (4) Radar equipment. (5) Alarm systems. (6) Electrically operated fire pumps. (7) Other electrical equipment designated in the Operations Manual by the licensee. (b) No emergency power generating equipment may be located in any enclosed space on a platform that contains oil transfer pumping equipment or other power generating equipment."
Fixed Fire Main	"(b) A firewater system of rigid pipe shall be installed and may include a fixed water spray system. Such a system shall be installed in a manner necessary to provide needed protection in areas where production handling equipment is located. A fire-fighting system using chemicals may be considered for installation in certain platform areas in lieu of a firewater system in that area, if determined to provide equivalent fire protection control. (c) Pumps for the firewater system shall be inspected and test-operated weekly. A record of the tests shall be maintained in the field and submitted semi-annually to the appropriate District Office. An alternate fuel or power source shall be installed to provide continued pump operation during platform shutdown unless an alternate fire-fighting system is provided."	"Each PPC must have a fixed fire main system for water that meets the requirements in § 149.453 through § 149.477" "§ 149.453 Fire Pumps (a) Each PPC must have at least two independently driven fire pumps that can deliver two streams of water at a continuous pitot tube pressure of 75 p.s.i. at each fire hose nozzle. (b) Each fire pump must have - (1) a relief valve on its discharge side that is set to relieve at 25 p.s.i. in excess of the pressure necessary to meet the requirement in paragraph (a) of this section. (2) a pressure gauge on its discharge side; and, (3) its own water source. (c) Fire pumps may only be connected to the fire main system." "§ 149.455 Fire Pump Location The fire pumps required by § 149.453 (a) may not be located in the same place."

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TABLE II-17 Comparison of OCS Orders and Deepwater Port Regulations (cont.)

"§ 149.457 Fire Hydrants
(a) Each part of the PPC that is accessible to any person, except machinery spaces, must have enough fire hydrants so that it can be sprayed with at least two spray patterns of water. At least one spray pattern of water must be from one length of hose.
(b) Each PPC must have enough fire hydrants so that each machinery space can be sprayed with at least two spray patterns of water from separate hydrants. Each spray pattern of water must be from one length of hose.
(c) A single length of fire hose, with nozzle attached, must be connected to each fire hydrant at all times."

"§ 149.459 Fire Hydrant Outlet
The outlet on each fire hose must not point above the horizontal"

"§ 149.461 Fire Hydrant and Control Valve Shut-Off Valve
Each fire hydrant and control valve must have a shut-off valve."

"§ 149.463 Fire Hydrant Access
Any equipment that is in the same space as the fire hydrant must not interfere with access to that hydrant."

"§ 149.465 Spanner
Each fire hydrant must have at least one spanner at the fire hydrant."

"§ 149.467 Fire Hose Rack
(a) Each PPC must have a hose rack at each hydrant.
(b) Each fire hose rack must be visible.
(c) Each fire hose rack in an exposed location must be protected from weather."

TABLE II-17 Comparison of OCS Orders and Deepwater Port Regulations (cont.)

"§ 149.469 Fire Hose
Each length of fire hose must be
(a) 1-1/2 or 2-1/2 inch nominal hose size diameter;
(b) 50 foot nominal hose size length; and
(c) lined commercial fire hose that conforms to Underwriters Laboratories, Inc. Standard 19 or Federal Specification ZZ-H-451D."

"§ 149.471 Fire Hose Coupling
Each fire hose coupling must
(a) be made of brass, bronze, or material that has strength and corrosion resistant properties at least equal to those of brass or bronze; and
(b) have 9 threads per inch for 1-1/2 inch hose or 7-1/2 threads per inch for 2-1/2 inch hose."

"§ 149.473 Fire Hose Nozzle
Each fire hose nozzle must be a combination solid stream and water spray fire hose nozzle that is approved under 46CFR 162.027."

"§ 149.477 Spray Applicator
Each PPC must have a low velocity spray applicator that is approved under 46 CFR 162.027 at each fire hydrant."

surate with local conditions but with no minimum criteria specified for either design or approval. The Coast Guard on the other hand dictates the criteria to which the platform must be designed, recommends a method to translate that criteria into quantitative forces, requires compliance with the American Petroleum Institute RP 2A for the basic structure design and construction, requires basic compliance with 46 CFR 110-113 (Subchapter J - Electrical Engineering Regulations) for the electrical installation, requires conformity with Sections I, IV, and VII of the ASME (American Society of Mechanical Engineers) Boiler and Pressure Vessel Code, and calls for main oil transfer piping to be in accordance with ANSI (American National Standards Institute) B 31.4 - Liquid Petroleum Transportation Piping Systems.

In practice, OCS platforms and structures may, from industry standards alone, meet all or most of the above referenced standards, codes, and practices. This is not required under the OCS order, however, and, thus it is conceivable that there may be disparity among OCS platforms and structures and even more conceivable that there may be disparity among OCS platforms and structures and those who fall within the purview of deepwater port regulations.

2. Emergency Power. In this instance, the USGS specifies a broad performance standard, i.e., "...provide emergency power capable of operating all electrical power required to maintain safety of operation..." whereas the Coast Guard specifically cites minimum services to be provided by emergency power such as communications equipment, radars, alarms, etc. The philosophical difference here

is that in the OCS instance, the applicant for the lease basically determines what is necessary for operational safety in terms of providing emergency power whereas in the deepwater port case the Coast Guard sets minimum emergency power loads for personnel safety and then accepts other operational safety loads specified by the applicant. (One exception to this is the USGS requirement for an alternate source of power to the fire pumps.)

3. Fixed Fire Main. At this level of equipment the disparity between the USGS Order and the Coast Guard Regulations is significant. While both require fixed fire mains in order "to provide needed protection" the USGS Order does not go beyond this conceptual requirement other than to give the applicant an option to substitute a chemical fire fighting system if desired and deemed equivalent and to require periodic tests of the pumps.

The Coast Guard on the other hand goes into elaborage detail on this system in its regulations concerning fixed fire main systems promulgated under the Deepwater Port Act of 1974. They, for example, require two independent fire pumps that can deliver two streams of water at a continuous pitot tube pressure of 75 p.s.i. at each fire hydrant. They also as a further example require that sufficient fire hydrants be provided throughout the platform such that any location can be protected with two hoses and that those fire hoses conform to UL Standard 19 or Federal Specification ZZ-H-451D with corrosion resistant coupling with a specified number of threads per inch as a function of hose diameter. As a final example, they require the fire hose nozzles and spray applicators to be approved under 46 CFR 162.027 which is a detailed equipment specification.

The significance of this discussion is that there is reason to doubt whether USGS has taken all reasonable regulatory steps possible to ensure that OCS facilities are safe and environmentally sound. However, one should add that it is to USGS and the Transportation Department's credit that the Survey and Coast Guard are working on a memorandum of understanding that will at least reduce the disparities between the regulations of the two agencies.

FEDERAL LAWS RELEVANT TO OFFSHORE DEVELOPMENT AND RELATED ONSHORE FACILITIES

This Appendix is meant as source material for the reader who wishes to know more about the federal statutes cited in the body of the total report. In the report itself, federal statutes are cited as the bases for the authority of a particular agency, but the statutes themselves are not described.

In this section, federal statutes relevant to all types of offshore development are summarized, and their particular relevance to offshore cevelopment is briefly described. Thus some statutes included relate only to Outer Continental Shelf oil and gas development, others to deep-water ports, others to any kind of offshore development, and still others relate only to the onshore facilities related to or resulting from offshore development.

A list of all federal statutes reviewed in this section immediately follows. Then reviews of each statute follow, in alphabetical order. Information contained in the review of each statute in most cases includes:

(1) Short Title
(2) Citation
(3) Pocket Part
(4) Synopsis of Law
(5) Lead Agency
(6) Relevance to Offshore Development
(7) Major Cases.

TABLE II-18 Listing of Federal Laws Reviewed

	Page
Anadromous Fish Conservation Act - 16 USC 757 a-f	II-113
Atomic Energy Act of 1954 - 42 USC 2011-2296 (See also Energy Reorganization Act of 1974)	II-114
Clean Air Act Amendments of 1970 - 42 USC 1957-1857f (1973)	II-115
Coastal Zone Management Act of 1972 - 16 USC 1451-1464 (1974)	II-117
Commercial Fisheries Research and Development Act of 1964 - 16 USC 779-779f (1974)	II-118
Department of Transportation Federal-Aid Highway Provisions - 23 USC 138, 204-217, 317, 319 (1966)	II-119
Deepwater Port Act of 1974 - 33 USC 1501-1524	II-120
Endangered Species Act of 1973 - 16 USC 1531-1543 (1974)	II-121
Energy Reorganization Act of 1974 - 42 USC 5801-5891 (See Atomic Energy Act)	II-114
Energy Supply and Environmental Coordination Act of 1974 - 42 USC 1857c-10 (1969) (See Clean Air Act) (Pocket Part in 1975)	II-123
Estuaries Areas Act - Title 16 1221-1226	II-163
Federal Power Act - 16 USC 791a-828c (1975)	II-124
Federal Water Pollution Control Act Amendments of 1972 (FWPCA) - 33 USC 1251+	II-125
Fish and Wildlife Act of 1956 - 16 USC 742(a)-754	II-127
Fish and Wildlife Coordination Act - 16 USC 661-667e	II-128
Fishery Zones--Extra-Territorial Sea - 16 USC 1091-1094 (1974)	II-129
Fish Restoration and Management Projects - 16 USC 777-777k	II-130
Intergovernmental Cooperation Act of 1968 - 42 USC 4201-4244	II-131
Intervention on the High Seas Act - 33 USC 1471-1487 (1970)	II-133
Investigations; Fish Propagation: Etc. - 16USC 744 (1974)	II-134

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Land and Water Conservation Fund
Act of 1965 - 16 USC 460-4 to 4601-11, etc. II-135

Marine Mammals Protection - 16 USC 1361, 62; 1371-1384 (1974) II-137

Marine Protection, Research, and Sanctuaries
Act of 1972 - 33 USC 1401-1444 II-138

Marine Resources and Engineering Development
Act of 1966 - 33 USC 1101-1108 (1970) II-139

Mineral Lands and Mining - 30 USC 181-199 (1971); 223-229; 351-359 II-140

Mining and Minerals Policy Act of 1970 - P.L. 91-631 (p. 2200)
84 Stat 1876 II-141

National Environmental Policy Act of
1969 (NEPA) - 42 USC 4321-4347 II-142

National Oceanic and Atmospheric Administration
- 33 USC 857-1 - 857-12 (1970) II-144

National Sea Grant College and Program Act of 1966 -
- 33 USC 1121-1124 (1970) II-145

Natural Gas Pipeline Safety Act of 1968 - 49 USC 1671 -1684 (1966) II-146

Naval Petroleum Reserves Act - Title 107421-7438 II-162

Occupational Safety and Health Act of 1970
-5 USC 5108, 5314, 5315, 7902 II-147

Oceanographic Research Vessels Act - 46 USC 441-445 (1958) II-150

Oil Pollution Act Amendments of 1973 - 33 USC 1001-1015 II-151

Outer Continental Shelf Lands Ace - 43 USC 1331-1343 (1964) II-152

Ports and Waterways Safety Act of 1972 - 33 USC 1221-1227 II-154

Recreational Use of Conservation Areas - Title 16 460K-K4 II-162

Resource Recovery Act of 1970 - 42 USC 3251-3254f; 3256-3259
(Amending the Solid Waste Disposal Act) II-155

Rivers and Harbors Act of 1899; Rivers and Harbors and Flood Control Act
of 1970 - 33 USC 401 et. seq. (1970); Title 33 CFR 33 USC 701 et. seq.
(1970); 205.10 et. seq.; 33 USC 540 et. seq. (1970); etc. II-156

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State Compacts for the Regulation of Fishing in Territorial Waters - Title 16 667	II-162
Submerged Lands Act (1953) - 43 USC 1310-1315 (1964)	II-158
Water Resources Planning Act - 42 USC 1962 (1974)	II-160
Wetlands Act of 1961 - Title 16 715CK-3) to CK-5)	II-162
Wildlife Restoration - 16 USC 669-669 (1974)	II-161

Anadromous Fish Conservation Act

Citation: 16 USC 757 a-f (1974); 43 CFR 17.1; 50 CFR 401.1 et. seq. IV

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act is for the purpose of conserving the anadromous fishery resources of the nation that are subject to depletion from water resources developments and other causes.

The Secretary of the Interior is authorized to enter into cooperative agreements with one or more states that are concerned with the conservation of such fish, and whenever he deems it appropriate, with other non-federal interests. Such agreements shall describe the actions to be taken by the Secretary and the cooperating parties, the estimated costs and benefits of these actions, and who is to bear the costs. Various cost sharing techniques are set forth to determine the federal cost involved in any project.

The Secretary shall study and recommend to the Secretary of HEW ways to eliminate or reduce polluting substances detrimental to fish in interstate or navigable waters.

Lead Agency: Department of the Interior

Relevance to Offshore Development: Federal moneys are available to help reduce any adverse effects on the anadromous fishery resources of the coastal states brought about by offshore development.

Major Cases: None

Atomic Energy Act of 1954

Citation: 42 USC 2011-2296; 10 CFR Pt. 0-199; 41 CFR 9,109

Pocket Part: For Use 1975 (No modification through 6/75)

Synopsis of Law: This act established a program for research in the area of atomic energy in order to encourage maximum scientific and industrial progress. It established program for government control and regulation of the possession, use and production of atomic energy and special nuclear material, whether owned by the government or others; and a program of administration which was to be consistent with U.S. policies, with international arrangements and with agreements for cooperation. The Act established the Atomic Energy Commission, outlined its organization, and transferred all interests of the U.S., concerning its fissionable material, atomic weapons, and facilities for processing fissionable material to the AEC. The Commissioner was given broad contracting powers to insure the ongoing researching of all aspects of the atomic energy field. The Act in general provides for licensing of, transportation of, and acquisition of special nuclear materials and other source materials, and utilization and production facilities.

Lead Agency: Atomic Energy Commission (AEC)

Relevance of Offshore Development: This massive enabling legislation is the foundation for federal control of atomic energy materials and production. Many provisions must be completed with (i.e. licensing procedures), prior to engaging in atomic energy activities. In addition, the Act provides for judicial action when damaging nuclear incidents occur within or outside the United States, especially if the occurrence involves a facility under contract with the United States.

Major Cases:

Northern Cal Ass'n v. Public Utilities Commission (1964)
390 P. 2d 200, 37 Cal. Rpt. 432. Federal government has not preempted questions of safety of location of atomic reactors.

Carter Corp. v. Seaborg (1966)
370 F. 2d 686. Commission can act in a governmental capacity

Nuclear Data Inc. v. AEC (1972)
344 F. Supp. 719. Commissioner's power and authority concerning patents.

Union of Concerned Scientists v. AEC (1974)
499 F. 2d 1069. The interaction of the Commission's relemaking procedures and licensing hearings.

Clean Air Act Amendments of 1970

Citation: 42 USC 1957-1857f (1973) (40 CFR 50 ff.)

Pocket Part: For Use on 1975 (no modification through 6/75)

Synopsis: This Act sets general guidelines and minimum air quality standards on a nationwide basis and the states are given the responsibility for developing comprehensive implementation plans for all regions within their boundaries to enforce and regulate these federal standards. Three major standards were authorized: 1) that of no significant deterioration of any air; 2) the National Primary Air Quality Standards (level of air quality necessary to protect public health) to be achieved within 3 years; and 3) the National Secondary Standards which are to be met within a reasonable time and which are to reflect the level of air quality necessary to protect public welfare.

Other standards to be complied with include the new Source Standards and the Hazardous Emissions Standards. The Act deals with both point and non-point sources of pollution. This is the major federal legislation dealing with air quality; however, states are not precluded from setting a more stringent standard for the air quality regions within their boundaries. A broad program is outlinged concerning motor vehicle emissions.

Lead Agency: Environmental Protection Agency

Relevance to OCS: It remains unclear whether this Act will operate to regulate air quality offshore. Differing interpretations of the Outer Continental Shelf Lands Act shed some light on this issue. The Deepwater Port Act specifically binds all such ports to compliance with the Clean Air Act. However, all shoreward facilities (within 3-mile territorial sea) which are OCS-related, must comply with the ambient standards and emission limitations (as well as new Source Standards) set for these respective areas. As it appears that the pipelines coming in from the Baltimore Canyon will terminate in heavily populated areas, conceivably very stringent standards will be enforced on these facilities.

Major Cases:

U.S. v. Bishop Processing Co. (1968)
287 F. Supp. 624. Constitutionality of charging polluter with moving pollutants across State lines.

Huron Portland Cement Co. v. City of Detroit (1959)
93 NW 2d 888, 355 Mich 227. Discusses both the retention by federal government of pollution regulatory powers, and the validity of local pollution ordinances which are deemed to not be regulations of interstate commerce.

South Terminal Corp. V. EPA (1974)
504 F. 2db46. Effects of EPA's regional transportation control plan which imposed parking space freeze.

Implementation Plan Cases Texas v. EPA (1974)
499 F2d 289
Friends of the Earth v. EPA (1974) 499 F2d1118
Comm/Pa v. EPA (1974) 500 Fed 246

State of Alabama v. Seeber (1974) 502 F2d 1238. Control and abatement of air pollution from federal facilities.

Amoco Oil Co. v. EPA (1974) 501 F2d 722. Regulations of fuels.

Coastal Zone Management Act of 1972

Citation: 16 USC 1451-1464 (1974); 50 CFR Pts. 200-299 NOAA

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: The main purpose of this act is to encourage and assist states in preparing and implementing management programs to preserve, protect, develop and whenever possible restore the resources of the coastal zone of the United States.

The Secretary of Commerce is authorized to make annual grants, until June 30, 1977, to coastal states to develop coastal zone management programs. Upon meeting certain requirements, a state's management program may be approved and allocated federal funds by the Secretary. Before approval, the Secretary must find that the state will control land and water uses within the coastal zone and that these controls do not unreasonably restrict or exclude land and water uses of regional benefit.

The Secretary is authorized to aid in the acquisition and operation of estaurine sanctuaries. The Secretary shall coordinate and cooperate with other federal agencies; also, any federal agency having activity which affects the coastal zone shall, to the maximum extent practicable, act consistent with approved state management programs. Federal agencies shall not approve proposed projects that are inconsistent with a coastal state's management program, except upon a finding by the Secretary that such project is consistent with the purposes of this chapter or necessary in the interest of national security.

Lead Agency: Department of Commerce

Relevance to Offshore Development: The states are being encouraged to develop coastal zone management programs in light of possible offshore development. Soon many or all of the coastal states will have such programs in operation. Once a state has an approved coastal zone management program, proposed offshore development will have to conform to the individual state's program, or show the Secretary of Commerce that the desired development conforms to the purposes of this act or is necessary in the interest of national security.

Major Cases: None

Commercial Fisheries Research and Development Act of 1964

Citation: 16 USCA 779-779f (1974); 50 CFR 253

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act authorizes the Secretary of Commerce to cooperate with the states through their respective state agencies in carrying out projects designed for the research and development of the commercial fisheries resources of the nation. In order to be eligible for the appropriated federal funds, a state must meet certain standards, submit projects, and have these projects approved by the Secretary.

Lead Agency: Department of Commerce

Relevance to Offshore Development: Federal funds are available to states to research and develop commercial fisheries in light of offshore development.

Major Cases: None

Department of Transportation Federal-Aid Highway Provisions

Citation: 23 USC 138, 204-217, 317, 319 (1966)

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: 138 - The Secretary of Transportation shall cooperate with Secretaries of Interior, HUD, Agriculture, and with the states in developing transportation plans and programs that include measures to maintain and enhance the natural beauty of the lands traversed. No plan for highways through publicly owned lands from the public park, wildlife refuge, etc., unless there is no feasible alternative and such plan minimizes possible harm to wildlife, etc.

Lead Agency: Department of Transportation

Relevance to Offshore Development: Onshore development possibly will involve transportation through public lands of various sorts. All roads to be built with federal aid must comply with these provisions.

Major Cases:

D.C. Federation of Civic Associations v. Volpe (1972) 459 F.2d 1231

Citizens to Preserve Overton Park, Inc. v. Volpe (1971) 401 U.S. 402

Citizens to Preserve Foster Park v. Volpe (1972) 466 F.2d 991

Brooks v. Volpe (1974) 380 F. Supp. 1287

Synopsis of Law: 317 - Appropriation for highway purposes of lands or interest in lands owned by the United States.

319 - Landscaping and Scenic enhancement.

These Sections also involve consideration of environmental and scenic factors in appropriating federal money for highways.

Lead Agency: Department of Transportation

Relevance to Offshore Development: Same as above.

Major Cases:

Allison v. State (1966) 101 Ariz. 418 420 P.2d 289

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Deepwater Port Act of 1974

Citation: 33 USC 1501-1524 (Pamphlet Book 1, 1975)

Pocket Part: February 1975 Supplement (No modification through 1975)

Synopsis of Law: This act establishes a licensing and regulatory program governing offshore deepwater port development beyond the territorial limits and off the coast of the United States. The Secretary of Transportation is authorized to issue licenses for the ownership, construction, and operation of deepwater ports. Safeguards are included in the licensing procedure to insure that environmental, safety, and antitrust considerations are taken into account. Adjacent coastal states are provided a means to gain compensation for costs incurred by them. Provisions are set out prohibiting and penalizing any oil discharges.

A deepwater port, licensed pursuant to the provisions of this chapter, may not be utilized for the loading and unloading of commodities and materials transported from the U.S. (except those to be used in the operation of the high seas oil port), nor the transshipment of oil, destined for locations outside the United States. The Secretary will only issue a license if he has not been informed by the EPA Administrator that the deepwater port will not conform with the Clean Air Act, the Federal Water Pollution Control Act and the Marine Protection, Research, and Sanctuaries Acts. A deepwater port will be considered a "new source" for the purposes of the Clean Air Act and the Federal Water Pollution Control Acts.

Lead Agency: Department of Transportation

Relevance to Offshore Development: In order for any party to construct and operate a deepwater port off the coast of the United States, a license must be obtained from the Secretary of Transportation. Further, a deepwater port and the appropriate storage facilities are subject to regulation as a common carrier under the Interstate Commerce Act.

Major Cases: None

Endangered Species Act of 1973

Citation: 16 USC 1531-1543 (1974); 50 CFR 17.1 et. seq.

Pocket Part: For Use in 1975 (no modification through 6/75)

Synopsis: The Secretary of Interior/Commerce shall by regulation determine whether any species is an endangered species or a threatened species based on one of several factors. Lists of these species will be published in the Federal Register. The Secretary of the Interior will implement programs to conserve endangered or threatened species in cooperation with the states. State laws which apply with respect to to interstate or foreign commerce in endangered or threatened species are void to the extent that they permit what is prohibited by this Act or any implementing regulations. The law lists the prohibited acts, outlines a permit system and authorizes the formulation of regulations as may be appropriate to enforce this Act. Scientific activity for the betterment of the species is generally exempt.

Lead Agency: Department of Interior or Commerce

Relevance to Offshore Development: Some of the prohibited acts might be perpetrated by parties involved in offshore development activities. Pertinent Department of Interior regulations could be enforced through the leases and OCS Orders.

Major Cases: None

Energy Reorganization Act of 1974
(To be read with the Atomic Energy Act)

Citation: 42 USC 5801-5891
Supplementary Pamphlet 1, February 1975

Synopsis of Law: This act operated to abolish the Atomic Energy Commission and divided its powers and duties between two organizations. The new Energy Research and Development Administration was established with the basic responsibilities and powers of research and development on the various sources of energy, to increase the efficiency and reliability in the use of energy, and to perform the AEC's other functions (except as stated below) including military and production activities. The ERD Administration is authorized to issue regulations as are appropriate to fulfill its functions.

The Nuclear Regulatory Commission (NRC) is established as an independent regulatory commission with the responsibility of conducting all licensing and related regulatory functions of the AEC. An Office of Nuclear Reactor Regulation was also established within the NRC to perform the licensing and regulation involving all facilities associated with the construction and operation of nuclear reactors licensed under the Atomic Energy Act of 1954. Nuclear energy center citing is a major responsibility of the Commission.

Lead Agencies: Energy Research and Development Administration; Nuclear Regulatory Commission

Relevance to Offshore Development: NRC will have regulatory power over the nuclear plants to be built off the Atlantic Coast.

Major Cases: None

Energy Supply and Environmental Coordination Act of 1974

Citation: 42 USC 1859c-10 (1969) (Pocket Part in 1975)
(See Clean Air Act)
Public Law 93-319; 88 Stat 246

Pocket Part: No modification through 6/1975

Synopsis of Law: This act was integrated into the Clean Air Act (CAA) to relax some of the latter's standards in order to meet some of the nation's needs for fuels during the recent energy crises. Under this act, the Federal Energy Administration may prohibit power plants (mandatory) and any major fuel burning installations from burning natural gas or petroleum products as its primary energy source when it has the capability and necessary plant equipment to burn coal. Thereupon, the EPA Administrator may, during the period between June 22, 1974 and June 30, 1975, temporarily suspend any stationary source fuel or emission limitation, as it applies to any person, if that person violates the CAA provisions due to lack of fuels or has converted to coal. Facilities for which extensions of compliance schedules are issued, shall not be prohibited from burning coal due to air quality requirements until January 1, 1979. The EPA Administrator shall promulgate applicable regulations.

Lead Agencies: Environmental Protection Agency (EPA); Federal Energy Administration (FEA)

Relevance to Offshore Development: If Congress perpetuates the EPA Administrator's power (past June 30, 1975) to ease the Clean Air Act's requirements, then any onshore facilities related to offshore development may be required to comply with less stringent air quality standards if they burn coal. However, as it reads now, the act only applies to sources violating standards or converting to coal prior to June 30, 1975 and March 1974, respectively.

Major Cases: None

Federal Power Act

Citation: 16 USC 791a-828c (1975); 18 CFR 31 et seq; 1.1 et seq.

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act creates the Federal Power Commission with the general powers and duties of investigating the utilization of water resources of any region and the water-power industry, requiring investment cost statements by licensees, and to grant licenses to any person, municipality, state, etc., for the purpose of constructing, operating and maintaining dams, water conduits, reservoirs, power houses, transmission lines and utilization of power across streams or other bodies of law where the United States has authority to regulate interstate commerce (or because the activity is on public lands, etc.).

No license will be issued which affects the navigability of navigable waters without the approval of the Army Corps of Engineers. Preliminary permits are available for potential licensees who wish to make examinations, surveys, etc., for preparing maps, etc. Other subchapters deal with regulation of electric utilities and public utilities.

Lead Agency: Federal Power Commission

Relevance to Offshore Development: The sections with the regulation of development of water power and resources will apply to onshore activities if any such facilities would involve the generation or transmission of power across navigable waters (or public lands). The regulation of a floating nuclear plant will probably be exclusively under the Atomic Energy Act, but this act will apply to hydroelectric power plants.

Major Cases:

Alabama Power Co. v. Gulf Power Co. (1922) 283 F. 606
This subchapter (creating the Commission) is constitutional.

Rochester Gas & Electric v. FPC (1965) 344 F2d 594
Navigability definition.

Municipal Electric Association of Massachusetts v. FPC (1969) 414 F2d 1206; 134 US App DC 310

Citizens Utilities Co. v. Prouty (1962) 122 Vt. 433; 176 A2d 751
Licensing authority.

Chemehuevi Triber v. FPC (1973) 489 F2d 1207

Federal Water Pollution Control Act Ammendments of 1972 (FWPCA)

Citation: 33 USC 1251 et. seq. (1970)

Pocket Part: For Use in 1975

Synopsis of Law: The major section of the act with relevance to offshore oil drilling is the Oil and Hazardous Substances section which establishes the National Oil and Hazardous Substances Contingency Plan. This section regulates offshore facilities only within the 3-mile territorial sea and vessels within the 12-mile contiguous zone.

The act in general establishes ambient water quality standards and effluent limitations for point and non-point discharge sources. The general goals of the act are to eliminate discharges of pollutants into navigable waters by 1985, to achieve swimmable water by 1983, and to entirely prohibit the discharge of toxic pollutants. The act sets up a comprehensive permit system to implement these goals and this permit system applies to all direct discharges including those discharging into ocean waters beyond the 12-mile zone.

Effluent standards are set on an industry-by-industry basis and new sources within regulated industries must comply with stricter regulations than do existing sources. The Army Corps of Engineers is authorized to license the disposal of dredged or fill materials.

This is the major federal legislative act regulating water quality within the United States. Other agencies, such as the Coast Guard and the U.S. Geological Survey, contribute to the implementation of this act. Regulations for treatment works were outlined.

Lead Agency: Environmental Protection Agency

Relevance to Offshore Development: Both offshore and onshore activities which involve discharge into navigable waters (which definition has been expanded from the traditional to include most navigable and tidal waters) must comply with this act's guidelines by applying for and obtaining permits. While some activities will be exempt, EPA guidelines for oil-rigging (which will apply to the OCS) are to be established this fall. States are authorized to take over the permitting procedures upon approval of EPA.

Major Cases:

U.S. v. Ashland Oil & Transportation Co. (1974) 504 F.2d 1317.
The 1972 Amendments are Constitutional.

U.S. v. Reserve Mining Co. (1974) 380 F. Supp. 11.
Action against effluents on nuisance grounds (rem'd on other grounds 498 F.2d 1083)

E.I. DuPont de Nemours & Co. v. Train (1974) 383 F. Supp. 1244.
Timetables for achievement of effluent objectives were intended to be promulgated as regulations apart from permit proceeding under Section 1342.

U.S. v. W.B. Enterprises, Inc. (1974) 378 F. Supp. 420.
Owner's subsequent removal of oil after spillage did not relieve them from liability for a civil penalty under the Oil and Hazardous Substance Act.

U.S. v. Rohm & Hass Co. (1974) 500 F.2d 167.
Discusses the national pollutant discharge elimination system and its retroactive effect.

Lake Carrier's Association v. MacMullan (1972) 406 U.S. 498.

Stream Pollution Control Board of Indiana v. U.S. Steel, Inc. (1974) 62 FRD 31.

U.S. v. Boyd (1973) 491 F.2d 1163.
Hazardous Substances and Oil Provisions.

Portland Pipe Line Corp. v. Environmental Imp. Commission (1973) 307 F.2d 1.

Mobil Oil Corp. v. Town of Huntington (1972) 339 NYS 2d 139; 72 Misc 2d 530.

Calvert Cliffs' Coordinating Committee, Inc. v. U.S. AEC (1971) 449 F.2d 1109; 146 U.S. App DC 33.

Colorado PIRG v. Train (1974) 507 F.2d 543.
Regarding the discharge of radioactive materials into navigable waters, the case discusses the construction of FWPCA with other laws.

City of North Miami, FL v. Train (1974) 377 F. Supp. 1264.

Fish and Wildlife Act of 1956

Citation: 16 USC 742a-754 (1974); 50 CFR 1.1 et seq.; 201 et. seq.

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This law was enacted to accomplish proper resource development. The United States Fish and Wildlife Service was established within the Department of Interior and vested along with the other named agencies with the following authorities:

(1) Pursuant to the rules and regulations as the Secretary of Interior may prescribe, the Secretary may make loans for financing the purchasing, constructing, repairing, etc., of commercial fishing vessels or gear.

(2) The Secretary of Interior makes investigations and reports to the public, Congress, and the President concerning production and flow of fish and fishery products; the biological requirements of fish and wildlife resources; and the collection and dissemination of statistics on nature and availability of wildlife, acquisition of additional refuges, etc.

(3) Studies of insecticides, etc., (vested in the EPA).

Lead Agencies: Department of Interior, Department of Commerce, and EPA

Relevance to Offshore Development: The Secretary of Interior is directed to investigate all causes of changes or diminution in the number of food fishes of the coast as well as inland waters of the United States and shall report to Congress what protective, prohibitory or precautionary measures should be undertaken to protect the fish resources in these areas. Offshore development related activities will have effects on the fish population off the coast and thus knowledge of the Service's concerns and potential action is recommended. Also, much of the information it publishes could be of interest to those involved in the development of the offshore technologies. The National Oceanic and Atmospheric Administration took over many of the functions of the old Fish and Wildlife Service.

Major Cases: None

Fish and Wildlife Coordination Act

Citation: 16 USC 661-667e; 50 CFR Pt. 25-70

Pocket Part: For Use in 1975 (no modification through 6/75)

Synopsis of Law: This act authorizes the Secretary of the Interior to assist and cooperate with federal, state, and public or private organizations in the protection of all species of wildlife.

Lead Agency: Department of Commerce, U.S. Fish and Wildlife Service.

Relevance to Offshore Development: The Department of the Commerce must be notified if a particular offshore development adversely affects wildlife.

Major Cases:

Construction of Act with other Acts:

Environmental Defense Fund v Froeheke (1972) 473F 2d 346 NEPA

Zabel v. Tabb (1970) 430F 2d 199, cert. denied 401 U.S. 910 NEDA

Udall v. Federal Power Commission (1967) 387 U.S. 428. FPC

Environmental Defense Fund, Inc. v COE (U.S. Army) (1971) 324 F Supp. 878
Facts necessary for an injunction to stop construction of barge canal.

Standing to Maintain Suit:

Rank v. Krug (1950) 90 F. Supp. 773

Fishery Zones--Extra-Territorial Sea

Citation: 16 USC 1091-1094 (1974)

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This legislation establishes for the United States a 12-mile exclusive fisheries zone contiguous to its shores. The United States will exercise the same exclusive rights in respect to fisheries in the zone as it has in its territorial sea, subject to any officially recognized traditional fishing by foreign states in such zone.

Lead Agencies: Department of Transportation; U.S. Coast Guard

Relevance to Offshore Development: Claims federal fishery jurisdiction on the Outer Continental Shelf.

Major Cases: None

Fish Restoration and Management Projects

Citation: 16 USC 777-777k (1974); 50 CFR 80.1 et. seq.; 43 CFR 17.1 et. seq.

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: The purpose of this act is to create a program of federal aid to the states for the restoration and management of their fishery resources. The Secretary of Commerce must cooperate with the states through their respective state fish and game departments in such projects. A state must meet certain requirements to become eligible for this program; for example, it must adopt fish conservation laws.

Lead Agencies: Department of Commerce; National Oceanic and Atmospheric Administration

Relevance to Offshore Development: Federal funds are available to states to restore and manage their fishery resources in light of offshore development.

Major Cases: None

Intergovernmental Cooperation Act of 1968

Citation: 42 USC 4201-4244 (1973); 5 CFR Ch. VII; 41 CFR 105-50.000 et seq.

Pocket Part: For Use in 1975 (Checked through 8/75)

Synopsis of Law: This Act is an overview treatment of the guidelines regulating grants (money or property provided in lieu of money) paid or furnished by the United States to a State, a political subdivision of a State or to a beneficiary under a plan or program administered by the State or subdivision. The "grants" and "grants-in-aid" included under the Act are defined. Rules designed to improve the administration of such grants include: the requirement that the U.S. provide the Governor and/or legislature of a recipient state of the purpose and amount of actual grants-in-aid to the State or a political subdivision, thereof upon request; no grant-in-aid to a State must be deposited in a separate bank account apart from other funds administered by the State; the time elapsing between the transfer of funds from the U.S. Treasury and the disbursement thereof by a State must be minimized by the Federal agency; and that no Federal law shall require the establishment or designation of a particular State agency or commission to administer the grant when a more efficient and effective organizational arrangement can be cited.

Federal agencies and departments are authorized to provide special or technical services for state and local units of government - including technical tests and information, statistical compilations, training activities, surveys, etc. This is aimed at avoiding duplication and inefficiency.

General policy considerations, as well as administrative guidelines, are outlined for Development Assistance programs. In planning programs dealing with land uses - housing, commercial, etc. - conservation of natural resources, transportation, planned community facilities, etc., all viewpoints and objectives must be taken into account - national, regional, state and local. The Act also states a preference for giving grants to general local governments, rather than to special-purpose units of local government.

Provisions for review of the Federal grant programs are to be conducted by respective congressional committees. The Act establishes the Advisory Commission on Intergovernmental Relations to study the impact of the grant program and the coordination of Federal administration of such program with State and local administration thereof, and make a report to Congress. (See 42 USC S4271-4279 for details on duties, etc.)

Lead Agency: All agencies involved. Office of Management and Budget

Relevance to Offshore Development: Grants dealing with development of natural resources and other aspects of planning connected with offshore development will be regulated by this Act, if the Grant is to a State, subdivision or to a beneficiary under a plan administered by the State.

Cases: Conservation Society of Southern Vermont v. Secretary of Transportation; 362 F Supp. 627 (1973) U.S. District Court, Vermont.

Intervention on the High Seas Act

Citation: 33 USC 1471-1487 (1970)

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: In order to protect the interests of the United States in its marine resources, wildlife, coastal zone and estuarine activities, and shorelines and beaches, this act accords to the Secretary of Transportation the power to mitigate or eliminate dangers to these interests created on the high seas by incidents, involving ships, which would result in oil pollution (except warships and other foreign governmental ships engaged in non-commercial service). The main focus of the act is foreign ships although the language does not exclude domestic ships from its coverage. (See also Ocean Dumping Act.)

The authority for this act is the Convention Relating Intervention on the High Seas in Cases of Oil Pollution Casualties, 1969. The Secretary of Transportation may (normally in consultation with the Secretary of State, other countries involved and the EPA Administrator) take reasonable and appropriate measures to protect our interests, including coordinating all efforts to eliminate the threatened pollution and removing or destroying the ship and cargo creating the danger, if necessary.

Lead Agencies: Department of Transportation; U.S. Coast Guard

Relevance to Offshore Development: All ships traversing the offshore area are subject to this act. Although non-signatories to the Convention might be treated differently, this act endows the U.S. government with limited territorial jurisdiction over the High Seas. It gives the U.S. rights on the High Seas similar to those created by the Ocean Dumping Act in the territorial and contiguous zones; however, enforcement under this act is less reliable for the act requires first a determination that a grave and imminent danger exists.

Major Cases: None

Investigations; Fish Propagation; Etc.

Citation: 16 USC 744 (1974)

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: The Secretary of the Interior or the Secretary of Commerce as appropriate shall investigate whether any and what diminution in the number of food fishes of the coast and lakes of the United States has taken place. If diminution has taken place, he shall report to Congress the causes and what protective measures should be adopted.

Lead Agencies: Department of the Interior; Department of Commerce

Relevance to Offshore Development: A federal agency will investigate and report to Congress what effect offshore development has on the food fishes of the United States.

Major Cases: None

Land and Water Conservation Fund Act of 1965
Water Project Recreation Act

Citation: 16 USC 460(d); 460(1) (4) et. seq. (1974); 460 (1) (12) et. seq.; 36 CFR 313.1 et. seq.; 36 CFR 327.0 et. seq.; 43 CFR 18.1 et. seq.

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law:

Title 16 - Conservation
Chapter 1 - National Parks, Military Parks, Monuments and Seashores

460(d) Construction and operation of public parks and recreational facilities in Water Resource Development Projects.

The Chief of the Army Corps of Engineers is authorized to construct, maintain, and operate public parks and recreational facilities at water resource development projects. The Secretary of the Army may also grant leases of land at such developments for such purposes as he may deem reasonable in the public interests. The water areas will be open to the public for recreational purposes, subject to the rules and regulations issued by the Secretary of the Army.

The Submerged Lands Act does not affect this law.

Land and Water Conservation Fund Act of 1965
460L-440 460L-11

This act provides for federal assistance to states in planning and development of needed land and water areas and facilities, and for funds for federal acquisition of certain lands and other areas. Several sources of revenue for this fund are listed, e.g., monies from leases under the Outer Continental Shelf Land Act).

Federal Water Project Recreation Act
460L-12 to L-22

The policy of this act is that in investigating and planning any federal navigation, flood control, reclamation, hydroelectric, or multiple purpose water resource project, full consideration shall be given to the opportunities if any which the project affords for outdoor recreation and for fish and wildlife enhancement. The act outlines possible federal bearing of costs in conjunction with the management of project land and water areas. It includes other provisions dealing with non-federal public projects.

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Lead Agency: Department of the Interior

Relevance to Offshore Development: These sections were included mainly for the purpose of giving an example of Title 16's broad range. Stretching the applicability of public lands and hydroelectric projects to involve the technologies under investigation in this study is only possible, not necessarily plausible. However, it may still be important to be familiar with provisions of this sort under Title 16.

Major Cases:

U.S. v. 2,606.84 Acres of Land (TX) (1969) 309 F. Supp., rev'd on other grounds 432 F.2d 1286. Discussion of the extent to which the Corps of Engineers can regulate public property.

U.S. v. 0.01 Acre of Land (MD) (1970) 310 F. Supp. 1379. Definition of "Water Resource Development."

Marine Mamals Protection

Citation: 16 USC 1361,62; 1371-1384 (1974) 50 CTR 17.1 et seq., 216 et seq., 10 et seq.

Pocket Part: None

Synopsis of Law: The policy of this Act is to protect the esthetic, recreational and economic significance of marine mammal resources. The Act outlines the prohibited activities, including taking any marine mammal on the high seas, to territorial sea; this provision is subject to exceptions and allowed activity upon the receipt of a permit. Importing, exchanging, selling and trading marine mammals is regulated under this Act, and the permitting system is established and outlined. Penalties are provided for violation of the Act, including fines, seizure and forfeiture of cargo. States are limited in their power to adopt any law or regulation relating to the taking of marine mammals. A Marine Mammal Commission is established.

Lead Agency: Department of Interior; Department where National Oceanic and Atmospheric Administration is.

Relevance to Offshore Development: The high and territorial seas are included in this regulatory scheme and all persons therein must abide by the Act.

Major Cases: Fouke County v. Mandel, 1974 386 F Supp. 1341.

Marine, Protection, Research and Sanctuaries Act of 1972
(AKA Ocean Dumping Act)
"Federal Environmental Controls on the High Seas"

Citation: 33 USC 1401-1444; 40 CFR 220-226;227

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act creates an EPA permit system regulating the transportation by anyone of material from the United States (or from outside the U.S. in the case of a U.S. flagship or U.S. instrumentality) for the purpose of dumping the materials in ocean waters (i.e. all waters of the open seas seaward of the baseline from which the territorial sea is measured); in addition, dumping of material with whatever origin into the territorial sea or contiguous zone is regulated. Dumping of radiological material, chemical or biological warfare agents, or high level radioactive wastes is never permitted. Oil is included as a regulated material "only to the extent that such oil is taken on board a vessel or aircraft for the purpose of dumping it into ocean waters. The Act defers to FWPCA of 1972 concerning other oil and sewage covered by the latter Act.

The Secretary of the Army will issue the permits for the transportation of dredged material to be dumped; and the Secretary of Commerce will initiate a comprehensive research program.

Lead Agency: Environmental Protection Agency (EPA)

Relevance to Offshore Development: All domestic ships carrying materials or wastes from offshore or related onshore facilities in order to dump them in any waters must obtain permits to do so. All ships with such materials must obtain permits to dump them into the territorial sea or contiguous zone.

Major Cases: None

Marine Resources and Engineering Development Act of 1966

Citation: 33 USC 1101-1108 (1970)

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act provides for the development, encouragement and maintenance of a national program in marine science, which would apply to oceanographic and scientific endeavors and disciplines, engineering and technology in and with relation to the total marine environment. The term "marine environmnet" includes the oceans, the Great Lakes, the Continental Shelf of the United States, and the resources thereof.

Lead Agency: Executive Office of the President, Commission on Marine Science, Engineering, and Resources

Relevance to Offshore Development: Offshore development will become part of the national program in marine science, and will be able to draw upon and provide information to the Commission on Marine Science, Engineering and Resources.

Major Cases: None

See below for different sections of
Title 30 - Mineral Lands and Mining

Citation: 30 USC 181-199 (1971); 223-229; 351-359; etc.

Pocket Part: Through February 1975

Synopsis of Law: These laws control the disposition of deposits of minerals, including oil and gas, on lands owned by the United States. Chapter 34 (33181-287) deals generally with Leases and Prospecting Permits, and is known as the Mineral Lands Leasing Act.

Some case law interprets "public lands" dealt with in this act as not to include submerged lands off the U.S. coast. The act deals with provisions of leases granted by the United States, limitation on leases held by private persons, rights-of-way for pipelines, easements, etc.

Chapter 7, Mineral Leasing Act for Acquired Lands, extends the Department of Interior's control to all lands acquired by the United States to which the "mineral leasing laws" have not been extended. It was passed subsequent to the Mineral Leasing Act, and this act specifically excludes minerals in submerged lands and the continental shelf from its purview, thus clarifying the question of the applicability of these laws to the offshore area.

Lead Agency: Department of the Interior

Relevance to Offshore Development: These acts do not cover leases on OCS tracts but refer the reader to the Submerged Lands Act and the Outer Continental Shelf Lands Act.

Major Cases:

Transwestern Pipeline Co. v. Reir-McGee Corp. (1974) 492 F.2d 878.

Wilderness Society v. Morton (1973) 479 F.2d 842, Cert. denied 411 US 917.

Hagood v. Heckers (1973) 513 P.2d 208.

Justheen v. McKay (1956) 229 F.2d 29, 97 US App DC, Cert Denied 351 US 933.

Broussard v. Amerada Petroleum Corp. (1972) 350 F. Supp. 104.

Mining and Minerals Policy Act of 1970

Citation: Public Law 91-631 (p. 2200) 84 Stat 1876

Synopsis of Law: The act briefly states a national policy of the federal government to foster and encourage private enterprise in the development of economically sound and stable domestic mining, minerals, metal and mineral reclamation industries; and the development of such resources in an orderly fashion to help assure satisfaction of the industrial, security and environmental needs, mining research, etc., including the recycling of scrap; and the study and development of methods for the disposal, control and reclamation of mineral waste products.

The Secretary of Interior will have responsibility for carrying out the provisions of this act when exercising his authority over such programs as are authorized by law.

National Environmental Policy Act of 1969 (NEPA)

Citation: 42 USC 4321-4347 (1973)
40 CFR 30.100
Parts 50-122

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act is the foundation legislation for regulation of activities affecting the environment. It sets out the national policy that mandates all federal, state, public, and private organizations to use all practicable means (including financial and technical assistance) to create and maintain conditions under which man and nature can live harmoniously. The Environmental Protection Agency was established under the included Reorganization Plan No. 3 of 1970.

The most significant part of the act is the requirement in Section 4332 that all federal agencies shall include in every recommendation or report on proposals for legislation and other major federal actions significantly affecting the quality of the human environment, a detailed statement on the environmental impact of the proposed action, alternatives to the proposed action, etc.

All federal agencies are directed to reform their procedures and regulations in compliance with this act. The Council on Environmental Quality was established under this act.

Reorganization Plan No. 4 - Establishing the National Oceanic and Atmospheric Administration is included in the notes of this act.

Listed in notes under this act are the following applicable Executive Orders:

11507 - Prevention Control, and Abatement of Air and Water Pollution at Federal Facilities (February 4, 1970)

This order requires heads of all agencies to ensure that federal facilities comply with the air and water quality standards endorsed by NEPA, and set out in the Clean Air Act and the Federal Water Pollution Control Act. Existing facilities were to comply by December 1972; new facilities will be authorized only if the plans include provisions for compliance with the pollution standards. Procedures for federal water resources projects are also outlined.

11472 - Cabinet Committee on the Environment and Citizen's Advisory Committee on Environmental Quality (May 29, 1969)

This Committee was established to advise the President on environmental quality matters. It has many areas of concern, including recommending measures for federal policies and programs to take

adequate account of environmental effects, reviewing adequacy of existing systems for monitoring and predicting environmental changes, etc.

Lead Agency: Council on Environmental Quality

Relevance to Offshore Development: Basically this serves to promote the protection of the environment in all activities involving federal money or action. Offshore activity on federally-leased tracts of land will fall under the purview of this act. The Department of Interior will publish a regional Environmental Impact Statement for the Baltimore Canyon in compliance with NEPA before leasing in the area.

Major Cases: There is a great wealth of litigation interpreting this act.

International Harvester Co. v. Ruckelshaus (1973) 478 F.2d 615

Minnesota PIRG v. Butz (1973) 358 F. Supp. 504

Environmental Defense Fund v. Corps of Engineers (1972) 470 F.2d 289

Environmental Impact Statements:

Natural Resources Defense Council v. Grant (1972) 341 F. Supp. 356

Hirim Clark Civic Club v. Lynn (1973) 476 F.2d 421

San Francisco Tomorrow v. Romney (1973) 472 F.2d 1021

Scherr v. Volpe (1972) 466 F.2d 1027

Hanly v. Kleindienst (1972) 471 F.2d 823

People of Saipan v. U.S. Department of Interior (1974) 502 F.2d 90
Law applies to the trust territory of the Pacific Islands and federal facilities operating therein.

Scenic Rivers Association of Oklahoma v. Lynn (1974) 382 F. Supp. 69

ISPIRG v. Callaway (1974) 379 F. Supp. 714

State of LA v. FPC (1974) 503 F.2d 844

Sierra Club v. Lynn (1974) 502 F.2d 43

Sansom Committee v. Lynn (1974) 382 F. Supp. 1245

Lathan v. Brinegar (1974) 506 F.2d 677

National Oceanic and Atmospheric Administration (NOAA)

Citation: 33 USC 857-1 to 857-12 (1970); 15 CFR IX; 50 CFR II

Pocket Part: For Use in 1975 (no modification through 6/75)

Synopsis: This Agency was created by the Reorganization Plan No. 4 of 1970, (35, F.R. 15627, 84 Stat 2090) which abolished the Environmental Sciences Services Administration (which had embodied the Weather Bureau, the Coast and Geodetic Survey, the Environmental Data Service, etc.). The general goal of these Acts was to develop an adequate warning system for the severe hazards of nature, and to provide environmental information to various segments of the U.S. economy, i.e. agriculture, transportation, communications and industry. The Act provides for several multi-disciplined scientific studies and surveys: geomagnetic data, analysis of tide and current data, hydrographic and topographic surveys, etc. A 1960 Amendment to the Coast and Geodetic Survey (CGS) Act eliminated the provisions which restricted the CGS in the conduct of its specified activities to the U.S., its territories and its possessions.

Lead Agency: Department of Commerce

Relevance to Offshore Development: The NOAA serves as a source of scientific data and analysis available to any carrier or builder working in ocean waters. The information provided for and the granting programs possible with this agency and the Department of Commerce in general, could affect planning for the onshore activities related to offshore development, as well as the activities on the high seas. See also Coastal Zone Management Act of 1972.

Major Cases:

Warden v. City of Los Angeles (1974) 112 Cal. Rept. 355, 37 CA 3d 256 Discussion of respective liabilities of City of Los Angeles and the U.S. Coast and Geodetic Survey concerning collision of sailboat with a submerged sewer pipe.

Thompson v. Consolidated Gas Electric Right v. Power Co. of Baltimore (1953) iii F Supp 719. Layman was chargeable with information on Coast and Geodetic Survey Chart, showing high tension cable over water.

National Sea Grant College and Program Act of 1966

Citation: 33 USC 1121-1124 (1970); NOAA 15 CFR IX; 50 CFR III

Pocket Part: For Use in 1975; checked through 8/75

Synopsis of Law: In order to promote the development of marine resources, this act provides for the establishment of a program of sea grant colleges and education, training, and research in the fields of marine science, engineering and related disciplines. The act authorizes Federal appropriations to the Secretary of Commerce to carry out the act's provisions. The Secretary will initiate and support educational and research progress at all suitable institutions (in the various fields related to marine resources) with one preference being research-aimed at practices, techniques and design of application equipment. The purposes of the act will be accomplished by grants to or contracts with the participating institutions. The act outlines the maximum percent of overall appropriation which can be allotted for individual participants and for all participants within one state, and for some prohibited uses of the money. The Secretary is also authorized to direct a study of the means of sharing, through cooperative programs with other nations the result of marine research useful in the exploration development, conservation, etc. of marine resources.

Lead Agency: Department of Commerce (National Oceanic and Atmospheric Administration)

Relevance to Offshore Development: The act has a potential broad application, due to its definitions of "development of marine development" to include (but not limited to) scientific endeavors related to conservation and economic utilization of chemical and geological etc. resources, marine commerce and marine engineering, the study of the economic, legal, medical etc. problems arising from the development and recovery of natural resources; the definition of "marine environment" to include the oceans, continental shelf and the seabed and subsoil and natural resources thereof to the 200 meter or exploitable limit; and the definitions of "sea grant college" to basically mean any institution deemed such by the Secretary, and of "sea grant program" to include many relaxed activities. Thus, funding for studies or programs relating to various aspects of offshore development could be obtained through this act.

Major Cases: None

Natural Gas Pipeline Safety Act of 1968

Citation: 49 USC 1671-1684 (1966) (1975 Pocket Part)
49 CFR 190.1-192 _____ Appendix

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act operates to regulate the distribution or transportation of gas by pipeline or its storage in or affecting interstate or foreign commerce. The interim federal regulations are to be existing state regulations regulating pipeline facilities. If no state rules exist, then the Secretary of Transportation shall establish interim federal safety standards which are common to a majority of states. The standards apply to the design, installation, inspection, testing, construction and maintenance of pipeline facilities.

The law outlines the administrative and penal procedures to be followed. The Technical Pipeline Safety Standards Committee was established by the act and is to prepare a report on the reasonableness of each proposed regulation. The act will not apply to pipelines within a state if certification of the adequacy of that state's laws is submitted annually to the Secretary of Transportation.

Lead Agency: Department of Transportation

Relevance to Offshore Development: The technologies under consideration in this study for the Baltimore Canyon provide for gas mining and presumably transportation of that gas by pipeline. The federal and state regulations under this act will apply to such pipelines, where both federal and state standards exist, the exact boundaries of their respective jurisdictions is not evident, but should be clear upon investigation of the state laws and federal regulations.

Major Cases:

Tenneco, Inc. v. Public Service Commission of WV (1973) 352 F. Supp. 719 Eff'd 489 F.2d 334, cert. denied 943 C 3071.
This field did not preempt field of pipeline safety with respect to interstate transmission facilities.

United Gas Pipeline Co. v. Terrebonne Parish Police Jury (1970) 319 F. Supp. 1138 Eff'd 445 F.2d 301.
Congress intended by this chapter to give exclusive jurisdiction to Department of Transportation to regulate safety of "interstate transmission facilities."

Baker v. Central and Southwest Corp. (1971) 334 F. Supp. 752.
The regulations promulgated under authority of this section have the force and effect of law.

Occupational Safety and Health Act of 1970

Citation: 5 USC 5108, 5314, 5315, 7902, Civil Service Organization Provisions;
15 USC 633,636 (1963-1975 Pocket Part)
18 USC 1114 (1966-1975 Pocket Part) Murder and manslaughter section for the killing of an officer or employee of the United States
29 USC 553,651-678 (1975)
42 USC 3142-1 (1973-1975 Pocket Part) (authorizes loans to carry out purpose of Act)
49 USC 142 (1963-1975 Pocket Part)
29 CFR XVII; 29 CFR XX
49 USC 1421 Subchapter VI. Safety Regulation of Civil Aeronautics. Airworthiness and noise standards 14 CFR 23.1 et seq. This section regulates installation of emergency locater transmitters, etc., and describes the aircraft subject to coverage. It also sets aviation fuel standards. Secretary of Transportation
Cases: Bibler v. Young 1974, 492 F2d 1351
Stanley v. U.S. 1965, 239 FS 973
Todd v. U.S. 1974, 384 FS 1284
Freeman v. U.S. 1975, 509 F2d 626
29 USC 3553 Authorized an increase in number of Assistant Secretaries of Labor to provide that one will be Ass't. Secretary of Labor for Occupational Safety and Health.
5 USC 7902 (1968) (Pocket Part 1975) Executive Order No. 11612 makes a Federal Agency head responsible for establishing and maintaining an effective and comprehensive occupational safety and health program consistent with the Labor Department regulations for interstate commerce Rusmesses. A Federal Safety Council is established, composed of representatives of Federal agencies and of labor organizations to advise the Secretary of Labor on carrying out a Federal Safety program. Executive Order No. 11807 superceded No. 11612. This ordered expanded on the efforts provided for in No. 11612. Generally, the Secretary of Labor will issue more detailed guidelines to agency heads, and will conduct more thorough evaluations of the safety programs. By agreement, federal employees working in geographical areas not covered by OSHA can be covered.
Title 29 553 Established the Office of Assistant Secretary of Labor for Occupational Safety and Health.
Title 29 3651-678 Occupational Health and Safety Act of 1970.

Synopsis of Law: The policy of this Act is to preserve human resources and provide positive working conditions by encouraging employers and empolyees to reduce hazards, by providing that employers and employees have

separate but dependent responsibilities and rights, by authorized Secretary of Labor to set mandatory occupational safety and health standards applicable to businesses affecting interstate commerce, by setting up an Occupational Safety and Health Review Commission, by calling for research in many related fields (medical, psychological, technical) and by giving grants to States to assist them in promerlgation and enforcement of safety and health standards.

The use of "employer" means a person engaged in a business affecting commerce who has employees, but doesn't include the U.S. or any state or political subdivision of a state.* Geographically, the Act applies to employment performed in states, territories, D. C., outer continental shelf lands, etc. - where no U.S. district court has jurisdiction the Department of Interior will provide for judicial enforcement. The law is not intended to interfere with anyone's common law or statutory rights, duties and liabilities or workmen's compensation awards.

States may assume responsibility for issues in this Act by submitting a plan of development and enforcement to and obtaining the approval of the Secretary of Labor.

Both employers and employees have duties to comply with standards. The Act provides procedures for fromelgation of all occupational safety and health standards variance from standards, judicial review of those standards, temporary emergency procedures, etc.

A national Advisory Committee on Occupational Safety and Health is established which shall advise the Secretaries of Labor and HEW on matters relating to administration of this Act.

The Secretary of Labor is given powers of inspection and investigation at all work sites. Also a procedure is outlined for employees requesting an inspection. The Secretary may issue citations to employers within six months of violations. And extensive enforcement procedures are outlined. If the employer wishes to contest a citation, he must notify the Secretary within 15 days; if he doesn't do this (or file a protest) the citation and assessment shall be deemed a final order of the court and not subject to review by any court or agency.

The Occupational Safety and Health Review Commission is established by this Act. It will have subpoena power. Injuction procedures are also outlined, as are the civil and criminal penalties.

* (668 provides for programs in Federal Agencies)

Lead Agency: Department of Labor; Occupational Safety and Health Review Commission; National Institute on the Department of HEW; National Commission on State Workmen's Compensation Laws.

Relevance to Off-Shore Development: The act specifically includes the outer Continental Shelf lands as workplaces under the jurisdiction of this Act. Employers will be required to comply with the standards issued under this Act.

Major Cases: Brennan v. Southern Confeastors Service 1974, 492 F2d 498

Brennan v. Gilles and Cotting, Inc. 1974, 504 F2d 1255 Common Law definition of employer is inapplicable in determining breach of this chapter.

Byrd v. Fieldcrest Mills 1974, 496 F2d 1323, Workmen's Compensation recovery.

Brennan v. OSH Review Commission 1974, 492 F2d 1027; 487 F2d 230 (1973); 501 F2d 1196, 502 F2d 946 Knowledge of employer

REA Exp., Inc. v. Brennan 1974, 495 F2d 822 Unpreventable hazards.

National Realty & Construction Co., Inc. v OSH Review Commission 1973, 489 F2d 1257 Hazardous conduct.

McClean Trucking Co. v. Occupational Safety and Health Review Comm. 1974, 503 F2d8 Ambiguity or Vagueness of Standards, 1974, 503 F2d8

Synthetic Organic Chemical Mfr's Assn v. Brennan 1974, 503 F2d 1155; 506 F2d 385

National Roofing Contractor's Assn. v. Brennan 1974, 495 F2d 1294

Fawvor v. Texaco 1975, 387 F Supp. 626

Otto v. Specialties 1974, 386 FS 1240 Duties of employers and employees

Society of Plastics Industry v. OSHA 1975, 509 F2d 1301

U.S. v. Dye Construction Company 1975, 510 F2d 78

Oceanographic Research Vessels Act

Citation: 46 USC 441-445(1958) - law is in the 1975 Pocket Part

Pocket Part: For Use in 1975 (no modification through 6/75)

Synopsis: This Act authorizes the Secetary of Transportation to make a determination that a vessel carrying scientific personnel for the purpose of conducting studies in oceanography or limnology is a non-passanger vessel so as to obviate the application of existing statutory regulations pertaining to passenger vessels. The personnel on board the oceanographic research vessels will not be considered seamen engaged in trade or commerce.

Lead Agency: Department of Transporation, U.S. Coast Guard

Relevance to Offshore Development: OCS geophysical and exploratory drilling operations will involve employing some scientific personnel to determine where and in what manner to drill. Maritime regulations for these personnel will differ from normal vessel regulation, and will be covered by this statute.

Major Cases:

Sennett v Shell Oil Co, (1971) 325 F Suppl. The Secretary of Transporation is now able to adopt new regulations more appropriate to such vessels.

Oil Pollution Act Amendments of 1973

Citation: 33 USC 1001-1015 (1975 Pocket Part of 1970 Volume)

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act operates to prohibit the discharge of oil or oily mixture from a ship above a certain specified rate of discharge. The act apparently does not regulate any vessels discharging oil beyond 50 miles from the nearest land. Exceptions to the prohibition include discharges for the purpose of securing the safety of a ship, discharges due to an unavoidable leakage if all reasonable precautions have been taken after discovery of the leakage for the purpose of preventing or minimizing the escape, and discharges from a stationary tanker which has been so cleaned since cargo was last carried therein, that the discharge leaves no visible traces on the surface of calm water.

The act outlines sections of the International Convention for the Prevention of the Pollution of the Sea by Oil, 1954, which domestic tankers must comply with and the certification procedure for foreign tankers. Administrative procedures and procedures for assessment of penalties are also outlined. See also 33 USC 331051-1094 for the International Regulations for Preventing Collisions at Sea.

Lead Agency: Department of Transportation, U.S. Coast Guard

Relevance to Offshore Development: This act forbids the dumping of oil within 50 miles of U.S. coastline. (Please see Marine Protection, Research and Sanctuaries Act.) Small discharges from ships en route are exempt. In conjunction with other laws, this act regulates discharges from vessels traveling within the 50 mile zone; beyond that range, international regulations seem to be the sole restrictions on dumping or discharging of oil. All ships moving to and from offshore facilities will be subject to this law while they are within the 50 mile zone.

Major Cases: None

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Outer Continental Shelf Lands Act

Citation: 43 USC 1331-1343 (1964); 30 CFR 188, 183, 189, 187b

Pocket Part: For Use in 1975 (No modification through June, 1975)

Synopsis: This Act establishes the U.S.'s jurisdiction, control, and power over the subsoil and seabed of the Outer Continental Shelf. The right to navigation and fishing above the OCS is not affected. The Act that the Federal Constitution and statutes will be extended to the OCS subsoil and seabed as well as to all the artificial islands and fixed structures erected thereon. It claims exclusive jurisdiction of this Act over mineral leases on the OCS. Consistent state laws of adjacent states will also apply to the OCS when the President of the U.S. issues projected state lines extending seaward from the Continental Shelf. No such lines have been drawn (although with the growing interest in environmental controls over the drilling, etc., there may well be such extensions of state boundaries soon).

The Secretary is authorized to establish rules and regulations implementing this Act. Pipelines will be afforded rights-of-way under the regulation of the Federal Power Commission (gas) or the Interstate Commerce Commission (oil). Generally, this Act sets the foundation for the DOI leasing tracts for resource developments and the OCS Orders.

Relevance to Offshore Development: This is the enabling legislation for the tract leasing program that will occur in the Mid-Atlantic in 1976. It establishes the federal and state jurisdictions (along with the Submerged Lands Act) in the ocean waters, and authorizes the Secretary of the Interior to regulate all OCS activities. It is under this Act that the applicability of federal or state civil and criminal laws will be ascertained.

Lead Agency: Department of the Interior (DOI)

Major Cases:

Guess v. Read (1961) 290 F2d 622 (Interprets Act to assert ownership of and jurisdiction over minerals in and under the Continental Shelf; and that it is only for that portion of subsoil and seabed of OCS and artificial islands and fixed structures erected thereon, that the state law applies, and does not include the sea above the subsoil and seabed, nor the air above the sea)

Questions pertaining to liability for injuries occurring on the OCS:

Smith v Chevron Oil Corp (1974) 503 F2d 966

Union Oil Co. v Oppen (1974) 501 F2d 558

Pure Oil Co v Snipes (1961) 293 F2d 60

Touchet v. Travellers Indemnity Co. (1963) 221 F Supp 376

Ports and Waterways Safety Act of 1972

Citation: 33 USC 1221-1227 (1970); Sec 33 CFR I, 46 CFR I, III and 49 CFR IV for Coast Guard Regulations

Pocket Port: For Use in 1975 (no modification through 6/75)

Synopsis: The purpose of this Act is to promote the safe and efficient conduct of maritime commerce by establishing vessel traffic service and systems for ports, harbors, and other waters subject to congested vessel traffic. The Act provides for civil and criminal penalties for wilfull violations of the systems established by the Department of Transporation. The Secretary is also authorized to issue reasonable rules and regulations and standards necessary to implement the Act.

Lead Agency: Department of Transportation, U.S. Coast Guard

Relevance to Offshore Development: The Act's territorial boundaries are the outer limit of the territorial sea, so that all vessels coming into that area will have to comply with the systems established here.

Major Cases: None

Resource Recovery Act of 1970 (Amending the Solid Waste Disposal Act)

Citation: 42 USC 3251-3259 (1973); 40 CFR 30.100 et seq
42 CFR 52, 1 et seq

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis: The purpose of this Act is to promote the application of solid waste management and resource recovery systems, to provide technical and financial assistance to states and local governments and interstate agencies and to provide for training grants in occupations involved in the solid waste disposal systems. The EPA Administrator shall conduct a study to determine means of recovering materials and energy from solid wastes, changes in current product characteristics, recommended incentives, the use of federal procurement to develop market demand for recovered resources etc. Broad granting authority was established in the areas of state, interstate, local planning; resource recovery systems, and improved solid waste disposal facilities; contracts with eligible organizations. The EPA Administrator also will promulgate guidelines for solid waste recovery, collection, separation and disposal systems whether on land or water systems.

Lead Agency: Department of Health, Education and Welfare under prior law; EPA after the 1970 Amendments. The Department of Interior is the lead agency with respect to problems of solid waste resulting from the extraction processing or utilization of minerals or fossel fuels where the facility involved could control the generation, production, or reuse of such waste.

Relevance to Offshore Development: As with other federal environmental laws, it is unclear whether this Act will apply to facilities beyond the 3-mile territorial sea. However, there is independent federal authority as well as enactment authority on the local governments. Also, Section 3254e states that if an executive agency enters into a contract with any person on any federal property or facility and the performance of such contract involves such person in solid waste disposal activities, then the operator must comply with the guidelines recommended by the EPA Administrator -- this could make the Act applicable to the offshore activities (as it is applicable to the onshore activities).

Major Cases:

American Can Co. v Oregon Liguor Control Commission (1973) 517 P 2691
Enactment of state law relating to beverage containers was clearly a legislative action in harmony with federal law, where Congress had directed the states to take primary responsibility for action in the field.

Hylton v. Mayor & City Council of Baltimore (1972) 300 A2d 656
Discussion of the Baltimore pyrolysis procedure.

Rivers and Harbors Act of 1899
Rivers and Harbors And Flood Control Act of 1970

Citation: 33 USC 401 et. seq. (1970) Title 33 CFR
33 USC 701 et. seq. (1970) 205.10 et. seq.
33 USC 540 et. seq. (1970) etc.

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: The Rivers and Harbors Act in general deals with the protection of navigable waters and of river and harbor improvements. There have been many amendments, minor and major of the original 1899 Act.

The Army Corps of Engineers receives its broad permitting authority over building improvements on navigable waters under these sections. The various aspects of river and harbor improvements which are to be regulated include construction of bridges, causeways, and dams (regulation includes needing the approval of the Corps of Engineers before beginning construction); any obstructions to the navigable capacity of any waters of the United States is inhibited; wharves, piers, excavations, etc., require Corps approval; depositing refuse is prohibited, etc.

Generally, the same authorities exist pertaining to the flood control improvements over navigable waters.

Lead Agency: Department of Transportation

Relevance to Offshore Development: There is a continuing debate over the definition of "navigable waters;" the resolution of such debate would aid in determining the seaward applicability of these acts and the Corps regulating powers. All onshore facilities will be subject to these provisions if navigable waters are in any significant manner affected.

Major Cases: There are many interpreting these statutes, especially regarding the definition of "Navigable Waters":

Rochester Gas & Electric FPC (1965) 344 F2d 594 Cert denied 382 US 832

U.S. v. Crow (1972) 340 F. Supp. 25 App'l Dism'd. 474 F2d 200

U.S. v. Cannon (1973) 363 F. Supp. 1045

Zabel v. Tabb (1970) 430 F2d 199 Cert denied 401 US 910

U.S. v. PA Industrial Chemical Corp. (1970) 111 US 655

U.S. v. Stoeco Homes, Inc., (DC, NJ) (1973) 359 F. Supp. 672

U.S. v. U.S. Steel (1973) 482 F2d 439 Cert. denied 414 US 909

U.S. v. Meidman (1971) 340 F. Supp. 395

U.S. v. Tulare Lake Canal Co. (1972) 340 F. Supp. 1185

Submerged Lands Act (1953)

Citation: 43 USC 1301-1315 (1964); 30 CFR II, (if at all) IV

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act operates to relinquish all U.S. ownership, title, and interests in the lands beneath navigable waters within the boundaries of the respective states (and the natural resources within such lands and waters) and assigns such interests to the states. The U.S. rights in the territorial sea (3 miles seaward from the coast line) are included in this assignment, while the rights to exploit the resources of the subsoil and seabed of the Continental Shelf remains in the United States.

This assignment of interest to the states does not affect the federal government's navigational servitude and powers of regulation in said lands and navigable waters for the constitutional purposes of navigation, commerce, national defense and international affairs. Section 1311 includes in those constitutional purposes, flood control and the production of power. Zabel & Tabb (see below) interprets this to apply to hydroelectric power. The Secretary of the Interior (or of Navy or the U.S. Treasurer) shall make payment to the states of monies paid under leases covering such lands and waters.

Lead Agency: Department of Interior

Relevance to Offshore Development: This act serves to outline the boundaries of the territorial sea in which the states have primary powers of control and regulation, with the exceptions listed above. The laws of the states will apply only to the outer boundaries of the territorial sea, wherever they are drawn, under this act. This act must be read in conjunction with the Outer Continental Shelf Lands Act.

Major Cases:

People v. Hicker (1960) 4 Cal Report 334
(This act serves a quit-claim from the Federal Government to the z States, not a grant of title.)

U.S. v. LA (1960) 364 U.S. 502
(Deals with the delineations of the Southern States' boundaries.)

U.S. v. States of LA (1960) 363 U.S. 1
(Discusses States' right on Submerged Lands not beyond 3 mile sea.)

Corsa v. Tawes (1957) 149 F. Supp. 771
(Regulation of the coastal fisheries is within the police power of the individual states.)

U.S. v. Fifty-Foot Right-of-Way (1964) 337 F2d 956
(Concerns compensation - the U.S. is required to pay New Jersey for a pipeline run over bed of navigable water in Newark Bay.)

State of Maine v. M/V Tamano (1973) 357 F. Supp. 1097
(In order to maintain a parens patrie suit for damage to its coastal waters, State must show that damage had an adverse effect on a substantial part of its citizens, i.e., oil spill.)

Bonelli Cattle Co. V. Arizona (1973) 94 U.S. 517
(Riparian lands may be deprived of their riparian character altogether by State or Federal Government in exercise of navigational servitude.)

U.S. v. State of LA (1969) 394 U.S. 11836
(Divides navigable sea into three zones: inland waters, territorial sea, and high seas.)

Zabel v. Tabb (1970) 430 F2d 199
(This act does not constitute relinquishment by Congress of its constitutional powers over commerce to regulate use of submerged property for conservation purposes.)

U.S. v. CA (1965) 381 U.S. 139
(Deals with determination of base line and territorial sea.)

Water Resources Planning Act

Citation: 42 USC 1962 (1974)

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act was enacted for the purpose of requiring the conservation, development and utilization of water, and related land resources on a coordinated basis by the federal government, states, private enterprises, etc. The objectives of the act are to be included in federally financed water resources.

Water Resources Council was established composed of the Secretaries of Interior, Agriculture, HEW, Army, and the Chairman of the Federal Power Commission. The council will study the adequacy of water supplies necessary to meet national and regional needs. There is a provision for federal grants to states for the development of comprehensive water and related land resources plans.

Lead Agency: Water Resources Council

Relevance to Offshore Development: This act will only affect onshore facilities related to offshore development, in terms of how they affect the overall water supplies of the region in which they are located.

Major Cases: None

Wildlife Restoration

Citation: 16 USC 669-669i (1974); 50 CFR 80.1 et. seq.

Pocket Part: For Use in 1975 (No modification through 6/75)

Synopsis of Law: This act authorizes the Secretary of the Interior to cooperate with the states, through their respective fish and game departments, in implementing and maintaining wildlife restoration projects. If the state's programs and projects are approved by the Secretary, federal funds will be allocated to help support such projects.

Lead Agency: Department of the Interior

Relevance to Offshore Development: Federal funds are available to the states for wildlife restoration projects in light of any disruption which may come about related to offshore development.

Major Cases: None

Other Relevant Federal Laws

Title 16 of the Code is entitled Conservation. It's range is broad and many of the requested laws are bits and pieces of the title.

Title 16 667. State Compacts for the Regulation of Fishing in Territorial Waters

The act in 1942 granted the consent of Congress to an interstate compact relating to the better utilization of the fisheries of the Atlantic seaboard and created the Atlantic States Marine Fisheries Commission. Any limitation on the life of this commission was repealed on August 19, 1950.

Title 16 715(K-3) to (K-5). Wetlands Act of 1961

These sections are part of Chapter 7, Protection of Migratory Game and Insects, Various Birds and in the subchapter Migratory Bird Conservation. The specific sections cited are appropriation authorization for the preservation of wetlands and other waterfowl habitat.

The Department of Interior is the lead agency for the entire chapter. Off-shore developers should be concerned with these laws only if their actions will interfere with the migratory birds. The act does not expressly indicate if OCS lands are under its jurisdiction, although presumably they are.

Title 16 460K-K4. Recreational Use of Conservation Areas

These provisions (part of the chapter National Parks, Military Parks, Monuments and Seashores) merely authorize the Secretary of Interior to administer areas within the National Wildlife Refuge System and other Conservation Areas for public recreation when in his judgement public recreation can be an appropriate incidental or secondary use.

See 50 CFR 25.1 et seq

The Secretary is given the authority to acquire areas of land for recreational development, and appropriations are authorized.

Title 10 7421-7438. Naval Petroleum Reserves Act

This act generally gives to the Secretary of the Navy the possession of all properties inside the naval petroleum reserves that are or may become subject to the control of and use by the U.S. for naval purposes. Other provisions deal with the Administration of such, consolidating and protecting the oil lands awarded by the U.S., the acquisition of such lands, leasing provisions. etc.

Title 16 1221-1226. Estuaries Areas Act (Natural Resources)
50 CFR 80 et seq.

The Secretary of Interior will direct a study of all the uses and resource value of estuaries in the United States, with the goal being the establishment of the most beneficial protection system. Agreements with States and Subdivisions will be entered into for the permanent management, development and administration of any estuarine areas within a State's or subdivisions jurisdiction.

III. STATE AND LOCAL GOVERNMENT MANAGEMENT OF OFFSHORE RELATED DEVELOPMENT

Introduction

Despite the fact that many important decisions concerning offshore energy development occur at the Federal level of government, the States and their political subdivisions possess important regulatory powers which may enable them to closely control the siting and rate of any such development. Such control may be exercised by the States or local government by regulating the siting, construction, and use of nearshore and onshore facilities, through measures such as special land-use laws, air and water pollution laws, pipeline regulations, and zoning and building codes.

New Jersey and Delaware each have a variety of laws which would provide for State review of proposed key offshore-related facilities in the coastal area.

Permits are required for various components of staging areas, for pipelines and tank farms, and for any onshore processing or refining facilities. Each state has subaqueous lands laws, coastal area facilities review laws (or prohibitions), wetlands protection laws, and air and water pollution regulations to complement the Federal Clean Air Act and the Federal Water Pollution Control Act Amendments of 1972. Each State also requires county or municipal approval of all proposed construction as a precondition to issuance of the State permit. Moreover, a particular facility might be subject to regulation under several, or possibly all, of the above types of laws.

The number of permits needed in either New Jersey or Delaware is dependent on the site and activities involved in the proposed project. Any construction along the shoreline of a waterway or in the waterway, or any alteration (e.g., dredging) in a waterway within the State boundary is subject to Riparian or subaqueous approval. Any construction on the wetlands or alteration of them is subject to Wetlands approval. Construction in the coastal zone also may require approval under New Jersey's Coastal Area Facility Review (CAFRA) or the Delaware Coastal Zone Act.

A major project requiring only Wetlands, CAFRA, or Coastal Zone Act approval could be processed within one year if the original application contains sufficient information (or if required information is quickly provided) and if there are no appeals. A project requiring multiple approvals could also be processed within one year (with sufficient information and no appeals) because applications for certain approvals may be considered concurrently, and there is some coordination between the staffs which process different permits.

New Jersey Legislation and Administration

The three major State statutes which govern land use in New Jersey's coastal area are: Riparian statutes; the Wetlands Act; and the Coastal Area Facility Review Act (CAFRA). The New Jersey Department of Environmental Protection (DEP) administers these three statutes and New Jersey's Coastal Zone Management planning effort (TABLE III-1).

Riparian Lands Administration

Approval under the New Jersey Riparian Law (N.J.S.A.

RESPONSIBLE AGENCY / ACTIVITY	RIPARIAN LANDS	COASTAL AREA FACILITY REVIEW ACT (CAFRA)	WETLANDS ACT
	1 DEPARTMENT OF ENVIRONMENTAL PROTECTION (DEP) BUREAU OF MARINE LANDS MANAGEMENT- RIPARIAN SECTION	1 DEP BUREAU OF MARINE LANDS MANAGEMENT- COASTAL SECTION	1 DEP BUREAU OF MARINE LANDS MANAGEMENT- WETLANDS SECTION
2 PRELIMINARY REVIEW A. AGENCY DECIDES ACTIVITY IS OR IS NOT WITHIN ITS JURISDICTION? B. TIME LIMIT FOR JURISDICTIONAL DECISION?	2 A. YES B. 30 DAYS	2 A. YES B. 30 DAYS TO NOTIFY APPLICANT OF COMPLETION	2 A. YES B. 30 DAYS TO NOTIFY OF COMPLETION
3 FORMAL APPLICATION BY APPLICANT A. LOCAL ZONING APPROVAL OR OTHER PREREQUISITE NEEDED BEFORE AGENCY CAN GRANT PERMIT B. EIS REQUIRED? C. PUBLIC HEARING 1. REQUIRED? 2. DISCRETIONARY? 3. PRIOR PUBLIC NOTICE? D. TIME LIMIT ON AGENCY DECISION?	3 A. NO B. NO C. ADJACENT LANDOWNERS ARE NOTIFIED OF APPLICATION. NO PUBLIC HEARING REQUESTED-ONE MAYBE HELD IF REQUESTED BY GOV'T AGENCY (I.E. ARMY CORPS OF ENGINEERS) D. NONE DESIGNATED	3 A. EIS IS TO INCLUDE LIST OF ALL OTHER REQUIRED PERMITS B. YES C. 1. YES 3. AFTER APPLICATION DECLARED COMPLETE: 15 DAYS TO SET HEARING FOR NO MORE THAN 60 DAYS LATE D. 60 DAYS AFTER HEARING. IF NEED ADDITION INFO, 90 DAYS AFTER NEW INFO. RECEIVED	3 A. RIPARIAN NEEDED AND ALL OTHER REQUIRED PERMITS B. YES C. 1. YES 3. AFTER APPLICATION COMPLETE 30 DAYS TO SET DATE FOR NO MORE THAN 75 DAYS LATER D. 90 DAYS AFTER HEARING. ADD. INFO- 90 DAYS AFTER RECEIPT OF IT
4. APPEAL TO A REVIEW BOARD? A. WITHIN WHAT TIME AFTER AGENCY DECISION? B. WHO MAY APPEAL? C. EIS REQUIRED D. PUBLIC HEARING REQUIRED? PRIOR PUBLIC NOTICE E. TIME LIMIT TO DECIDE APPEAL?	4. YES. NATURAL RESOURCES COUNCIL A. NO APPEAL FOR LEASES OR GRANTS, OTHERWISE 2 YEARS B. LANDOWNER C. NO D. NO E. ?	4. YES. COSTAL AREA REVIEW BOARD A. ? B. APPLICANT C. BOARD REVIEW ORIGINAL EIS D. BOARD REVIEWS RESULTS OF ORIGINAL HEARING E. NO FORMAL LIMIT. AVERAGES 6 MONTHS TO 1 YEAR	4. NO. QUASI-JUDICIAL HEARING WITH DEP HEARING EXAMINER A. 90 DAYS AFTER DECISION B. ANY AFFECTED PARTY C. NO. MAY REQUEST ADDITIONAL INFOR D. NO E. NO FORMAL LIMIT
5. APPEAL TO JUDICIARY? A. WITHIN WHAT TIME AFTER DECISION? B. WHO MAY APPEAL	5. YES A. WITHIN 1 YEAR - INFORMAL LIMITS B. ANY AFFECTED PARTY	5. YES A. 21 DAYS AFTER DECISION B. ANY AFFECTED PARTY	5. YES. APPELLATE COORT. SUPREME COURT. A. 90 DAYS ON DECISION TO ISSUE PERMITS. 19 DAYS TO NOT ISSUE PERMIT. B. ANY AFFECTED PARTY

SOURCE: REVIEW OF SELECTED NEW JERSEY COASTAL AREA LEGISLATION. PREPARED BY RUTGERS UNIVERSITY. 1975.

TABLE III-1 New Jersey: Selected Relevant Legislation

12:3-1 et. seq.) is required for any facilities constructed in coastal waters within the three-mile limit (i.e., in state-owned coastal waters), for any facilities built on land along rivers, and for any facilities which require access via navigable rivers or estuaries. (TABLE III-2 for the boundaries of reparian lands, wetlands, and the coastal zone within CAFRA). Riparian approval is also required for improvement or expansion of existing facilities if those facilities are on riparian land or if expansion would include riparian land (e.g., refinery expansion).

Riparian lands are lands within the boundaries of the State along natural waterways which are now or were formerly covered permanently or periodically by tidal waters at and below the line of normal (mean) high tide.[49] Title to riparian lands belongs to the State of New Jersey, which may lease or grant these lands to persons who file applications and pay such fees as are established by the Natural Resource Council, the DEP Commissioner, and the Governor. Riparian lands are held in trust by the State and proceeds of leases or sales are put into a trust fund designated for the support of the free public schools.

Applications for use of riparian lands are submitted to DEP's Bureau of Marine Lands Management, Riparian Section. The staff of the Riparian Section reviews the application to determine whether it is complete prior to its presentation to the initial decision-making agency,

49/ New Jersey Department of Environmental Protection. Application for Coastal Zone Management Program Development Grant. Trenton, N.J. May 31, 1974.

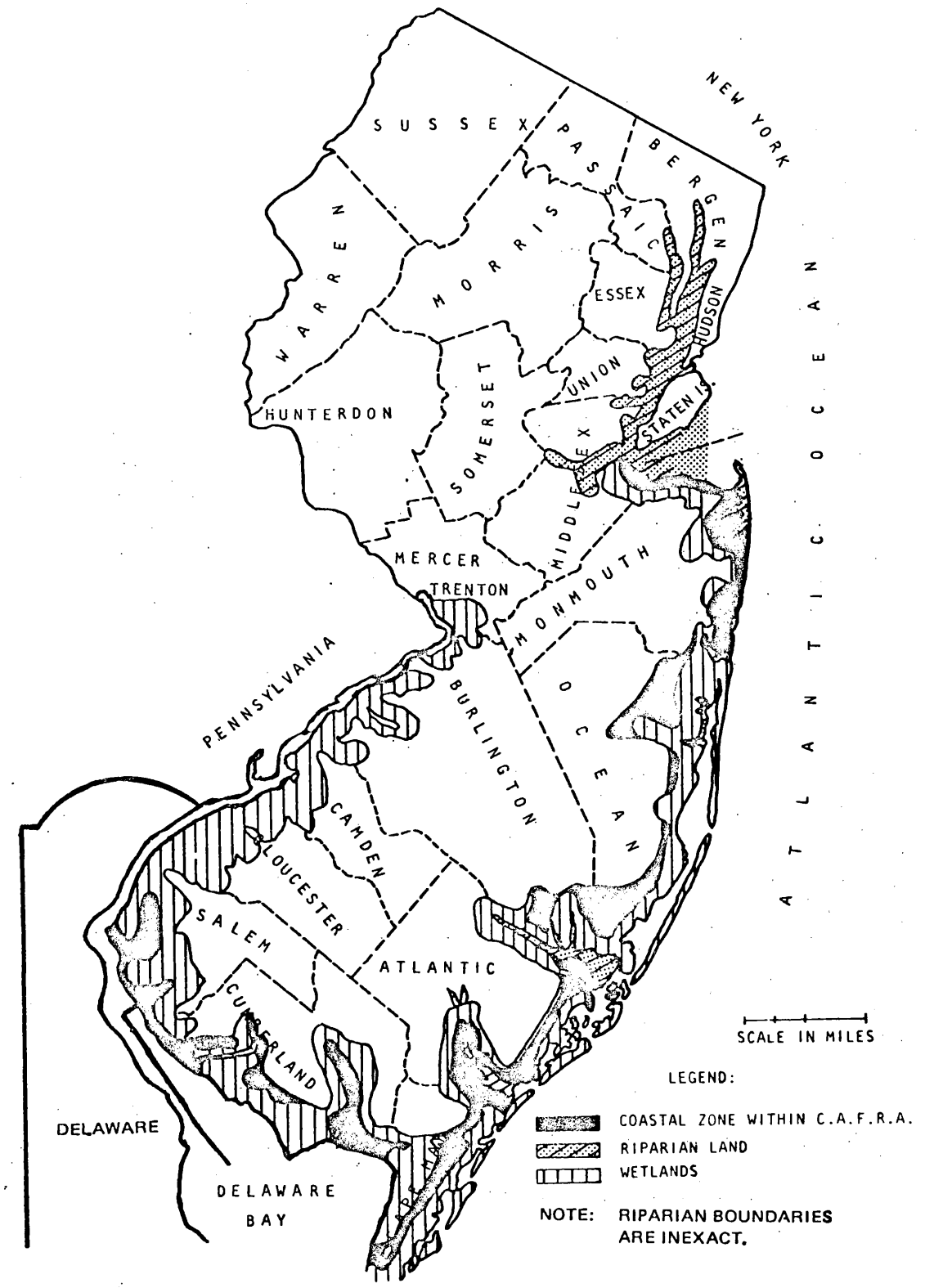

TABLE III-2 New Jersey Coastal Area: Riparian Lands, Wetlands, CAFRA Lands

the Natural Resource Council. The Natural Resource Council thus receives an application which has been designated "complete."[50]

Proposed riparian grants, leases and licenses are circulated to several divisions of DEP and other State agencies, for their comments. No municipal approval is required of a riparian applicant for a grant, lease or license, unless construction is involved.

The Natural Resource Council consists of twelve private citizens representing the general public, with an attempt to balance environmental and economic interests. Council members are appointed to the Council by the Governor. Decisions concerning riparian grants, leases, licenses (permission to use the land) and permits (to construct on the land) are made by the Council. Grants and leases must be approved by at least 7 of the 12 Council members. The Commissioner of DEP may veto and thus override the Council approvals or he may approve a more restrictive land use. There are cases where the Council has given approval and the Commissioner has denied such approval. The Council is the final authority on its negative decisions and the preliminary authority on approvals (see, e.g., R.S. 12:5-3). However, a negative decision at any level terminates the process.

Final State-level approval of construction permits is vested in the DEP Commissioner. Final land approvals (e.g., grants, leases and licenses) is the Governor's prerogative. The Governor has the power

50/ Review of Selected New Jersey Coastal Area Legislation. Prepared by Rutgers University, 1975.

to override any riparian land use decision of the DEP Commissioner, but no Governor has ever used that power.

An application for riparian permission must demonstrate that the proposed project will serve the public interest and will result in minimum harm to the environment. The Council may request an environmental impact statement (EIS) or baseline data on major projects. For example, the Council requested an EIS and one full year of baseline data in the Shell refinery application.[51] Even if an actual impact statement is not required, virtually the same information is provided in the process of demonstrating that the project serves the public interest and does minimal damage to the environment.

After a riparian grant, lease or license is approved by the Council, the applicant cannot alter the land until a waterfront development permit is obtained from the Council. Grants convey legal title to the State-owned riparian lands. Leases are rentals, usually for a maximum of 25-30 years with the option to renew the lease. Recent riparian policy has been to favor leases rather than grants. Licenses confer the right to occupy the land, and are approved for temporary uses, for a minimum of two years and average of 5-10 years. They are renewable and revokable. Permits allow construction on riparian lands and are issued for one year. If construction is not completed in one year, application must be made for an extension of the permit. Improvement permits for expansion of existing structures, etc., are also issued under riparian law. An applicant for an improvement permit who does not

51/ Ibid.

already have a riparian grant or lease and license for the new land involved in the proposed improvement, must obtain one of those approvals before applying for the improvement permit.

The time period to decide upon a riparian application may be as short as three days in clear cut cases and as long as six years in complicated decisions where baseline information is missing and raw data must be collected. The average time for an improvement permit to be processed is four months. The Mobil refinery expansion at Paulsboro took five months to review.[52] There is no legal time limit before which a riparian permit application decision must be reached.

Under riparian law no public hearings are required. The Council's monthly meetings are open to the public, but attendees do not have the right to be heard.

Since the Council serves as a landowner, applicants for grants or leases have no recourse to legal action. The State, like any other landowner, can just refuse to sell. If the applicant feels the decision was unjust he may request further review, perhaps on the basis of new evidence. The Natural Resource Council reviews its own decision. The Commissioner of DEP also passes judgement on Natural Resource Council review decisions and has a veto power which could override the Council's decision, although this is unlikely to happen. Although the right to appeal the denial of a grant or lease has no legal basis, it is conceivable that some disappointed applicant could decide to sue the Governor.

The riparian process is currently under review in New Jersey in order to determine a set of policy statements and guidelines

52/ Ibid.

pertaining to the public trust doctrine that are based on clear-cut legal decisions.[53] In current practice, the Riparian Section of DEP is issuing very few permits because there have been very few applications, except for dredging and an occasional marina. Public attitude seems to be that the area between Sandy Hook and Cape May is vacationland with a large income based on tourism and recreation, and that those industries ought not to have any competition in the coastal area. Applications currently under consideration tend to be in the Camden or Raritan Bay area.[54]

Wetlands Administration

Any alteration of or construction upon the coastal wetlands of New Jersey will require approval by the Wetlands Section of DEP. Coastal wetlands include all marshland along the Atlantic coast, from Raritan Bay to Cape May, and all marshland along the Delaware Bay and River to the head of the tide at Trenton, including tidal portions of an estimated 1,000 streams.

The purpose of New Jersey's Wetlands Act is to protect coastal wetlands resources. The Act preceded the Federal Coastal Zone Management Act. Under the Wetlands Act, development which might affect the marshland adversely may be prohibited. This act is designed to consider effects of a modification of the Wetlands environment before

53/ Private communication with Dave Moore, Chairman, Natural Resource Council by Rutgers University personnel. June 20, 1975.

54/ Private communication with P. McDowell, Permits Section, Riparian Section, Bureau of Marine Lands Management, DEP to Rutgers University personnel. June 19, 1975.

the project is allowed to proceed, and is based on the rationale that destruction eliminates choice (N.J. S.A. 13:0A-1 et seq.). Through a permit process including an environmental impact statement, public hearings and regulations similar to those provided in CAFRA (see discussion below) the Wetlands Act has for the past three years assured land and water usage compatible with the wetlands environment.[55]

Applications for Wetlands permits are submitted to DEP's Bureau of Marine Lands Management, Wetlands Section, and are sent to other divisions of DEP if their involvement is indicated. There are also exchanges of review opinions among DEP personnel administering Wetlands, CAFRA and Riparian Lands policies if their involvement is indicated. If an application does involve Riparian and/or CAFRA uplands, the Wetlands staff works very closely with the Riparian and/or CAFRA staffs in processing the application. The head of the Wetlands Section attends all Natural Resource Council meetings and picks out all applications that Wetlands would be concerned with. Wetlands applications, unlike CAFRA, are not routinely sent out of DEP to other agencies for review. For the most part, although the review of Wetlands applications is extensive, it is primarily an internal process.

Decision on a Wetlands application must await all Riparian clearance if Riparian land is involved. The major source of delay in processing Wetlands applications is acquisition of Riparian approvals. Wetlands and Riparian Sections do review applications simultaneously,

55/ Review of Selected New Jersey Coastal Area Legislation, op. cit.

but the Wetlands decision must await the Riparian decision, and as a result is usually strongly influenced by the Riparian decision.

Approval of a Wetlands application cannot occur until all other required permits - State and local - are obtained. The review process for a substantial facility like a staging area, tank farm, pipeline, refinery, or gas processing plant normally takes about one year.[56] The Wetlands review process is subject to delays similar to those described below in the CAFRA process - delays due to incomplete applications because of insufficient information in the environmental impact statements.

Personnel in the Wetlands Section of DEP review all applications and forward their report to the Commissioner of DEP who renders a decision. In contrast to CAFRA, Wetlands' reports are not recommendations, but are worded to show pros and cons, costs and benefits, problems and corrections regarding a proposed project.

The Wetlands Act does not provide for a review board to hear appeals on the Commissioner's decision. Appeals are handled via a quasi-judicial process. DEP's legal officer assigns appeal cases to lawyers from the Attorney General's office who act as hearing officers.

The hearing is conducted on the basis of information previously collected and available in case files, although additional information may be requested as a result of the hearing. A quasi-judicial hearing is not advertised as a public hearing, but interested persons are welcome to attend. There is no legal time limit on the

56/ Ibid.

appeal decision. Decisions of the DEP hearing officer may be appealed to the State Appellate Division and eventually to the New Jersey Supreme Court. Appeals at all levels may take up to 2 years.[57]

Applications currently under consideration by the Wetlands Section are for such projects as: underwater cables, telephone cables and poles, water mains and sewer lines, etc.[58] As with riparian lands, public attitude seems to be that the wetlands are recreation lands and there should not be any competition with that use of the land.[59] As a result, there have been few applications for any kind of industry, light or heavy.

One industrial application is currently pending in the Wetlands Section. It is an application from Public Service Electric and Gas Company to construct an electricity generating plant on 100 acres of riparian lands and wetlands on Raritan Bay. The application was filed in 1973 for a riparian grant and for a wetlands permit. The riparian grant has not been approved and may not be approved because construction of the plant involves a substantial amount of dredging and because the plant will discharge heated water to the bay. The wetlands section cannot act until the Natural Resource Council decides on the riparian grant.[60]

57/ Ibid.

58/ Private communication with Darryl Jernus, Wetlands Section, DEP by Rutgers University personnel. June 20, 1975.

59/ Private communication with P. McDowell, op. cit.

60/ Private communication with Walter Dryla, Coastal Area Section, DEP, to Rutgers University personnel. June 20, 1975

Administration of the Coastal Area Facility Review Act (CAFRA)

The Coastal Area Facility Review Act (CAFRA) regulates development activity - construction and expansion of industrial plants or large residential units - in the coastal area of New Jersey. The coastal area subject to CAFRA comprises about 20 percent of the land area of the State, and presently is delimited according to geographic boundaries and highways. It includes areas designated as wetlands and adjacent uplands, and extends from Raritan Bay on the Atlantic coast to Salem County on the Delaware River. (TABLE III-3)

CAFRA specifically regulates any petroleum - related development and to a certain extent electric power development activity onshore. The Act extends the power of review and regulation by permit procedures of the DEP beyond heavy industry and housing into roads, sanitary landfills, waste treatment plants, and specified uses involving electric power generation, food processing, waste incineration, paper production, agri-chemical production, inorganic acid and salt manufacture, mineral production, chemical processing, storage, metallurgical processing, installation of above or underground pipelines designed to transport petroleum, natural gas and sanitary sewage, marine terminal and cargo handling facilities, and the disposal of radioactive wastes.

The main purpose of CAFRA is protection of New Jersey's coastal zone from adverse environmental impacts associated with heavy development pressures in that area.[61] In order to accomplish that objective, CAFRA requires of the Department of Environmental Protection:

61/ N.J.S.A. 13:19-1, et seq.

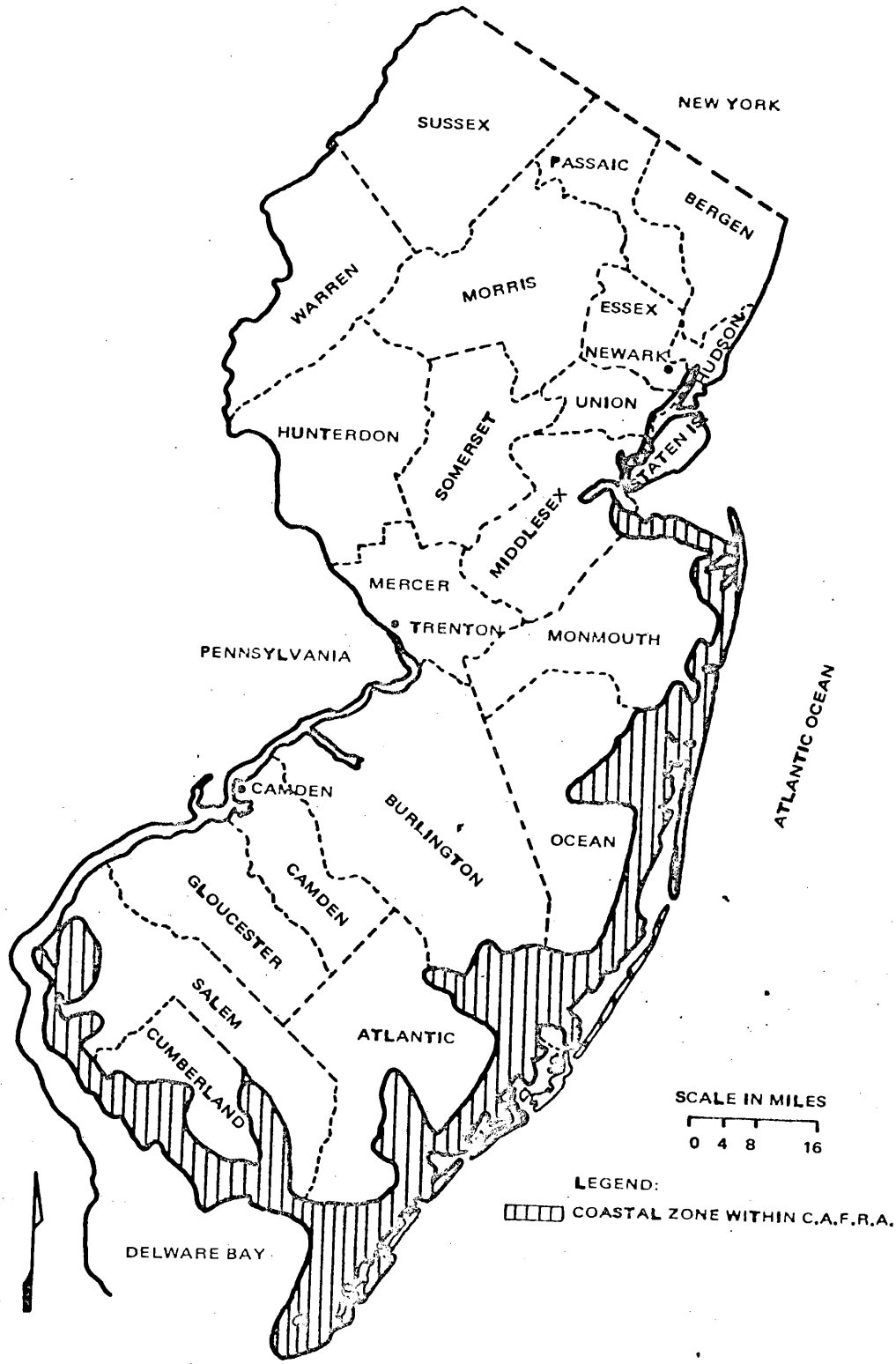

TABLE III-3 New Jersey Coastal Zone as Defined by CAFRA

(1) Preparation of an environmental inventory of resources in the coastal area, and an assessment of the impact of possible new development,

(2) Preparation of long-term management strategies which all balance environmental, economic, and development values,

(3) Preparation of an "environmental design" for management of development of the coastal area, based on one of the alternate management strategies.

These requirements of CAFRA are very similar to those of the federal Coastal Zone Management Act. The New Jersey Coastal Zone Management Program is described below, and CAFRA requirements and the boundaries of the CAFRA coastal area are compared with those of the Program.

The CAFRA permit procedure requires formal application with an environmental impact statement which allows DEP to assess project impacts. Permits are submitted to the Coastal Section of the Bureau of Marine Lands Management, DEP, and are subject to review by all division of DEP and by the Departments of Community Affairs and Labor and Industry. Proposed changes in CAFRA rules would include municipal approval at this point also.

The average time for completing the CAFRA process is currently 12-14 months. Delays are most commonly a result of incomplete information in the applications.[62] One of the main difficulties in

62/ Private Communication with Walter Dryla, Coastal Area Section, New Jersey DEP, to Rutgers University personnel, May 29, 1975, and Private communication with Tom Hampton, Wetlands Section DEP, to Rutgers University personnel. June 23, 1975.

preparing complete applications is the unsatisfactory addressal of impact questions by the average civil engineer who fills out the applications. A question such as "What do you assess the impact of this project to be on the environment?", is often glibly answered "None". Such a reply is usually sufficient reason for declaring the application incomplete. Impact questions are perhaps too general in wording, and may need to be revised to request more specific information which can be derived using standard geological, soil, botanical and zoological techniques - some of which may be foreign to the average civil engineer.[63]

After the application is complete, a public hearing is held. Frequently additional information is requested as a result of the hearing. Such requests for additional information have been known to delay the decision-making process for a considerable period of time. In half of the applications that have been reviewed under CAFRA, additional information requested as a result of the hearing was supplied within a few days and did not delay the decision-making process. However, in the other half of the applications reviewed, such requests for additional information have stopped the decision-making process entirely.[64] One means of remedying this situation might be to involve the public earlier, perhaps at the same time agencies are reviewing the application, and to allow public input to determine completeness of the application.[65]

Many applications are deficient in information requested. As long as this is the case, the length of the permit process will depend on the time required to correct deficiencies.

63/ Private communication with Tom Hampton, op. cit.

64/ Private communication with Walter Dryla, op. cit.

65/ Review of Selected New Jersey Coastal Area Legislation, op. cit.

CAFRA decisions may be made by the Commissioner of DEP. Appeals on CAFRA decisions may be made to the Coastal Area Review Board which is composed of the Commissioners of the Departments of Environmental Protection, Community Affairs, and Labor and Industry. Appeals may be made to the judiciary if an affected party wishes to contest the Coastal Area Review Board decision. All appeals are lengthy, taking from 6 months to 1 year.[66]

The position of the DEP Commissioner as both the decision-maker regarding CAFRA permits and a member of the Board reviewing appeals of his decisions raises potential due process problems. Although the potential problem is there, to date no one has challenged a CAFRA decision on these grounds.

DEP has displayed a high degree of flexibility in administering CAFRA. It frequently suggests changes in a project which will allow issuance of a permit. For example, although it denied a permit for the high-rise condominium in Toms River, the DEP opinion described project changes which may lead to issuance of a permit.[67] (That case has been appealed to the State judiciary and is still pending).

DEP permit application decisions have tended to set policy regarding certain kinds of development. Decisions regarding housing developments tend to discourage excessive earth movements, approve of preserving natural topography, and encourage cluster development

66/ Ibid.

67/ Environmental Factors which Shape Local Planning. Report to the New Jersey Department of Community Affairs. Grant #00518. CPA-JN-1020. New Brunswick: Institute for Environmental Studies, Rutgers University, 1975.

as both less costly to the builder and most in line with preserving open space. Denials of permits and appeals reinforce policies of preserving historic sites, promoting mass transportation, aesthetic considerations, and lowered population density.[68]

DEP also has claimed CAFRA authority to stop developments which would spawn air or water pollution, whether directly or indirectly (i.e., through increased automobile traffic), and has claimed the right to veto development if the air quality at a proposed site fails to satisfy air quality standards - even if the planned project itself would add no emissions.[69]

Administration of Air and Water Quality Standards

DEP is the lead agency in the State of New Jersey in the administration of air and water quality standards, which in turn provides the department with additional land use control. Some of DEP's authority in these matters derives from CAFRA, as described above.

A range of state laws confer on DEP water quality enforcement authority which in turn provides DEP with broad powers to indirectly control land use. Under N.J.S.A. 58:10-17, DEP can issue effluent permits for the development of industrial projects located on watersheds, and under the Clean Ocean Act of 1971, N.J.S.A. 58:10-23.25, DEP regulates ocean dumping.[70]

Of greater significance for the control of land use is DEP's regulation of sewage treatment works. N.J.S.A. 58:12-3 mandates

68/ Review of Selected New Jersey Area Legislation, op. cit.

69/ Environmental Factors. . ., op. cit.

70/ Ibid.

that DEP approve the plans for the construction of any new sewage facility. DEP also can establish conditions governing the construction or use of sewers, drains, or sewerage systems. Complementing DEP powers granted under N.J.S.A. 58:12-3 are those conferred by the Realty Improvement Sewerage and Facilities Act of 1954, 58:11-23. Under this act DEP can halt the issuance of building permits for a residential development of 50 or more units if these new units will "require the installation or erection of a water supply system or sewerage facilities other than an existing approved water supply and/or sewerage system" or if DEP determines that the proposed new facilities do not comply with State standards.[71]

The land use implications of the sewage control laws are clearly manifested by the State's present building permit moratorium resulting from DEP findings of sewerage system inadequacies. As of September, 1973, 73 municipalities were barred from issuing building permits for residential construction which requires new sewage connections. In effect, in these communities no new building can proceed unless it can be serviced by a septic tank.[72] All new buildings are subject to the regulations of local boards of health. More than 50 units of development requires State approval.

Efforts to cleanse New Jersey's air also involve land use controls. The Federal Clean Air Act of 1970, 42 U.S.C. 1857c-5 (1970), requires the states to submit plans for meeting certain air quality standards. Pursuant to this act, the Federal Environmental Protection

71/ Ibid.

72/ Ibid.

79-065 O - 76 - 14

Agency (EPA) had ordered the states, by January 1, 1975, to regulate land development to the extent necessary to assure that new land uses will not generate automobile traffic which causes air quality standards to be exceeded. This regulation of traffic-generating land uses is known as complex source or indirect source regulation.[73]

DEP does not have express state-wide authority to regulate complex source emissions. Within the coastal zone CAFRA gives DEP authority to regulate land use, and DEP, in its opinion denying a permit for the Lehigh Construction Company Toms River Condominium construed CAFRA air quality requirements as providing complex source regulatory authority. That opinion, however, only dealt with residential development, and CAFRA's express listing of covered uses does not include commercial uses and some industrial uses. Elsewhere in the State, and for any uses in the coastal zone not regulated by CAFRA, two possible statutory references for complex source regulatory authority - neither of which expressly deals with land use - are available:[74]

(1) The Air Pollution Control Act of 1954, (26:2C-1 et seq.) gives DEP power to prevent, control, and prohibit air pollution - especially see 26:2C-8; and

(2) N.J.S.A. 13:10-9 as one of the provisions establishing the Department of Environmental Protection contains some general language concerning DEP's mission to protect the state's environment - especially see 13:1D-9(e), (f), and (g).

73/ Ibid.

74/ Ibid.

Even if comprehensive State authority is lacking, DEP was to be in the complex source regulation business State-wide by January 1, 1975. EPA is prepared to delegate some of its Federal authority for controlling land use to DEP as the administrator of the New Jersey complex source program for satisfying the federal primary air standards. Although the ability of EPA to delegate this authority to the States is open to legal challenge, the Clean Air Act does clearly grant EPA significant power to control land use. See 42 U.S.C. 1857 c-5(a) (2) (B).[75]

Although complex source regulation may not lead to the kind of municipal and areawide building bans associated with DEP's sewerage tie-in moratoria, a permit process could eventually yield a similar result. Under a complex source regulatory scheme prospective development with a parking capacity above a certain size will encounter a DEP permit requirement. Complex source regulation may favor single family housing over multi-family housing. A regulatory system keyed to parking lots could ignore single family developments. Also, since single family housing involves fewer vehicles per unit of area than apartments, such development is less likely to create a localized carbon monoxide problem than is apartment development.[76]

Of course, eventually single family developments could be restricted because at some point the area, in the aggregate, might face the prospect of exceeding its approved carbon monoxide level. Such an area-wide complex source judgment already has prompted EPA to determine that an air quality-related Ocean County growth ceiling should delimit

75/ Ibid.

76/ Ibid.

the capacity of a sewage treatment plant receiving 75% EPA funding. Higher density development, however, if directed along development cores or corridors could survive complex source reviews if public transportation were provided which alleviated the carbon monoxide problem.[77]

In addition to the above-described authority concerning air and water quality standards, DEP also has direct land use control over flood plains, N.J.S.A. 15:16A-50, et seq. and stream encroachments, N.J.S.A. 58:1-26 et seq. Statutorily, floodplains are divided into floodways and flood fringe areas. DEP exclusively regulates floodways and sets minimum standards for local government regulations of flood fringe areas. Proposed DEP regulations prohibit construction in floodways which, upon completion of floodplain mapping, may be found to encompass as much as 10% of the State's territory. Floodways sometimes extend several hundred feet beyond riverbanks and are located in urban as well as rural areas.

Stream encroachment permits to cross streams with a drainage area greater than .5 square mile must be obtained from DEP's Division of Water Resources. This permit procedure operates similarly to the riparian procedure. There is a Water Policy and Supply Council which is a quasi-judicial body similar to the Natural Resource Council, which reviews and grants stream encroachment permits. The DEP Commissioner has final approval authority.

The Division of Water Resources is inadequately staffed, and the Water Policy and Supply Council has a heavy backlog (up to two

77/ Ibid.

years) of stream encroachment permits.[78] Currently, the chief delay in the system is caused by incomplete applications (see discussion in CAFRA section above) in addition to bureaucratic and organizational problems. Thus stream encroachment permits may take two or more years to process, given present administrative problems.

New Jersey Coastal Zone Management Program

The New Jersey Departemnt of Environmental Protection, Bureau of Marine Lands Management, is responsible for development of the State's version of the Federally-initiated Coastal Zone Management Program. The New Jersey Program was funded for the first of three years of planning in July of 1974, with $275,000 in Federal funds, and $137,000 in State funds. Second year Federal funds amount to $470,000.

The objectives of the New Jersey Coastal Zone Management Program are very similar to those of CAFRA. The major difference between the two programs is that CAFRA's coastal area is considerable smaller than the Coastal Zone Management planning area (TABLE III-4). The Coastal Zone Management Program is scheduled for completion by June of 1977, as are the CAFRA studies. Both Coastal Zone Management and CAFRA require:

(1) Environmental inventory of natural resources, land use, etc.;

(2) Delineation of coastal boundaries;

(3) Delineation of critical areas and priority uses;

(4) Evaluation of alternative long-term management strategies for the coastal zone;

78/ Private communication with Walter Dryla, op. cit.

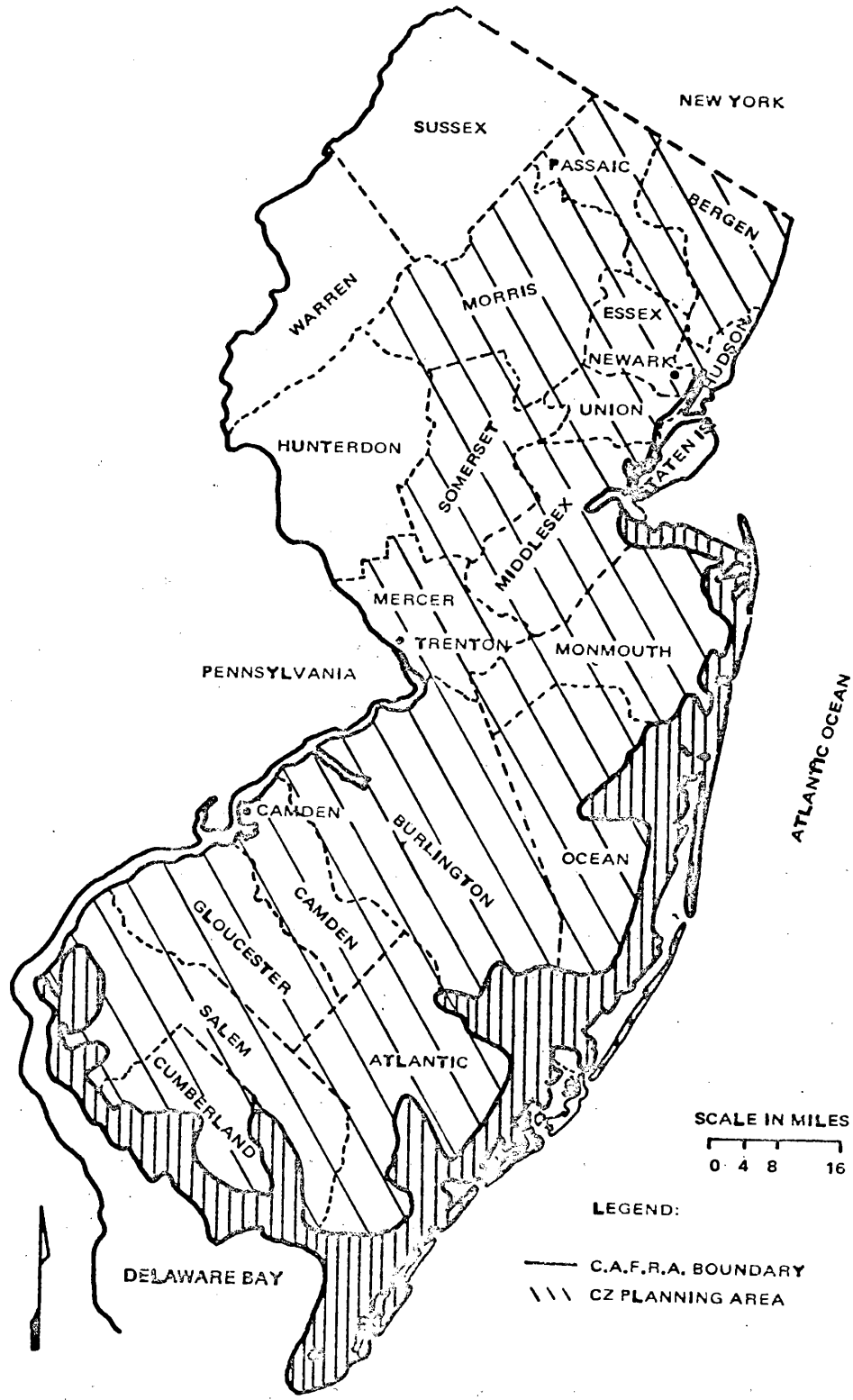

TABLE III-4 New Jersey Coastal Zone Management Planning Area and CAFRA Lands Within Planning Area.

(5) Formulation of a management plan for development of the coastal area.[79]

The final management plan for both CAFRA and Coastal Zone Management will provide a means of coordinating all of the legal tools available to DEP for control of coastal zone land and water uses. Thus the direct and indirect control provided by all of the statutes described above will be coordinated by this plan.

New Jersey's general goal for their Coastal Zone Management Program is "to plan, regulate and control land and water uses of coastal area resources so as to enhance the environment, prevent further degradation, and at the same time achieve maximum utilization of these resources by present and future generations."[80]

Specific goals and objectives are to:

(1) Enhance recreational uses of natural resources of the coastal zone to provide greater recreational opportunities for the public.

(2) Make recreational facilities accessible to the user.

(3) Plan and regulate residential development, industrial facilities, commercial activities and other related uses of the coastal zone to minimize the adverse effects to the environment and conflicts with other desirable uses of coastal resources.

(4) Conserve and enhance the biological productivity of the wetlands.

79/ Review of Selected New Jersey Coastal Area Legislation, op. cit., and New Jersey Department of Environmental Protection, op. cit.

80/ New Jersey Department of Environmental Protection, op. cit.

(5) Maintain a balance of acceptable air and water quality while meeting the social and economic needs of the public.

(6) Preserve and enhance for posterity areas of unique value, such as the New Jersey Pine Barrens, and the Mullica River.

(7) Preserve open spaces for recreational uses and wildlife habitat.

(8) Maintain the unique esthetic qualities of the shore and the coastal zone.

(9) Encourage land and water uses that are damaging to the coastal zone environment to seek environmentally suitable areas.

(10) Reverse the decline of the older urban resort areas such as Atlantic City and Asbury Park.

(11) Reverse the decline of recreational and industrial shellfishing.

(12) Undertake corrective programs and projects to offset the erosion of beaches, river banks and land areas.

(13) Plan, regulate and control development to minimize storm and flood damage to life and property.[81]

Local Government Administration

At the local level, municipal planning boards, boards of adjustment, and municipal boards of health have primary responsibility for approval and regulation of development and construction activities. Governing bodies adopt ordinances establishing these administrative agencies - board of health, planning board, zoning board, board of adjustment - and provide for their powers and responsibilities.

81/ Ibid.

Any construction or expansion project submitted by a landowner must be approved by the local planning board and/or board of adjustment, and governing body, of the municipality in which it is planned. Courts in most cases are reluctant to allow any broad exercise of local authority unless specifically authorized by State enabling statutes. However, in New Jersey, the legislature specifically directs the courts to be liberal in their treatment of local decision-making, thereby bolstering the time-honored home rule tradition. The fact of strong local government in New Jersey is important, because every square mile of the State is incorporated into a municipality, the local governmental unit below the county level.[82] In the virtual monopoly which New Jersey municipal government has on planning and zoning, county government is basically ineffectual.

It is the municipal planning boards which would review OCS-related onshore facilities, and whose approval would be required before State approval of the project could be given. If no subdivision is anticipated the likelihood exists that the board of adjustment would approve OCS activities as special use. In such a case the planning board's role would be that of only site plan review. Local planning boards do have the power to stop the project altogether if it comes under their regulation, or, if they approve of the project, to strongly influence State officials to grant their approval. The determining action will essentially issue from the governing body whose reaction to

82/ Review of Selected New Jersey Coastal Area Legislation, op. cit.

offshore development might be to amend zoning ordinances so as to pursue their policies, thus by-passing the authority of other municipal agencies.

Environmental committees and commissions, although granted only an advisory and review status, play an increasing role in the planning process via the ordinances they recommend to the governing body concerning activities such as soil removal, tree removal, erosion and sedimentation.

Summary of New Jersey Management Structure

Any individual or group wishing to alter or make new use of New Jersey's shoreline, marshlands and/or uplands is subject to Riparian law, the Wetlands Act, and/or CAFRA, respectively, and numerous air and water quality statutes. Any activity subject to all three statutes such as pipeline laying, or creation of a staging area for offshore development must be initiated with an application for a riparian grant, lease, or license. No municipal approval is required of a riparian applicant for a grant, lease, or license. However, if construction is involved, it must meet with local approval. After a riparian grant, lease, or license is approved, Wetlands and CAFRA applications may be considered concurrently. The whole permit process could take as short a time as one year, or as long as five years.

Factors affecting the length of time involved in going through these procedures are:

(1) Need for one, two, or all three of the major approvals (e.g., Riparian, Wetlands, CAFRA)

(2) Sufficiency of information in the original application(s)

(3) Appeal on DEP decisions

The need for any one of the three major approvals is dependent on the land and activities involved in the proposed project. Any construction along the shoreline of a waterway or in the waterway, or any alteration (e.g., dredging) in a waterway within the state boundary is subject to Riparian clearance. Any construction on the wetlands (marshes) or alteration of them is subject to Wetlands approval. Any construction in the coastal zone that is not on Riparian lands or Wetlands is subject to CAFRA approval.

A major project requiring only Wetlands or CAFRA approval could be processed within one year if the original application contains sufficient information (or if required information is quickly provided) and if there are no appeals. A project requiring both approvals could also be processed within one year with sufficient information and no appeals because applications for both approvals may be considered concurrently, and there is a great deal of coordination between the Wetlands staff and the CAFRA staff in DEP.

Requirement of Riparian clearance for a major project can add years to the review process, depending on the amount of baseline data available at the time of application. Riparian clearance is required before Wetlands or CAFRA applications can even be considered, so any combination of Riparian review with Wetlands or CAFRA will probably take at least two years. Unlike Wetlands and CAFRA, Riparian clearance involves two approvals: approval of a grant or lease of acreage (for permanent uses, e.g., a refinery, processing plant, tank farm) or of a license (for temporary uses, e.g., pipelines) and approval of a permit to construct the facility or the pipeline. The additional approval is unique to the Riparian review process.

Insufficient information is a major factor in delay of the review process in all three applications. The Natural Resource Council (Riparian rights) has been known to require that an applicant supply baseline data for one to two years.[83] If that data is unavailable and must be collected, the review process is lengthened by the amount of time required for the data collection.

Insufficient information as a function of lack of expertise on the part of the applicant was described earlier. Another reason for insufficiency of information in the application process may be the reticence of the applicant to supply certain information (e.g., information that might indicate the project to be potentially damaging to the environment). Also, an incomplete application is many times an attempt on the part of the applicant to negotiate the terms of a project.[84]

When additional information is requested further along the review process, such as during public hearings, two problems may cause an applicant to delay providing the information or to withdraw the application altogether. First, the kind of information requested at public hearings, such as a very precise and definitive cost-benefit analysis of the project, is many times very difficult to supply. Second, the applicant may be very reluctant to spend additional time and money and perhaps hire more consultants in order to supply the requested information.

83/ Shell Oil was required to submit one full year of baseline data for its Gloucester Counter refinery application. (Review of Selected New Jersey Coastal Area Legislation, op. cit.).

84/ Personal communication with Walter Dryla, op. cit.

Appeals from DEP decisions on any of three approvals discussed above can delay a final decision for years. There are no legal time limits on appeal decisions for any of the three review processes, and appeals may be made to at least three levels of appeal bodies consisting of an appeal board, and at least two courts (e.g., Appellate and Supreme). Examples of major cases under all three permit procedures which are still being appealed indicate that appeals on any single major application may take one year or more.[85]

85/ A Lehigh Construction Co. CAFRA application for a condominium in Toms River, New Jersey, is still under appeal. The appeal process began in November of 1974. A Wetlands application by American Dredging Corp. to increase the size of its present dredge spoils dumping area in Delaware Bay was denied by DEP in January of 1974 and the decision appealed. The appeal is still under review. (Review of Selected New Jersey Coastal Area Legislation, op. cit.).

DELAWARE

Introduction

As in New Jersey, State and local government in Delaware possesses important regulatory powers which may enable it to closely control the siting and rate of offshore-related development. This section discusses these regulatory powers in Delaware and the laws behind them. While deepwater ports and floating nuclear power plants are discussed briefly, the focus here is on managing development related to outer continental shelf activities.

State Laws and Administration

A staging area, onshore support facility, pipeline, gas processing plant, refinery, or other offshore-related facility might be subject to a number of Delaware laws, including:

(1) Coastal Zone Act

(2) Environmental Protection Act

(3) Water and air pollution regulations

(4) Wetlands Act

(5) Beach Preservation Act, and

(6) Subaqueous Lands Act.

All of these laws are administered primarily or exclusively by the Department of Natural Resources and Environmental Control (DNREC), with the exception of the Coastal Zone Act which is administered by the State Planning Office, a branch of the Executive Office of the Governor.

The Department of Natural Resources and Environmental Control (DNREC) has jurisdiction over nearly all of the public lands of the State, including subaqueous lands in the Atlantic Ocean and Delaware Bay

and River. DNREC administers the Wetlands Act, Beach Preservation Act, Subaqueous Lands Act, air and water pollution laws, (including pipeline and tank farm permits), and provides technical support to the State Planning Office in evaluating applications under the Coastal Zone Act. Within DNREC are several divisions, of which the Division of Environmental Control and the Division of Soil and Water Conservation are most directly involved in administering these laws and permits. The Division of Environmental Control is composed of an Air Resources Section, a Water Resources Section, a Wetlands Section, and a Technical Services Section. The Division of Soil and Water Conservation contains, among others, the Beach Preservation Section.

The State Planning Office is responsible for coordination of comprehensive and other land-use plans, for coordination of State and local government participation in numerous Federal programs (e.g., Environmental Protection Agency and Department of Housing and Urban Development grants and programs), for preparation of Delaware's coastal zone management plan pursuant to the Federal Coastal Zone Management Act, and for administration of the Delaware Coastal Zone Act.

In addition to DNREC and the State Planning Office, other agencies may be involved in reviewing, or at least commenting upon, major permit application. For example, under the proposed Wetlands Act regulations, a fact sheet on an application is to be prepared by DNREC and distributed for review and comments to the following agencies or persons:

(1) All Divisions of DNREC

(2) Delaware Geological Survey

(3) State Planning Office

(4) Department of Highways and Transportation

(5) Department of Health and Social Services

(6) Governor's Council on Environmental Control

(7) Council on Historical and Cultural Affairs, Archaeological Office

(8) Adjacent property owners

(9) Local planning department that has jurisdiction over land involved

(10) Environmental Protection Agency

(11) Division of Fish and Wildlife of the Department of the Interior

(12) Corps of Engineers

(13) Federal Regional Council

(14) Other interested parties who have requested the fact sheet for the particular project.

One should note that the terms of several of the Delaware laws, or the geographic areas encompassed by them, are so expansive as to preclude any serious attempt at comprehensive enforcement. Simple manpower and fiscal constraints will mandate a selective approach to administrative application of these laws, akin to the "prosecutorial descretion" which exists in the criminal area.

It is reasonable to assume, however, that any operations related to OCS development, whether such operations be on-shore or off-shore, will be subject to close scrutiny by the cognizant Delaware agencies.

Many specific activities at an onshore facility will require individual permits. For example, air pollution permits are required for incinerators, fuel burning equipment, and various types of process equipment that may emit air contaminants. Water pollution permits are needed for septic tanks, sewer systems, waste treatment or discharge, surface

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water withdrawal, and water wells. Additional permits such as a site permit for solid waste disposal also may be necessary.

Any pipelines, storage tanks, or pumping stations associated with either a staging area or production facilities would be subject to multiple regulation under the Coastal Zone Act, air and water pollution regulations, the Subaqueous Lands Act, and the Wetlands Act. Additionally, pipeline regulations have been issued by DNREC pursuant to Section 6003 (a) (v) of the Delaware Environmental Protection Act.

The many permits described in this chapter are not the only ones which must be obtained for an onshore facility. State requirements for the siting or construction of roads, railroad spurs, and heliports (or airports) must also be met. The local governing body also may have requirements such as building permits or sewer system hook-up procedures which must be satisfied.

Moreover, separate permits may be required for the construction, alteration, and operation of these assorted facilities. County or municipal zoning approval also must be obtained. Indeed, such local zoning approval is a prerequisite to issuance of a permit under the Coastal Zone Act, Wetlands Act, and air and water pollution regulations pursuant to the Delaware Environmental Protection Act.

The seven major relevant Delaware laws are described below.

Coastal Zone Act

Many onshore facilities clearly would be subject to review under the Coastal Zone Act (7 Del. C. 7001 et seq.) and would have to obtain a Coastal Zone permit from the State Planner prior to construction or operation of the facility.

The purpose of the Coastal Zone Act is: "to control the location, extent, and type of industrial development in Delaware's coastal areas. In so doing, the state can better protect the natural environment of its bay and coastal areas and safeguard their use primarily for recreation and tourism." The Act establishes a "coastal zone", from the limits of the State's territory in the Delaware River and Bay and Atlantic Ocean landward to certain roads which skirt the wetlands (TABLE III-5). Within this zone, offshore bulk product transfer facilities and "heavy industry" are flatly prohibited. Examples of "heavy industry" include oil refineries, chemical plants such as petrochemical complexes, basic steel manufacturing plants, and basic cellulosic pulp paper mills. Certain criteria are provided to help determine whether or not a facility is a "heavy industry".

Permits are required for other nonprohibited "manufacturing" uses, subject to evaluation of the use with respect to the following factors:

(1) Environmental impact as determined from a rather thorough federal-type environmental impact statement

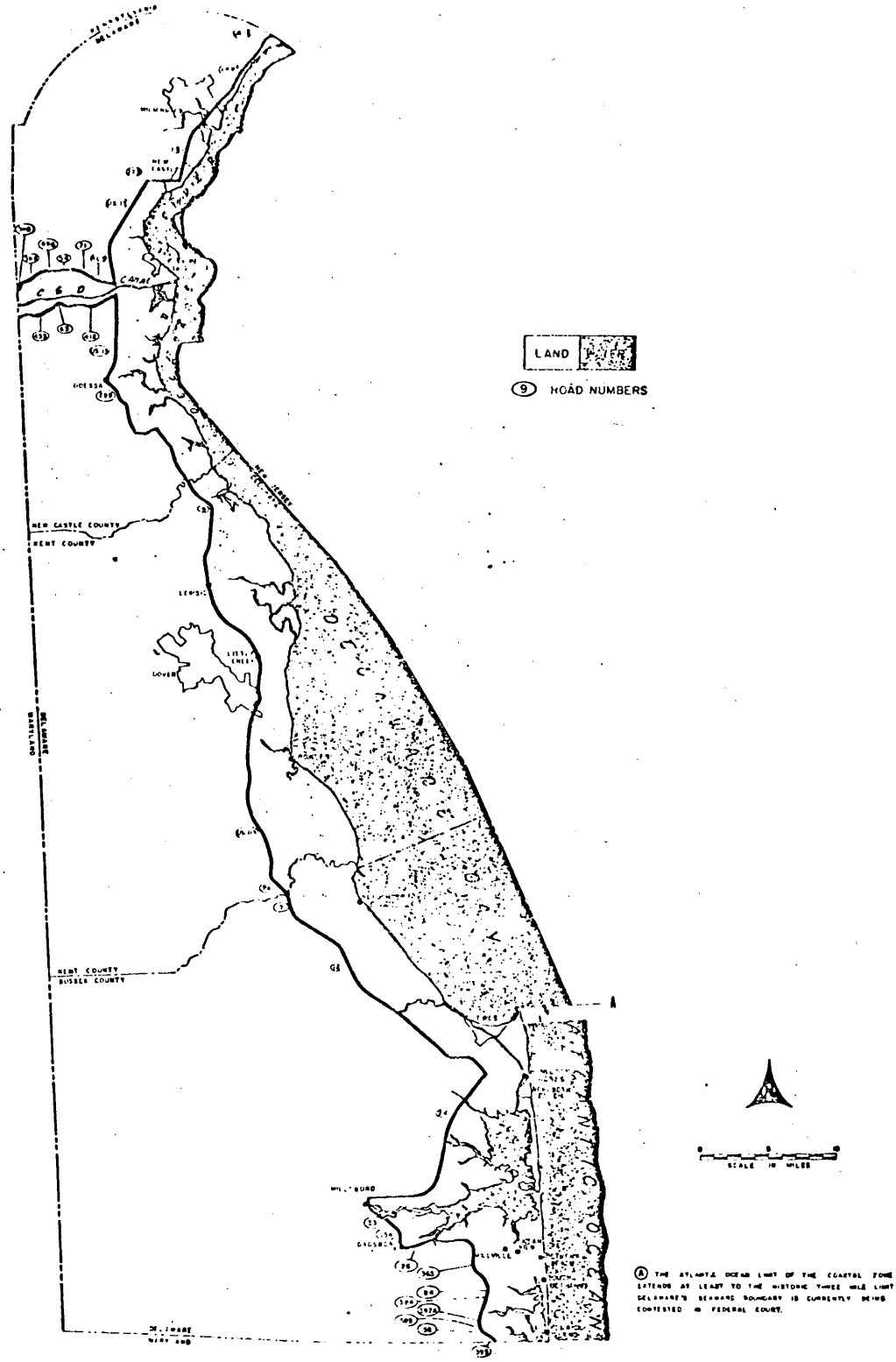
(2) Economic effect

(3) Aesthetic effect

(4) Effect of supporting facilities

(5) Effect on neighboring land uses, and

(6) Compatibility with the affected county or municipal comprehensive plans (prior local zoning approval also is a prerequisite to issuance of a permit).



(SOURCE: Coastal Zone Act Administration, June 28, 1971 - June 30, 1974)

TABLE III-5 Delaware Coastal Zone

The State Planning Office administers the Act, and is directed to develop a comprehensive plan, guidelines which determine the kinds of manufacturing allowed, and regulations to further define "heavy industry". Permit requests are initially screened in a "status decision" process wherein the State Planner determines that the proposed use is:

(1) A prohibited heavy industry use or bulk product transfer facility

(2) A manufacturing use allowable by permit, or

(3) A use not regulated by the Act.

The "status decision" application is not publicly advertised, but public notice must be given if the "status decision" review finds that the project is prohibited or is outside the jurisdiction of the Coastal Zone Act.

Formal permit applications require a public hearing. Thereafter, the State Planner may grant the application, deny it, or grant it subject to conditions. The Planner must state the reasons for his decision. Appeals from the State Planner's decision may be taken to the State Coastal Zone Industrial Control Board. The Board must hold a public hearing on the appeal, and may affirm, reverse, or modify the State Planner's decision. Appeals from the Board's decision may be taken to Superior Court by any aggrieved person, including the State Planner.

Delaware Environmental Protection Act

Any emissions or effluents from an onshore facility would be subject to air and water pollution regulations issued pursuant to the Delaware Environmental Protection Act (7 Del. C. Section 6001 et seq.). This Act is very broadly worded, and requires a permit from DNREC for any

activity ("...construction, or operation, or use of any facility, property, or device") which may cause or contribute to air or water pollution, ground or surface water withdrawal, solid waste collection or disposal, pipeline systems and storage tanks, and water wells, inter alia. Similarly, a permit is required to construct, install, or operate any equipment which may cause air or water pollution, which is intended to control or prevent pollution, which is intended for water withdrawal, or which is used for solid waste disposal. County or municipal zoning approval of the activity is a prerequisite to issuance of such permits by DNREC.

A public hearing may be held if the Secretary of DNREC deems it to be in the best interest of the State to do so and must be held if there is a meritorious request for such a hearing in response to the advertising of the filing of the application. After the hearing (if there is one) the Secretary makes findings of fact based on the record. He then enters "an order that will best further the purpose of this Chapter," and states his reasons. The Secretary's decision may be appealed to the Environmental Appeals Board, which may affirm, modify, or reverse the Secretary's decision. On any appeal, the Board must hold a public hearing. If the Board overrules the Secretary, it must state its reasons. Appeal to Superior Court (in the county where the activity is located) from the Board's decision is provided, and may be taken by any aggrieved person, including the Secretary.

Water Pollution Control

Water Pollution Regulations have been adopted pursuant to Section 6010 of the Delaware Environmental Protection Act and are designed to complement the Federal water pollution and permit requirements pursuant

to such laws as the Federal Water Pollution Control Act, the Water Quality Improvement Act, and the Refuse Act.

In addition to discharges into the waters of the State, the following activities are specifically subject to the permit requirements:

(1) Any septic tank system

(2) Any liquid waste treatment system

(3) Any new bulk storage system, any new or existing bulk transfer facility, and any new or existing pipeline facility, and

(4) Any sewer or pipeline which conveys liquid waste.

Discharges subject to the National Pollutant Discharge Elimination System (NPDES) established by the Federal Water Pollution Control Act Amendments of 1972, also must comply with the Delaware Regulations. Both NPDES and State permits may be conditional upon the licensee's adherence to any compliance schedule or monitoring requirements that the Department may require. Effluent limitations, performance standards, and load allocations also may be imposed as a condition to the permit. An application for a permit may be required to include a feasibility report (in addition to a possible "predesign conference" for certain discharge facilities), an engineering report, an operation manual, and other information similar to that required for NPDES permits.

A public hearing may be held pursuant to the terms of the Delaware Environmental Protection Act, with certain additional requirements described in the Regulations. The criteria which DNREC must use to decide whether or not to issue a permit are not specified in the Regulations; it appears that the criteria of the Delaware Environmental

Protection Act would apply. Any appeal from the Secretary's decision apparently would go to the Environmental Appeals Board, and thence to Superior Court.

Air Pollution Control

Regulations governing the control of air pollution were issued by DNREC's Division of Environmental Control on May 28, 1974, pursuant to Section 6010 of the Delaware Environmental Protection Act. The Regulations complement the Federal Clean Air Act and do not allow construction or operation of any facility which will emit an air contaminant prior to receiving approval from DNREC.

The Regulations established ambient air quality standards for certain contaminants; the standards "...shall not be interpreted to allow significant deterioration of existing air quality in any portion of the state". Ambient air quality standards have been established for various contaminants, including particulates, sulfur dioxide, carbon monoxide, photochemical oxidants, hydrocarbons, nitrogen dioxide, and hydrogen sulfide.

Certain emission requirements are specified in addition to or supplemental to the air quality standards. Permissible emission rates for particulates, SO_2, NO_x, and CO are specified, and standards are set for control of both visible and odorous emissions.

A list of specific exemptions to the Regulations stipulates various types of existing and new sources and equipment which do not require permits under these Regulations. No exemption is available, however, for equipment directly involved in various industries including, inter alia chemical processing, petrochemical operations, and petroleum refining or storage.

Compliance with local, State, and Federal requirements, as well as with the terms or conditions of a permit under these Regulations, may be ascertained by use of emission monitoring devices and fuel or emission sampling analyses which DNREC may require the "owner or operator of an air contaminant source" to provide. Additionally, DNREC may conduct such tests itself.

Permit application procedures, public hearing requirements, discretionary variances, appellate procedures, and enforcement provisions are apparently governed, with respect to most particulars, by the Delaware Environmental Protection Act.

Wetlands Act

If construction of the staging area involves dredging, filling, bulkheading, or pier construction in a "wetlands" area, a permit from DNREC would be required under the Wetlands Act. (7 Del. C. Section 6601 et seq.)

"Wetlands" is defined, generally, as lands above mean low water elevation whose surface is at or below an elevation of two feet above local mean high water, and upon which may grow or is capable of growing a variety of types of vegetation.

Any expansion or extension of a pre-existing use requires a permit; the only activities exempted from the Act are relatively innocuous uses such as construction of duck blinds or grazing of animals.

An applicant for a permit must submit plans, specifications, and other information as required in regulations issued by DNREC. (Regulations under the Wetlands Act have been drafted but not adopted as yet.)

In deciding whether to grant a permit, the Secretary of DNREC is directed to consider the following factors:

(1) Environmental impact

(2) Impact of site preparation on flood control and land erosion

(3) Impact on quality and quantity of tidal, surface, and subsurface waters

(4) Aesthetic effect

(5) Number and type of public and private supporting facilities, and their impact on the other listed factors

(6) Effect on neighboring land uses

(7) State, county, and municipal comprehensive plans (note also that DNREC cannot grant a permit "unless the county or municipality having jurisdiction has first approved the activity in question by zoning procedures provided by law"), and

(8) Economic effect, including potential tax revenues, number of jobs created, and the relation of job-produced income to the amount of land required.

The Secretary's decision may be appealed to the Wetlands Appeals Board, which may affirm or reverse the Secretary's decision. The Board must hold a public hearing on the appeal. The Board must state its reasons if it reverses the Secretary. Nonaction by the Board for 90 days is construed as affirmation of the Secretary's decision.

Appeal from the Board is to the Superior Court for the county in which the proposed project would be sited. Possible appellants include the applicant and the Secretary of DNREC.

Beach Preservation Act

An onshore facility also would be subject to regulation under the Beach Preservation Act (7 Del. C. Section 6801 et seq.) if it involves bulkheading (or erection of other erosion-control structures), or if a building is to be constructed near the water, since any "substantial change in the existing characteristics of any beach" requires prior approval by DNREC.

The definition of "beach" in Regulations promulgated under the Act is fairly extensive:

> "that portion of the shore of any body of water which extends from the mean low water mark inland one thousand feet, or to a roadway for automobiles, whichever is closer."

Regulations issued by DNREC, Division of Soil and Water Conservation, effective May 6, 1974, provide for both construction permits and siting permits pertaining to the erection of any structure in the "beach" area. If the proposed project involves a groin, jetty, bulkhead or similar erosion-control structure (usually at or near the water's edge), then a "construction permit" is required.

If the proposed project involves a "dwelling, commercial establishment, or any other structure" which is not primarily an erosion control structure and the building is to be located, in general, on or in front of the primary dune, then a "siting permit" is required. If the proposed project involves a building or structure landward of the primary dune, then written approval by the Division is required (not technically a "permit" requirement). If, however, the Division decides that such a project "may have a substantial effect on beach protection", then the

project is subject to the same permit process as though the building were to be on or in front of the dune.

Efforts will be made to streamline the composite application process: "If a proposed project requires other permits from the Department (DNREC), the application process shall be coordinated." However, the Regulations offer no insight into the specifics of such coordination.

Upon receipt of a proper application, public comments are solicited by newspaper advertisement and by notification of adjacent property owners. In making a decision, the Division considers any comments received, potential effect on flooding, beach erosion, and storm damage, and the feasibility of alternate means of protection from storm damage.

Appeal from the Division's decision may be taken to the Secretary of DNREC. The Secretary shall hold a public hearing, and shall render a decision (stating his reasons) after making findings of fact based on the record. An appeal from the Secretary's decision may be taken to Superior Court.

Subaqueous Lands Act

The pier at the staging area, any pipeline from the OCS, and certain other facilities probably would be subject to the Subaqueous Lands Act (7 Del. C. Section 6101 et seq.). Specifically, the State would have to issue a grant or lease for the underwater land involved before the facility could be built.

In general, the Secretary of DNREC and the Governor have exclusive jurisdiction to sell, lease, or grant permits or easements in or over any submerged public lands in the state, "...and no use of such lands shall be undertaken except pursuant to a permit or grant".

An applicant for a grant, lease or permit files a request with DNREC stating the type of grant, lease or permit desired, showing the location and specifications of the proposed construction. DNREC may request such additional information as it may need to consider the application, and may request other state agencies to comment on an application. DNREC may, but need not, appoint a special investigative board to study any application and make recommendations to DNREC.

The Governor may refuse to approve an application that the Secretary has recommended, but may not execute any lease, permit, deed or other grant unless it conforms to the recommendation of the Secretary (apparently a reference to the conditions which the Secretary may recommend placing upon such grant).

Note that under 7 Del. C. Section 4518 (d), sale or lease of subaqueous lands also requires the specific approval of the General Assembly if the lands are to be "transferred or conveyed to any person... having the power to sell or lease such lands."

Regulations issued pursuant to the Subaqueous Lands Act provide for some regulation of pipelines across subaqueous lands; they also regulate certain projects (e.g., building or filling) on lands adjacent to public subaqueous lands.

Coastal Zone Management

Delaware's Coastal Zone Management program is designed to provide an information base, management structure, and strategy for administrating lands and resources of the coastal zone.

(1) Inventory of Coastal Resources and Compilation of Data Base; Major program tasks include:

(2) An Assessment of the Adequacy of Current Management Methods and Legal Authorities;

(3) Efforts to Measure the Relative Sensitivity of Coastal Resources to Various Physical and Environmental Characteristics and Changes;

(4) Measurement of Characteristics of Various Uses of the Coastal Zone;

(5) Estimation of Demands on Coastal Lands and Water; and

(6) Determination of Permissible Uses.

The final result will be a regulatory package featuring an organizational structure for CZM focused at the State level and including enabling legislation which will assure intergovernmental coordination and an opportunity for public input and review. The package will provide a practical means to implement the management program.

Local Government Administration

The primary location of power to influence OCS-related development at the local level is probably the county planning and zoning boards. In theory, the boards plan development in accordance with a pre-established approved master plan, which stipulates (in general terms) the type and location of development that can be allowed in the area.

These local authorities play a significant role in screening potential development, since prior local approval is a condition precedent to issuance of many state permits. If the local zoning board denies approval, the project is effectively blocked.

Summary of Delaware Management Structure

Major laws include the Coastal Zone Act, Wetlands Act, Underwater Lands Act, Beach Preservation Act, and air water pollution laws. All of the above laws are administered by the Department of Natural Resources

and Environmental Control, with the exception of the Coastal Zone Act, which is administered by the State Planning Office.

These laws would regulate siting, construction, and use of any major OCS-related facilities in the Delaware coastal area, both onshore and offshore; staging areas, pipelines, tank farms, refineries, gas processing plants, deep water ports, floating nuclear power plants, and other related facilities, would be subject to the jurisdiction of Delaware laws (some of these facilities would be banned by the Coastal Zone Act).

Obtaining permits to build and operate a major OCS-related facility could require anywhere from several months to several years, depending upon various legal and administrative factors in the permit system (e.g., the requirement of prior local zoning approval most State permits can be issued).

Working Paper #2

Biological Impacts of the Three Offshore Energy Technologies

Prepared for OTA
by Ecological Analysts, Inc.
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CHAPTER I

INTRODUCTION

This particular working paper examines the likely effects of the technologies on the coastal and marine environments of New Jersey and Delaware. The document is qualitative in its findings, intended to show the reader the general types of environmental impacts which might result from the introduction of these energy technologies. It remains for site-specific studies coupled with actual proposed designs to quantify any potential impacts.

Chapter II of this document is a summary which provides a brief overview of the technologies and their potential effects. Chapter III discusses the technologies in greater detail and identifies the specific types of biological impacts associated with each energy system. Chapter IV describes the study area, identifies the unique habitats found in these coastal areas, and briefly describes the native flora and fauna. Chapter V is a detailed discussion of six specific effects which can be caused by implementing the technologies: dredging, the reef effect, entrainment and impingement, effluents and emissions, petroleum discharges, and terresrial impacts. Resulting biological effects are discussed under each of these six topics.

A glossary, a bibliography, and three appendices also are included. The glossary defines various biological, ecological, and environmental assessment terms used in the text. Appendix A is a discussion of basic ecological concepts and provides background material defining some of the

principles underlying environmental assessment. Appendix B provides an expanded description of the biology of the study area. Appendix C contains supplementary materials on the impacts of petroleum wastes.

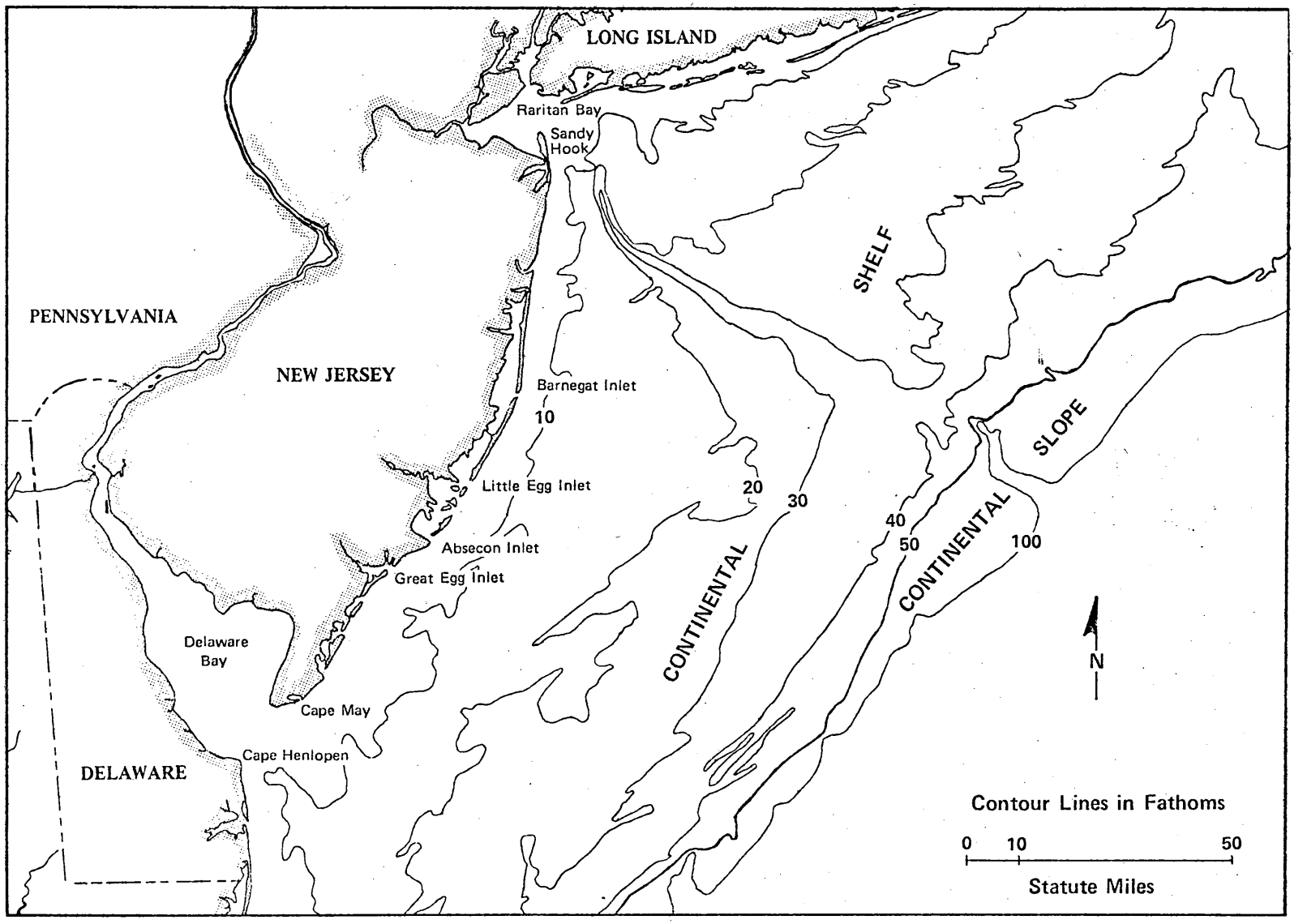

Figure I-1. Map of the Study Area.

CHAPTER II

SUMMARY OF FINDINGS

The increased demand for energy has led to proposals to use three energy technologies in the coastal and offshore areas of New Jersey and Delaware. These technologies include the construction and operation of offshore floating nuclear power plants (FNPs), the development of outer continental shelf (OCS) oil and gas reserves, and the construction and operation of deepwater tanker ports. The introduction of these energy activities into the coastal areas of New Jersey and Delaware will result in some environmental impacts.

The coastal areas of these states include beaches, barrier islands, and marshlands. Most of these coastal areas support lucrative tourist industries as well as significant sport and commercial fisheries. All of these activities are dependent on good water quality.

Because certain aspects of these three technologies are either new or being introduced into new environments, there is a lack of information on their effects on ecosystems. This lack of information prevents a complete and quantitative description of the specificity and severity of such impacts at this time. When basic research is conducted to provide the necessary data, and the results can be combined with an examination of specific sites, designs, and construction and operation methods, the nature and magnitude of impacts can be determined thoroughly and quantitatively.

A. GENERAL FINDINGS

In recent years considerable development has taken place in the

coastal zones of New Jersey and Delaware, and of course this development has affected the environment of those states. For example, between 1953 and 1973 filling and diking activities destroyed 61,678 acres of New Jersey wetlands, 23.5% of what the state possessed in the early 1950s.

Development activities such as dredging change the physical environment of an area. In turn, these physical changes have both direct and indirect biological effects. Direct impacts include the destruction of some fauna and flora in the development area; in some cases these effects may only be temporary. However, areas such as estuaries (rivers or other inlets where fresh and salt water meet) play an important role in the life cycles and food supplies of many species in surrounding areas; thus their disruption or destruction can indirectly affect an entire region. For this reason development in coastal estuaries and wetlands should be avoided when possible.

In general, the biological impacts of offshore energy activities are more severe the closer the activity is to shore. This is partly because coastal waters contain many more organisms than most offshore areas, and partly because of the central role coastal estuaries and wetlands play in a surrounding region's ecology. Thus there are certain environmental advantages to siting facilities away from shore.

With the exception of irretrievable commitments of land and natural resources, most construction impacts of these three energy technologies are temporary. More significant in the long term are impacts from operations, especially those from chronic low-level oil discharges and accidental oil spills.

B. FLOATING NUCLEAR POWER PLANTS

Generally, the environmental impacts of floating nuclear power plants (FNPs) are similar to those of land-based nuclear plants operating in the coastal zone. The main difference is that the FNP can dispose of its waste heat into a much larger body of water; thus its thermal pollution is more easily handled.

Major construction impacts associated with FNPs include:

-- Dredging is required when assemblying the breakwater. This disrupts life in the area, though the effects are usually temporary. It is important to dispose of the dredging "spoils" carefully.

-- Dredging also is required for burying the electrical transmission lines from the plant to shore. The near-shore damage from this activity is less if the dredging is done in either (1) already developed coastal areas, or (2) beaches and sandbars rather than ecologically-important estuaries and wetlands.

-- About 100 acres of offshore land is needed for the artificial island.

-- Also, two other environmentally significant activities take place outside the coastal area. First, large amounts of stone must be quarried, to provide material for the breakwater. Second, there are environmental effects at the site of the FNP manufacturing facility.

Routine operating impacts from FNPs include:

-- The reef effect. FNP breakwaters--and OCS platforms as well--are "artificial reefs" which attract fish. This is an advantage

for some fishermen, but in the case of FNPs may lead to other problems. One is that fish become accustomed to the heat from the plant's discharge water; if the plant shuts down, its waste heat discharges cease, and the surrounding water temperature suddenly drops, fish kills can result. One suggestion is always to keep one heat discharge unit working. A second issue is determining how close people can fish near an FNP, given the need for a restricted zone around the nuclear facility.

-- Entrainment and impingement. The organisms attracted by the "reef effect" also are subjected to two other problems. Impingement occurs when organisms are caught by cooling system water which flows and is trapped against the screens which protect the system's water intakes. Entrainment occurs when small organisms are drawn into an intake. The resulting biological damage can be minimized through careful design of water intake equipment.

-- Effluents and emissions. As with all power plants, FNPs require large amounts of cooling water and produce large waste heat discharges (thermal pollution). However this should not pose any serious environmental problems, given careful design of discharge systems and given the size of the ocean. Routine radiation emissions would be very low, and it is unlikely that they would have any detectable effects on marine life. However, chemicals used to prevent corrosion, mineral deposits, and biofouling in the cooling system may pose an environmental problem. For example, the concentrations of chlorine necessary to control

biofouling are higher than existing Environmental Protection Agency recommendations for permissible discharge concentrations.

The impacts of a major FNP radiation accident offshore are hard to estimate, since so little is known about this important subject. This subject is discussed in Working Paper #8.

C. OUTER CONTINENTAL SHELF OIL AND GAS DEVELOPMENT

Environmental effects of construction include:

-- Onshore impacts result from both the construction of pipeling terminals, tank farms, and related facilities and from staging area operations related to offshore activities.

-- Installing OCS drilling and production platforms requires some dredging.

-- Installing pipelines from the platforms to the shore requires considerable dredging. Here care should be taken to avoid both estuaries and valuable offshore areas, such as commercial surf clam beds.

Impacts from OCS operations:

-- Non-petroleum effluents include drilling "muds," drill cuttings, and brines. Drilling "muds" are chemicals used to lubricate the drill cutting head, counterbalance the pressures of subsurface brines (high-salt water mixed in with the oil), and raise the cuttings (small chunks of rock) to the surface. The "muds" can be toxic and should be neutralized before disposal into the ocean. Rubble mounds from drill cuttings appear to have few adverse impacts; in fact, they enhance the reef effect created by the

fixed oil rig. To avoid possible adverse impacts of brines on marine life, methods, such as the use of high pressure discharges, should be used to assure rapid dilution.

-- Chronic low-level oil discharges and oil spills. There are still important gaps in our understanding of the effects and fate of petroleum in the marine environment. However, the biological effects appear worse closer to shore; in particular, organisms in shallow, confined bodies of water such as estuaries are likely to be exposed to more toxic concentrations of oil than are organisms in the open ocean. And the organisms most directly affected by spilled oil in the coastal zone are those living on or near the ocean floor; commercially valuable shellfish are included in this group.

-- Oil spill cleanup methods also can adversely affect the environment. This is especially true of chemical dispersants and detergents

D. DEEPWATER TANKER PORTS

Construction impacts include those associated with onshore staging activities and with the construction of such onshore facilities as tank farms and pipeline terminals. The impacts of constructing a deepwater port itself is minimal if a monobuoy design is used for the port. Dredging is required for the pipelines which carry the oil from port to shore.

Operating impacts are chronic low-level petroleum discharges and accidental oil spills, similar in nature and biological effect to discharges from OCS operations.

CHAPTER III

BIOLOGICAL IMPACTS OF OFFSHORE ENERGY TECHNOLOGIES

A. BIOLOGICAL IMPACTS OF OFFSHORE FLOATING NUCLEAR POWER PLANTS (FNP'S)

1. General

The siting of floating nuclear power plants (FNPs) in the offshore area was conceived as an alternative to the decreasing availability of land-based sites. The ecological effects of both the construction and operational phases of FNPs are similar to those of conventional, land-based nuclear plants currently operating in the coastal zone. These impacts are common to power plants whether they are located in an estuary, on a tidal river, or in the offshore marine environment.

In each of these locations there is a need during the operational phase for cooling water to transfer excess heat from the plant to the environment via some type of aquatic system. Many of the biological impacts caused by nuclear power plants result from this use of cooling water. However, adverse ecological effects of plant operation may be lessened by taking advantage of the greater volume of water in the offshore area to cool, dilute, and disperse plant effluents.

The construction and operation of FNPs in the offshore area would also be less likely to affect the stocks of embryonic, larval, and juvenile fishes that are often concentrated in estuarine breeding and nursery grounds.

Fluctuations of physical and chemical parameters in offshore areas are generally less extreme than in estuarine areas. Correspondingly, organisms inhabiting offshore areas may lack the genetic or physiological flexibility needed to acclimate to effluents of FNPs and thus be more vulnerable to changes in the immediate vicinity of the effluents than are more adaptable estuarine species. Recent studies have indicated that environmental parameters at one potential FNP site located 2.8 miles off an inlet showed significant short-term fluctuations similar to high-salinity estuaries (E.G.& G. 1974, 1975). Thus, the above generalizations must be applied to site-specific evaluations. Some of the biological impacts associated with the use of cooling water are discussed in Sections V-C (Entrainment and Impingement) and V-D (Effluents and Emissions).

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Since all power plants generally have similar impacts on aquatic organisms, the total ecological effects of similar plants in both estuarine and offshore areas can be compared. Impacts on organisms are best discussed by separating those that occur during construction of the plant from those that occur during operation.

2. Construction

Since, in its proposed form, the FNP will be manufactured offsite and outside the study area, impacts resulting from this activity will not be discussed.

Site preparation and construction activities for a land-based plant involve the construction of access roads, clearing and leveling of the site, and actual construction of the plant structure and its associated support facilities. Site preparation for an FNP is in many ways a more extensive undertaking than for a land-based plant. A massive breakwater must be constructed to protect an FNP structure from storms, collisions with ships, and other catastrophes. This activity involves the transport of millions of tons of rock to the FNP site, followed by construction of the breakwater. Also unique to the FNP is the laying of an underwater transmission cable to link it with a land-based transmission facility. Placement of this cable, which must be entrenched under the ocean floor, involves dredging.

These major activities, breakwater construction and transmission line emplacement, are the ones most likely to affect organisms adversely during site preparation. Most of the adverse effects will be the result of dredging. A detailed discussion of dredging is presented in Section V-A.

The direct biological impacts of dredging include the killing or injuring of organisms because of mechanical damage and smothering. The magnitude of direct losses can be predicted for a specific area if the density of the various biota and the dimensions of the affected area are known. Because concentrations of benthic organisms are often greater close to shore, a similar amount of dredging is likely to cause more direct damage in inshore areas than offshore. Some inshore dredging will be necessary for both onshore and offshore sites, in the former for intake and discharge canals and in the latter for transmission line installation.

Indirect biological impacts of dredging include alterations in the habitat that make it less suitable for native species. Changes in water quality and in sediments likely to be caused by dredging are increased turbidity, suspension or resuspension of toxic materials, and channelization. The effect of each of these changes depends on the dredging technique used, the hydrography of the area, the nature of the substrate, and the time of year that dredging takes place relative to life histories of native species. The indirect effects of dredging are likely to be more severe in estuarine areas than offshore areas. Estuaries are shallower, more enclosed, and usually have finer, more highly organic sediments than offshore areas. These characteristics make inshore areas more vulnerable to the previously mentioned habitat alterations.

In addition to dredging, another potentially adverse impact of breakwater construction for the FNP site is the extensive quarrying necessary to supply materials. Because few, if any, suitable quarries are located within the study area, this impact has not been considered. However, consideration of this impact is necessary to assess the total environmental impact of the offshore FNP.

3. Operation

The first factor to be considered in the operational phase of nuclear power plants in both offshore and estuarine areas is the physical presence of such facilities. The land-based plant, depending on its size, removes a given amount of land from the terrestrial ecosystem, thereby destroying or displacing organisms living there. The proposed FNPs require about 100 acres for onshore support facilities, which is similar to the requirements of a land-based plant. A more detailed discussion of terrestrial impacts is presented in Section V-F. In addition, the breakwater will occupy about 100 acres of sea bottom and destroy or displace organisms living there. This loss of benthic organisms may be compensated for by the creation of an artificial reef community with increased species diversity and greater productivity. For a discussion of such a reef effect, see Section V-B.

Other factors to be considered in the operational phase of nuclear power plants are those associated with the cooling system. Impacts on organisms result from changes in the environment due to:

(1) the discharge of various plant effluents such as heated water and chlorine compounds

(2) the trapping of organisms at the plant intake

(3) the entrainment of small planktonic biota within the cooling water.

The impacts on organisms due to effluents are discussed in Section V-D, and those due to entrainment and impingement in Section V-C.

Effluents are basically the same for plants located in either inshore or offshore areas. While effluents are similar, the potential ecological effects on organisms in the two areas are different. Variation in water volume and concentrations of organisms are responsible for this difference. The greater volume of water in the offshore area permits more dilution of the effluents so that organisms are subjected to lower concentrations. Greater concentrations of organisms (including embryonic, larval, and juvenile fishes) in the inshore or estuarine system may result in more organisms being directly affected by the effluents. Such factors indicate that the same amount of an effluent could potentially have a lesser effect offshore than in estuarine areas. However, the breakwater might concentrate organisms within the influence of the plant effluents, thus exposing more organisms. The potential concentration of organisms would be the result of the unique habitat created by the FNP breakwater. Even if some organisms are lost through plant operational impacts, the net productivity of the waters surrounding the facility may still be greater than before construction of the breakwater. Impacts on organisms that result directly from the operation of the cooling water intake system are discussed in Section V-C.

Differences between inshore and offshore environments will affect the degree of ecological disturbance created by the removal of organisms through entrainment and impingement. As with effluents, greater concentrations of organisms (often the more delicate embryonic and larval stages of fish and shellfish) in estuaries could cause a greater impact there than in offshore areas. Placement of offshore FNPs opposite the mouths of estuaries may increase the exposure of adults and juvenile fishes to potential plant impacts during seasonal migrations in and out of estuaries. The reef effect of the breakwater may both concentrate organisms in the vicinity of the FNP and promote the impingement or entrainment of portions of these populations. However, the net effect of the breakwater should be an increase in productivity in waters adjacent to the FNP.

4. Summary

Offshore FNPs and comparable onshore facilities have more similarities than differences with respect to environmental impacts. The unique potential impacts of FNPs, though, are: the construction of the breakwater and its role as an artificial reef; the installation of a transmission line from the FNP to the shore; and the use of an enormous amount of cooling water available to an FNP.

It is difficult to determine whether an FNP or an onshore facility is environmentally preferable. Only when specific plant/site combinations are examined, with preoperational studies, can a preference be established. In either case, it seems possible to design and construct a facility compatible with its environment. Thus, the selection of an offshore FNP becomes a matter of the availability of a suitable site, as with other nuclear installations.

B. BIOLOGICAL IMPACTS OF OUTER CONTINENTAL SHELF (OCS) OIL AND GAS DEVELOPMENT

1. General

The extraction of oil and natural gas from the Mid-Atlantic Outer Continental Shelf (OCS) would have a number of biological impacts on the coastal and offshore environments. Some of these impacts are further discussed in Section V-E.

To begin development and to support exploration and production, it is necessary to construct onshore staging facilities. A number of platforms, depending upon the extent of reserves, are placed offshore to extract crude petroleum and natural gas. The oil and gas travel from the producing wells to gathering pipelines, and then to larger collecting pipelines which extend onshore. There, tank farms store the crude oil awaiting refinement, and gas-processing plants process the natural gas. New oil refinery growth is not expected since, if necessary, the capacity of existing refineries in the region can be expanded.

Alterations in the abiotic environment change the structure and function of biological communities by altering natural habitats and interfering with physiological functions. The biological impacts resulting from physical alterations vary with the degree of development; the

location and construction methods of pipelines, platforms, and onshore facilities; and the types of drilling and production operations conducted. These variables provide both a means of predicting biological impacts, and options for minimizing adverse ones.

The magnitude of OCS development cannot be predicted until leasing and exploration activities begin and the potential of the oil field reserves is determined. Because of this uncertainty about the size of the operation, and the exact location of its structures, the use of impact-minimizing methods and devices during exploration and production is essential.

Another reason to use impact-minimizing techniques is the ecological and economic value of the study area. The coastal regions of New Jersey, Delaware, and surrounding states are highly productive and valuable biological systems which support many species of fish, shellfish, and other wildlife. The biota of the study area is presented in detail in Appendix B. Young fish and shellfish obtain food and cover during initial years of growth and development, and waterfowl use the coastal regions for nesting grounds. These young aquatic organisms and waterfowl are especially vulnerable to adverse effects of OCS oil and gas development. In addition, the area supports an extensive and lucrative tourist trade and is heavily used by foreign and domestic fishing fleets.

2. Major Facilities with Potential Impacts

Physical alterations of the environment occur with the construction of the onshore staging facilities, tank farms, gas-processing plants, gathering and major collecting pipelines, and platforms. Because this document is primarily concerned with impacts on aquatic habitats, less attention has been given to the land-based activities.

a. Staging Facilities

Staging facilities are located in inlets, river mouths, or other estuarine areas where both protection from adverse seas and adequate ground transportation are available. Since estuaries are biologically productive and essential for the development of many ecologically and commercially valuable organisms, siting of staging facilities is an important concern.

Development could occur either in a relatively undisturbed area or in a previously developed area. An undisturbed or natural area would be

relatively inexpensive to purchase or lease. However, physical alterations and consequent biological impacts would probably be more significant than in a developed area. It would be necessary to dike and bulkhead wetlands and fill the site with sediment dredged and dried from adjacent waters. It is also possible that a navigation channel would have to be dredged between the staging area and the nearest navigable water to accommodate supply vessels. More information on dredging is contained in Section V-A.

The development of the petroleum reserves of the OCS would permanently destroy a relatively small area of wetlands compared to the total area of wetlands in New Jersey or Delaware. However, wetlands in these states have been decreasing in area for many years, and increasing development will inevitably continue this trend. Thus, loss of wetlands, no matter how small, is a matter of major concern. Further information on the ecological role of wetlands is in Chapter IV.

An alternative is the siting of staging facilities in areas previously or presently used for industrial functions. Abandoned piers, bulkheads, and warehouses formerly used by shipbuilding or seafood canning industries might be suitable, provided there is sufficient water depth.

b. Tank Farms

Tank farms for intermediate storage of oil are generally constructed in coastal areas. Two problems associated with tank farms are sediment erosion and runoff of oil-contaminated water. Such measures as diking and bulkheading can often reduce these problems, and should be incorporated into the initial design of the tank farm.

The area selected for a tank farm will be determined by availability of sites, plant specifications, and pertinent governmental regulations. The choice of site will also influence the extent of biological impacts. Selection of wetlands, meadows, or other natural areas which have been undisturbed for many years should be discouraged. Unique ecological habitats like the Pine Barrens or environments supporting endangered, threatened, or rare species deserve special protection from industrial development.

c. Gas Processing Plants and Refinery Growth

Gas processing plants may be needed to filter and blend the natural gas produced by offshore wells. The principal impact of

these facilities would be the loss of the land on which they are constructed. These terrestrial effects are discussed in Section V-F. If possible, the processing plants, like the tank farms, should be sited away from wetland areas.

The biological impacts which would result from the expansion of existing oil refineries and the construction and operation of new ones are not addressed in this study, since little such expansion and construction need is anticipated.

d. Gathering and Major Collecting Pipelines

An important activity associated with OCS oil and gas development with significant biological impact is the construction of transporting pipelines both in inshore and offshore waters.

1) Pipelines in Inshore Waters

Transmission lines connecting offshore gathering lines with the tank farms on land pass through the coastal zone, and must be buried all along their length. Their burial disrupts sediments, benthic organisms, and vegetation in estuaries, wetlands, and along coastal beaches. Increased water turbidities and resultant sedimentation occur during pipeline burial, causing both acute (hours, days) and chronic (weeks, months) physical and biological impacts.

The severity and duration of impacts resulting from the dredging necessary to bury the pipelines depends on the geology, hydrography, biology, and pollutional history of an area, as well as on the extent of dredging required. More information on dredging is given in Section V-A.

In general, biological alterations from dredging appear to be more damaging in estuaries and less damaging on coastal beaches and sand dunes, because, as mentioned earlier, estuaries are critical habitats for young fish, shellfish, other wildlife and their respective food sources. Coastal beaches, on the other hand, are usually much less productive than estuaries. There would be, therefore, less disruption of natural populations in such areas. Turbidity would also be less on beaches because sands settle out of suspension much faster than do the finer substrates found in estuaries. Also, the redeposition of sands would probably not bury and suffocate many organisms because beach biota are usually adapted to naturally shifting sands.

2) Pipelines in Offshore Waters

Physical impacts of pipeline burial in the outer continental shelf would probably be less than near shore, unless surf clam or other important shellfish beds are involved. The indirect effects of smothering benthic organisms with dispersed sediments, and the higher water turbidity, are difficult to assess because of the uncertainty of the magnitude of development. Turbidity is generally less severe offshore than in estuaries because the sediment particles are larger and settle more rapidly. The impacts of smothering may be of more concern.

Biological impacts on offshore biota can vary considerably. Minimal destruction by dredging and rapid recovery of benthic communities are perhaps best achieved by selective routing of the pipeline. The route should avoid biologically unique and commercially valuable areas such as offshore clam beds. Hydraulic dredging is presently a common method of harvesting clams and may be adversely affecting substrates, but supportive data are not available. Clam beds are densely populated and the organisms often require several years of growth before attaining maturity. Such a long maturation is unusual for most benthic invertebrates. Former commercial clam beds should be avoided. Planktonic clam larvae need the type of substrate provided by former beds to attach to and metamorphose into adults. Jetting of sediments during dredging might change the substrate into a less-preferred type and thereby retard recolonization by clam larvae. It is also suggested that offshore dumping sites remain undisturbed. Dredging through these municipal and industrial wastes could resuspend and disperse sediments and chemicals with deleterious biological consequences.

d. Platforms

The reef effect of platforms has had significant impact on sport fishing in the Gulf of Mexico. This reef effect is described more fully in Section V-B. The colonization on reeflike structures (platforms) by invertebrates and plants attracts fish and consequently, fishermen. On the basis of studies that show higher biomass and productivity on hard substrates than soft ones, a long-term net increase in biological activity in waters surrounding these structures is expected (Unger 1966, Port of Mobile 1972). This extensive reorganization of ecological relationships between an artificial habitat and the local biota distinctly contrasts with the anticipated minor adverse

impact of emplacement of a platform. More difficult to assess is the significance of the impact of chronic, harmful effluents (oil and non-oil) from platforms upon these reef populations.

Commerical fishing may be affected by platform emplacement if the platforms interfere with existing or future clamming or trawling grounds. Preplanning of platform placement taking the local commerical uses into account should minimize this concern.

3. Operation

In the course of OCS oil and gas extraction and transport, some biological alterations of plant and animal communities in wetlands, estuaries, coastal beaches, and offshore waters occur. These OCS operations include disposal of routine operational effluents (non-oil) and the chronic and major additions of petroleum discharges.

a. Disposal of Routine Operational Effluents (Non-Oil)

Major waste products of the operation of petroleum rigs are drilling muds (oil already separated), cuttings, and brines. Most offshore drilling operations can neutralize the toxic fractions of these substances (U.S. Dept. of Interior 1971).

The composition of drilling muds varies according to the specific characteristics of the well being drilled. Components of drilling muds (see Section V-D) can be toxic to marine life. Most studies on the biological effects of drilling muds and their components deal only with freshwater organisms. Further studies to determine the effects of drilling muds and their components on marine biota seem warranted.

Even if the toxic substances in drilling muds are neutralized, the overboard disposal of the muds and cuttings could still increase turbidity and smothering. Additional information from the U.S. Department of the Interior on the persistence of drilling muds and constituents around drilling platforms (see Appendix C, Table C-11) will be available in 1976. The amount of increased turbidity and smothering can only be estimated from previous drilling sites, but it is likely that in offshore regions these substances are much diluted and dispersed, thus reducing the potential damage. However, in regions of shellfish beds, spawning areas, and other unique biological regions this method of disposal could endanger ecologically and commercially valuable species.

Disposal of cuttings around the platform is likely to provide increased substrate for reef-oriented organisms (see Section V-B).

Brines, often a significant component of the bleedwater effluents, are disposed overboard like muds and cuttings. The effects of an effluent with a salinity higher than surrounding waters near a platform is unknown but probably of little significance due to the relatively small quantities involved.

b. Chronic and Major Additions of Petroleum Discharges

The potential addition of petroleum, either by chronic or major accidents, is a significant impact of OCS petroleum development and operation. Chronic (prolonged) additions result from the use of drilling muds in the drilling process. It is important to determine if significant sublethal alterations to biota occur due to these prolonged releases. Further, a determination of the physical and biological persistence of hydrocarbons in the environment is also needed. Major oil spills can result from drilling well blowouts, pipeline breaks, and ship collisions with platforms.

4. Summary

There are bound to be some biological effects as a result of offshore oil and gas development. These effects must be weighed against the economic and social advantages of the petroleum reserves developed and a point of balance reached where development is not at the expense of irreversible and significant environmental damage.

C. BIOLOGICAL IMPACTS OF DEEPWATER PORTS

1. General

A deepwater port is an offshore mooring facility connected to the shore by an oil pipeline. Although the facility may permit loading of refined products onto vessels, its primary function is to receive oil from very large crude carriers (VLCC). Onshore support facilities for a deepwater port include a pumping station and an intermediate storage area (tank farm).

There are three basic designs of deepwater port facilities: an offshore, artificial island with oil storage tanks and docking facilities

on the lee side; a sea pier with breakwater; or a single-point mooring (SPM) buoy, also called a monobuoy. One or more deepwater ports may be constructed along the coast of New Jersey and Delaware (Sea Girt, New Jersey, is being considered). The actual mooring and offloading facility will be sited about 15 miles offshore and in water at least 100 feet deep where a VLCC can maneuver.

2. Potential Impacts

Impacts will be caused by both the construction and operation of deepwater ports, and influenced strongly by their design.

During construction, pipelines would be buried under the sea bottom from the offshore docking facility through the coastal zone to the onshore tank farms. The impacts of pipeline burial are discussed in Section III-B. Onshore impacts will occur during construction of equipment staging areas, pumping facilities, tank farms (approximately 50 acres or more), and possibly, additional refineries. A discussion of these impacts is in Section V-F.

During operation, there will also be impacts. The high-velocity flow of bottom water induced by VLCC docking maneuvers will continuously shift bottom sediments. Nearshore impacts will include the erosion of spoil deposits both in estuaries and along shorelines due to dredging for pipeline emplacement (consult Section V-A for more information). Also, if additional refineries are required, they would cycle large quantities of water which could be an additional source of harmful effluents. The potential for the chronic and major addition of oil, either during the transfer of oil from the tanker to the port or from leaking pipelines, is also discussed in Section III-B.

The monobuoy design would cause little biological alteration of the offshore environment, the artificial island more, and the sea pier the most. These projections are based upon the area of sea bottom disturbed and the area of new substrate created. Monobuoy construction would involve only installation and would disturb only those benthos in the limited area of the bottom where anchors are placed. Invertebrate losses would be small. The reef effect, which is discussed in Section V-B, would also be minor because little new, submerged substrate would be created.

Construction of either a sea pier with associated breakwater or an artificial island might cause greater biological changes. Mortalities of benthic invertebrates would result from several acres of bottom being covered with rock and sediment. Additional mortalities would result in the area (presumably near the port site) from which sediment is dredged for fill material. Dredging should avoid densely populated shellfish beds.

A potentially beneficial impact would be the colonization of the dredged bottom, and of the new, artificially created breakwater or island. The latter phenomenon, or reef effect, is described more fully in Section V-B. This colonization of reef-like structures by invertebrates and plants subsequently attracts fish. On the basis of studies that show higher biomass and productivity on hard substrates than on soft substrates, a long-term net increase in biological activity is anticipated in waters around sea pier or artificial island deepwater ports. The largest increase is expected after creation of the artificial island port because more area would be available for colonization and manifestation of the reef effect.

3. Summary

The extensive reorganization of ecological relationships between either a constructed breakwater or artificial island habitat and the local biota distinctly contrasts with the anticipated minor impact of emplacement of a monobuoy deepwater port. However, apparently neither sea pier nor artificial island designs will have a long-term harmful impact on local biota, provided the site is not inhabited by organisms such as clams and scallops which mature slowly.

Commercial fishing and alternative use of the offshore area, will not be affected adversely with wise port design, site selection, development, and operation. Sport fishermen might realize larger catches of fish near a sea-pier breakwater or an artificial island if small-boat navigation in the area is permissible. Commerical fishing could continue unimpeded if the deepwater port site does not coincide with existing or future clamming or trawling grounds. Thus, it would be advisable to consult private fishing industries and governmental marine resource managers in the course of making any plans for deepwater ports.

CHAPTER IV
DESCRIPTION OF STUDY AREA

A. GENERAL

This study addresses the potential impacts of offshore energy-related activities on the coastal areas of New Jersey and Delaware shown in Figure I-1. The study area is bordered in the east by the edge of the continental shelf and in the west by the beaches, barrier islands, and marshlands extending from Sandy Hook to Cape May in New Jersey, and including all of Delaware Bay and the southern Delaware coast.

Most of this region, with the exception of portions of the Upper Delaware Bay, supports a significant seasonal tourist industry. The barrier beach and onshore communities depend upon good water quality for the tourist industry and for sport and commercial fisheries.

B. ADJACENT INLAND AREAS

The adjacent inland regions that could be affected by support facilities for offshore, energy-related activities include natural, agricultural, and industrial areas. In general, natural areas are most vulnerable to any adverse biological effects of industrial development.

In southern and central New Jersey there are extensive natural areas. These are called the Pine Barrens and are characterized by a 15-to-20-foot scrub pine forest with blueberry and laurel undergrowth. Many streams supply freshwater and nutrients to the extensive coastal marshlands. Agriculture and recreation are the most common uses of this land. Large blueberry and cranberry farms occupy sections with sandy, acidic soils and clean, fresh waters.

The inland areas of Delaware that could be affected by OCS technologies are primarily agricultural lands used for poultry farming, production of poultry feed, dairy farming, and truck farming. The watersheds that drain into the coastal wetlands also contain numerous small towns and light industries (mostly food-processing plants). Effluents associated with these activities (municipal sewage, industrial effluents, and

agricultural land runoff) already affect to some degree the Delaware Bay marshes. The increased industrialization of OCS technology support facilities could both remove agricultural land from production and place additional stress on the aquatic systems.

The rest of the study area--northern Delaware near Upper Delaware Bay and northern and west-central New Jersey--is heavily industrialized and heavily populated. Many of the coastal marshes have been filled or drained. Additional stresses there would probably have less effect than would comparable stresses in less-developed areas.

C. COASTAL AREAS

The New Jersey shoreline from Sandy Hook to Cape May is characterized by small bays and salt marshes often extending several miles inland, such as the ones in Cape May and Atlantic counties. Long, sandy barrier island beaches like Long Beach and Island Beach front the shoreline. In Delaware, the coastline consists of narrow barrier beaches in front of embayments and infrequent medium-salinity estuaries such as Indian River and Rehoboth Bay.

The major coastal habitats found in New Jersey and Delaware include: (1) high-energy beaches, (2) oyster beds, (3) salt marshes, (4) worm and clam flats, (5) grass bottom systems, (6) low-salinity systems, (7) medium-salinity plankton systems, (8) neutral embayments, and (9) coastal plankton systems (Odum and Copeland 1974). The following is a general description of these habitats.

1. High-Energy Beaches

High-energy beaches extend along the seaward side of barrier islands and barrier beaches of New Jersey and Delaware. These beaches are characterized by the high-energy waves that break directly along the shoreline. Small burrowing crabs (*Emerita* spp.) clams, (*Donax* spp.) and other beach fauna living within the sands filter out and feed upon organic matter brought in by the waves. The longshore current, characteristic of these beaches, aids the many migrations of fish and macroinvertebrates. Commercially valuable surf clams inhabit many of the subtidal zones. Because of the waves surging upon the beaches and the filter-feeding of the fauna, high-energy beaches are particularly vulnerable to such surface-bound wastes as oil (Odum and Copeland 1974).

2. Oyster Beds

Communities of filter-feeding organisms, including oysters, are abundant in the strong current, shallow-water systems of New Jersey and Delaware. The organisms in these communities feed on suspended organic material brought in by the currents. Protected by hard outer coverings, oysters, mussels, and serpulid worms concentrate in dense and often exposed beds, banks, bars, and flats.

Siltation is particularly harmful to oysters, since spat (young oysters) will settle only on hard substrates. Reduced freshwater input is also harmful to oysters. Oysters can thrive in estuaries with fluctuating salinities, temperatures, and water levels, but prolonged exposure to high salinities makes oysters more susceptible to disease, predation from oyster drills, and competition with less commercially valuable species (Odum and Copeland 1974).

Oysters are commercially valuable both as human food and as a source of calcium carbonate for concrete manufacture. Oyster beds are regulated by both New Jersey and Delaware. Some of the regulated areas are condemned from harvesting due to bacteria contamination. In New Jersey, large state-regulated oyster beds exist in Delaware Bay, Great Bay, and Great Egg Harbor. In Delaware, they exist in Rehoboth Bay and Indian River Bay (Spinner 1969).

3. Salt and Freshwater Marshes

Marshes are among the most valuable and productive of coastal areas, and are extensive in both New Jersey and Delaware. The major types of salt marshes which characterize the wetlands of these states are, from closest to the shoreline to further inland: (1) tall or high-vigor salt marsh cordgrass (*Spartina alterniflora*) at low elevation, immersed by the tide twice daily; (2) short or low-vigor cordgrass (*Spartina alterniflora*) at high elevation, kept moist but not immersed by tides; (3) salt meadow cordgrass (*Spartina patens*) found at higher elevations than short cordgrass, drier than the previous two but immersed by spring tides; (4) reed (*Phragmites communis*) found above the spring tide line. In the brackish and freshwater marshes along rivers, arrow arum (*Peltandra virginica*), wild rice (*Zizania aquatica*), cattail (*Typha* spp.), or three square (*Scirpus olneyi*) are the most common types of dominant vegetation (Alpaugh and Ferrigno, n.d.).

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These marshes play important roles in the maintenance of coastal ecosystems. Marsh vegetation stores nutrients and energy from coastal runoff and tidal inflow, and supplies those nutrients and energy to the food webs of estuaries and coastal waters. Decayed marsh vegetation (organic detritus) is used as food by a variety of small organisms, especially arthropods (amphipods, mysids, shrimp, etc.) and annelids (polychaete worms, etc.) which are in turn used by higher trophic level organisms. Detrital particles are also consumed by bacteria. The primary role of the bacteria is to decompose the detritus to basic nutrients, making them again available within the ecosystem. Table IV-1 lists some marsh community (short cordgrass) animals in New Jersey and gives estimates of the standing crop of individuals per acre. These productive marsh communities provide valuable food, cover, nesting, and wintering grounds for migratory waterfowl of the Atlantic Flyway (see Appendix B for a discussion of waterfowl).

Other valuable functions that marshes perform are the removal of toxic materials and excess nutrients and the trapping of sediments and other suspended materials. The reduction in sedimentation and turbidity benefits shellfish beds and plant productivity. Marsh vegetation also slows floodwaters, thus stabilizing shorelines and preventing erosion in estuaries. For these reasons, marshes are valuable as nutrient cyclers, water purifiers, sediment traps, storm barriers, shore stabilizers, and energy storers in the ecosystem.

It is important to observe that the valuable marshlands of New Jersey and Delaware have diminished in the last 20 years. In 1953, approximately 263,051 acres of coastal wetlands were recorded in New Jersey (Alpaugh and Ferrigno, n.d.). In 1973, only 201,373 acres remained. Delaware, which has also lost marshlands, had approximately 115,000 acres of coastal wetlands as of 1972 (Klemas et al. 1973).

Tidal marsh losses have been and continue to be the result of increased recreational and industrial development along the coast. In New Jersey, filling activities have destroyed 32,874 acres and diking activities have destroyed 28,804 acres (see Table IV-2). The total loss in New Jersey has been 23.5 percent over a 20-year period. Most of the development and the resulting losses probably occurred in the more recent years. Further destruction of marshlands could have serious consequences for the wetland ecosystems of these two states.

Table IV-1

Estimated Gross Production of New Individuals per Acre per Year in a Short Cordgrass Marsh, Marmora, New Jersey

Organism	Estimated Gross Production per Acre per Year
Ribbed mussels (*Modiolus demissus*)	1,620
Periwinkle (*Lithorina litorea*)	160
Salt marsh snail (*Melampus bidentatus*)	3,035,820
Mud snail (*Nassarius obsoletus*)	570
Isopoda	51,820
Amphipoda (Gammaridae)	441,260
Copepods (*Metacyclops* sp.)	A
Shrimp (*Palaemonetes vulgaris*)	A
Fiddler crab (*Uca pugnax*)	11,750
Marsh crab (*Sesarma reticulatum*)	40
Blue crab (*Callinectes sapidus*)	A
Spiders (Arachnida)	257,880
Mites (Acarina)	15,340
Crickets (Gryllidae)	570
Leafhoppers (Homoptera)	728,690
Ants (Formicidae)	8,420
Beetles (Coleoptera)	17,970
Mosquito larvae (*Aedes sollicitans*)	336,010
Grasshoppers (Locustidae)	160
Eels (*Anquilla rostrata*)	A
Killifish (*Fundulus heteroclitus*)	A
Silversides (*Menidia menidia*)	A
Sheepshead minnow (*Cyprinodon variegatus*)	A
Diamondback terrapin (*Malaclemys terrapin*)	40

Note: A = Organism abundant.
Source: Adapted from Alpaugh and Ferrigno, n.d.

Table IV-2

Twenty-Year Tidal Marsh Losses for New Jersey

Acres of coastal wetlands in 1953.....263,051
Acres of coastal wetlands in 1973.....201,373
Acres of coastal wetlands lost between 1953 and 1973... 61,678

Categories of Marsh Losses	Acres of Marsh Losses	Percent of Marsh Losses
Filling		
Channel dredging	4,488	1.7
Buildings and roads	28,386	10.8
SUBTOTAL	32,874	12.5
Diking		
Salt hay impoundments	10,678	4.1
Agricultural impoundments	5,996	2.3
Mosquito impoundments	2,481	0.9
Muskrat impoundments	3,876	1.5
Waterfowl impoundments	2,781	1.1
Road impoundments	2,991	1.1
SUBTOTAL	28,804	11.0
TOTAL	61,678	23.5

Source: Adapted from Alpaugh and Ferrigno, n.d.

4. Worm and Clam Flats

Another habitat of the coastal ecosystems of New Jersey and Delaware is the worm and clam flat. The animals which inhabit these flats of mud and sand along the intertidal zone filter out particles of organic matter as the water flows by. This habitat, like the oyster beds, depends upon large volumes of circulating water to supply adequate amounts of particulate organic matter to the invertebrate community. Common species in these areas are the soft clam (*Mya arenaria*) and the commercially important hard clam (*Mercenaria mercenaria*) (Odum and Copeland 1974). Soft clam beds are found in Raritan Bay, Manasquan River, and Metendeconk River (Spinner 1969). Hard clam beds are found in Raritan Bay, Little Egg Harbor, Great Bay, and many of the small embayments southward to Delaware Bay. Delaware Bay, Indian River Bay, and Rehoboth Bay have extensive populations of hard clams. Bay scallop beds are found in southern Barnegat Bay (Spinner 1969).

5. Grass Bottom Systems

Grass bottom systems occur in shallow waters with strong currents and low turbidity. Dense mats of bottom algae and rooted vascular plants cover the bottom and provide food and shelter for many fish and invertebrates. Grass bottom systems are found in Barnegat Bay and in embayments throughout the area (Odum and Copeland 1974).

6. Low-Salinity Systems

Low-salinity (oligohaline) habitats are characterized by salinities of 0.5 to 5.0 parts per thousand (sea water is usually 33 to 34 parts per thousand along the continental shelf). The oligohaline habitats in the study area usually have fluctuating salinities as a result of tidal intrusions and seasonal freshwater runoff. Oligohaline habitats are found in the headwaters of Raritan Bay, Delaware Bay, and Indian River Bay. Species diversity is usually low because of the special adaptions needed to withstand the widely fluctuating salinities (Odum and Copeland 1974).

7. Medium-Salinity Plankton Systems

Medium-salinity estuaries are deeper and more saline than oligohaline habitats. Productivity is unusually high, although not as high as marshlands. High concentrations of nutrients and favorable circulation of water support important plankton populations as long as

water clarity is maintained. These habitats are extensively used for spawning and nursery grounds by many ecologically and commercially valuable species of fish and shellfish (Clark 1974).

8. Neutral Embayments

Neutral embayments have high, stable salinities which result from the lack of freshwater inflow. Most circulating water comes through outlets to the sea. This habitat is a high-salinity plankton system with a greater species diversity than most estuarine systems. Neutral embayments often serve as migration zones for fish moving into medium-salinity estuaries to spawn. Commercial and sport fishing activities are often concentrated in these areas because many valuable fish species attain recruitable size there (Odum and Copeland 1974).

9. Coastal Plankton Systems

The offshore area covered by this study is the central Middle Atlantic Bight. Physically, the area is a broad, shallow shelf extending seaward to the continental slope. The shelf is indented by several canyons. Lowest temperatures are generally recorded in late February and highest temperatures in late August. The greatest seasonal variations in temperatures occur in the more shallow, nearshore areas (Bumpus 1973). The few studies that have been done indicate that the substrate is uniform and composed of sand, silty-sand, and silty-clay (Pratt 1973).

The offshore community is composed of numerous species in each of the trophic levels. These organisms are classified according to where they live: plankton (open water, at the mercy of currents and tides), nekton (open water, free swimming), and benthos (bottom dwellers).

D. SUMMARY

The natural habitats which comprise the adjacent inland and coastal areas of New Jersey and Delaware have been described. These unique terrestrial and aquatic systems are all interrelated components of the overall coastal ecosystem. When examining the potential impacts of offshore energy-related activities, it is necessary to recognize that because of the close interdependencies, induced changes in one habitat or component of the ecosystem can affect other components.

The study region includes important natural and agrarian areas supporting recreational and commerical fisheries, a tourist industry, and various types of farm operations. These present uses of the area should also be taken into account when designing programs to minimize the impacts of the offshore technologies.

CHAPTER V

DISCUSSION OF SPECIFIC IMPACTS

The six categories of specific impacts covered in this study are dredging impacts, the reef effect, entrainment and impingement, effluents and emissions, petroleum discharges, and terrestrial impacts. Within each category are discussed, as applicable, the roles of the three technologies: floating nuclear power plants (FNPs), outer continental shelf (OCS) oil and gas development, and deepwater tanker ports.

A. DREDGING IMPACTS

The construction of any of the three energy-related technologies under consideration in the Middle Atlantic Bight will disturb bottom sediments to some degree. The degree of biological impact of these activities will vary with the extent, duration, and location of the activity. Generally, greater biological impact will result from more extensive, longer term, and more estuarine inshore activities. These generalizations will be discussed in detail later.

Dredging and other forms of sediment disturbance are expected during bottom preparation for installation of oil rigs, deepwater tanker port facilities, and floating nuclear plant breakwaters. The greatest areas will be disturbed during the construction of oil pipelines and electrical transmission lines.

Maintenance and operation of these pipelines and transmission lines should have little or no adverse impact except in the case of chronic leaks of oil or major accidents. In those cases, damage would result from the addition of oil to the environment, which is discussed in Section V-E (Petroleum Discharges).

1. Biological Effects

A potentially substantial cause of biological impacts due to OCS oil and gas development and FNP installation is the construction of oil pipelines and electrical transmission lines. Oil pipelines originate offshore on the continental shelf either at production rigs or deepwater tanker ports and terminate at a shore-based tank farm. Transmission

lines connect FNPs to inland switching stations. Biological impacts would vary in the several aquatic habitats crossed by the pipelines or transmission lines, depending upon the route chosen. Possible pipeline routes include the shelf floor, beaches, dunes, estuaries, and marshes.

The biological effects of pipeline and transmission line installation can be divided into several categories, each type of effect having a slightly different impact on each of the different habitats. Each type of impact will be discussed separately in relation to the various habitat types. Because qualitatively similar effects are expected for both pipelines and transmission lines, both will be referred to as "pipelines."

a. Direct Mortality

The violent displacement of organisms during dredging causes direct mortality and reduces the biomass of the benthic community. This impact occurs wherever dredging and pipeline laying take place. Biomass losses due to such displacement are proportional to the area disturbed and the density of biomass. The mobility of certain benthic organisms, particularly fish, minimizes the biomass loss of the most mobile forms.

Using published data, the expected biomass losses due to pipeline placement have been calculated and presented in Table V-1. No data were available for the New Jersey and Delaware areas but data collected in Massachusetts can be used for approximations.

The total mileage of pipeline laid will have a direct effect on impact. If the field is large, there could be two 80-mile pipelines with 100 miles of connecting pipelines, resulting in 260 miles of pipeline. If such were the case, there would be 173.3 tons (dry weight) of biomass lost based on the average values in Table V-1. The data in Table V-2 are fairly recent and comparable to other estuarine and offshore biomass values (Sanders 1956, 1960; Pfitzenmeyer 1971; Zenkevich and Birstein 1956).

Rowe et al. (1974) relate the productivity of benthos off the North Atlantic coast to other areas and depths. Two conclusions were reached which are pertinent to the problems of laying pipelines: (1) the benthic biomass per unit of area of the Northwest Atlantic OCS is greater than that of the Gulf of Mexico, and (2) the benthic biomass decreases with

Table V-1

Biomass Losses Expected from Dredging in the OCS

Source	Biomass (g/m^2)		Biomass Lost with 200-ft Trench (tons/mi)		Biomass Lost from 80-Mile Pipeline with 200-ft Trench (tons)	
	Wet	Dry	Wet	Dry	Wet	Dry
Wigley (1965)		10.0	4.0[a]	1.08	320.4[a]	86.5
Lee (1944)		1.0	0.4[a]	0.108	32.04[a]	8.65
Rowe et al. (1974)	4.54		0.44	0.12[a]	35.78	9.66[a]
Wigley and McIntyre (1964)	51.8		5.07	1.37[a]	407.0	109.9[a]
AVERAGE	24.27	6.56	2.48	0.67	198.8	53.68

a. Value converted from the reported biomass value based on Holme's (1953) conversion factor (dry weight = 27% of wet weight).

Table V-2

Biomass Losses Expected from Dredging in Estuaries

Source	Biomass (g/m^2) (dry weight)	Biomass Lost (tons/mi) (dry weight)		
		200-ft Trench	100-ft Trench	50-ft Trench
Kaplan et al. (1974)	36.83	3.86	1.93	0.970
Sanders (1956)	54.63	5.95	2.98	1.49
Sanders (1960)	12.19	1.32	0.66	0.33
Pfitzenmeyer (1971)	19.65	2.09	1.05	0.52
AVERAGE	30.83	3.30	1.65	0.83

increasing depth. The first conclusion suggests that comparisons between impacts of Atlantic and Gulf OCS pipeline laying would not be entirely valid. The second conclusion suggests that the OCS supports greater benthic biomass per unit of area than the open ocean. Therefore, any adverse impacts on benthos will likely decrease with the distance from shore.

The best available descriptions of offshore benthic fauna are reviewed by Pratt (1973), Pearce (1974), and Watling and Maurer (1974). These documents generally describe the offshore fauna as dependent on the substrate type and topography (see Appendix B, Biota of the Study Area).

Repopulation rates are not known for offshore benthos, but may be similar to those in estuaries (Pfitzenmeyer 1970, Leathem et al. 1973, Saila et al. 1972). Pfitzenmeyer (1970) reported that in Upper Chesapeake Bay recovery began shortly after dredging, and was completed in both the dredged and spoil disposal areas in about 18 months. Leathem et al. (1973) found significant repopulation in a disposal site in Lewes Harbor, Delaware, after six months. In a study of spoil deposition in Rhode Island Sound, Saila et al. (1972) found that recolonization involved both larval settling and adult migration. Thorson (1950) reviewed several studies of benthic communities and concluded that commonly occurring benthic organisms are capable of maintaining population levels because of their great reproductive capacities.

Dredging and pipeline construction will also reduce the benthos standing crop within estuaries. The community in this habitat differs from that in the offshore area and therefore will receive separate consideration.

There have been few studies of estuarine benthos and benthic biomass in New Jersey and Delaware. Therefore, data have been used from comparable areas. For further discussion of estuarine benthic fauna, see Appendix B.

Kaplan et al. (1974) give an average biomass (dry weight) value of 36.83 g/m^2 for a small estuary in New York. Sanders (1956, 1960) gives an average biomass (dry weight) value of 54.63 g/m^2 in Long Island Sound, and 12.19 g/m^2 in Buzzard's Bay, Massachusetts. Pfitzenmeyer (1971) gives an average biomass (dry weight) value of 18.65 g/m^2 in the Chester River, Maryland. Using the average of these values, and using widths

of 200, 100, and 50 feet for pipeline paths, biomass losses per mile were recorded. Results are presented in Table V-2.

The biomass lost in an estuary seems large in relation to the area affected. However, when compared with the total benthic biomass of an estuary, the loss is small. Further reduction of the impact of biomass loss can be expected because repopulation in dredged areas does occur (Saila et al. 1972, Maurer et al. 1974, Cronin et al. 1970).

If a pipeline is constructed through a commercial shellfish bed, there will be some destruction of a marketable resource. The reestablishment of this resource will take 3 to 10 years, depending on the species involved. Furthermore, there is no biological certainty that reestablishment will occur.

Marshes are the final area where significant biomass loss can occur due to dredging. The valuable function of these areas has been discussed in Section IV-C.

The disruption of marshlands in the right-of-way will cause the loss of some plant and animal material. This loss can be quantified by multiplying the area of the right-of-way by the measured biomass density values. A study of the productivity of marsh grass in Delaware (Daiber 1974) suggests that marsh grass is produced at a minimum of 2 tons per acre per year. This figure may be applicable to New Jersey marshes also, but only as an approximation. The loss of this material from the ecosystem may be detrimental to the organisms dependent on it. Methods of rebuilding marshes to their original condition are being studied and developed (Woodhouse et al. 1972, Clark 1974), but the methods have yet to be proven successful.

b. Indirect Mortality

The impacts due to indirect mortality will be categorized as turbidity, smothering, channelization, and toxicity.

1) Turbidity

Increased turbidity and siltation result from dredging, overboard spoil disposal, and runoff from onshore spoil disposal sites. The extent, magnitude, and duration of turbidity due to sediment suspension depend on the characteristics of the dredged material and surrounding waters, and on the methods of dredging and disposal. Because such factors depend upon the site, Maurer et al. (1974) concluded that generalizations

on the physical aspects of turbidity and siltation are not advisable. Maurer et al. (1974) and Sherk (1971) suggested that before dredging begins the sediment characteristics, methods to be used, and description of surrounding waters should be assessed on a site-by-site basis.

Since the substrate in the offshore area has been reported to be primarily sand or mixtures of sand and silt as far as 60 miles from shore (Pratt 1973, Swift 1974), natural refilling of dredged trenches should occur swiftly. This rapid refilling would promote rapid repopulation. Because the substrate is expected to be mostly sand, the resulting turbidity should be low.

Brehmer (1965) and Saila et al. (1972) reviewed the real and potential effects of increased turbidity in estuaries. Other workers have studied effects of turbidity on certain components of estuarine communities (Davis 1960, Davis and Hidu 1969, Lunz 1938, Loosanoff and Tommers 1948, Saila et al. 1968). These authors indicate that turbidity is not lethal to most adult and some larval organisms for short periods of time (less than 2 days) and in small concentrations (less than 0.50 grams of suspended solids per liter of water). Milliman (1973) gives average estuarine turbidity as 0.02 mg/l. Turbidity generally becomes lethal over longer periods of time or in greater concentrations (greater than 1.0 g/l). Kaplan et al. (1974) indicate that turbidity can be lethal and cause severe impacts in estuaries and bays.

Sherk (1971) reviewed the biological effects of turbidity, suspended sediment, and siltation on estuarine organisms and stated the need for further research. Sherk also points out that each biological system has the capacity to tolerate some turbidity and siltation, but when that capacity is exceeded, adverse effects occur. Although the available data on biological effects are incomplete, the potential effects include: (1) decrease in light penetration; (2) loss of habitat; (3) direct mortality of all life stages of microplankton and of larvae of larger organisms; (4) gill clogging; (5) flocculation of algae; (6) increased microbial activity; and (7) depletion of dissolved oxygen supplies. These effects, both lethal and sub-lethal, cause behavioral and physiological responses that may cause local extinction and changes in distributions for some species.

2) Smothering

Organisms residing near a dredging operation may be killed or injured by being covered with dredged materials. Saila et al. (1972) reviewed the effects of smothering and suggested that many species are able to burrow through up to 10 centimeters of deposited material. This seems reasonable because many benthic organisms are not sessile, but burrow in or crawl upon the sediments. Hale (1972) showed that the commercially valuable ocean quahog (*Artica islandica*) was able to burrow through as much as 14 centimeters of sand.

Sediment dispersion is one of the more important factors that affect the degree of impact due to smothering. The extent of such dispersion depends upon the amount of suspended material, method of dredging, method of spoil disposal, size and nature of the suspended particles, and the hydrodynamics of the surrounding waters. Sediment dispersion has been studied by several authors in the mid-Atlantic region (Cronin et al. 1970, Saila et al. 1972, Kaplan et al. 1974, Leathem et al. 1973, Maurer et al. 1974).

3) Channelization

When pipelines are buried in estuaries and marshes, the trenches are usually filled in afterwards. Insufficient backfilling could cause secondary channelization and alter the flow patterns in a small estuary. Kaplan et al. (1974) found that the deepening of a channel in a small estuary on Long Island, New York, had an adverse impact on the entire aquatic ecosystem by altering the flow pattern. For this reason, the potential impacts of channelization in small estuaries warrant monitoring.

Closely related to channelization in a shallow estuary is the alteration of drainage patterns in marshlands. Teal and Teal (1969), Daiber (1974), and Clark (1974) emphasized the dependence of marshes on tidal and river inflow. The impacts of flow alteration include changing the patterns of: (1) sediment deposition; (2) detrital transport, (3) nutrient release, (4) water level fluctuation, and (5) floral and faunal distribution of habitats, all of which influence the productivity of a salt marsh. A major conclusion reached by these authors is that any activity in a marsh which alters the flow pattern is likely to disrupt the marsh ecosystem and should be prevented (see Section IV-C).

4) Toxicity

An additional consideration is the impact of resuspension or leaching of toxic materials contained in dredged spoils. The extent of sediment contamination by toxic substances depends on the particular site. Such toxic substances include heavy metals, chemicals, pesticides, oil, and oil derivatives. The present data on lethal and sublethal effects of these toxic substances are incomplete (Boyd et al. 1972), but show enough adverse impact to warrant further study. The uptake of toxic substances by estuarine organisms is of particular concern because of possible concentration of such substances in the food web and the use of estuarine organisms as a food source by man.

Dump sites are another source of toxic substances. These sites, their associated benthic communities, and the effects of dumping on those communities have been described by Pearce (1974) and Watling and Maurer (1974). The sites currently in use near the study area are indicated in Figure V-1. Pearce (1970) found that dumping often had lethal effects on local biota. Impacts included chemical toxicity, oxygen depletion, smothering, and avoidance by pelagic organisms. To lay a pipeline through a dumping site could resuspend toxic substances, including chemicals, heavy metals, pesticides, oil, oil derivatives, and harmful microbes.

Contamination of habitats and associated biota may occur if toxic materials in the dredged spoil are washed or leached out. Boyd et al. (1972) concluded that little is known about the extent of leaching and its impact on biota. The U.S. Army Corps of Engineers is initiating field studies to examine the leaching of heavy metals and toxic chemicals from dredge spoils.

There are also indirect toxic effects of dredging and spoil disposal in estuaries. These effects are due to an alteration of the chemical composition of the surrounding waters. Concentrations of organic compounds may increase and contribute to proliferation of algal and bacterial populations. An increase in bacterial populations could significantly lower the dissolved oxygen concentration in the water and stress all local estuarine biota.

2. Routing

To reduce any adverse effects of dredging and pipeline installation, the route of the pipeline must be carefully considered. If

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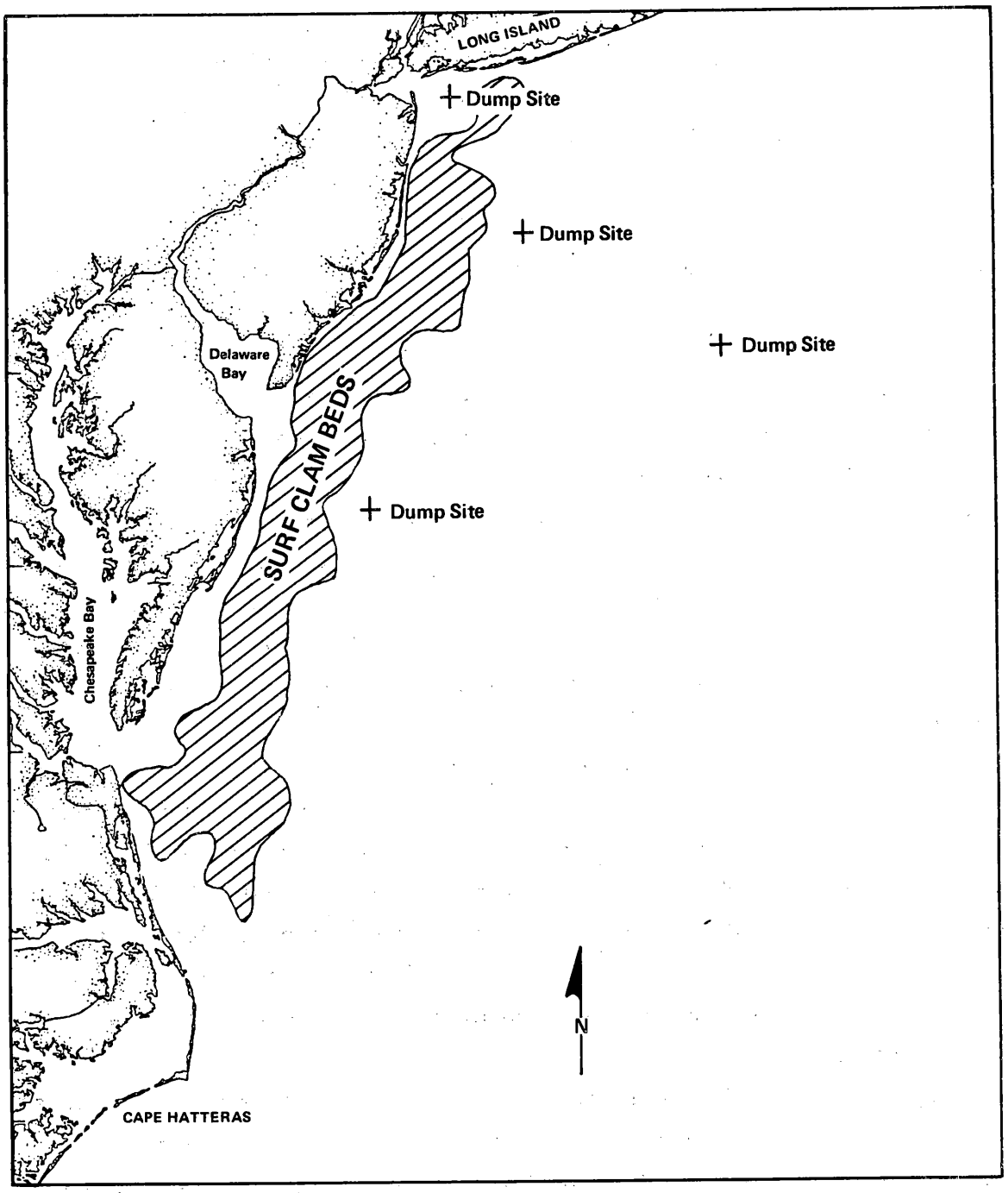

Figure V-1. Mid-Atlantic dump sites and surf clam beds (Adapted from U.S. DOC 1974).

possible, known shellfish beds should be avoided. Surf clams occur from New Jersey south to North Carolina, and from just off the shore to about 60 miles off the coast (Haskin and Merrill 1973). However, there are two primary locations (see Figure V-1), both near the three-mile limit, where surf clams occur in commercial densities (U.S. Dept. of Commerce 1974). A survey by the National Marine Fisheries Service (U.S. Dept. of Commerce 1974) indicated that the New Jersey surf clam beds were overharvested, and that the Virginia surf clam beds were becoming more densely populated. Haskin and Merrill (1973) also found that peak densities of surf clams occur within the three-mile limit between Absecon Inlet and Cape May (see Figure V-1).

To minimize the adverse impacts of pipeline laying, the two areas (New Jersey and Virginia) indicated in Figure V-1 as surf clam beds should be avoided. This may not be a workable alternative. Another option is to remove as much of the resource as possible before dredging, market the catch, and reseed the fished-out area later. Haskin and Merrill (1973) recommended that inshore clam sanctuaries be set up for stock conservation.

In addition to surf clam beds, the ocean quahog exists in the study area. A recent study (U.S. Dept. of Commerce 1974) indicates that commercial sizes and densities of the species occur in deeper waters north of Absecon Inlet. The option of fishing out a pipeline route also exists in the offshore region. This option can apply to sea scallop stocks as well.

3. Dredge Spoil Disposal

The amount of dredge spoil produced as a part of construction operations varies with the different technologies. If a floating nuclear plant is sited in water greater than 40 feet deep, then little onsite dredging is needed. In areas less than 30-35 feet deep, a channel to the plant site approximately 500 feet wide and at least 35 feet deep will have to be dredged, generating large quantities of dredge spoil. A depth of at least 40 feet will have to be dredged from within the FNP breakwater to provide adequate water depth to float the FNP during all combinations of tidal and meteorological conditions. With an FNP, it is likely that most of the dredge spoil material can be disposed of by placing it in the caissons which make up part of the plant breakwater.

An additional dredge spoil disposal problem could be created if it is necessary to dredge navigation channels to an FNP support facility.

The disposal of dredge spoil created by offshore oil and gas development is not expected to cause serious environmental impacts. Little dredge spoil is generated at the well sites and most material dredged while laying transmission pipelines is used to bury the pipes. Some dredge spoil disposal may be required to provide adequate navigation depths at onshore support facilities.

If deepwater ports are sited in water greater than 100 feet deep, little onsite dredging may be required. In most cases the materials dredged while laying transmission pipelines will be used to cover these lines. The monobuoy deepwater port will require the least amount of onsite dredging. If offshore piers or artificial island ports are built, all dredge spoil will be disposed of within the containment walls of these structures.

Unused dredge spoil can be disposed of in two ways, either by open water disposal or on land. Various areas off the eastern coast of the United States have been designated as dredge spoil dumping sites. The U.S. Nuclear Regulatory Commission (USNRC 1975) summarized existing literature on dredge spoil disposal in estuarine and ocean waters. It concluded that (1) dispersal of spoil rarely exceeds a distance of one or two miles from the dump site, and (2) turbidity subsides shortly after dumping. The extent of spoil dispersion is dependent on water depth, currents, meteorological conditions, and the composition of the spoil material. Several studies are underway to evaluate the effects of ocean dredge spoil disposal but no conclusions are presently available (USNRC 1975).

Boyd et al. (1972) discusses several beneficial open-water spoil disposal options. These include the use of dredge materials to create marshlands and islands for wildlife habitat and for enrichment of beach sand. These authors emphasize the need for greater research in these areas.

Growing concern over open-water dredge spoil disposal may lead to more land disposal in future years. However, suitable land sites are increasingly hard to find. All wetland areas should be avoided. Boyd et al. (1972) state that substantial improvements are necessary in dike design and construction in order to prevent expensive and environmentally damaging results for land disposal.

Whether dredge spoil materials are disposed of in open water or on land, it is necessary to carefully select potential disposal sites in order to minimize adverse environmental effects.

4. Summary

By far the greatest amount of dredging in the construction of oil transmission pipelines will occur in the offshore area. Although less is known about the offshore area than about nearshore waters, it can be assumed that little permanent damage will occur and that temporary damage will be less severe. These assumptions are based on the following: (1) the substrate is primarily sand that will settle quickly and produce minimum turbidity; (2) the area to be impacted is a small part of the total habitat; (3) the large volume of water will adequately dilute and disperse suspended sediments and leached material; and (4) the offshore habitats generally have lower productivity and lower biomass density than the inshore habitats. However, there are certain exceptions: dense shellfish beds and dump sites located offshore should be avoided if possible.

The inshore areas that will be crossed by pipelines include estuaries, marshes, and beach-dune habitats. These areas are more susceptible to both the temporary and permanent damage of dredging. This is partially due to the smaller relative size of these habitats--the ratio of impacted to unimpacted habitat is much larger than would be the case offshore.

The factors that minimize impacts in the offshore area are all missing from estuaries. Substrates usually contain more organic matter and fine silt and tend to remain in suspension much longer than sand. Water volume is considerably less, which results in less dilution and dispersion. Estuarine habitats are extremely productive and support a much higher biomass density than do offshore environments. Finally, estuaries serve as spawning and nursery grounds for valuable offshore fisheries (see Appendix B).

Marshes are similar to estuaries. The effects of dredging are likely to be at least as severe, temporarily, for the same reasons. Permanent alteration of the marsh will reduce its productivity and interrupt the food and nutrient supply to adjacent estuaries.

B. THE REEF EFFECT

The term "reef effect" refers to the attraction of aquatic organisms to natural and man-made structures in aquatic environments. These structures provide surfaces for attachment of ecologically, commercially, and esthetically important organisms. The consequences of forming artificial reefs by depositing automobile bodies and tires, sunken vessels, and concrete blocks on the sea bottom, or suspending specially fabricated structures above the sea bottom, have been documented by Buchanan (1972), Smith (1972), Stone (1972), and others.

These studies indicate that the reef effect is a time-dependent phenomenon which can occur relatively quickly. Wickham et al. (1973) noted that structures suspended between the water surface and the sea floor immediately attracted schools of jacks (carangids) and baitfishes in commercially harvestable quantities. Stone (1972) noted that over several months, the surfaces of sunken objects became encrusted with barnacles, hydroids, polychaete worms, bryozoans, and, if light intensity was adequate, algae. As communities of attached invertebrate organisms develop, populations of various carnivorous fishes and larger invertebrates become more abundant and diverse. Table V-3 shows the types of fishes caught over artificial reefs and other habitats in a survey of the New York Bight.

Because reefs and reeflike structures are well marked and easily found, sport-fishing intensity around artificial reefs is often greater than over natural bottoms (Buchanan et al. 1974). Because of this disproportionate fishing intensity, angler success (catch per unit of time) over reefs could potentially be less than over natural bottoms. However, another study used only expert fishermen to evaluate an artificial reef in a freshwater lake in Florida. The expert fishermen had a much higher catch per unit effort over the artificial reef than over the natural bottom (Crumpton and Wilbur 1974).

Artificial reefs are both popular and productive sport-fishing areas (Hart 1972), but the specific biological effects of artificial reefs have not been demonstrated. There are three hypotheses: (1) artificial reefs only attract fish from nearby natural habitats so that the increases in fish populations near the reefs are offset by decreases

Table V-3

Common and Scientific Names of Fishes Caught during the 1970 Marine Sport Fishing Survey and the Types of Habitat Where They Were Caught

Local Name	Scientific Name	Type of Habitat: Artificial Reef	Natural Bottom	Wreck
American eel	*Anguilla rostrata*		X	
Angler	*Lophius americanus*		X	
Atlantic bonito	*Sarda sarda*	X	X	
Atlantic cod	*Gadus morhua*	X	X	X
Atlantic herring	*Clupea harengus*	X	X	
Atlantic mackerel	*Scomber scombrus*	X	X	
Atlantic menhaden	*Brevoortia tyrannus*		X	
Black sea bass	*Centropristis striata*	X	X	X
Bluefin tuna	*Thunnus thynnus*	X	X	
Bluefish	*Pomatomus saltatrix*	X	X	X
Cunner	*Tautogolabrus adspersus*	X	X	X
Dolphin	*Coryphaena hippurus*		X	
Jacks	Carangidae		X	
Little tunny	*Euthynnus alletteratus*	X	X	
Northern kingfish	*Menticirrhus saxatilis*	X	X	
Northern puffer	*Sphaeroides maculatus*	X	X	
Northern searobin	*Prionotus carolinus*	X	X	
Northern stargazer	*Astroscopus guttatus*		X	X
Ocean pout	*Macrozoarces americanus*	X	X	X
Oyster toadfish	*Opsanus tau*		X	
Pollock	*Pollachius virens*	X	X	X
Red hake	*Urophycis chuss*	X	X	X
Sculpins	Cottidae	X	X	X
Scup	*Stenotomus chrysops*	X	X	X
Shad	*Alosa* sp.		X	
Sharks	Squaliformes	X	X	X
Silver hake	*Merluccius bilinearis*	X	X	X
Skates and rays	Rajiformes	X	X	X
Skipjack tuna	*Euthynnus pelamis*		X	
Striped bass	*Morone saxatilis*	X	X	X
Summer flounder	*Paralichythys dentatus*	X	X	
Tautog	*Tautoga onitis*	X	X	X
Weakfish	*Cynoscion regalis*		X	
White hake	*Urophycis tenius*	X	X	X
Windowpane	*Scophthalmus aquosus*		X	
Winter flounder	*Pseudopleuronectes americanus*	X	X	X
Yellowtail flounder	*Limanda ferruginea*		X	

Note: Adapted from Buchanan (1972).

in surrounding natural habitats; (2) artificial reefs actually increase fish populations in an area; or (3) the total effect is a combination of (1) and (2).

The first situation could possibly harm the fishery if, because of the concentrating effect, the fish were overharvested. The second situation could result from an increase in the primary productivity or the utilization of existing production. In the absence of definitive data, the reef effect is probably due to the third hypothesis.

While sport fishermen generally favor artificial reefs, commercial fishermen object to structures that can snag their nets. There is little chance for such snagging in the case of drilling and production rigs or FNP breakwaters. However, heavy objects lost overboard could interfere with trawls. The Japanese use artificial reefs to attract commercially harvestable numbers of fish that are then collected by pole and line, gill nets, or other passive gear that eliminate the snagging problems of trawls (Takashi 1974). The use of passive gear could be an alternative to the use of trawls if fish were concentrated enough around artificial reefs to justify a commercial fishery.

There are some data available on the utilization of drilling and production rigs as artificial reefs by sport fishermen in the Gulf of Mexico (Kalman 1975, Shinn 1974). Oil production platforms make the best artificial reefs because their high profile attracts pelagic game fishes and their extensive surface area attracts encrusting organisms. Production platforms extend from the sea bed to the surface, and in 100 feet of water they provide approximately two acres of surface area (Shinn 1974).

Oil rigs in the offshore environment will probably have a reef effect similar to artificial reefs in the inshore environment, although the types of fishes would differ. Sport fishing activities might not flourish, however. The mobile exploratory drilling platforms and fixed production platforms will probably attract a variety of bottom, midwater, and surface fishes. However, the platforms will be 60 to 80 miles offshore versus 3 to 10 miles for most artificial reefs. Good fishing near oil rigs this far offshore might attract sport fishermen, but rough seas there may endanger inexperienced boatmen.

The reef effect of oil platforms is minor compared with that of the massive breakwaters proposed for floating nuclear power plants. Because the FNP breakwaters rise from the ocean floor to the surface, and have numerous crevices, they provide nearly ideal conditions for a variety of fish and epifauna. Additions of warmwater effluents will probably enhance the reef effect of the breakwater. Because of the attractiveness of such structures to sport fishermen and the necessity for restricted areas around nuclear installations, there is a possibility of conflict over the use of the breakwater as a fishing reef.

Substrate will be created by the construction of deepwater tanker ports, particularly the artificial island or breakwater designs (see Section III-C, Biological Impacts of Deepwater Tanker Ports). The usefulness of the deepwater port as an artificial reef for sport fishing will depend upon both its distance from shore and on restrictions needed to protect small pleasure boats in an area of concentrated, large shipping traffic.

C. ENTRAINMENT AND IMPINGEMENT

1. Introduction

Because of the complexity of ecosystems and the different designs of modern generating stations, the net biological impact of a power plant is difficult to predict. Entrainment and impingement result from the need to withdraw large amounts of water from the aquatic environment to cool power plant condensers. This section will consider the biological impacts of using coastal waters for this purpose. It is necessary to define the terms "impingement" and "entrainment" since they are often used in different contexts. As the flow of water with organisms in it approaches the screens that protect the plant intake, some organisms cannot escape and become trapped by the velocity of the flow. They will either be impinged upon the screens or, if small enough, be passed through the screens and become entrained in the cooling system. Eventually, they will be discharged from the plant into the receiving waters. Entrained organisms are subjected to mechanical, thermal, and possibly chemical stresses as they pass through the heat-exchange system. The distinction is made between this type of entrainment (pump entrainment) and the type

of entrainment where organisms from surrounding waters are swept only into the discharge (plume or secondary entrainment). The temperature changes, turbulence, time of exposure, shearing forces, and pressure are distinctly different for the two types (Coutant 1974).

Any assessment of the environmental impact of power plants must determine if pelagic organisms in the cooling water source can withstand the selective damage of the intake and condenser systems and maintain normal population levels.

2. Impingement

The first contact of a power plant with its cooling water supply is the water intake structure with protective screens. Design engineers are currently trying to reduce approach velocities to minimize intake of debris and organisms. Most new screen intake structures have velocities of one foot per second or less; however, even at these relatively low velocities, sometimes the capture of fishes does occur.

One reason for the accumulation of fish at intake structures is that fish are attracted to hydraulic flows as an efficient way to obtain food. Fish, like other organisms, do not waste energy looking for food when they can be relatively stationary in these flows and select food as it is swept by. Even predators take advantage of the concentration of prey. The result is the establishment of a relatively concentrated biological food chain within the area influenced by the flow. Other aquatic organisms, such as crabs and shrimp, are also frequently found at intake structures, especially in inshore areas.

At power stations where water quality is high, provided intake velocities are low enough not to trap and impinge organisms, these accumulations of organisms seem to present no significant problem. However, if water intake velocities periodically fluctuate enough to create harmful conditions for certain species residing in these artificial habitats, then death can occur. The screening equipment must then remove and dispose of the bodies. Natural occurrences such as upwelling, seiches, and surface currents can also cause mortality.

Many intake structures, however, have been built with such high velocities that fish suffer physiological exhaustion in the rapid hydraulic flow. The result is that fish are highly vulnerable to any additional stresses at these intake sites.

Discharges of heated water, and of antifouling and anticorrosion products to maintain the condenser, can also adversely affect the relatively dense populations of fish at such intake structures. Solutions to these problems will require considerable research into the ability of many species of fish to maintain both sustained and darting swimming efforts. Age and size differences must also be considered in such endurance experiments.

Most current literature suggests that the biological damage that results from impingement is the combination of suffocation, mechanical injury, and thermal shock. Suffocation occurs when water pressure is sufficient to hold a fish against the screen and prevent it from opening its gill covers and breathing. Mechanical injury occurs during rotation and washing of the screens. Thermal shock occurs when impinged animals are removed from the screens and deposited into the plant's thermal discharge. A secondary and possibly significant effect is the predation by crabs and other predators upon impinged organisms.

The organisms most likely to be impinged by the proposed FNPs are pelagic organisms too large to pass through the screens. Large numbers of impinged organisms can also restrict the cooling water intake so that the plant may have to be periodically shut down because of the blockage of water flow. This problem will be compounded by the fish-attracting characteristics of the breakwater (see Section V-B, The Reef Effect) and the heated effluent (see Section V-D, Effluents and Emmissions).

Power plants with long intake canals and stubby cul-de-sac or funnel-shaped intakes are more likely to have impingement problems than intake systems flush with the shore. The former systems have few areas where rest and recuperation by swimming organisms can occur. With shoreline-flush intake systems, lateral escape routes are usually available; tides and shoreline currents can also carry fish away from the screening equipment.

Much research has been done in the attempt to minimize impingement. Various intake configurations have been designed for site-specific situations, each aimed at removing the maximum number of impinged organisms without injury and sustaining the flow of cooling water into the plant (Jensen 1974). Fish-guiding systems to divert fish from the intake screens are being investigated (Schuler 1974). Bright lights and air bubbles are

components of two such systems that have been used with limited success to frighten fish away from intake structures (Mayo 1974, Alevras 1974, Bibko et al. 1974).

The probabilities of biological damage depend upon the specific site. Studies of the spatial and temporal distribution of marine organisms in Little Egg Inlet for the proposed Atlantic Generating Station (AGS) have been underway since late 1971 (Ichthyological Associates 1972, 1974). These and future studies should indicate any vulnerable populations in the area. Analysis of local hydrology and intake velocity for the AGS can be found in Volume 2, Section 5 of the AGS Environmental Report (PSE&G 1974). Detailed analysis of the probability of impact on major species was not made. Insufficient data were given as the reason for not predicting the net ecological impact of impingement at the proposed AGS.

3. Entrainment

Three major groups of plankton can be described, based on their different responses and susceptibilities to entrainment. These groups--phytoplankton, zooplankton, and meroplankton--are discussed below.

a. Phytoplankton

Because these microscopic algal cells are the primary producers of organic energy they are very important, and because they are totally planktonic they are highly vulnerable to entrainment. Phytoplankters reproduce successive generations within minutes to hours. Thus, should destruction of a portion of the population occur due either to pump or plume entrainment, the population has a potential for rapid recovery. Moreover, death of these algal cells does not change the nutrient levels in the environment since most predators of phytoplankton do not distinguish between dead and living cells.

The response of phytoplankters to entrainment is mostly related to the ambient water temperatures and the temperature rises (ΔT) of particular condenser cooling systems. Plankton mortality can be predicted on the basis of seasonal high water temperatures, which usually occur only a few weeks or months each year. At other times of the year, the phytoplankton appear to be stimulated by entrainment as indicated by increases in the rates of photosynthetic processes, chlorophyll levels, and absolute numbers of cells of individual species found in discharge

and mixing areas (Warinner and Brehmer 1966, Gurtz 1973, Brooks et al. 1974, Smith et al. 1974).

Destruction of large volumes of planktonic organisms can lead to their subsequent bacterial decomposition and a resultive reduction in dissolved-oxygen levels. Lowered dissolved-oxygen levels in bodies of water where levels are already somewhat low can cause the death of additional organisms. Thus, the significance of damage to phytoplankters should be determined on a site-specific basis.

b. Zooplankton

The term "zooplankton" describes a diverse assemblage of invertebrates that are mostly microscopic. Many zooplankters are, like the phytoplankton, dispersed throughout the water column. Some zooplankters, however, often congregate in distinct layers. Thus, the effects of entrainment on zooplankters are likely to be more species-specific than on phytoplankters.

Diel vertical migrations of zooplankton have been shown by Kelly (1970), Kelly et al. (1971), Kelly and Chadwick (1971), Icanberry and Adams (1974), Davies and Jensen (1974), and others. Such migrations expose these zooplankters to water strata that are affected by both pump and plume entrainment. Different life stages of zooplankters have shown vastly different vulnerability to both thermal and mechanical damage. Eggs and early larval stages appear to be more resistant than later, more physiologically complex stages. Prolonged exposure to high temperature in long discharge canals has been shown to cause thermal damage to zooplankters (Davies and Jensen 1974). Shearing forces and mechanical turbulence in condenser systems and discharge structures can physically damage larger zooplankters. Little research has been done on the effects of turbulent plume mixing processes on zooplankters. Research by Carpenter et al. (1974) suggests that exposure to once-through cooling systems can alter behavior in microcrustacean zooplankters which can result in population reductions. Chlorine compounds and heated water, used to control biofouling in the condenser system, can destroy most entrained plankton organisms, depending on the amount used and the susceptibility of each species.

c. Meroplankton

Meroplankton are organisms which are planktonic for a

brief period early in their life cycle. Numerous invertebrates such as crabs, lobsters, shrimp, clams, oysters, and others have meroplanktonic eggs and larvae. Most fish have meroplanktonic egg and larval stages (known as ichthyoplankton) that are present for a period of days to weeks following spawning.

Prevailing currents and tidal flows can bring these temporary plankters into contact with aquatic cooling systems. The entrainment damage of meroplankton can have considerable influence upon the populations of fish and invertebrate species well beyond that detected in the near-field mixing area, because these organisms have a much lower reproductive potential than do the truly planktonic forms.

Entrainment studies suggest that considerable physical damage occurs to the delicate larval forms of both invertebrates and vertebrates. Egg stages appear to be less susceptible. Excessive turbulence and pressure, such as that produced by cavitation, increase the extent of damage. While some power stations have been reported to cause almost total destruction of meroplankton, others cause much less damage. Current research and modeling of condenser cooling structures should reveal the reasons for these observed differences (Marcy 1975).

d. Special Entrainment Considerations

The ecological significance of the point-source types of entrainment described above must be determined by the use of biological modeling, not yet developed. Thus far, it can only be approximated.

Nonrandom distributions of these planktonic stages (clusters, patches, etc.) can lead to disproportionate effects of entrainment damage upon individual populations. Considerable sampling effort should be made of the near- and far-field areas to ascertain such distribution differences at individual power plant sites.

D. EFFLUENTS AND EMISSIONS

A variety of pollutants will be released into the water and air in both chronic and acute amounts during the development of OCS oil and gas reserves, the operation of floating nuclear power plants, and the use of deepwater tanker ports. The major effluents and emissions originating from these three technologies are identified and their potential biological impacts examined in the following sections.

1. Effluents and Emissions of OCS Oil and Gas Development

Potential water pollutants resulting from the development of OCS oil and gas reserves include drilling muds, drill cuttings, and brines. Oil additions into marine and estuarine waters are discussed in Section V-E (Petroleum Discharges).

a. Drilling Muds

Drilling muds lubricate the drill cutting head, counterbalance the pressures of subsurface brines (high-salinity waters), and raise cuttings to the surface. They consist of a mixture of naturally occurring and manufactured chemicals, having a viscosity and weight suitable for circulation around the drill string.

The amount and composition of mud used to drill a well is specific for each well. According to a Bureau of Land Management (BLM) estimate, on the average approximately 656,000 pounds (328 tons) of mud components are needed to drill a 10,000-foot well and an additional 728,000 pounds (364 tons) are needed to drill a 15,000-foot well (U.S. Dept. of Interior 1974a, 1974b).

The potential biological impacts of these muds are a function of the volumes, components, and rates of mud disposal into the marine environment. These parameters are difficult to determine accurately, however. The barite in drilling muds is an expensive mineral, so it is reused, while non-barite components are usually discharged overboard (Shinn 1974b). An infrequently used method is to treat all of the mud and reuse it as packing fluid in the well (U.S. Dept. of Interior 1974b). When cuttings are mechanically separated from mud and disposed overboard, some mud is lost. Estimates of mud additions to the environment must consider both current and projected mud-use practices and the efficiencies of methods used to retain and recirculate muds.

Recent estimates by BLM (U.S. Dept. of Interior 1974b) indicate that 100,000 tons of drilling muds would be dumped into the Gulf of Mexico near Louisiana during the drilling of 900, 10,000-foot wells. BLM notes the following physical effects of this disposal: the reduction of light penetration and probably photosynthetic processes in water adjacent to the outfall, smothering of some benthic invertebrates, and interference with respiration and feeding of gill-bearing and filter-feeding animals. Although no studies are cited by BLM in support of

these statements, such effects are probable in the mid-Atlantic OCS since similar impacts occur in shallow water during dredging (for these effects due to dredging, see Section V-A). The overall impact of increased suspended solids offshore is probably not major because potential reductions in species diversity or productivity would be localized and small in relation to the entire mid-Atlantic OCS region.

The components of drilling muds will vary with the pressures and substrates encountered while drilling. Many of the drilling mud components from three land-based drilling sites in the Mackenzie Delta, Northwest Territory, Canada, were tested for acute toxicity by Falk and Lawrence (1973). These tests were performed using rainbow trout, lake chubs, and ninespine sticklebacks as test organisms for 96-hour LC_{50} bioassays. Whole drilling fluids resulted in LC_{50s} between 3.55 and 12.0 percent, or 35,500 to 120,000 parts per million (ppm). Results of laboratory bioassays by Logan et al. (1973) in conjunction with the above field studies indicated that the 96-hour LC_{50} of the mud components ranged from above 10,000 ppm ("practically non-toxic") to less than 100 ppm ("toxic"). Table V-4, developed from data by Logan et al. (1973), summarizes the results of the laboratory bioassays on rainbow trout. One of the most important conclusions from the Logan bioassay study is that the toxicity of whole drilling mud can be calculated from the toxicity of the relative proportions of its components. Therefore, the toxicity of drilling mud effluents released into the environment can be estimated if accurate records are kept of the components and their proportions.

b. Drill Cuttings

Drill cuttings are the thumb-nail sized chunks of rock brought to the surface by the drilling process. BLM Publication DES 74-90 (U.S. Dept. of Interior 1974a) indicates that approximately 1,153 tons of cuttings will be dumped into the ocean for each well (15,000-foot depth). Sub-surface clay and sand brought to the surface will probably be incorporated into drilling muds since separation techniques would probably be ineffective. Again, as with drilling muds, any oil contaminating the material to be dispersed would have to be reduced, in accordance with regulations, to an average level of 50 ppm and a maximum level of 100 ppm.

Table V-4

Toxities of Some Common Drilling Mud Components to Rainbow Trout (*Salmo gairdneri*)

Component	Trade Name	Toxicity (LC_{50} in ppm)
Gypsum		>56,000 ppm
Bentonite		>10,000 ppm
Sodium carboxymethylcellulose	CMC (regular)	>10,000 ppm
Sodium carboxymethylcellulose	CMC (HiVis)	>10,000 ppm
Calcium chloride		>10,000 ppm
Barite		> 7,500 ppm
Sodium bicarbonate		7,550 ppm
Sulfonated triglycerides, aliphatic alcohols, isopropyl alcohol	Torq-trim	2,270 ppm
Potassium chloride		2,020 ppm
Ferrochrome lignosulfonate		1,530 ppm
Sodium acid pyrophosphate	S.A.P.P.	870 ppm
Potassium chromium sulphate	Chromalit	730 ppm
Polyvinyl acetate, maleic anhydride	Ben-Ex	665 ppm
Long chain organic polymer	Kelzan XC	440 ppm
Not available	Metso Beads	330 ppm
Sodium hydroside (caustic)	Celanese	105 ppm
Capryl alcohol		83 ppm
Dihydroxypropane, inorganic salts, tall oil soaps, alkyl aryl sulfonates	Tricron	63 ppm
Paraformaldehyde		60 ppm
Mixed alcohols	Skot-free	52 ppm
Not available	Swift's Rig Wash	22 ppm
Not available	B-Free (10-day LC_{50})	7.5 ppm
Not available	Cominion Rig Wash	14 ppm
Organic polymer*	SS-100	>1,000 ppm
Organic polymer*	FLR-100	>1,000 ppm
Organic polymer*	Statflo	>1,000 ppm

* Preliminary bioassays only - LC_{50} not definitive.
Source: Adapted from Logan et al (1973).

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The fate of drill cuttings, when dumped from an oil platform, is difficult to determine. These small pieces of rock settle to the bottom more quickly than the less dense clay and sand particles. Although currents disperse the rock during its descent to the bottom, a mound of rubble collects under and around the platform.

Shinn (1974) indicated that in the Gulf of Mexico these mounds of rock provide a suitable substrate for a wide diversity of invertebrate organisms. Parker (1975) and Nagle (1968) have shown that such hard-substrate invertebrate communities may be more diverse and abundant than local surface-sand and silty-sand communities.

The rubble mounds would thus appear to enhance the reef effect created by the fixed oil rig. Lobsters (*Homarus americanus*) may inhabit rubble mounds near the OCS if they can create caves in them. Smith (1972) described the attraction of fishes to even very low-relief features on the nearshore OCS. Although the stimuli which attract fishes to breaks in the rather smooth shelf floor are not fully known, shelter from predators and greater abundance of food are good hypotheses.

c. Brines

A pollutant associated with pumping oil is subterranean brine. This liquid is brought to the surface with the oil, separated out on the platform, and sometimes disposed of in the ocean. BLM Publication DES 74-90 (U.S. Dept. of Interior 1974a) indicates that typical production wells may produce 75 barrels (bbl) per day of brine which can contain 61,000 to 270,000 ppm of dissolved salts. It has been estimated that the median concentration value of salts is greater than 150 parts per thousand (ppt) compared with an average OCS ambient saltwater concentration of 32 to 35 ppt (Bumpus et al. 1973).

If 24 wells were developed from each platform, all brines discarded overboard, and disposal values converted to hourly rates, then approximately 75 bbl of brine per hour containing five times more salt than ambient seawater would be dumped from each platform.

At present, there are few studies of the effects of elevated salinities on marine organisms. Fluid loss is generally experienced by animals placed in an environment of higher salinity because the osmoregulatory mechanism does not function at a sufficient rate. Studies involving freshwater fishes--fathead minnow (*Pimephales promelas*),

mosquitofish (Gambusia affinis), green sunfish (Lepomis cyanellus), red shiner (Notropis lutrensis), blind bullhead (ictalurid), largemouth bass (Micropterus salmoides), white crappie (Pomoxis annularis), bluegill (Lepomis macrochirus), and channel catfish (Ictalurus punctatus)--have shown that the median toxicity threshold for these species ranges from 11.2 to 4.2 percent by volume of brines containing 200 ppt dissolved solids (Wilber 1969). Since they are already adapted to a concentration of 35 ppt of dissolved salts, it is possible that marine organisms can withstand higher concentrations.

To avoid possible adverse effects of the brine upon marine biota, methods, such as the use of high-pressure discharges, should be devised to assure rapid dilution. This would reduce the remote chance of the brine settling to the ocean bottom in a mass due to its greater density. The lack of detailed knowledge about the effect of brines on marine organisms, and the absence of data concerning their dilution rate, indicate that further study is necessary before a confident assessment of their biological impact can be made.

2. Effluents and Emissions of FNPs

The major effluents associated with the operation of nuclear power plants are waste heat, radionuclides, chemicals and biocides, and solid wastes. With the exception of radionuclides, these effluents are similar to those associated with the operation of any type of power plant, including conventional fossil-fueled stations.

a. Waste Heat Discharges

The volume of heated water discharged from a typical FNP will be approximately 1,000 cubic feet per second (cfs) at a temperature elevated 17 degrees F above the ambient water. Additionally, approximately 150 cfs at a ΔT[1] of 10 degrees F are discharged from the service water system. The combined total of approximately 1,150 cfs at a ΔT of 16 degrees F will be discharged with a velocity of approximately 12 ft/sec.

The proposed Atlantic Generating Station (AGS) will utilize a surface jet discharge system that releases heated effluent at a high velocity parallel to and at the water surface. This type of discharge

1. ΔT: change in temperature, usually given as the amplitude of thermal elevation above ambient temperatures.

was chosen for both ecological and economic considerations. The factors that affect the dispersal of a surface plume in coastal waters (velocity and depth of discharge, depth of substrate, and others) vary for all FNPs depending on site-specific conditions.

To predict both specific and general ecological effects of such thermal effluents, the rate of heat dissipation, the size of the affected area, the extent of various isotherms,[2] and the ΔT must be determined. These parameters, when related to the results of biological studies, should provide a basis for predicting biological responses of aquatic populations in the affected areas. For example, computer simulation models of the proposed AGS thermal plume suggest that the area enclosed by the isotherm that is 2.5 degrees F above the ambient temperature, is 30 acres if no natural currents are present. This area decreases rapidly in the presence of currents (PSE&G 1974). Predictions of the biological effects of the heated discharge from an FNP are primarily based upon the small size of the thermal plume relative to the size of the Atlantic Ocean on the continental shelf.

There is much laboratory data on the effects of elevated temperatures on organisms occupying various trophic levels. These data can be used to predict the effect of the thermal plume on phytoplankton, zooplankton, and fishes. Little effect is anticipated, however, primarily because of the small size of the thermal plume relative to the surrounding coastal system.

Behavioral studies suggest that most fish will avoid lethal temperatures in thermal plumes, either because of the high temperatures or the high velocities in the areas of high temperatures. However, if fish were somehow trapped in water with high temperatures, they would undergo both behavioral and metabolic changes (Pearce 1974).

Additionally, during winter migrating fish could be attracted to and remain in the heated discharge from an FNP rather than continuing south. Fish kills due to cold shock could occur if the plant experienced a shutdown during those times. Fish kills of this nature have occurred at onshore stations.

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2. Isotherm: area where temperatures are similar.

Winter fish kills may be avoided in an FNP if two discharge units are built and one of them is kept in operation at all times. Further, the temperature increases in the plume may not be sufficient to cause cold shock because of the discharge dilution. In any event, fish kills are a potential impact which is recognized and can be avoided by design and operational constraints on the FNP.

Beneficial effects of an FNP breakwater will probably be enhanced by interactions with the thermal plume (see Section V-B, The Reef Effect). Heated effluents are often associated with increased harvest of fish by anglers, especially during the winter. The combination of the reef effect and the warm water may significantly increase the standing crop of game-fish species in the vicinity of an FNP.

b. Radionuclides

There is some discharge of radionuclides from all operating nuclear power generating stations. Standards concerning allowable discharge quantities and acceptable radiological doses to various segments of the human population have been established by the International Commission on Radiological Protection (ICRP), the National Commission on Radiological Protection (NCRP), and the U.S. Nuclear Regulatory Commission (USNRC). Generally, the doses resulting from allowable discharges are limited to a very small percentage of that attributable to ambient background radiation. Allowable annual dosage is 500 millirem (one-thousandth of a roentogen equivalent man) for an individual in the population but only 170 millirem for the average of all individuals in the population. However, since the USNRC imposes a "low as practicable" operational limit on discharges and defines this to be five millirem per year, the resultant doses are far less than one percent of the natural background. None of these exposure limits would theoretically preclude the use of FNPs in the coastal zone.

Regulations concerning maximum permissible concentrations of radionuclides in marine environments are intended to prevent the dose limits of 5 millirem from being exceeded. These maximum permissible concentrations take into account the uptake of radionuclides by aquatic organisms either directly or via the food chain. The rationale behind these assumptions suggests that by imposing these low limits of exposure (both internal and external) to humans, other organisms, lower in the food chain, will also be protected.

Exposure to radiation occurs when organisms come into contact with some source of radiation. Fish and other aquatic organisms inhabiting receiving waters with radionuclides and feeding upon food from such waters are normally exposed to minute levels of radiation. In all cases, the projected doses are given as fractions of ambient background levels. It is unlikely that there would be any detectable effects on biota resulting from levels of these magnitudes.

c. Chemicals and Biocides

In addition to waste heat and radionuclides, certain chemicals will be discharged with power plant effluents. These chemicals originate primarily from the treatment of cooling water systems to prevent corrosion, mineral deposition, and biofouling. Other chemicals which could be used in the reactor coolant system are neutron absorbers (boron compounds), corrosion inhibitors (lithium hydroxide), and oxygen scavengers (hydrazine). A chemical laboratory aboard the FNP would use a variety of reagents. The majority of these chemical reagents would be disposed of off-site via solid and liquid waste disposal systems, although some will be discharged directly via the condenser cooling water system.

1) Chlorine

Chlorine will be used for biofouling control at FNPs (USNRC 1975). Biofouling of power plant cooling water systems involves the coating of various structures by a variety of aquatic organisms, micro- to macroscopic in size. Mussels, barnacles, and other encrusting organisms colonize the hard substrates provided by intake canals, trash racks, and the conduits that carry cooling water to the condenser. This incrustation increases both the friction and the pumping power required to supply the cooling water. Bacterial slimes also grow on the inside of condenser tubing and significantly reduce the heat exchange capacity of the condenser. If such biofouling continues, the cooling system efficiency is eventually reduced to a point where the unit must be shut down for mechanical cleaning.

To prevent costly shutdowns and mechanical cleaning, chlorine is commonly added to the intake water to prevent the buildup of fouling organisms. Two major methods of chlorine application are utilized, continuous and intermittent. Continuous application involves the addition of a sufficient amount of chlorine to the cooling water to maintain an effective residual concentration, thus preventing the accumulation of

fouling organisms upon treated surfaces. Intermittent application involves the addition of periodic doses of chlorine to kill any organisms that may have become established since the previous application (Cole and Baker 1973). The amount of chlorine added and the time interval between applications are a function of two opposing factors. The chlorine concentration to which fouling organisms are exposed must be sufficient to cause mortality or inhibit settling on the intake structures. At the same time, residual concentrations must be small enough to prevent ecological damage in the discharge area.

To satisfy the requirements of both of the above factors, the capacity of cooling water to chemically bind chlorine must be determined. This capacity is referred to as the chlorine demand and it depends upon the pH of the water; its organic, inorganic, and ammonia content; and the time involved between application and organism exposure.

The effectiveness of both the chlorine added at the intake and the residual chlorine in the discharge are a function of chlorine demand, pH of the water, and time of exposure. When added to water, chlorine immediately dissociates to hypochlorous acid. This product is an effective disinfectant, but it further dissociates to free hydrogen and hypochlorite. The hypochlorite is also a disinfectant, but not as effective as hypochlorous acid. The ratio of hypochlorous acid to hypochlorite is a function of the pH of the water. Hypochlorous acid, referred to as available chlorine, is further reduced by ammonia, inorganic salts, and other organic materials. The last two categories of reducing agents are, in turn, reduced by hypochlorous acid into non-disinfectant products. However, when ammonia is reduced by hypochlorous acid it forms chloramines. Chloramines, while not as effective as hypochlorous acid, also have disinfectant properties. Chloramines are more persistent than the other chlorine forms and thus remain toxic for longer periods of time.

In the offshore environment, mussels, barnacles, and hydroids will likely be the cause of fouling in power plant cooling water systems. Several studies indicate dosages necessary to control biofouling by these organisms. Constant exposure to 2.5 ppm of chlorine kills exposed mussels in 5 to 8 days. Chlorine concentrations of 1.0 ppm for 15 days did not affect barnacles or sea anemones, but 10.0 ppm for one hour per

day killed all tunicates and bryozoa. The same concentration (10.0 ppm) killed some mussels and anemones exposed for eight hours per day, and some barnacles exposed for four hours per day (Becker and Thatcher 1973). In contrast, Cole (1964) suggested that 100 percent control of marine biofouling can be achieved by continuous chlorination at 0.15 to 0.5 ppm residual chlorine.

The concentrations of chlorine necessary to control marine biofouling organisms are higher than existing U.S. Environmental Protection Agency (USEPA) recommendations for permissible discharge concentrations. These recommendations cover both the application (at or near the intake) and permissible residual (at the discharge) levels. The current recommended application factor for seawater treatment is 10 percent of the amount that is found to kill half of the test animals (most sensitive species to be protected) during exposure over a 96-hour bioassay period. At the present time, no definite recommendation exists for the permissible amount of free residual chlorine in seawater discharges. However, concentrations in excess of 0.01 ppm have been suggested to be harmful to marine biota (USEPA 1973). Brungs (1973) has suggested maximum concentration limits for both continuous and intermittent treatment schedules:

(1) In areas receiving wastes treated continuously with chlorine, total residual chlorine should not exceed 0.01 ppm for the protection of the most resistant organisms, or not exceed 0.002 ppm for the protection of most sensitive organisms.

(2) In areas receiving wastes treated intermittently with chlorine, total residual chlorine should not exceed 0.2 ppm for a period of 2 hours per day for the protection of the most resistant organisms (lower concentrations are recommended for areas containing trout and salmon. However, this does not apply to the mid-Atlantic continental shelf).

The antifouling system for the proposed AGS will consist of continuous application of enough chlorine to maintain a concentration of 1 ppm of chlorine within the water systems. The concentration in the discharge

area is not expected to exceed 0.5 ppm and is expected to average 0.1 ppm or less (PSE&G 1974).

Alternative methods to control marine biofouling involve surface treatments such as toxic coatings, physical abrasion, heat treatments, and increased water velocities to retard settlement and growth on exposed surfaces. Available alternatives are currently not used because of the technical and environmental difficulties associated with their use on FNPs.

2) Other Chemical Effluents

Chromates will be used in FNP service water systems as a biocide and corrosion inhibitor. Unlike chlorine, this material will not be intentionally discharged into the environment, but will be collected and disposed of onshore. There is a possibility, however, that a leak could develop, resulting in loss of chromate to the environment. In the event of such a leak, the discharge surveillance system on the AGS will detect as little as 0.01 ppm. Before discharge, this concentration would be diluted to 0.1 ppb. This predicted concentration of chromate in the plant effluent is well below the EPA recommendations for permissible chromate concentrations in marine effluents.

Some heavy metals will probably be present in FNP effluents as a result of corrosion. Typical metals such as iron, copper, and nickel, however, are all discharged, under normal operating conditions, at concentrations well within EPA recommendations for drinking water.

3) Sanitary Wastes

Sewage treatment facilities will also operate aboard the FNP. EPA recommendations on the discharge of sewage effluents are based upon the permissible buildup of such materials in receiving water. Primary concern is that the assimilative capacity of the system is not exceeded and that the available oxygen supply is not depleted. The amount of nutrients in the treated effluent that an FNP would typically discharge would not be expected to degrade the surrounding waters. The addition of these nutrients would also interact with the surface growths on the breakwater and thus promote the reef effects discussed in Section V-B (The Reef Effect).

Sludge resulting from the onboard treatment of sewage on an FNP will usually be incinerated. The incineration of a probable 100 pounds of

sludge per day will result in 3,000 cubic feet of exhaust gas, which will have no appreciable effect on the air quality in the offshore area.

4) Platform Drain System

Any water exposed to such oily surfaces as deck drains, water-tight compartments, and turbine halls will be collected and processed to remove oil before being discharged through the circulating water system. The resultant effluent from a typical FNP will probably contain less than 10 ppm of oil. This concentration is well below the EPA recommendation of 50 ppm for surface waters. The separated oil will be stored and removed periodically from the FNP site.

d. Solid Wastes

Debris from the intake screens and other solid and semi-solid refuse will be collected, compacted, and removed for offsite disposal. For this reason, trash disposal should not cause any biological degradation at the site.

3. Effluents and Emissions of Deepwater Tanker Port Operations

The principal effluents associated with deepwater tanker ports are various forms of petroleum. The biological impacts of oil additions to marine and estuarine waters are discussed in Section V-E (Petroleum Discharges).

Of the three deepwater port designs, the monobuoy installation would have the least non-oil effluents and emissions. This unmanned port would not require support facilities for operators and thus would not have potential sewage treatment plant effluents that an offshore artificial island or sea pier might require.

The manned artificial island port or sea pier would also have power requirements which would most likely be met with some onsite electric generating facility. Since such a generating facility would be modest in size, the potential impact from the plant's effluents or airborne emissions would be expected to be limited.

Any requirement for the use of seawater at the port facilities would also most likely require a chlorination system to prevent fouling of the seawater system. This operation would result in the additional discharge of chlorine. However, the impact of this discharge should not be too great since it is not anticipated that large volumes of seawater would be required.

Overall, the principal effluents from deepwater tanker ports are petroleum-based materials. Only limited environmental impact is anticipated from the release of non-oil effluents and emmissions.

E. PETROLEUM DISCHARGES

1. Introduction

The potential development of oil reserves and the construction of deepwater ports in the offshore and coastal areas makes it important to understand the effects of petroleum on organisms and biological communites which might be affected by accidental spills. Further, to reduce the likelihood of possible petroleum spillages and the damage they could cause to coastal and marine environments, preventive practices and emergency control plans are being developed.

2. Sources of Spills

Petroleum is introduced into the coastal and marine environments from various sources. Tables V-5 and V-6 give various estimates of the annual world input of petroleum. Inputs from marine transportation and offshore oil production have been subtotaled to show the percentage of the total input attributable to the activities addressed in this report. There is considerable variation in these estimates. However, they are presented only as a frame of reference to evaluate the biological effects of petroleum discharges from deepwater port operation and offshore production.

It is probable that some petroleum releases will occur in the New Jersey and Delaware coastal and offshore environments during the exploration and production phases of the proposed mid-Atlantic Outer Continental Shelf (OCS) oil and gas development and during the operation of a deepwater port. Large releases could result from accidents such as: (1) tanker accidents and collisions, (2) blowouts of exploration and production wells, (3) broken pipelines, and (4) fire on production platforms. Some examples of major releases that have occurred are: (1) the Santa Barbara spill (blowout) off California in 1969, (2) the Chevron spill

Table V-5

Sources of Petroleum Discharges (million metric tons/yr)

Source	MIT SCEP Report (1970)	USCG Impact Statement (1973)	NAS Workshop (1973)
Marine transportation	1.13	1.72	2.133
Offshore oil production	0.20	0.12	0.08
SUBTOTAL	1.33	1.84	2.213
Coastal oil refineries[a]	0.30	--	0.2
Industrial waste[a]	--	1.98	0.3
Municipal wates[a]	0.45	--	0.3
Urban runoff[a]	--	--	0.3
River runoff[a,b]	--	--	1.6
Natural seeps[a]	?	?	0.6
Atmospheric rainout[a]	9.0[c]	?	0.6
SUBTOTAL	9.75+?	1.98+?	3.9
TOTAL	11.08+?	3.82+?	6.113

a. Sources of petroleum discharges not addressed in this assessment.
b. Input from recreational boating assumed to be incorporated in the river runoff value.
c. Based upon assumed 10 percent return from the atmosphere.

Source: Adapted from NAS 1975.

Table V-6

Input Rates for Sources of Petroleum Discharges
(million metric tons/yr)

Source	Point Estimate	Interval Estimate	Original Reference
Offshore production	0.08	0.08-0.15	Wilson et al. (1973)
Transportation			
LOT tankers	0.31	0.15-0.4	
Non-LOT tankers	0.77	0.65-1.0	
Terminal operations	0.003	0.0015-0.005	
Bilges bunkering	0.5	0.4-0.7	
Tanker accidents	0.2	0.12-0.25	
Nontanker accidents	0.1	0.02-0.15	
SUBTOTAL	1.963		
Dry docking[a]	0.25	0.2-0.3	
Natural seeps[a]	0.6	0.2-1.0	Wilson et al. (1973)
Coastal refineries[a]	0.2	0.2-0.3	Brummage (1973a)
Atmosphere[a]	0.6	0.4-0.8	Feuerstein (1973)
Coastal municipal wastes[a]	0.3	--	Storrs (1973)
Coastal, nonrefining industrial wastes[a]	0.3	--	Storrs (1973)
Urban runoff[a]	0.3	0.1-0.5	Storrs (1973), Hallhagen (1973)
River runoff[a]	1.6		Storrs (1973), Hallhagen (1973)
SUBTOTAL	4.15		
TOTAL	6.113		

a. Sources of petroleum discharges not addressed in this assessment.

Source: Adapted from NAS 1975.

(blowout) from Platform C in the Gulf of Mexico in 1970, (3) the West Falmouth spill (tanker grounding) off Massachusetts in 1969 and (4) the Torrey Canyon spill (tanker grounding) off Great Britain in 1967. Refer to Table C-1 in Appendix C for estimates of amounts of petroleum lost into the environment from these accidents and others.

Petroleum may also enter the marine and estuarine environment by much less spectacular means. Small releases can occur during both the production and transportation of petroleum. Major sources of discharges from the former are drilling muds and cuttings, bleedwater effluents, and routine machinery operation and pipeline leakages. Examples of discharges from the latter are deballasting, bilge cleaning, bilge pumping, and cargo transfers.

Many of the effects of major and chronic additions of petroleum to the coastal and marine environments are not completely understood. The following sections address some of the problems of defining and predicting the damage of petroleum discharges on organisms, communites, and habitats.

3. Biological Research on Oil Pollution

a. Research Efforts to Date

Several studies have addressed the biological consequences of spilled petroleum from offshore oil production and deepwater port operation in the Atlantic region: the Massachusetts Institute of Technology Offshore Oil Task Force (MIT 1973), the Council on Environmental Quality (CEQ 1974), Maurer (1974), and the National Academy of Sciences (NAS 1975). All four studies extensively discuss the available research on the effects of previous oil spills, and the results of laboratory and field work.

The MIT (1973) study addressed the impacts of petroleum development in the Georges Bank region. The CEQ (1974) study addressed the impacts of petroleum development in the Atlantic and Alaskan Outer Continental Shelf. Maurer (1974) projected the biological impacts at several deepwater tanker port sites in and near Delaware Bay, with oil being a major aspect of the projection, and the NAS (1975) report summarized a 1973 conference

on the fate and effects of petroleum in the marine environment.

The NAS (1975) report and the MIT (1973) study compiled several tables to illustrate and summarize research available on the biological effects of petroleum. These tables are presented in Appendix C. Table C-1 (NAS 1975) in Appendix C is a summary of 15 major oil spills which occurred during the period 1960-1971, and the scientific observations of the biological damage they caused. The majority of these studies were qualitative in nature and examined only the subtidal and intertidal zones along the shore. The reports showed varying degrees of damage and of recovery time to plants, invertebrates, fish, and waterfowl subsequent to oil contamination.

Tables C-2 through C-9 (MIT 1973) in Appendix C summarize research on the toxic responses to oil by selected marine flora and fauna, including embryonic and larval stages. The intent of the MIT (1973) study was to utilize these specific toxicity responses in their modeling efforts to predict the impact of petroleum discharges on the biota of the Georges Bank. However, because of insufficient data on the biological responses to petroleum of relevant aquatic species, it was decided that this model would be unfeasible. The report, however, does evaluate the research that has been done on the biological effects of oil pollution and begins the task of relating present knowledge to a specific contaminant in a specific region.

Maurer's report relates present knowledge on oil pollution to siting criteria for deepwater ports.

Table C-10 (NAS 1975) in Appendix C is a tabulation of available research on the sublethal effects of petroleum on organisms. Research on the effects of oil on reproduction, growth, metabolic processes, behavior, and histologic conditions of various organisms are summarized and evaluated.

One of the common conclusions of these literature evaluations is that there are still important gaps in our present knowledge of the effects and fate of petroleum in the marine environment. Many studies have investigated the biological

responses to oil and data exist on responses to specific spills. However, the overall impact of oil is still not totally understood because few comprehensive, systematic studies of the problem have yet been attempted (NAS 1975, MIT 1973).

It is the opinion of Moore (1973) that the inadequacies of past research prevent comparison of different studies because of a lack of comparable methods, accurate measurement of the concentrations and composition of the crude petroleum in solution during the experimentation, and accurate measurement of the concentration and composition of fractions of crude petroleum in the bodies of the tested plants and animals.

b. Suggested Future Research

The NAS (1975) study suggested that the framework of future oil spill studies should be interdisciplinary, and attempts to identify water chemistry and sediment composition changes, and sediment transport mechanisms. Biological studies should consider both plants and animals in the various habitats which may be contaminated by oil. If before-the-spill data is not available, control areas should be studied which are geographically and biologically similar to what the spill site was before oil contamination.

Several other research topics are suggested in the previously cited literature as being critical to understanding the oil spill impact process. For example, before determination and prediction of the influence of oil, the natural functioning and stress responses of ecosystems must be known. There must also be more ecological research into the productivity, diversity, stability, and predictability of individual ecosystems. Further, a better understanding of the influence of abiotic (temperature, light, salinity, etc.) and biotic (interaction of organisms with their own species and other species) factors on natural biological variation and relative organism abundance also seems to be necessary.

It is further suggested in the previously cited literature that it is necessary to identify and describe the

populations inhabiting the marine regions that are in potential danger from sources of spilled petroleum. In this regard, the estuarine and coastal regions of New Jersey and Delaware are more adequately described biologically than the mid-Atlantic offshore region (See Chapter IV, Description of the Study Area).

There are two most probable reasons for the more adequate knowledge of inshore versus offshore regions along the New Jersey-Delaware coasts. One is the accessibility of inshore regions for research efforts. Second, technological development has until recently been restricted to the inshore areas and is only now extending into the mid-Atlantic offshore regions. The CEQ (1974) study and the University of Rhode Island Coastal Inventory (URI 1973) both include descriptions of the mid-Atlantic environment and indicate areas where information is inadequate. Because this lack of biological information concerning the mid-Atlantic offshore region has been recognized, a number of research studies are now in progress which are attempting to fill this gap before oil and gas development begins (See Table C-11 in Appendix C).

An additional requirement for assessing environmental impacts of oil pollution is the identification of the specific ways that petroleum wastes degrade biological systems. Several research topics are identified in the NAS (1975) study which are considered to be critical to understanding the impact of oil on ecosystems. These include: (1) the rate of oil degradation in subtidal sediments, (2) the specific toxicities of various constituents of oil, (3) the transport and fate of various components of different oil types in the food web, (4) the mechanism of incorporation of petroleum products into the food web, and (5) the effectiveness of present cleanup methods.

In summary, considerable data are available in the literature concerning the effects of petroleum and petroleum products on the marine and coastal environments. However, there are serious limitations in the data which restrict our ability to understand fully the entire oil impact process. Research efforts are now beginning to separate naturally induced

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changes in organisms and populations from oil-caused changes, to standardize methods of research and reporting of results, to quantify the effects of oil polluting, and to fill in the gaps in understanding the oil impact process. Results of such research should make it possible to propose more realistic alternatives for the siting and implementation of technological development where oil spills are potential environmental problems.

4. The Biological Effects of Oil

a. Introduction

Although it is difficult to quantify the biological changes which result from the additions of petroleum and petroleum products to the environment, there is some qualitative understanding of the factors which influence the severity of a spill and the susceptibility of certain habitats and organisms to the impacts of petroleum. This qualitative knowledge can be used to identify the conditions which might cause the most severe damage, protect the most sensitive regions and biological communities, and develop procedures and alternatives which can reduce the impact of petroleum spills.

b. Factors Influencing the Effects of an Oil Spill

The ultimate fate of spilled oil and the magnitude of its impact on biota are influenced by physical, biological, and cleanup method factors. These factors can determine whether the impact of oil results in severe and long-lasting, intermediate, or relatively undetectable biological damage to the affected area.

1) Physical Factors

a) Types and Concentrations of Oil

The concentration of oil to which an animal is exposed is determined by a number of variables. The actual volume of oil released is one of the most important variables. Another variable is the volume of water affected; large bodies of water offer a greater potential for dilution, thereby decreasing the localized concentration of oil (NAS 1975). Thus, organisms in shallow, confined bodies of water such as estuaries and embayments are likely to be exposed to more toxic concentrations

of oil than are animals in the open ocean (Rose 1974, Revelle et al. 1971).

Tables C-8 and C-9 in Appendix C present percent compositions, solubility, and estimated toxicities of various petroleum products. Table V-7 shows a breakdown of different oils into their various fractions to illustrate the number of oil products that could go into solution and the number that could contain soluble, aromatic hydrocarbon derivatives--the highly toxic fractions of oil compounds. Table V-8 shows the concentrations of soluble aromatic hydrocarbon derivatives that experimental data have indicated are toxic to various types of organisms.

Table V-8 also summarizes the literature reviewed by Moore (1973) (See Tables C-2 to C-9 in Appendix C). The minimum toxic concentrations of soluble aromatics given in Table V-8 are only estimates of the concentrations required to cause toxicity to the various groups of organisms shown. Moore stated that because of the fragmented nature of the available evidence, these toxic concentrations may vary by a factor of ten. Moore felt that one important conclusion of his evaluation was that the fractions most toxic to organisms were the lower-boiling aromatics (a lower boiling point corresponds to higher solubility in water). Moore also suggested that the toxicities of other fractions (low molecular weight paraffins, heterocyclic compounds, and higher molecular saturated compounds) are of less concern because of the low concentrations usually found in petroleum, and the low water solubilities which would reduce the amount of these substances available to produce toxic effects in the marine environment.

b) Oceanographic Conditions

Oceanographic conditions such as wave action, water currents, and coastal formations can also influence the chemical and geographical fate of the spilled oil. Wave action and water currents can effectively reduce the concentration and toxicity of oil by dilution, dispersion, increased volatilization, and emulsification (NAS 1975). Water currents and coastal formations can determine whether oil is carried into open waters

Table V-7

Estimated Percent Composition (by weight) and Comparison of Solubilities for Various Petroleum Substances

Fraction	Description	Crude A (Heavy)	Crude B (Medium)	#2 Fuel Oil	Kerosene[c]	Residual
1	Low boiling paraffins	1	10	15	15	0
2	High boiling paraffins	1	7	20	20	1
3	Low boiling cyclo-paraffins	5	15	15	20	0
4	High boiling cyclo-paraffins	5	20	15	20	1
5	Mono- and di-cyclic aromatics	2	5	15	15	0
6	Polycyclic aromatics	6	3	5	2	1
7	Naptheno-aromatics	15	15	15	8	1
8	Residual	65	25	--	--	96
Estimated maximum % soluble		10	30	60	65	1
Estimated maximum % soluble aromatic derivatives		0.1-10	0.1-10	1-30	1-20	0-1
Reported % soluble aromatics obtained in seawater extracts		0.1[a]	0.01[b]	0.1[a]	0.01[b]	

a. Medium crude extract, Kuhnhold 1970.
b. Kuwait and kerosene extracts, Boylan and Tripp 1971.
c. Table values for BP 1002 would be similar to kerosene.

Source: Moore 1973.

Table V-8

Toxicities of Soluble Aromatics

Class of Organisms	Estimated Concentration (ppm) of Soluble Aromatics Causing Toxicity	Estimated Amount (ppm) of Petroleum Substances Containing Equivalent Amount of Soluble Aromatics	
		#2 Fuel Oil	Fresh Crude
Flora	10 - 100	50 - 500	10^4 - 10^5
Finfish	5 - 50	25 - 250	10^4 - 10^5
Larvae (all species)	0.1 - 1.0	0.5 - 5	10^2 - 10^3
Pelagic crustaceans	1 - 10	5 - 50	10^3 - 10^4
Gastropods (snails)	10 - 100	50 - 500	10^4 - 10^5
Bivalves (oysters, clams, etc.)	5 - 50	25 - 250	10^4 - 10^5
Benthic crustaceans (lobsters, crabs, etc.)	1 - 10	0.1 - 10	10^3 - 10^4
Other benthic invertebrates (worms, etc.)	1 - 10	5 - 50	10^3 - 10^4

Source: Moore 1973.

or into confined waters where the impacts might be greater (NAS 1975).

c) Meteorological Conditions

Meteorological conditions can either reduce or intensify the effects of spilled oil by determining its destination and rate of dilution. Wind-driven storm waves may drive oil slicks into confined areas such as estuaries, small embayments, and inlets, thus intensifying the effects of oil (NAS 1975). For example, in the West Falmouth spill, oil in solution and wind-dispersed oil droplets bypassed the barriers used to seal off the harbor areas. As a result of adverse weather, containment was ineffective and considerable biological damage resulted (Blumer 1971). On the other hand, storms can have a positive effect if the spill occurs in the open ocean or if there is a strong offshore wind. An offshore wind tends to push the oil further from the coast.

Storms can also increase water turbidity which in turn can have a significant effect on the fate of spilled oil. The surfaces of small suspended particles absorb and trap the oil. This oil-sediment flocculant then settles to the bottom. Although this process hastens dispersal and starts biodegradation before the oil reaches the beach, there can be an effect on bottom organisms, (Blumer et al. 1971, cited by NAS 1975). Damage by this process to commercial beds of oysters (if oil reaches estuaries), scallops, and clams in the offshore bottom has been reported (Blumer 1971, Boesch 1973).

2) Biological Factors

a) Habitat Sensitivity

The intensity of the effect of an oil spill, whether chronic or accidental, can be a function of the type of habitat it reaches. Habitat types found in the New Jersey and Delaware coastal regions are discussed below with respect to oil spill effects.

A habitat which is likely to be affected by spilled oil is the intertidal area, which included sandy beaches, mud flats, and *Spartina* spp. marshes. The intertidal area is that area between the mean high-water mark and the mean low-water mark. Organisms in this habitat are subjected to a variety of natural stresses,

including alternate exposure to air and immersion in water, rapid variations in temperature, and changes in salinity (NAS 1975). Although organisms in this habitat are generally more tolerant of natural environmental changes than organisms in more stable habitats, the effects of oil are increased because of the physical characteristics of the habitat. For example, an ebbing tide leaves small pools of water in which oil can be stranded. The concentrations of oil in these pools can be high during the several hours of low tide. The biota living in these pools are then subjected to increased levels of toxic substances. Evaporation can release the low-boiling fractions and reduce the toxicity of the oil, but a tarlike residue remains which can smother some organisms. When the tide rises, the remaining oil fractions which have not been volatilized are often pushed further up the beach (NAS 1975).

Oil on sandy substrates may percolate downward and affect the organisms that reside in the interstices of the sand grains. Spills which become trapped in sandy substrates can have extended effects if the affected sediment is transported by waves or currents to unaffected areas along the shore or into the subtidal region (NAS 1975).

Other areas where sediments may become soaked with oil are marshlands and estuarine mud flats. Cowell (1969) has shown that oil can have direct lethal effects on the flora and fauna of salt marshes. Burns and Teal (1971) have shown that different species can accumulate hydrocarbons and that oil can remain in sediments to a depth of at least 70 centimeters for at least a year. Severe oil spills can destroy marsh flora, which in turn could destroy the marsh and its dependent ecosystems (Baker 1971).

Oil deposited in marsh muds may be released at a later time and again affect the area. This is important since estuaries shelter vulnerable life stages of fish and shellfish. Although a spill might occur during a season of low biological activity, the oil could be released when the estuary is most active and could significantly affect the early life stages of estuarine organisms (NAS 1975).

Subtidal substrates can also be affected by oil in areas of

high turbidity by means of the settling of oil-soaked, suspended sediments (NAS 1975).

b) Species Sensitivity

The effect of oil on biological organisms depends on the sensitivity of the individual species. There are several distinct responses of organisms to spilled oil. The following five major categories of responses have been suggested by Moore (1973) (see Table V-9):

(1) Direct lethal toxicity--interference with cellular processes leading to death directly

(2) Sublethal disruption of physiological or behavioral activities--interference with cellular processes not leading to death directly

(3) Coating with oil--smothering or mechanical interference with cellular processes

(4) Tainting and/or accumulation in food chains--accumulation, especially of carcinogens, and tainting of édible organisms

(5) Changes in habitats--physical or chemical environmental alterations that cause changes in species composition and distribution.

The responses of organisms vary considerably according to the specific characteristics of the spill and the particular vulnerabilities of the impacted organisms. The following sections will discuss the general effects of oil on various assemblages of organisms. The general responses of phytoplankton, macroalgae, vascular plants, zooplankton, benthic organisms, fish, birds, and mammals are also included.

1. Phytoplankton, Macroalgae, and Vascular Plants

The role of plants in ecosystems is discussed in the presentation of basic ecological concepts

Table V-9

Effects of Oil on Organisms

Oil Fraction Causing Response	Effect	Response		
		Cellular	Physiological	Behavioral
Lower boiling aromatics	Direct lethal toxicity	X	X	
Lower boiling aromatics	Sublethal effects		X	X
Residual	Coating with oil		X	X
Possibly all fractions	Incorporation of oil into food webs	X	X	
Residual	Changes in habitat		X	X

Source: Moore 1973.

in Appendix A. Phytoplankton, macroalgae, and vascular plants are easily recognizable groups within the plant kingdom which may be impacted by spilled oil. Effects of oil on vascular plants and macroalgae are similar so that the two groups will be discussed together. The response of phytoplankton to spilled oil will be discussed separately.

A reduction in primary productivity, whether from damage to phytoplankton, macroalgae, or vascular plants, will have some adverse impact on the ecosystem. Substantial reductions at the producer level can often cause substantial reductions at higher trophic levels. Some reduction in primary productivity could occur without subsequent reduction at higher trophic levels if only a portion of the available plant material is normally utilized (Kormondy 1969).

Evidence of damage to plants due to spilled oil exists in the literature cited by NAS (1975). Data from other spills suggest that plants can survive some spills unharmed (NAS 1975).

The susceptibility of plants to adverse impacts due to an oil spill partially depends upon the degree of exposure to the oil. In this respect, most plants are at a disadvantage. With only a few exceptions, vascular plants and macroalgae are firmly attached to the substrate and cannot leave the affected area. Once the oil moves onshore, only those plants that remain below the tide line will remain unexposed. Phytoplankters are generally near the surface of the water, where they can be exposed to a surface slick. Since the same forces affect the movement of both oil and phytoplankton, exposure can last for extended periods.

The impacts on vascular plants and macroalgae are varied. Coating with oil can stop or severely limit such vital functions as photosynthesis, respiration, and reproduction. A slick of crude oil or heavy refined products can prevent sunlight from reaching submerged plants. Only rarely will such blockage occur long enough to have a noticeable effect. Direct coating of leaves and fronds can have the same effect but often lasts longer. Certain macroalgae have a slimy coating which protects the fronds from

coating with oil (IMCO 1973). Exchange of gases (respiration) in plants occurs through specialized structures on the outer surfaces of the leaves. Coating with oil could interfere with this process and damage the plant. Similarly, reproductive processes such as the production or dispersion of spores and seeds can be limited by oil coating. In most cases, destruction of macroalgae has been followed by rapid repopulation (Sittig 1974). In other cases, damage has not occurred and losses of grazing herbivores have resulted in uncontrolled plant growth (NAS 1975).

The primary impact of petroleum and petroleum products on phytoplankton is chemical rather than mechanical, although algae can become trapped within or under the oil slick and become directly impacted. Toxic effects of petroleum vary according to species, life stage, oil type, and dosage. These effects range from algicidal to algistatic (prevention of reproduction but not causing permanent damage). Some species have demonstrated the ability to utilize some hydrocarbons as a source of food (IMCO 1973).

Oil spills are expected to cause only localized adverse impacts to the phytoplankton community. This is partly due to the size of the area involved since even a very large spill is likely to impact only a small percentage of an area. In addition, selectivity will probably occur with decreases in some species being compensated for by increases in others so that the standing crop could potentially be maintained (IMCO 1973).

2. Zooplankton

The effect of oil on zooplankton will ultimately be determined by several variables. Among these are the species and life stages of the organisms, the amount and fate of the spill, and the type of oil. One important generalization that can be made about the effect of oil on zooplankton is that if zooplankters are exposed to an oil spill, they cannot leave the area. The organisms remain in the vicinity of the oil slick until wind or currents separate them. If conditions are such that both the plankton and the oil slick are being moved by the same forces,

the exposure time can become significant.

Zooplankton can be affected by oil in three ways: direct external exposure, direct internal exposure, and indirect effects. The magnitude of damage is determined by the variables listed earlier. For example, a surface slick of heavy fuel oil is not likely to directly affect pelagic plankton. However, if the oil were to sink due to water turbulence or chemical additives, the plankton would then be directly exposed.

Direct external exposure of zooplankton to oil can be caused by: (1) certain fractions of petroleum going into solution, (2) heavier fractions sinking due to chemical surfactants, and (3) organisms encountering surface oil during vertical migrations. Toxic effects of the soluble fractions of petroleum on zooplankton have not received much attention except in laboratory studies. Concentrations used in such studies are generally much higher than those found in the environment (IMCO 1973). Many of the toxic effects observed in actual spills are thought to be due to the use of toxic dispersants. These chemicals are likely to be used only in open areas so that dilution is fairly rapid and lethal concentrations are localized.

Mechanical damage to zooplankton due to direct external exposure to oil is unlikely. In most cases, spilled oil remains on the surface while zooplankters generally remain below the surface. Suffocation or loss of motility could occur if the oil were to sink or if the organisms were to surface into the oil slick in the course of their vertical migrations.

Direct internal exposure to oil occurs when the organisms consume either oil or oil-contaminated food. This is most commonly brought about through the use of dispersants which cause the oil to break up into small droplets and sink. One such case was reported by Conover (1971) where many droplets of Bunker C oil were observed in subsurface samples. Several species of copepods had apparently ingested these droplets since oil globules were observed within their digestive tracts. The ingested droplets were expelled with the fecal pellets with no apparent damage. Conover hypothesized that the deposition of oil with copepod fecal pellets is a significant factor in the removal

of oil from the water column.

Indirect effects of oil on zooplankton stem from changes to the environment. Localized reductions in phytoplankton standing crops could lead to zooplankton starvation due to lack of food supply. However, starvation could also result from a reduction in the number of predators upon zooplankton. Without the predation, zooplankters could outgrow their food supply.

3. Benthic Organisms

The group of organisms most directly affected by spilled oil in the coastal zone is the benthic fauna. Commercially valuable shellfish and biologically valuable forage organisms are included in this group. A description of the benthic fauna is presented in Appendix B.

The extreme vulnerability of the benthic community is due to the large fraction of the community which is sessile. Mature adults usually cannot leave an unfavorable area. For this reason, such organisms are often used as indicator organisms. The presence of only very tolerant species often indicates a heavily stressed or polluted environment. Conversely, the presence of very sensitive species usually indicates a high quality environment.

The impact of spilled oil on benthic organisms is influenced by several factors. The kind and amount of oil spilled and the area involved determine the concentration and toxicity of oil affecting the benthos. Meteorological conditions affect the fate of the spilled oil and the kind of benthic community impacted. For example, a falling tide tends to deposit a film of oil on the shoreline substrate.

Oil and oil derivatives can affect benthic organisms directly by external or internal exposure, or indirectly by habitat alteration.

Direct external exposure occurs: (1) when oil is deposited upon the substrate either by sinking by tidal action, or by wave action; and (2) when the soluble fractions go into solution. Mortality is most often due to asphyxiation due to coating of the organisms by the less toxic fractions of either crude or heavy oil. Lighter, more soluble fractions, such as diesel oil or

gasoline, can be more lethal than crude oil. The toxicity of these fractions has caused extensive mortality to some species, especially in confined areas (Sittig 1974). In most cases, the community has recovered within two years, generally as a result of high repopulation potential (IMCO 1973, Sittig 1974).

A sublethal effect often associated with direct exposure to oil is tainting. The absorption of hydrocarbons can give an oily taste to the flesh of edible species and reduce the value of commercially valuable species (Anderson 1975).

Direct internal exposure of benthic organisms to oil can occur when oil or oil-contaminated food is ingested. This type of exposure can affect filter feeders if droplets or contaminated food organisms are in the water. Detrital feeders and worms that consume sediments can likewise be exposed to oil-soaked sediments. Tainting of flesh might also occur from this type of exposure.

Indirect effects of spilled oil upon the benthic community are those that result from changes in the habitat. Such changes can alter the community structure by favoring certain species and discriminating against others. This can produce competititve advantages for less desirable species. Sinking large quantitites of either heavy or crude fractions could cause localized changes in the substrate, which would probably change the community structure since most benthic communities are substrate-dependent.

4. Fish

There is concern that OCS oil and gas development may cause damage to important fisheries. However, there have been no reported major fish kills or reduction of fish populations associated with acute spills of crude oil (IMCO 1973). This is probably due to the ability of fish to detect minute quantities of oil and avoid the area (Rose 1974). There are, however, cases where fish and their eggs and larvae could encounter an oil spill and suffer lethal or sublethal damage. Such damage could result directly from external or internal exposure, or indirectly from food or habitat loss. The magnitude of damage

will depend upon several variables such as the amount and type of oil spilled, and the area and time of year in which the spill occurs, relative to the species and life stages affected. Light, refined petroleum products in shallow, confined areas are potentially more damaging than crude oil or heavy fuel oil in deeper, open areas. Eggs and larvae are considered to be more sensitive to petroleum and petroleum products than adults.

Direct external exposure of adult fish to oil is unlikely as long as the oil remains on the surface. The primary expectation of direct contact is irritation or coating of the gills with subsequent respiratory impairment or failure. This effect is somewhat lessened by the oil-repellant, mucoid coating of the gills. This coating can repel oil but cannot repel oil-water emulsions (Nelson-Smith 1970). Eggs and larvae, especially those associated with the surface film, are more susceptible to damage from spilled oil. Reduced mobility and suffocation result from entrapment within the slick after it has formed a mousse (Nelson-Smith 1970). In addition, all life stages may experience lethal or sublethal toxic effects due to high concentrations of aromatics from large spills of refinery products and effluents into shallow, confined areas (IMCO 1973).

Direct internal exposure to petroleum results from ingestion of oil or oil-contaminated food. Oil globules have been observed in the digestive tract of adult fish, probably from ingesting oil-contaminated detritus (Nelson-Smith 1970). Copepods have been shown to ingest oil droplets (Conover 1971) which could then be transferred to fish feeding upon the copepods. Little research is available concerning the effect of ingested oil on fish, but some tainting of the flesh has been reported (IMCO 1973, Nelson-Smith 1970).

Indirect effects of spilled oil to fish can occur by several means. Destruction of habitat or food supply could cause a localized long-term or temporary reduction of fish in an area where oil is spilled. Specific effects due to such losses of food or habitat include mortalities due to starvation, predation, or disease, and losses due to migrations to more favorable areas.

The latter could create mortalities in those other areas due to crowding or overuse of food stocks. Finally, an oil spill near the mouth of a river or estuary could form a chemical barrier to anadromous or catadromous fishes. This would reduce the spawning success of the affected species.

5. Birds

Aquatic birds are among the most vulnerable of organisms to spilled oil. Losses of aquatic birds due to an oil spill would probably be severe because of their gregarious nature. A further risk is that such birds as the larger herons require specific nesting sites. Spilled oil would not only damage many adults but, with some species, also significantly reduce breeding success. On the other hand, the prolific breeding of species such as ducks, geese, and swans may, in some cases, prevent any long-term population declines. Species with lower breeding success such as auks are severely threatened by oil pollution (IMCO 1973).

Spilled petroleum or petroleum products can adversely affect aquatic birds through external exposure to surface oil films, internal exposure by feeding and preening, and loss of habitats or food supplies. Birds that come into direct contact with spilled oil either by swimming in a surface film, or by walking through vegetation that has been coated with oil, are among the first and most obvious victims of an oil spill. Bird kills that numbered in the thousands have been documented as a direct result of several major spills. Examples of such spills are: Torrey Canyon (10,000 birds), Arrow (2,300 birds), Arizona (3,600 birds), and the Santa Barbara spill (3,600 birds) (NAS 1975).

The primary effect of direct contact of birds with oil is destruction of the water repellency and insulation properties of the plumage (Nelson-Smith 1970). In lightly oiled birds, buoyancy is lost and insulation is reduced.

In heavily oiled birds, flight is impossible and swimming ability is reduced. Many of these birds die of exposure or starvation while others are suspected of drowning at sea (Nelson-Smith 1970). Records of the latter are not included in bird kill

statistics because they have not been directly observed. Birds are susceptible to death by exposure after contamination because vital body heat is not retained by oil-impregnated feathers. Starvation is due to the oil-induced mortality of food items or the inability of oily birds to search for food (Erickson 1963, Rose 1974). Mortalities due to exposure and starvation are closely related because exposure can sometimes be avoided if sufficient feeding takes place to maintain body reserves. In oil-soaked birds, increased metabolic rates quickly deplete reserves in order to maintain body temperatures.

Another type of waterfowl mortality occurs during the nesting season. Brooding adult birds can transfer oil from their feathers to the surfaces of their eggs. Oil does not allow respiratory gases to pass through pores in the egg, and subsequent hatching success may be significantly reduced (Hartung 1965). Reference was made in Nelson-Smith (1970) to several studies in which none of the eggs contaminated in this manner hatched. Hartung (1965) demonstrated substantial reduction in hatching success in mallard eggs that had been coated with medicinal mineral oil. Attempts have been made to rescue birds that have been exposed ot oil by cleaning their feathers. However, current methods can only approach a 20 percent success rate (Sittig 1974).

Internal exposure of aquatic birds to oil occurs when the oil is ingested, either with contaminated food or during preening (cleaning of the plumage with the bill). Ducks that have been exposed to oil often come ashore and preen continuously (Nelson-Smith 1970). Ingestion of petroleum or its derivatives probably has a wide variety of adverse effects, depending upon the amount and type of oil ingested. Little specific information is available on the toxicity of oil to birds (Erickson 1963). Erickson reported a real or imaginary tainting of the flesh in oil-contaminated birds harvested by hunters. Nelson-Smith (1970) cited a study in which "oil fed to ducks caused lipid pneumonia, intestinal irritation, fatty changes in the liver, necrosis, and adrenal enlargement." The amount and type of oil used was not reported.

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Indirect effects of spilled oil on birds are those induced by habitat alteration, especially the loss of food supply. Spilled oil may destroy vegetation or invertebrates in traditional feeding grounds. This loss of potential food organisms may reduce survival of wintering, nesting, or migrating populations long after most oil has been removed.

6. Mammals

Terrestrial mammals are not likely to be directly affected by spilled oil. Two orders of mammals, whales and dolphins (Cetacea) and seals (Pinnipedia), could be exposed to oil. The probability of such exposure is low, however, due to the sparse populations of these animals in the study area. If mammalian kills should result from an oil spill, the effect on the population may be quite severe since many of the marine mammals indigenous to the study area are currently in danger of becoming extinct.

Records of kills due to spills (Torrey Canyon, Arrow, and Santa Barbara) have not been well documented. Results of mammalian studies at the above spills did not show oil to be the cause of any of the deaths (IMCO 1973). It is difficult, however, to assess the impact of an oil spill on marine mammals because of their normally high mortality rate due to stranding (whales and dolphins) and reproductive behavior (seals) in nearshore areas.

Direct physical damage by oil seems to be limited to eye irritation. Some of the insulation capacity of seal fur may be lost but this is effectively compensated for by layers of subcutaneous fatty tissue. There is also a possibility that heavy crude and fuel oil could plug the blowhole of whales and dolphins (Nelson-Smith 1970).

Records of past spills indicate that many marine mammals avoid areas where oil has been spilled. This may be due to the presence of oil, the increase in ship traffic, or both.

3) Oil Spill Cleanup Methods

a) Introduction

A number of methods of oil cleanup have been developed to reduce environmental damage as much as possible.

These are dispersants and detergents, physical sinking, combustion, booms and barriers, and biodegradation. The effectiveness of these techniques has been highly variable due to the different properties of oil, the unpredictability of weather conditions, and the different locations of a spill. In addition, some of the methods have been found to cause as much or more damage than the original spill.

The following discussion will deal with the biological damage and problems associated with present cleanup methods.

b) Cleanup Techniques

1. Dispersants and Detergents

Dispersants and detergents lower the surface tension of oil so that it will disperse into small droplets. The value of dispersants as a cleanup method comes from their ability to breakup the oil slick before it reaches the coast. However, severe ecological damage can result from the use of dispersants. In the Torrey Canyon incident, dispersants were found to be toxic to biological organisms (Blumer 1971, Bellamy) et al. 1967). Attempts have thus been made to develop a nontoxic dispersant. Unfortunately, even with nontoxic dispersants the breaking up of the oil slick causes severe biological damage. Instead of removing the oil, the dispersant creates a finer degree of dispersion, with the most toxic fractions of the oil dissolving rapidly and reaching higher concentrations than would have occurred through natural dispersion. The toxic and carcinogenic portions are made available to marine filter feeders through ingestion. Then, by incorporation into the food web, these toxins and carcinogens are made available to man (Blumer 1971). Because of these problems, dispersants are not widely used at present. Research is still being done, though, to determine if dispersnats can be made ecologically acceptable (Canevari 1975).

2. Physical Sinking

Another recommended method to remove an oil slick is that of physical sinking. With this practice, ecological damage can occur to bottom fauna. Sunken oil can quickly coat and kill both sessile and mobile organisms, including those with commercial value such as clams, oysters, and scallops.

An additional effect of physical sinking is the incorporation of oil into the sediment. As the oil-soaked sediments are degraded by microorganisms, a considerable amount of oxygen is utilized, eventually causing the sediments to become anaerobic. This stops further biodegradation by aerobic benthic organisms. The limited oxygen supply and fragile fauna of the offshore regions are particularly vulnerable to physical sinking (Blumer 1971).

3. Combustion

The use of combustion as a means of dispersing an oil slick is more ecologically attractive than other methods. However, it is only effective if it can start immediately after the spill and if complete combusion can be attained. Weather conditions can limit combustion and lower the effectiveness of this method (Blumer 1971).

4. Booms and Barriers

Booms and barriers are containment devices that can protect vulnerable areas like harbors, estuaries, and beaches from oil slicks. Although this technique minimizes the biological damage resulting from oil removal, it has several problems and restrictions. Weather conditions have negated the effectiveness of booms. In the West Falmouth spill, oil in solution and wind-dispersed droplets bypassed the barrier and caused severe biological damage in sealed-off harbors (Blumer 1971). Mechanical and design failures have also presented problems in using containment devices. In the Oakland Estuary oil spill cleanup, mechanical failure occurred in the boom's fabric, at the joints, and because of faults in design. Some boom damage was due to debris, handling, and towing around obstructions. Recommendations for review and improved construction by the manufacturers resulted from this incident (Hanson and Koches 1975).

5. Biodegradation

Another method of cleanup and dispersal that has been considered is bacterial seeding and fertilization of oil slicks. This type of oil removal method, however, has many limitations. First, no one microbial species can completely

degrade crude oil. Most species are substance-selective and complete degradation would require numerous bacterial species. An additional restriction is the production of many intermediate products during this bacterial oxidation of hydrocarbons. Many of these intermediates may be as toxic as the oil itself, so that other organisms would be necessary to degrade these toxic by-products.

The rate of degradation could be limited if some of the hydrocarbon components are bacteriostatic or bactericidal. The fractions most readily degraded are the least toxic, whereas the toxic aromatics are attacked more slowly. High oxygen requirements during degradation can also limit the effectiveness of this method. Areas of low dissolved oxygen, such as polluted areas, can be additionally depleted of oxygen by oil-degrading bacteria to the point that further degradation is inhibited (Blumer 1971).

In summary, cleanup methods still require much research and development to be biologically acceptable. Preventive actions and techniques seem to be a better course of action than cleanup activities.

F. TERRESTRIAL IMPACTS

1. Introduction

The most obvious terrestrial impacts of OCS energy-related technologies include both temporary and permanent displacement of natural lands and the associated biota by transmission lines, required buildings, storage areas, and parking facilities. All technologies require some type of transmission line to carry electric current or to pipe oil and gas supplies. All technologies also require onshore support facilities and other commitments of onshore acreage.

2. Floating Nuclear Power Plants (FNPs)

A typical FNP requires an onshore support facility with a permanent land commitment of approximately 100 acres (USNRC 1975). The large volumes of stone needed for the breakwater would mean significant commitments from regional quarries. An FNP will also require a casting yard for manufacturing the breakwater dolosse and caissons. However, due to the locations of quarries and other sources of materials, it is unlikely that this casting yard will be located in the Atlantic

coastal areas of New Jersey or Delaware. However, if the dolosse and caissons are not manufactured near the FNP site, extensive truck, train, and barge transportation will be required to move the breakwater components from the casting yard to the site. This additional stress on both land and water will be temporary, only occurring during the construction period.

Electric transmission lines will be buried in the ocean floor from the FNP to the shore. At the shoreline the transmission lines can continue underground to an inland switching facility, or they can be overhead.

One of the first considerations is where the transmission lines should be brought ashore. A great portion of the New Jersey shoreline is composed of barrier beaches (see Chapter IV, Description of the Study Area). These barrier beaches absorb high-energy waves which batter them during storms, and thus protect inland bays and marshes. There is a concern that if transmission lines were buried in a transect across a barrier beach this disruption of the fragile beach vegetation and substrate could lead to a physically weakened area. A hurricane or severe northeast storm would be more likely to breach the barrier beach at this weakened point. It is recommended that underground transmission lines be brought ashore through natural breaks in the barrier islands (inlet areas) to minimize this potential problem (USNRC 1975).

If the transmission cables are run underground to the inland switching station, they will have to be insulated by circulating oil in a jacket surrounding the cables. This cooling method will require pumping stations with heat exchangers to cool the circulating oil. The pumping stations require an area of approximately 1 acre. The underground transmission lines will disrupt the vegetation in bands ranging from 15 to 25 feet wide, and require a right-of-way 100 feet wide (USNRC 1975, Montgomery and Newcomb 1975). Location of these underground transmission lines along existing roadways as is proposed at the Atlantic Generating Station site will minimize the disruption of natural areas.

During the transmission line burial process it is important to take steps to minimize soil erosion. Erosion can lead to problems of increased turbidity and siltation in surrounding marshlands, contribute additional nutrients to the waterways, and alter water flow patterns in the adjacent

areas. Once the burial process is complete, restorative planting of natural vegetation can help stabilize the area and minimize subsequent erosion problems.

If overhead transmission lines are used from the shore to the inland switchyard a right-of-way of 350 feet would be required. The switchyard itself would use about 10 acres of land (USNRC 1975). In addition to the right-of-way requirements for overhead transmission lines, they are esthetically unappealing and also take a toll on migrating birds. Utilization of overhead transmission lines in coastal marshlands should be avoided if possible since these are corridors used by migrating waterfowl.

3. OCS Oil and Gas Development and Deepwater Ports

The terrestrial impacts of these two technologies are discussed together since the onshore requirements have many similarities. Both OCS oil and gas development and deepwater ports require a commitment of land for support facilities. They both require onshore pumping stations and oil or gas pipelines.

The oil and gas pipelines will require land disruption in a path approximately 50 feet wide. The same recommendations apply to pipeline installations in soil: not breaching barrier beaches, and preventing erosion by restorative plantings.

Deepwater ports and most likely OCS oil and gas development will require onshore bulk storage facilities and gas processing plants. It is estimated that a storage facility for a deepwater port will require a land commitment of 640 acres (U.S. Coast Guard 1975). Large amounts of oil at the storage facility could lead to construction of a new refinery and associated petrochemical industries with a total land requirement of approximately 3,000 acres. The availability of oil and refined petrochemical products could lead to related industrial development and local population growth, with additional land requirements (U.S. Coast Guard 1975).

In all cases where significant land requirements exist terrestrial impacts can be minimized if existing rights-of-way or previously altered or industrialized areas are utilized. If at all possible upland areas should be used as opposed to filling wetlands to create suitable sites.

4. Direct Terrestrial Impacts

The permanent commitment of land to meet the requirements of these energy-related technologies results in a loss in primary production and terrestrial populations which is proportional to the amount of land used. Since the lands committed to permanent support facilities represent an irretrievable loss, it is important to site these facilities in areas of minimal ecological importance.

Terrestrial siting studies are as necessary as aquatic siting studies if the overall impact of the energy-related technologies is to be minimized. Unique or sensitive terrestrial areas should be identified and avoided as should any areas harboring rare or endangered species of plants or wildlife. Utilization of breeding or overwintering habitats of migrating upland birds and waterfowl should be minimized. The avifauna that frequent the study area are identified in Appendix B (Biota of the Study Area).

Burial of electric transmission lines and oil and gas pipelines leads to temporary disruption of the terrestrial ecosystem. Vegetation will be destroyed in the burial area and populations of birds and animals temporarily displaced. However, if a restorative program reestablishes the natural vegetation over the pipeline the original fauna will likely return in time. During the construction period adjacent lands may be unsuitable for nesting or overwintering birds because of disruptive noise; this also is a temporary impact. These temporary impacts can be minimzed by avoiding sensitive ecological areas and utilizing existing rights-of-way whenever possible (USNRC 1975).

GLOSSARY

abiotic. The non-organismal components of an ecosystem.

adsorption. The adhesion of molecules to solid bodies.

aerobic. Living in the presence of free oxygen.

algae. Any of a group of chiefly aquatic, nonvascular plants.

algal bloom. Seasonal increase in algal populations due to increased nutrient levels; compare with eutrophication.

anadromous. Fish that ascend rivers from the ocean to spawn.

anaerobic. Living in the absence of free oxygen.

annelid. Any of a group of invertebrates that are usually elongated and segmented (earthworms, various marine worms, leeches).

anoxic. A deficiency of oxygen that causes permanent damage to body tissues.

aquatic. Found in or originating from water.

arthropods. Any of a group of invertebrates that have jointed bodies and limbs (e.g., crabs, lobsters, shrimp, insects, spiders).

asphyxiation. A lack of oxygen or excess of carbon dioxide in the body that causes unconsciousness or death.

assimilative capacity. The amount of nutrients that can be utilized within an ecosystem within a certain period of time.

Atlantic Flyway. The route used by migrating waterfowl along the East Coast.

bactericidal. Destroying bacteria.

bacteriostatic. An agent that inhibits the growth of bacteria without destroying them.

baitfish. Small fish that provide a primary forage base, or food source, for larger fish and are used as bait by sport fishermen.

barnacles. Any of a group of marine crustaceans that have feathery appendages for gathering food and that are free-swimming as larvae but fixed to solid objects as adults; noted as fouling and encrusting organisms.

behavioral response. Alteration in the activity of an organism (e.g., change in migration patterns, disruption of mating bahavior) due to some stimulus.

benthic. Dwelling in or upon the bottom sediments.

benthic fish. Fish species that are associated with the bottom of a body of water.

benthos. Organisms living at the bottom of a body of water.

bioassay. Quantitative estimation of the effects of various substances on living organisms.

biodegradation. Breaking down of substances by organisms (e.g., bacteria, fungi).

biofouling. Nuisance growth of encrusting organisms.

biomass. The amount of living matter in an area.

biota. The organisms in an ecosystem.

brackish. Water that is a mixture of salt and fresh, as estuarine water.

bryozoan. Any of a group of aquatic invertebrates that reproduce by budding and usually form permanently attached branching or mossy colonies.

carcinogenic. An agent that promotes cancer.

carnivorous. Killing and feeding on animal tissues.

catadromous. Fish that migrate downstream and into the sea to spawn.

climax condition. The state of equilibrium reached by a community after a systematic series of species replacements.

coastal waters. Waters adjacent to the shoreline which contain a measurable percentage of sea water.

commercial fishery. The system of harvesting fish or shellfish species for monetary gain,

community. Interacting populations of various species in a common location.

continental shelf. A shallow underwater plain, bordering the continents, that varies in width from several miles to hundreds of miles, usually ending with a continental slope.

continental slope. The usually steep slope from the continental shelf to the ocean depths.

copepods. Any of a group of small aquatic crustaceans.

Coriolus force. An apparent force that, as a result of the earth's rotation, deflects moving objects clockwise in the northern hemisphere and counterclockwise in the southern hemisphere,

crustacean. Any of a group of invertebrates characterized by a hard outer skin or shell and jointed appendages.

cumacean. Any of a group of small, marine crustaceans with immovable eyes.

ΔT. Change in temperature, usually given as the amplitude of thermal elevation above ambient temperature.

decomposers. Any organism, including many bacteria and fungi, that returns constituents of organic matter to the abiotic environment by feeding on and breaking down such matter.

demersal. Located on the bottom of a body of water.

deposit feeders. Organisms which feed upon sediments, absorb any nutrients, and return remaining sediments to the environment (e.g., earthworms).

detrius. Particles of organic matter in various stages of decomposition.

diatoms. Golden-brown algae that possess a siliceous cell wall consisting of two valves overlapping each other.

diel. A 24-hour period including day and night.

dinoflagellate. A protozoan possessing two flagella, one longitudinal and one transverse.

diversity. As species diversity, it is the number of species of organisms compared to the total number of organisms in an area or sample.

drilling snail. A parasitic snail which drills through oyster and clam shells and feeds on body tissues.

dry weight. The weight of a substance minus the weight of contained water.

ecosystem. A biological community and its nonliving environment functioning as a unit.

emulsification. The process of liquid dispersion, with or without the aid of a surface-active agent, in an immiscible liquid, usually as droplets that are larger than those with colloidal properties.

encrusting organism. Any of a group of aquatic organisms that attach to hard substrates.

energy. The capacity to do work.

entrainment. Capture of organisms within a water mass as it is drawn into a pump or other industrial intake structure.

environment. The aggregate of all external conditions affecting an organism.

epibenthic. Dwelling on the sea bottom between the low water mark and 100 fathoms (600 feet).

epifauna. Benthic animals living on top of the substrate.

estuary. The region of a river with a variable salinity due to intrusions by the sea; an inlet where seawater is diluted by inflow of freshwater.

eutrophication. Nutrient enrichment of a body of water leading to increased production of aquatic plant and animal tissue.

fathom. Unit of water depth equal to six feet.

fauna. A collective term for the animal species in an ecosystem.

flocculation. Fine particles in suspension collecting into larger particules that eventually settle to the bottom.

flora. A collective term for the plant species in an ecosystem.

flushing rate. The rate that a body of water replaces or renews itself, usually expressed as the time for one complete replacement.

food web. The network of feeding relationships in a biological community.

forage fish. Fishes consumed by larger predators.

habitat. The area where an organism lives.

herbivore. A plant-eating organism.

holoplankton. Animals that live their entire lives as planktonic organisms.

hydrocarbon. An organic compound (e.g., acetylene, benzene) containing only carbon and hydrogen and often occurring in petroleum, natural gas, and coal.

hydrodynamics. The movements of fluids.

hydroid. Any of a group of invertebrates that are related to jellyfish and corals and that often attach to firm substrates.

ichthyoplankton. Planktonic eggs and fry of fish.

impingement. Hydraulic capture of organisms against screens that protect water intake structures.

indigenous. Native to an area.

infauna. Animals which live within the substrate.

ingestion. Taken into the body by swallowing.

inorganic. Matter other than organismal.

intertidal. The benthic zone between the mean high tide line and mean low tide line.

invertebrates. All animals lacking backbones.

isotherm. Area where temperatures are the same.

LC_{50}. The concentration of a substance in a suitable diluent at which 50 percent of the test animals survive in a given time period.

leaching. To dissolve a substance with a percolating liquid.

lethal. Resulting in death.

longshore current. A current flowing parallel and adjacent to the shoreline.

lower-boiling aromatics. Aromatic compounds that are volatile at ambient temperatures or with little heat.

macroplankton. Planktonic organisms that can be recognized by the unaided eye.

meroplankton. Organisms that are planktonic for only a part of their life cycle, usually the larval stages are planktonic.

metabolic processes. Internal, biochemical processes that extract energy and nutrients from foods and convert nutrients into tissues.

microbial. Generally refers to single-celled organisms, especially bacteria.

migration. Mass movement of a population of organisms from one area to another, usually triggered by an outside stimulus (e.g., temperature, salinity, duration of daylight).

minimum toxic concentration. The smallest concentration of a substance necessary to produce an adverse effect on an organism.

mollusc. Any of a group of shell-bearing animals (e.g., snails, clams, oysters, squids, and octopuses).

niche. Functional position occupied by an organism in a community or ecosystem.

nutrient. Any element or compound that is necessary for the continuation of metabolic processes in organisms.

olfactory. Referring to the sense of smell.

organic. Any chemical compound that originates in living tissue and contains carbon.

oyster drills. See drilling snail.

pelagic. Existing in or referring to areas of open water.

photosynthesis. The chemical process by which plants convert inorganic materials into organic compounds; this process requires the presence of sunlight, carbon dioxide, water, and chlorophyll.

physiological response. Alteration in the functioning of an organism due to some stimulus.

phytoplankton. A planktonic algae, usually microscopic and able to photosynthesize.

plankton. Organisms that have little or no motility and that travel primarily by drifting with currents and tides.

polychaetes. Any of a group of primarily marine, benthic worms.

population. A group of organisms of the same species that interbreed and occupy the same habitat.

primary productivity. The rate that a plant community converts inorganic materials into organic materials.

productivity. The rate of creation of plant or animal tissue.

psammon. The microorganisms that inhabit the spaces between sand grains of beaches.

recruitment. Addition of organisms to a population through either reproduction or immigration.

REM (roentgen equivalent man). The dosage of an ionizing radiation that will cause the same biological effect as one roentgen of X-ray or gamma-ray dosage.

renewable resource. Materials that originate from living organisms (e.g., timber, seafood).

repopulation. Resettlement of organisms into a cleared or disturbed area.

respiration. Biological exchange of gases.

resuspension. The mixing of previously settled sediments with overlying water, usually caused by mechanical disturbance.

riparian land. Land along the edge of bodies of water.

salinity gradient. Change in salinity through space.

salinity regime. The range of salt concentrations to which an organism or area is subjected.

serpulid worm. Any of a group of sedentary, tube-dwelling polychaetes.

sessile. An organism with little or no ability to move about, usually attached to the substrate.

siltation. The deposition of soil particles smaller than sand grains, yet larger than clay particles; heavy siltation can suffocate animals and fill in shipping channels.

solubility. The ability of a material to dissolve.

soluable aromatics. Organic compounds that contain at least one benzene ring (or its derivative) and that are soluble in water.

spatial distribution. Horizontal and vertical distribution of organisms.

spat. The young of oysters and other bivalves.

spawning. To produce and deposit eggs or other reproductive products.

species range. The geographic limits where a species is found.

standing crop. The amount of living material found in an ecosystem; often expressed as weight per unit of area; often separated by species, groups of species, or trophic levels.

sublethal. Having an adverse, but not lethal effect.

substrate. Any material that provides a point of attachment for organisms or that is an underlying layer (e.g., the ocean floor).

subtidal. That portion of the coastal zone below the low tide mark that is always submerged.

surface tension. A condition that exists at the free surface of matter, especially liquids, due to intermolecular forces about the individual surface molecules, and that resembles an elastic skin under tension.

taxa. Taxonomic groups of any rank or size.

taxonomy. The arrangement of organisms into groups based on their natural relationships.

temperature gradient. Change in temperature through space.

temporal distribution. Distribution of organisms through time.

terrestrial. Living or growing in or on the land.

toxic. Having a poisonous effect.

trophic levels. Hierarchial levels of a food web characterized by organisms that are the same number of steps removed from the primary producers.

turbidity. The degree of cloudiness of the water that is caused by suspended particles.

veliger. The free-swimming larva of certain mollusks that are characterized by a thin, curtain-like membrane (velum).

volatile. Readily vaporized at a relatively low temperature.

volatilization. Process by which solid or liquid substances are converted to a vapor.

wet weight. Weight of living organisms used as a method to measure standing crop.

wetlands. Naturally vegetated areas situated in and near waters.

zooplankton. The planktonic animals.

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APPENDIX A
BASIC ECOLOGICAL CONCEPTS

Ecology is the study of the relationships between organisms and their environment. The living (biotic) components of an ecosystem may be divided into three categories: producers, consumers, and decomposers. The nonliving (abiotic) components may be divided into energy and matter. The complex interactions between the biotic and abiotic components of ecosystems have evolved over millions of years and created intricate interdependencies. The following discussion deals with some of the underlying principles of biotic-abiotic interactions.

All ecosystems, both large (such as the New Jersey and Delaware coasts), and small (such as a tidal-stream marsh), function because of the flow of energy. The only major source of energy is solar radiation. Limited amounts of solar radiation are incorporated or "fixed" into energy-rich carbon compounds by plants, the producers. In turn, the plants provide an energy source for animals, the consumers. At each transfer, however, some energy is lost. Each feeding (trophic) level passes on less energy to the next level than it received.

Simple nutrients are fixed by plants into complex carbon compounds which carry energy through the system. Herbivores consume the plants, convert plant tissue into animal tissue, and both use and release the plants' energy. All tissues not utilized by increasingly higher trophic levels are decomposed from dead or waste organic matter back into basic nutrients by organisms such as bacteria. This decomposer component of the ecosystem releases the remaining energy and makes the nutrients again available to the producers, completing the unidirectional cycle (see Figure A-1).

Abiotic factors other than solar radiation and nutrients influence the functioning of an ecosystem. Several such factors in a coastal environment are water input and movement, wind, temperature, and suspended and dissolved substances. Alterations of any of these factors, either natural or man-induced, will produce consequent changes.

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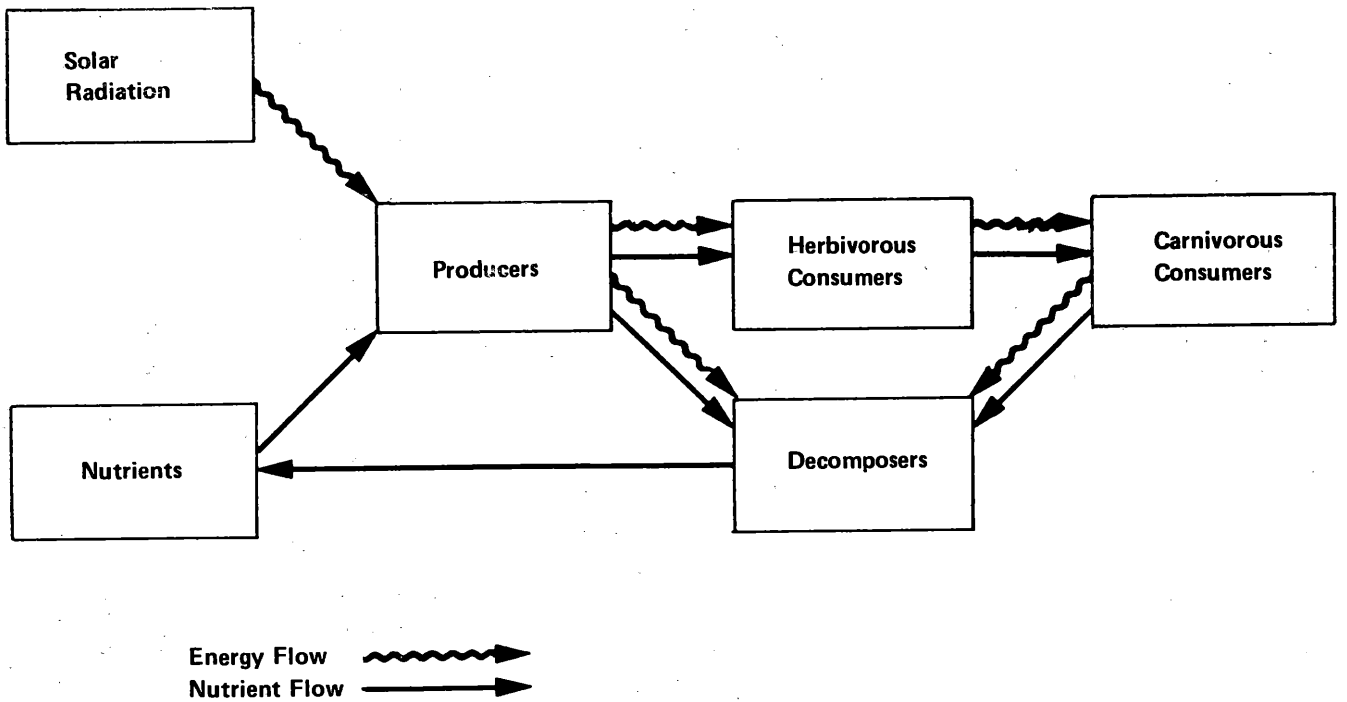

Figure A-1. A simple model of energy and nutrient flow through an ecosystem showing the former as noncyclic and the latter as cyclic (adapted from Kormondy 1969).

Some current concepts of ecosystem dynamics are summarized below to illustrate the potential impacts of introducing new technologies into coastal ecosystems (Clark 1974).

Coastal ecosystems contain terrestrial, freshwater, and saltwater environments. Freshwater input (e.g., groundwater and surface runoff, precipitation), which varies in volume, pattern, and seasonal rate of flow, and seawater movement (e.g., upwellings, tidal incursions) supply nutrients to the coastal ecosystem.

Tidal circulation is important: the rate of tidal flushing, for instance, influences the capacity of an ecosystem to assimilate excess nutrients. A high rate of flushing can dilute and disperse nutrients so that eutrophication (the nutrient enrichment of water to such levels that there is excessive growth of aquatic plants) does not occur.

Primary productivity (energy fixation by plants) depends upon the supply of nutrients, availability of carbon dioxide, and access to solar radiation. Declining primary productivity results in declining energy flow and nutrient cycling through all other trophic levels in the food web.

Nitrates and phosphates are important plant nutrients, and insufficient nitrate often limits primary production. However, excessive additions of nitrogenous compounds from untreated sewage and agricultural fertilizers to normally productive ecosystems can lead to eutrophication and degradation.

An important link between plants and animals is the respiration cycle. Plants use carbon dioxide, one of the respiratory waste products of animals. Plants then release oxygen as a respiratory waste product which animals in turn use. Each is critically bound to the other since the waste of one is necessary raw material for the other. Oxygen concentrations adequate for this interchange are usually maintained in undisturbed coastal waters through natural processes. However, when untreated sewage and other organic wastes are discharged into coastal waters, the decomposers use more oxygen in order to decompose more waste. The available oxygen is then depleted faster than it can be replaced by either plants or the atmosphere.

Turbidity, which is the reduction of water clarity by suspended and dissolved substances, inhibits the penetration of light through

the water column. Increased turbidity caused by siltation from dredging or land development, or excessive growth of phytoplankton due to an overabundance of nutrients, can inhibit plant production.

Temperature, another abiotic factor, has a major influence on coastal ecosystems. Species abundance and distribution are partially temperature-dependent. Basic functions of aquatic organisms such as migrations, spawning, embryonic and larval development, feeding behavior, and basic metabolic processes, can be altered by temperature.

Salinity also influences aquatic organisms, affecting certain metabolic functions, reproductive behavior, and feeding habits. Activities which alter the natural salinity of a system may disrupt these functions and affect the distribution of marine or estuarine organisms.

A high capacity for energy storage is necessary for successful maintenance of a coastal ecosystem. Organic sediments, phytoplankton populations, fish schools, stands of marsh grass, and even sand dunes, are storage units that accumulate energy for use during periods of seasonal shortage (Clark 1974).

The ecological principles discussed above demonstrate some of the complex interdependencies that are characteristic of ecosystems. Because of this complexity, a seemingly small alteration can have a far-reaching ecological effect. For this reason, ecological principles must be considered when projecting possible alterations, due to new technologies, onto an ecosystem.

APPENDIX B

BIOTA OF THE STUDY AREA

Descriptions of the Principal Floral and Faunal Assemblages
Found in or upon the Coastal Waters of New Jersey and Delaware

Contents

1. Phytoplankton
2. Zooplankton
   a. Holoplankton
   b. Meroplankton
   c. Macroplankton
3. Benthic community
   a. Benthic algae
   b. Epifauna
   c. Level-bottom communities
4. Fishes of the middle Atlantic coast
   a. Fresh- and brackish-water fishes
   b. Estuarine fishes
   c. Marine fishes
   d. Commercial and sport fisheries
5. Waterfowl
6. Marine mammals

1. PHYTOPLANKTON

The taxonomy (i.e., identification, classification, and nomenclature) of phytoplankton in the central Middle Atlantic Bight is currently incomplete (Smayda 1973). Many studies are available on the primary productivity of phytoplankton of the various bays and inlets. However, few studies are available in the offshore areas likely to be impacted by OCS development. Current baseline studies by the Virginia Institute of Marine Science for the Bureau of Land Management, U.S. Department of the Interior, are gathering more data to fill this void.

In the middle-Atlantic estuarine and marine phytoplankton communities, usually only a few species are abundant and only one species is dominant at any given time. As the season progresses, these species that are abundant and/or dominant change in a fairly predictable and primarily temperature-dependent pattern called "species succession" (Raymont 1963).

Diatoms and dinoflagellates make up the bulk of the phytoplankton community in Raritan and Delaware Bays. Both areas have had intensive blooms of algae and "red tides" in the past. An increase in the nutrient levels in these estuaries could produce similar blooms in adjacent offshore areas (Smayda 1973, Marshall 1974).

A description of the phytoplankton community of lower Delaware Bay and adjacent coastal waters, developed from the work of several authors, is found in Maurer (1974). The area is dominated by dinoflagellates in spring and summer and by diatoms during late fall, winter, and early spring. Early fall and late spring are transitional periods for the phytoplankton community. During this time there is a shift in dominant organisms. Species diversity is usually higher during these transitions, but standing crop is generally lower, especially in the late summer-early fall period when nutrients are least available (Maurer 1974). However, research in Little Egg Inlet and the adjacent coastal and marine waters showed that standing crop was highest in late August and early September (Currie 1974). The Maurer (1974) study expressed standing crop as volume (m^3 of organisms) while the Currie (1974) study expressed it as density (numbers/m^3).

In the Delaware Bay study, the dominant dinoflagellates were *Ceratium* spp. and *Peridinium* spp. (Maurer 1974), and in the oceanic collection

in the Little Egg Inlet study they were Prorocentrum spp., Dinophysis norvegica, and Peridinium spp. (Currie 1974). By fall, diatoms began to dominate the Delaware Bay area. Nitzchia seriata and Thalassiosira sp. were the most abundant species in October, Stephanopyxis turris and Rhizosolenia alata in November, and Guindaria flaccida in March. The diatom dominance was interrupted in January by the dinoflagellate Ceratium tripos (Maurer 1974). The most common diatoms in the vicinity of Little Egg Inlet were Skeletonema costatum and Nitzchia alosterium. Thalassiosira spp. were also present (Currie 1974).

2. ZOOPLANKTON

The term zooplankton refers to animals that drift with the tides and currents. Most forms have some other method of moving about and vertical migration is common. The three major types of zooplankton are holoplankton, meroplankton, and macroplankton. These categories are arbitrary since some organisms can be placed in more than one group. For example, the mysids, which are small, shrimp-like organisms, often drift passively at night and rest on bottom sediments, much like benthic invertebrates, during the day. Amphipods, which exhibit similar behavior, are categorized as benthos, whereas mysids are categorized as plankton (Raymont 1963).

Holoplankton includes microscopic organisms that spend their entire life cycle as plankton. The most common holoplankters in the middle-Atlantic area are the subclass Copepoda and the order Cladocera. Meroplankton are planktonic only during part of their life cycle. Meroplankton includes both the larvae of many benthic invertebrates and the eggs and larvae of many fish (which will be discussed in the fisheries section as ichthyoplankton). Macroplankton includes zooplankton that is readily visible and not included in the other groups. Various shrimp, ctenophores, jellyfish, and worms are considered macroplankton.

Significant gaps exist in the data on zooplankton populations in the study area. The majority of studies describe the plankton of inshore areas, and most of these, as well as the studies done offshore, have used such a variety of research techniques and reporting methods that it is difficult to compare findings. The result is that much of the data that

now exists is largely unusable to describe quantitatively the offshore plankton community (Forns 1974).

a. Holoplankton

The holoplankton community of the Middle Atlantic Bight is dominated primarily by copepods (Maurer 1974, Sandine et al. 1974). Maurer (1974) reviewed several studies and described the holoplankton in lower Delaware Bay and adjacent offshore regions. Sandine et al. (1974) studied holoplankton in the inshore and offshore areas adjacent to Little Egg Inlet, New Jersey.

The volume (biomass) of zooplankton in the Delaware Bay region is greatest in spring through early summer and again in the fall. Increases in biomass are believed to be in response to increased abundance of phytoplankton, the primary food of zooplankton. The greatest number of zooplankton species usually occur during late summer when water temperatures are highest and many southern, warmwater species are present, whereas the least number of species occur in winter months (Maurer 1974). In the Little Egg Inlet area, copepods increase in abundance from winter (lowest densities) to fall (highest densities), with zooplankton other than copepods reaching highest densities from July through September (Sandine et al. 1974). The differences in the methods used (biomass vs. density) and the presentation of results (zooplankton vs. copepods and "other holoplankton") in these two studies illustrate the difficulties often encountered in comparing studies which quantitatively describe the zooplankton populations of different areas.

In the Delaware Bay area, *Acartia tonsa* and *Centropages* spp. were present throughout the year. *Centropages typicus* occurred in the winter, *C. hamatus* in spring and summer, and *C. furcatus* in summer and fall. Another copepod that occurred in the winter was *Pseudocalanus minutus*, while *Metridia lucens* and *Temora longicornis* appeared in spring and summer. The greatest number of species occurred in summer and fall with the presence of *Corycaeus* spp., *Candacia armata*, *Euchaeta marina*, *Labidocera aestiva*, *Nannocalanus minor*, *Scolecithrix danae*, *Temora turbinata*, and *Undinula vulgaris*. Other holoplankton observed in this area were five species of Cladocera which were never dominant but often abundant. The most numerous of these, *Evadne nordmanni*, occurred from May to August. It was replaced by *E. spinifera* from August to October (Maurer 1974).

In the area off Little Egg Inlet, Sandine et al. (1974) found Acartia tonsa more often than any other species, but it did not appear in April. A. tonsa was most abundant in summer and fall. Other summer and fall species included Oithona brevicornis, Paracalanus crassirostris, and Centropages typicus. Winter and spring species included Oithona similis, Temora longicornis, and Pseudocalanus minutus. A total of 25 copepod species were identified in the Little Egg Inlet study. Other holoplankton (non-copepod) made up 5.3 percent of the total holoplankton community. These were primarily summer and fall cladocerans that reached maximum densities in July through September.

b. Meroplankton

The term meroplankton refers to organisms that spend only a portion of their life cycle as plankton, usually as larval and/or immature forms. Meroplankton in the Middle Atlantic Bight consists primarily of larval and/or immature benthic invertebrates and ichthyoplankton. The latter organisms consist of eggs and larvae of fishes and will be discussed in Section B-4.

Maurer's (1974) description of the lower Delaware Bay plankton community gives little detailed information on meroplankton. Larvae of three groups of organisms were found: echinoderms (e.g., starfish), molluscs (e.g., clams, snails) and decapod crustaceans (e.g., crabs, lobsters, shrimp). Pluteus (echinoderm) larvae were common in May, June, and August; maximum densities were recorded in November. Veligers (mollusc larvae) were found during all months from May through November, with the exception of August. A maximum density of gastropod larvae occurred in May and was attributed to the abundance of the pteropod Limacina spp. Detailed descriptions of zoea (e.g., crab, lobster, shrimp larvae) were not given.

In their study of Little Egg Inlet, Sandine et al. (1974) found that meroplankton made up 13.7 percent of the total zooplankton community and occurred from June through November with maximum densities in July and September.

Bivalve veligers made up 80 percent of the meroplankton and were primarily Spisula solidissima (Atlantic surf clam) and Modiolus demissus (ribbed mussel). Six percent of the metroplankton were polychaete larvae (Polydora spp.), which occurred in April, and July through September. Gastropod veligers were common in July and August

and made up 5 percent of the meroplankton. Echinoderm larvae were present in July and September and represented 3 percent of the total. The remaining meroplankton (about 7 percent) consisted of ectoproct larvae (October through December), barnacle larvae (March and July through September), and crustacean zoea (May through September.)

c. Macroplankton

The organisms that make up the macroplanktonic community are actually a part of the holoplankton since they are planktonic throughout their life cycle. However, they are usually collected by different techniques because of their larger size and are treated separately in most reports. Macroplanktonic organisms range from a few millimeters in length, in such groups as the small chaetognaths (arrowworms), to 50 centimeters in length and several kilograms in weight in some of the jellyfish.

The Delaware Bay studies cited by Maurer (1974) indicate that the macroplankton in that area consists of chaetognaths (*Sagitta* spp.), pteropods (*Limacina retroversa*, *Creseis* spp., and *Cavolina* spp.), tunicates (*Oikopleura* spp. and *Doliolum* spp.), coelenterates (*Aglantha digitale* and others), ctenophores (*Beroe ovata* and *Mnemiopsis leidyi*), and arthropods (mysids and shrimp).

The arrowworms exhibit seasonal species succession as do copepods. Most arrowworms occur primarily in winter but *Sagitta tenuis* began to appear in November and *S. elegans* did not become abundant until May. The dominant species, *S. serratodentata* occurred in mid-winter.

Limacina retroversa (a planktonic gastropod commonly called the "sea butterfly"), which occurred during summer, was the most abundant pteropod. Ctenophores and jellyfish occurred throughout the year but primarily during warmer months within the estuary. Three species of mysids were collected, including *Gastrosaccus* sp., *Mysidopsis bigelowi*, and *Neomysis americana*. Mysids exhibit a seasonal migration pattern of living within the estuaries in summer and moving offshore in winter. This same pattern has been exhibited by a variety of shrimp in Delaware Bay, including *Penaeus* spp., *Palaemonetes* spp., and *Crangon* spp.

Investigations by Sandine et al. (1974) indicate generally the same groups present in the Little Egg Inlet. The tunicates (*Oikopleura* spp. and *Fritillaria* spp.) were present from July through December with

maximum densities in August. Arrowworms (Sagitta spp.) were present throughout the year. Highest densities occurred quite suddenly in April, tapered off during summer and fall, and reached lowest densities in winter. A variety of ctenophores were collected including Pleurobrachia spp., Beroe ovata, and Mnemiopsis leidyi. Highest densities of these organisms appeared in February. Fifteen species of hydromedusae and a jellyfish, Cyanea capillata, represented the coelenterates. The dominant hydromedusa was Obelia spp. which was at peak abundance in April and May with a lesser peak in September. Greatest numbers of species occurred in the spring. Jellyfish were abundant at "nuisance" levels in July and August. The mysid, Neomysis americana, was collected all year and was most concentrated from late spring to early fall. The sand shrimp, Crangon septemspinosa, was also present throughout the year and was most abundant in August.

3. BENTHIC COMMUNITY

Benthic organisms (benthos) burrow in bottom sediments, crawl upon sediment surfaces, or attach to hard substrates such as natural or artificial reefs, bulkheads, and pilings. Like plankton, benthos consists of producer, consumer, and decomposer organisms. The producers are benthic macroalgae (e.g., Ulva, Gracilaria, Agardhiella) and small demersal diatoms. The consumers are made up of a multitude of invertebrates such as annelids, molluscs, echinoderms, and a variety of arthropods.

Benthic communities have often been characterized by indicating the association of organisms with specific types of bottom sediments (Sanders 1958, 1960). Using this as a criterion, a number of communities can be identified in the middle-Atlantic area, including epifaunal, level-bottom, and canyon types. Epifauna are highly productive organisms that occupy various hard substrates. Pratt (1973) separated level-bottom communities in the mid-Atlantic shelf area into three types: sand, silty-sand and silty-clay. Finally, the outer reaches of the continental shelf contain a number of canyons that support a different kind of community than level-bottom areas (Pratt 1973).

a. Benthic Algae

In order for algae to grow on the substrates of reefs and reef-like structures, light must penetrate to the plant. For this reason, the distribution of benthic algae is a function of water depth and water clarity, as well as of substrate type.

Maurer (1974) summarized several reports on the marine algae present in the lower Delaware Bay and adjacent offshore areas. These studies indicate that out of 100 species present, 95 are benthic. The standing crop is highest in summer and lowest in winter. A variety of genera were found in all habitats, including tidal pools, jetties, and both high- and low-intertidal areas.

In the Little Egg Inlet area, most collections by Smith (1974) were from jetty and bay areas. The overall dominant genera were *Ulva*, *Agardhiella*, and *Gracilaria*. *Ulva* was the most common genus in the bays and *Enteromorpha* was the most common genus around the jetties in the intertidal zone.

b. Epifauna

Two types of habitats are colonized by epifaunal organisms, intertidal (areas that are exposed in varying degrees during tidal cycles) and subtidal (areas below the lowest low-tide mark).

Intertidal assemblages generally exhibit a vertical distribution or zonation that is determined by tidal range and wave exposure (Pratt 1973). In the New Jersey and Delaware area of the mid-Atlantic region, these communities are limited to a few naturally exposed rock outcroppings or to man-made structures (e.g., jetties, bulkheads, buoys). The most common organism types include a variety of snails, mussels, starfish, anemones, hydroids, bryozoans, tunicates, amphipods, and sea urchins (Pratt 1973). These organisms require large amounts of water circulation (filter feeders) or attached macroalgae (grazers) to maintain their food supply.

Subtidal epifauna, which are submerged at all times, do not exhibit the vertical zonation common in the intertidal communities. Community structure of this area is similar to that of the intertidal zone, with the mussel *Mytilus edulis* being the dominant organism. Other organisms in this habitat include hydroids and barnacles.

An artificial substrate study was conducted off the New Jersey coast by McCullough (1974). Subtidal colonies were made up of 42 species, of

which five clearly dominated (Mytilus edulis, Teredo navalis, Balanus eburneus, Jassa falcata, and Caprella equilibra). Generally, deeper test panels (35 feet) had fewer organisms than did shallower ones (4 feet and 12 feet). Intertidal areas showed various degrees of vertical zonation depending upon the profile of the structure. Zonation on pilings (straight, smooth profile) was more pronounced than on jetties (irregular, broken profile). The shallowest areas (maximum exposure) were heavily colonized by barnacles. The areas below the barnacle colonization consisted of broad bands of attached algae. The areas below the algae bands were utilized most by blue mussels and below that mostly by narrow (3-inch) bands of hydroids. This same kind of stratification and community development can be expected to take place on any new man-made structure in the study area (Pratt 1973).

c. Level-Bottom Communities

1) Sand Fauna

The sand faunal community extends from sandy beaches to the 50-meter contour, an area in which water depths allow wave-induced sediment transportation at least part of the time (Pratt 1973). Studies cited by Pratt indicate that suspension feeders dominate this habitat, but that all feeding types are represented. A number of polychaete worms inhabit the area and are probably important sources of fish food. The molluscs are represented by the bivalves Spisula solidissima, Astarte castanea, Ensis directus, and Tellina agilis, and by gastropods (snails) that prey on the bivalves. Amphipods and decapods (e.g., crabs, shrimp) are also present and are important food items for fish. In addition, echinoderms, ascidians, and anthozoans are present. The most important species, in terms of direct human use, is Spisula solidissima, the surf clam, which supports an extensive commercial fishery.

In a study of the Little Egg Inlet area, Garlo et al. (1974) found that polychaetes were the most abundant organisms in sandy areas. Bivalves usually ranked second, with Tellina agilis and Spisula solidissima occurring most often. Amphipods were the third most abundant organisms. Most stations sampled during the study contained sandy sediments.

2) Silty-Sand Fauna

The silty-sand faunal community exists in an area outside the influence of wave-induced sediment transport. It is generally defined

as having at least 25 percent silt content in the substrate. This area supports both suspension and deposition feeders, many living within the substrate and often in tubes (Pratt 1973).

Generally, the same organism types are found in this area as in the sand communities; differences are at the genus and species level according to an expanded list given by Pratt (1973). Polychaetes and bivalves are common. Spisula solidissima is usually replaced by Artica islandica, the ocean quahog, a potentially important commercial species.[1] Amphipods, isopods, and cumaceans are deposit feeders that form an important forage base for fish.

3) Silty-Clay Fauna

A limited area of the Middle Atlantic Continental Shelf is characterized by a silty-clay substrate. These fine sediments are found only near the shelf edge or within some channels outside bays and estuaries (where fine sediments are common). Polychaetes, echinoderms, and a few bivalves make up this community which is generally considered not as productive as sand and silty-sand communities (Pratt 1973).

4) Benthic Macroinvertebrates

Garlo et al. (1974) studied the larger and more motile benthic macroinvertebrates. Garlo et al. (1974) used a trawl to sample for these benthic macroinvertebrates that can often escape the dredges that are normally used in studying benthos. Therefore, the macroinvertebrates collected in this trawl study supplement the community descriptions of level-bottom habitats discussed earlier. Sediments at the trawl stations were primarily sand with about one percent silt content (Garlo et al. 1974).

A total of 74 taxa were collected. Decapods, the largest group (86 percent), consisted primarily of sand shrimp. Other decapods included rock crab, lady crab, blue crab, lesser blue crab, and brown shrimp. Echinoderms accounted for 8 percent of the total organisms collected; 73 percent of these were sand dollars and 27 percent were starfish. Other

1. There is some uncertainty as to the exact boundary between the sand and silty-sand areas and there is some thought that S. solidissima and A. islandica may be used as indicator species to establish these boundaries (Pratt 1973).

species collected were horseshoe crab, Atlantic long-finned squid, northern moonsnail, and the channeled whelk.

5) Canyon Community

At the eastern edge of the continental shelf there are nine canyons between Great South Channel and Cape Hatteras (Pratt 1973). Three of these are within the study area, the largest of which is the Hudson Canyon. Canyon walls are V-shaped, fairly steep, and with rocky outcroppings forming a terraced profile. The canyons support a valuable lobster fishery and a potentially important red crab fishery (Saila and Pratt 1973). Other species include *Ophiomusium lymani* (an ophiuroid echinoderm), *Peniagone willemoesia* (a sea cucumber), sea pens, seastars, and anemones. Deeper than 3,000 feet, echinoderms, crabs, and sea spiders are important.

4. FISHES OF THE MIDDLE ATLANTIC COAST

a. Fresh- and Brackish-Water Fishes

Because this study focuses on coastal and offshore impacts, freshwater fishes inhabiting the fresh waters bordering the coastal zone will be treated briefly. The freshwater fishes mentioned in this section can also inhabit the brackish areas which interface with fresh and estuarine waters, while certain marine fishes can also live in this freshwater zone.

DeSylva et al. (1962) and Thomas et al. (1974) record the presence of several groups of fishes in this zone: freshwater residents, estuarine residents, and anadromous and catadromous species. The latter three groups will be considered in Section B-4-b.

Some common freshwater fishes of the mid-Atlantic coast are sunfishes, such as the bluegill, pumpkinseed, and large-mouth bass; perches, such as the yellow perch; minnows, such as the spottail shiner, carp, bridled shiner, goldfish, and golden shiner; pikes, such as the chain pickerel; and catfishes, such as the white catfish, brown bullhead, and channel catfish.

b. Estuarine Fishes

Various fishes use estuarine waters during different phases of their life histories. Generally, four categories of inhabitants may

be defined: residential, anadromous, catadromous, and marine migrants. However, many species can be placed in additional categories. A complete listing of species in each category is not possible because the life histories of many fishes are poorly understood.

Residential fishes occur in estuarine waters throughout the year. Spawning, growth, and local movements occur during considerable seasonal variations in water temperature, salinity, dissolved oxygen, turbidity, and other water quality characteristics. As a consequence, many estuarine residents show evolutionary and behavioral adaptations to estuarine environments which minimize environmental stresses such as pollution. Evolutionary adaptations of the silversides (Menidia) and the killifish (Fundulus) include two species for each genus that overlap considerably in their habitat preferences. Normally, Menidia beryllina and Fundulus heteroclitus inhabit low-salinity water while Menidia menidia and Fundulus majalis inhabit higher-salinity water (DeSylva et al. 1962). Behavioral adaptations include movements of these species and others into deeper, warmer water of estuaries during winter, when shore-zone waters approach the freezing point. Other general characteristics of residential estuarine fishes are reproduction over widely varying conditions during several months of the year, short life span, rapid growth, and consumption of a wide variety of organisms (Hildebrand and Schroeder 1928).

The above fishes, among others, are characteristic species of the estuarine shore zone. Benthic estuarine species include the naked goby (Gobiosoma bosci) and the hogchoker (Trinectes maculatus). The bay anchovy (Anchoa mitchilli) is an abundant, small fish of the estuarine pelagic zone. It is an important predator on zooplankton and prey of many larger fishes (Darnell 1958). In many estuaries along the Atlantic coast south of Cape Cod and along the coast of the Gulf of Mexico, this species is an important member of the food web. Fortunately, it is relatively tolerant of stressful environments. Its presence in polluted estuaries (Bechtel and Copeland 1970, Taylor and Saloman 1968) probably contributes to faunal stability.

Two members of the Serranidae family, the white perch (Morone americana) and the striped bass (Morone saxatilis), and members of the Clupeidae family, the freshwater shads (Alosa spp.), constitute a

second category of estuarine fishes, the anadromous forms. They typify the migrating fishes which inhabit lower estuaries or marine coastal waters as yearlings or adults and move into upper estuaries or freshwater during spring to spawn (Mansueti 1961a, 1961b, 1962). White perch and striped bass typically spawn in tidal portions of estuaries where freshwater runoff initially mixes with low-salinity water, while the shads spawn further upstream in freshwater. The striped bass appears to spawn most successfully where massive quantities of flowing water are also available (Talbot 1966). The Chesapeake Bay area, the upper Potomac River, and the Susquehanna Flats (near the upper Chesapeake) are major spawning grounds for striped bass. Some evidence indicates that striped bass in these different spawning areas are different populations (Morgan et al. 1973).

Because these low-salinity spawning grounds favored by anadromous fish are often in or near rivers, access to the grounds can be blocked by thermal or chemical effluents (Talbot 1966). If an effluent plume extends across the river and from surface to bottom, the migratory path from feeding grounds in the lower estuary to spawning grounds in the upper estuary may be blocked and the population drastically reduced.

The dissolved oxygen content of river water is important for successful development of fish eggs (Blaxter 1969). However, municipal and industrial effluents carry a high organic load which characteristically causes downriver dissolved oxygen reductions (Warren and Doudoroff 1971). A low-oxygen zone may coincide with an otherwise favorable low-salinity, high-flow-rate spawning area. The result could be a decline in the area where successful reproduction can occur and an eventual reduction in the population of striped bass, white perch, and freshwater shads.

In contrast, the American eel (*Anguilla rostrata*) moves downstream out of the estuary and into the Sargasso Sea in the western Atlantic Ocean to spawn. Young eels that are spawned in this oceanic area eventually migrate long distances to coastal estuaries as both "glass eels" and, as a subsequent development stage, "elvers." This life-history movement pattern is referred to as catadromous (the third category of estuarine fishes), and the American eel is the only fish exhibiting this behavior (Lagler et al. 1962). Young eels migrate

toward freshwater and the females often move hundreds of miles upriver. Little is known of factors which influence the successful spawning and population size of this species..

Fishes that spawn only a few miles from the coast and whose larvae subsequently move into estuaries where they reside as young collectively form a fourth category of estuarine ichthyofauna. For these fishes, the estuary is almost exclusively a nursery, and their life cycles are apparently estuarine dependent (Gunter 1945, Smith et al. 1966). These fishes include, in the herring family, the Atlantic menhaden, (Brevoortia tyrannus); in the mullet family, the striped mullet (Mugil cephalus) and white mullet (M. curema); in the drum family, the Atlantic croaker (Micropogon undulatus), the spot (Leiostomus xanthrus), the northern kingfish (Menticirrhus saxatilus), the weakfish (Cynoscion regalis) and the spotted seatrout (C. nebulosus); in the flounder family, the winter flounder (Pseudopleuronectes americanus), the summer flounder (Paralichthys dentatus), and the gulf flounder (P. albigutta); and others (McHugh 1967).

The majority of these species are believed to spawn in schools in coastal waters approximately 3 to 20 miles from shore. Direct observations of their behavior and locations during spawning are generally lacking, and current knowledge is largely based on the offshore distribution and abundance of eggs and larvae (Anderson 1958, Kendall and Reintjes 1975). Additional evidence supporting the belief that spawning does not occur far from the coastline is the relatively small size of larvae collected near the mouths of estuaries and the time in which that developmental stage is reached. However, few studies have explained the means by which these young, essentially nonswimming planktonic larvae are transported from offshore spawning grounds to estuarine nursery areas, hence, transit times remain unknown.

Landward water currents may be the transporting mechanism. Eddies formed between southerly longshore currents and the northerly Gulf Stream may carry these planktonic stages close to the coast. General shoreward winds during the spring, caused by rising masses of warmer air over the land, may also assist in this process. Pritchard (1967) has described the net movement of nearshore, subsurface saltwater into estuaries, replacing a net offshore movement of lighter freshwater

with some entrained saltwater. The essentially two-layered, two-directional net movement of estuarine water, inshore at the bottom and offshore near the surface, during periods other than maximum flood and ebb tides, is the most likely long-term transporting mechanism for the entrance of nearshore larval fishes into many estuaries.

Water velocities are often much lower in the body of an estuary than they are in and near the constricted inlet. Larvae, having gained entry to the estuarine habitat, may begin a slow migration toward headwaters in the tongue or wedge of subsurface saltwater that protrudes along the bottom, often as far as the river mouth. This wedge of ocean-derived saltwater is being continuously diluted by surface freshwater along a nearly horizontal, fresh-saltwater frictional interface and larvae gradually acclimate to declining water salinities. Dovel et al. (1969) suspect this accounts for the distribution of hogchoker and naked goby eggs and larvae. These fish spawn in high-salinity water, but shortly thereafter larvae are recovered further upstream in low-salinity water.

Some larvae in surface waters outside inlets, such as Atlantic menhaden, may be carried into estuaries on flood tides. Due to the Coriolis force, flood-tide waters enter and disperse into Atlantic coastal estuaries on the north sides (Reid 1961). Larvae carried in by these waters may not be carried back out on ebb tides, since ebbing water is primarily older, estuarine water on the south side of estuaries. This physical mechanism would tend to accumulate surface-swimming larvae in estuaries. These larvae may then move toward low-velocity, fresh water in shoal areas.

In addition to being physically carried by movements of water masses, fish larvae may respond physiologically and behaviorally to gradients in water quality such as salinity, density, temperature, light, dissolved organics, suspended solids, food, or dissolved oxygen. Responses to density and light, for example, are shown by phyto- and zooplankton which undertake vertical migrations in the water column. Increasing temperatures, decreasing salinities, or increasing food or metabolic by-products may provide a positive stimulus to young fishes. Menhaden have usually metamorphosed into adult form by the time they enter estuaries and have switched their

diets from zooplankton to phytoplankton. From the air, schools of menhaden have been observed moving into an arm of a bay which was eutrophied with unicellular algae, rejecting a less productive nursery zone.

By the time most marine-spawned larvae enter the nursery zone they have developed some swimming ability. They characteristically form schools consisting of individuals of similar size and swimming abilities and seek areas of highest food concentration. The shore zone is especially favorable since currents are often less strong, planktonic and benthic foods are available, and vegetation for shelter is present. In addition, larger, predatory fishes are often less common in shallow water.

In completing their life cycle, most species move, during the fall, toward estuarine mouths, where they may overwinter as sexual immatures or, if mature, they may join the adult populations in offshore, winter spawning grounds.

c. Marine Fishes

The fishes of coastal and shelf waters in the Middle Atlantic Bight are, in some respects, as difficult to categorize as are estuarine fishes. Some fishes (the "estuarine-dependent" fishes described above) whose larvae inhabit the estuary as young during the spring and summer are present in estuaries as adults during late summer and fall when the lower estuary becomes more saline. During this brief time many other coastal fishes regularly but temporarily inhabit the lower bay. Some authors have referred to these latter fishes as "incidental" estuarine fishes, but for the purpose of this discussion, they will be considered marine fishes. There are many species farther from shore that rarely enter estuaries and that might be termed "shelf residents." Little is known of the distribution, abundance, and life histories of many of these fishes, and even less is known of those inhabiting the continental slope.

Coastal marine fishes which often venture into high-salinity water at the mouths of estuaries during late summer and fall include some stingrays and sharks, Atlantic herring, cusk eels, halfbeaks, sea basses, several species of jacks, snappers, some searobins, boxfishes, puffers, and many others. Fishes termed "shelf residents," which

rarely enter estuaries, include a wide variety of skates, sharks, stingrays, several species of herring, cods, hakes, squirrelfishes, some sea basses, cobia, some jacks, snappers, tunas, swordfishes, marlins, spearfish, sailfish, some searobins, rattails, anglers, frogfishes, and many others.

Most estuarine-dependent fishes, which were cited earlier, and many mid-Atlantic coastal and continental shelf fishes, cited above, are seasonally migratory. During spring and summer, when nearshore water temperatures are increasing, there is a net movement of fishes northward and shoreward. During fall and winter, as coastal water temperatures slowly decline, a massive offshore and southerly migration of fishes occurs.

Although some fishes migrate northward as far as the Gulf of Maine during summer, the Cape Cod, Massachusetts area, is apparently a northern limit for many others. During winter, when these fishes move south or offshore, very few coldwater fishes from the Gulf of Maine migrate south of Cape Cod to the mid-Atlantic area. Therefore, the marine fish fauna of the Middle Atlantic Bight is abundant and diverse during summer and depauperate during winter.

Approximately 300 species of marine fishes have been recorded from the mid-Atlantic area, but fewer than 50 percent are regularly observed. Most species are apparently southern fishes which only occasionally stray into the area or which reach the northern limit of their range near the Chesapeake Bight. Others may include oceanic or continental slope species which are intermittently caught on the shelf.

d. Commercial and Sport Fisheries

The term "fisheries" refers to both the populations of aquatic organisms caught by fishermen and the efforts expended to harvest them. These organisms consist of the true fishes, or finfishes, and the shellfishes. The shellfishes are comprised of two groups: the bivalve molluscs (e.g., clams, oysters, scallops); and the crustaceans (e.g., crabs, lobsters, shrimp).

Many of the species which comprise the commercial catch are also sought by sport fishermen. Species such as bluefish, Atlantic mackerel, striped bass, spot, crabs, clams, and other finfishes and shellfishes are prized catches of weekend fishermen and charter boat parties. However,

at least one fish species, Atlantic menhaden, is not suitable for human consumption. They are reduced to oil and meal products, and remain solely a commercial species. On the other hand, a few species, such as the billfish, are sought primarily by sport fishermen. Tables B-1 and B-2 show important commercial fishes caught in the mid-Atlantic area in 1974.

The commercially and recreationally important fishes constitute only a small fraction of the total number of fish species inhabiting the Middle Atlantic Bight. Many species that are not captured for food or pleasure are, nevertheless, indirectly important as forage for the commercial or sport species.

1) Life History Information for Mid-Atlantic Fishes

Knowledge of saltwater fishes is generally related to the importance of a particular species as food for man, or to the nearness of its habitat to the coast. Thus, life history information is available for the commercial and sport species mentioned in the previous section. There is also information available on many of the fishes which inhabit estuaries, coastal river mouths, bays, and beaches. Further offshore and toward the continental slope (the 200-meter depth contour), progressively less is known of the fish fauna.

This lack of understanding of comparatively inaccessible fishes is not only a function of the convenience with which nearshore species may be studied; it is also understandably a function of the areal size of the habitat of offshore fishes and the distances they migrate seasonally.

2) Ongoing Studies of Mid-Atlantic Fishes

Currently, studies of Middle Atlantic Bight fishes are being conducted by the Middle Atlantic Coastal Fisheries Center at Sandy Hook, New Jersey. A comprehensive survey of Atlantic Coast benthic fishes has been in progress for the past 10 years. The Northeast Fisheries Center in Woods Hole, Massachusetts, is studying fish north of Cape Cod, while the state of South Carolina is examining fish south of Cape Hatteras, North Carolina (Pacheco 1974)

Data are collected to assess the fluctuations of fish stocks in response to fishing mortalities. The purpose is to maximize sustainable yield without decimating the stock. Because foreign fishing fleets are catching an increasingly larger portion of offshore fishes, the International Convention for the Northwest Atlantic Fisheries is attempting to regulate multinational fishing pressures (Graham 1970).

Table B-1

1974 Landings of Commercial Fish and Shellfish by Species--Delaware

Species	Pounds (000)	Dollars (000)
Alewives	1	
Bluefish	3	
Flounder, black	2	
Hake, red	13	1
Menhaden	25	1
Sea bass, black	85	19
Sea trout, gray	225	52
Striped bass	140	38
Whiting	1	
Fish, other	96	26
TOTAL FISH	591	137
Crab, blue	1,820	419
Crab, other	62	30
Lobster, American	17	37
Clam, hard	60	50
Clam, surf	5,817	770
Oyster meat	201	173
Shellfish, other	8	2
TOTAL SHELLFISH	7,985	1,481
GRAND TOTAL	8,576	1,618

Source: U.S. DOC, unpubl., compiled 1975.

Table B-2

1974 Landings of Commercial Fish and Shellfish by Species--New Jersey

Species	Pounds (000)	Dollars (000)
Alewives	11	
Bluefish	1,004	115
Bonito	3	
Butterfish	979	135
Cod, true	337	82
Croaker	44	6
Flounder, black	140	17
Flounder, fluke	3,499	1,154
Flounder, yellow	266	48
Flounder, Atlantic	35	7
Hake, red	894	55
Hake, white	58	11
Herring, sea	346	15
Mackerel, Atlantic	775	109
Menhaden	107,307	2,735
Pollock	1	
Scup, or porgy	6,039	880
Sea bass, black	778	252
Sea trout, gray	2,686	312
Sharks	2	
Mackerel, Spanish	2	
Striped bass	714	178
Tuna, bluefin	872	231
Tuna, little	1	

Table B-2 (Cont.)

Species	Pounds (000)	Dollars (000)
Whiting	7,022	587
Fish, other	1,444	414
TOTAL FISH	135,159	7,343
Crab, blue	2,745	671
Crab, other	497	77
Lobster, American	1,191	1,916
Clam, hard	1,741	1,739
Clam, soft	87	73
Clam, surf	22,657	2,948
Oyster, meat	1,009	1,029
Scallop, bay	16	24
Scallop, sea	328	507
Squid	1,287	238
Shellfish, other	145	42
TOTAL SHELLFISH	31,703	9,264
GRAND TOTAL	166,962	16,607

Source: U.S. DOC, unpubl., compiled 1975.

3) Present Trends in Mid-Atlantic Fish Populations

Generally, fishing has substantially increased all along the Atlantic Coast since the early 1900s, when data were first collected, and this increased effort has apparently overfished several important species. Presently, the mid-Atlantic area is being fished by New England companies and foreign nations as well as by local fishermen.

Graham (1968) and Henry (1971) describe declines in catches due to overfishing. Graham (1968) generally concludes that much of the continental shelf area has been explored and no new substantial stocks of fishes are likely to be found. Thus, if heavy fishing pressures are maintained, the population sizes of many offshore fish will decrease until efforts are no longer economical. Henry (1971) attributes drastic declines in Atlantic menhaden populations to poor reproduction and survival rates of fish in the early 1960s, and to subsequent overfishing.

5. WATERFOWL

The coastal marshes and wetlands of New Jersey and Delaware support large and varied populations of birds. These populations consist of many varieties of songbirds, game birds, raptorial birds, and waterfowl. This report is concerned with birds that are intimately associated with the aquatic environment, such as the swimming birds (e.g., ducks, geese, swans), the wading birds (e.g., herons, egrets, sandpipers), and the gull-like birds (e.g., gulls, terns, petrels).

The resident populations vary through the year and may be divided into three basic types. Summer residents include most of the wading birds, as well as others. These nest in the area and move south for the winter. Winter residents nest far to the north and reside in the study area during the winter. Migrants are seen in the area in the spring on their way north to nesting grounds and again in the fall on their way to southern feeding grounds. Few individuals remain in the same area all year (except for some semi-domestics) although the same species may be seen throughout the year. This occurs when there is some overlap between the summer and winter range of a species. The birds of that species seen in summer nest in the study area and move south for the winter, and are replaced by birds which in the summer nest farther north.

Many of the birds occupy an ecological niche at or near the top of the food web. Wading birds, the gull-like birds, and some of the ducks feed upon fishes and invertebrates. The remainder of the ducks feed upon a variety of plants. As is the case with many higher-order consumers, no other animal relies entirely upon these birds as a food source.

Because both Delaware and New Jersey are traversed by the Atlantic Flyway (one of the major migratory routes for waterfowl), they host large numbers of migratory game birds each year. These transient populations attract substantial numbers of hunters each fall, who often have a positive impact on local economies. In addition, the spring and summer populations of waterfowl that concentrate at various refuges attract many visitors each year who come to observe or photograph the birds.

Lists of the more common waterfowl, along with information on their occurrence and major breeding grounds in the study area, are contained in Tables B-3 and B-4.

6. MARINE MAMMALS

Members of two groups of marine mammals inhabit or migrate through the New Jersey and Delaware offshore marine environments. The two groups are the whales and porpoises (Cetacea), and the seals (Pinnipedia).

Pilson and Goldstein (1973) list 36 species from Cape Cod to Cape Hatteras that "occur regularly in this region or have occurred here sometime in the historic past, or have been reported so close to the southern or northern boundaries of the region that occasional strays may be expected." The restricted area covered by this report has a less extensive species list. Table B-5 contains the 36 species given by Pilson and Goldstein. One additional species, the bowhead whale, was added since it is on the Delaware list of endangered species (Alexander, personal communication 1975). Species listed for Chesapeake Bay (Wass et al. 1972), on the New Jersey endangered species list, and on the Delaware endangered species list, are indicated. In addition, species likely to appear in Delaware or New Jersey have been indicated, using the ranges for marine mammals given by Burt and Grossenheider (1964).

Table B-3

Waterfowl of the Study Area

List of Abbreviations

acc = accidental
cas = casual
a = abundant
c = common
fc = fairly common
u = uncommon
r = rare
o = occasional
rg = regular
i = irregular

R = resident
Sp = spring
S = summer
F = fall
W = winter
V = visitant
M = migrant, migrates
YR = year-round
loc = local

Symbols for Abundance

These symbols represent the average number of birds likely to be seen in one day, or at a particular locality. The highest figures given for a species mean the average number during peak seasons. An asterisk (*) beside a symbol indicates that the greatest concentrations occur at that time or locality.

I = 1-100
II = 100-500
III = 500-1,000
IV = 1,000-5,000
V = 5,000-10,000
VI = 10,000-100,000
VII = over 100,000

List of Definitions

Pelagic = ≥5 miles offshore.
Littoral = <5 miles offshore.
Salt marsh = tidal marsh estuary, brackish marsh, seaside salt marsh.
Outer shore = beaches, rocky shoreline, tidal rocks, jetties.
Tidal flats = mud flats and areas exposed by the falling tide.
North Shore = Long Island Sound and the land areas bordering it (western Connecticut and the north shore of Long Island).
East Shore = the area around Montauk Point, Long Island, and the ocean from Montauk Point to Block Island, Rhode Island.
South Shore = the south shore of Long Island and the eastern shore of New Jersey.

The locations given for each species (e.g., East Shore, bays/inlets) indicate where the species is most likely to be found. This does not mean that the birds do not occur in other locations. In a few cases (e.g., the wood duck), the species is more common inland on fresh water, and rare in the location indicated in the study area.

Table B-3 (Cont.)

	DELAWARE	LONG ISLAND, NEW YORK and NEW JERSEY									
	STATUS	Open ocean	Outer shore	Bays/sounds	Salt marsh	Tidal flats	North Shore	South Shore	East Shore	STATUS	DATES PRESENT
Common loon	oM+WV;rSV	X		X	X			X	X	c/aM+WV;I-II	YR; *Nov; *Apr-May
Red-throated loon	oFM+WV	X		X	X			X	X	c/aM+WV;I-II	*Nov-Dec; *Apr
Red-necked grebe	acc	X		X	X			X	X	u/fcM+iWV;I	Oct-Apr
Horned grebe	oM+WV;rSV	X		X	X		X	X	X	c/aM+WV;I-III	mid Oct-late Apr
Pied-billed grebe	YR			X	X			X*	X*	fc/cM+uWV;I	YR;*Sep-Apr
Mute swan	rM+SV			X	X			X	X*	R;I-II	YR
Whistling swan	oM+WV;rSV			X	X			X	X	u/rM+WV;I	Nov-Mar
Canada goose	c/aM+WV;cSR			X	X	X		X		aM+WV;I-V	YR;*Mar-Nov
Brant	oM+WV	X		X	X	X		X*		r/aM+WV;I-VI	Dec-Apr
Snow goose	c/aM+WV;rSV			X	X			X		r/cM+WV;I-III	*mid Nov-Dec; *mid Mar-mid Apr
Mallard	c/aM+WV; c/aSR			X	X	X				c/aR,M+WV;I-II	YR
Black duck	aYRR	X		X	X	X		X*		aFM+WV; SR;I-IV	YR
Gadwall	c/aM+SR;oWV				X			X*		a/uM+WV;loc;I	YR;*Sep-Apr
Pintail	aM+WV;oSR				X			X*		fcFM+WV;I-III	Sep-Apr
Common teal	acc			X	X					r/casWV;I	Dec-Apr

Source: Adapted from Heppner and Gould 1973.

Table B-3 (Cont.)

	DELAWARE	LONG ISLAND, NEW YORK and NEW JERSEY								
	STATUS	Open ocean	Outer shore	Bays/sounds	Salt marsh	Tidal flats	North Shore	South Shore	East Shore	STATUS	DATES PRESENT
Green-winged teal	c/aM+WV;oSR			X	X			X		c/aM;uWV;I-II	Sep-Apr
Blue-winged teal	c/aM+SR;rWR				X			X*		r/locaFM; casWV;I	Apr-Oct
European widgeon	rM+WV			X	X			X	X	u/rM+o/fcWV;I	Oct-Mar
American widgeon	c/aM+WV;oSV			X	X			X	X	c/aM+WV;I-IV	Sep-Apr
Shoveler	c/aM;oSR+WV				X			X		locc/aM+WV;I	Sep-Apr
Wood duck	c/aM+SR;oWV				X					cFM;rWV;I	Mar-mid Nov
Redhead	oM+WV;rSV			X	X				X	r/fcWV;I	Oct-Apr
Ring-necked duck	cM;oWV;rSV			X	X					locc/aM+WV; I-II	late Oct-mid Apr
Canvasback	cM+WV;oSV			X	X					cWV;I-III	Nov-early Apr
Greater scaup	cM+WV;oSV			X	X		X	X		aWV;I-VI	YR
Lesser scaup	cM+WV				X					fcSpM;rWV	unknown
Common goldeneye	oM+WV;rSV	X		X			X		X	c/aWV;I-V	Nov-early Apr
Bufflehead	cM+WV;rSV			X	X			X	X	locc/aWV;I-II	mid Oct-Apr
Oldsquaw	oM+WV;rSV	X		X			X		X	c/oaWV;I-IV	YR; *late Oct-Apr
Common eider	acc	X		X			X	X	X	c/aM+WV;I-IV	Oct-Apr

Source: Adapted from Heppner and Gould 1973.

Table B-3 (Cont.)

	DELAWARE	LONG ISLAND, NEW YORK and NEW JERSEY									
	STATUS	Open ocean	Outer shore	Bays/sounds	Salt marsh	Tidal flats	North Shore	South Shore	East Shore	STATUS	DATES PRESENT
White-winged scoter	oM+WV	X							X	aM+WV;I-VI	Nov-Mar
Surf scoter	oM+WV	X		X			X		X	c/aM+WV;I-VI	Oct-Apr
Common scoter	oYR	X		X			X	X	X	c/aM+WV;I-VI	Oct-Apr
Ruddy duck	cM+WV;oSR			X	X			X	X	c/aFM+WV; I-III	Oct-Mar
Hooded merganser	cM+WV;oSV				X			X	X	c/aM+WV;I	Oct-Apr
Red-breasted merganser	oM+WV;rSV	X		X			X		X	c/aM+WV;I-V	Nov-Mar
Common merganser	cM+WV;rSV			X						uWV;I	Nov-Apr
King rail	cM+SR;oWR				X					rM+WV;I	Nov-Mar
Clapper rail	cM+SR;oWR				X		X	X		cSR;u/rWV;I	YR
Sora rail	cM+oSV				X					fcFM;rWV;I	YR *Mar; *Nov
American coot	c/aM;oWV+SR			X	X			X	X	c/aFM+WV;I-III	YR
American woodcock	cM;rWV;oSR							X		fcM;rWV;I	Mar-Nov

Source: Adapted from Heppner and Gould 1973.

Table B-3 (Cont.)

	DELAWARE	LONG ISLAND, NEW YORK and NEW JERSEY									
	STATUS	Pelagic	Littoral	Outer shore	Bays/sounds	Salt marsh	North Shore	South Shore	East Shore	STATUS	DATES PRESENT
Fulmar	no records	X	X							acc;I	Nov-Jan
Corys shearwater	no records	X	X						X	c/aS+FV;I-III	July-mid Nov; *late Aug-late Nov
Great shearwater	no records	X	X						X	r/cSV;I-II	late May-early Nov
Sooty shearwater	no records	X	X						X	c/aSV;I-II	late May-mid Sep
Audubons shearwater	no records	X	X							acc;May records	Aug
Leachs petrel	acc	X	X							casS+FV	early May-early Nov
Wilsons petrel	acc	X	X						X	c/aSV;I-V	late May-late Aug
Gannet	acc	X	X						X	c/aM;oWV	late Mar-mid May; late Nov-early Dec
Red phalarope	acc	X	X						X	cS+FM;I-IV	late Mar-late Apr; Sep-early Nov
Wilsons phalarope	oSpSFV		X		X	X		X		Sp+FM;casSM; I-III	mid Apr-May; Aug-mid Nov
Northern phalarope	oFM	X	X		X				X	rFM;casSpM;I	July-Sep
Pomarine jaeger	no records	X	X					X		u/rgM;I	early May-mid Nov
Parasitic jaeger	acc	X	X		X			X		rgM;I	early May-mid Nov
Long-tailed jaeger	no records	X						X		casM	late May-early June; early Aug-early Sep
Glaucous gull	acc		X	X				X	X	u/r/rgWV;I	YR

Source: Adapted from Heppner and Gould 1973.

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Table B-3 (Cont.)

	DELAWARE	LONG ISLAND, NEW YORK and NEW JERSEY								
	STATUS	Pelagic	Littoral	Outer shore	Bays/sounds	Salt marsh	North Shore	South Shore	East Shore	STATUS	DATES PRESENT
Iceland gull	no records		X	X						r/u/rgWV;I	Nov-Mar; *Dec-Feb
Great black-backed gull	YR;cSpFWV;oSV		X	X	X	X	X	X	X	c/aR+M;II-IV	YR;*Sep
Herring gull	YR;c/aR		X	X	X	X	X	X	X	Very aR;VI	YR;*Sep-Feb
Ring-billed gull	c/aM+WV;oSV; Aug-May			X	X			X		c/aM+WV; fcSV;I-IV	YR;*Aug-Nov
Black-headed gull	no records				X		X	X		u/rWV;oSV;I	Nov-late Mar
Laughing gull	c/aM+SV;VI		X	X	X		X	X		c/aM+SV;uWV; I-IV	*late Mar-mid Dec
Bonapartes gull	oYRV				X		X	X	X	c/aM+WV;oSV; I-V	Nov-May
Black-legged kittiwake	no records	X	X					X	X	u/cWV;I-II	Nov-Feb
Gull-billed tern	acc		X	X				X	X	r/iS+FV;I	early Jun-mid Sep
Forsters tern	cSV+FM;oSpM		X	X		X		X	X	u/cFM;rSpM; SR;I-II	Aug-early Nov
Common tern	oSR+M		X	X	X	X	X	X	X	aM;SR;II-IV	May-mid Nov
Arctic tern	no records									acc	
Roseate tern	acc		X	X			X	X	X	u/aSR+FM;I-II	mid May-Sep
Least tern	cSR;oM		X	X				X		c/aM;fcSR;I-II	May-mid Sep
Royal tern	rFM		X	X				X		rS+FV;I	July-Nov

Source: Adapted from Heppner and Gould 1973.

Table B-3 (Cont.)

	DELAWARE	LONG ISLAND, NEW YORK and NEW JERSEY									
	STATUS	Pelagic	Littoral	Outer shore	Bays/sounds	Salt marsh	North Shore	South Shore	East Shore	STATUS	DATES PRESENT
Sandwich tern	no records		X					X		cas	Sep
Caspian tern	oM+SV			X	X			X		uM;SR in N.J.; I-II	May; Aug-Sep
Black tern	oM+SR		X	X	X			X		u/oaM;oSV; I-IV	late May-early Oct
Black skimmer	oFM+SWV			X		X		X		locSR;c/a/oSV; I-IV	mid May-mid Oct
Razorbill auk	no records	X	X					X	X*	r/iWV;I	late Dec-early Mar
Common murre	no records									cas;I	
Thick-billed murre	no records	X	X					X	X	r/iWV;I	Dec-Feb
Dovekie	no records	X	X					X	X	r/rgWV;I	mid Nov-early Mar
Black guillemot	no records		X	X					X	cas/rWV;I	Nov-Mar
Common puffin	no records		X	X					X	casWV;I	Nov-Mar

Source: Adapted from Heppner and Gould 1973.

Table B-4

Major Breeding Areas in New Jersey and Delaware and Representative Birds Breeding in Each Locality

NEW JERSEY

Barnegat National Wildlife Refuge: Waterfowl, marsh birds.

Brigantine National Wildlife Refuge: Waterfowl, marsh birds, shorebirds (e.g., Wilson's plover, black skimmer, American oystercatcher), rails, terns (e.g., Forsters tern), songbirds.

Cape May: Cattle egret, snowy egret, Louisiana heron, herring gull, laughing gull, black skimmer, songbirds.

Hackensack Meadows: Least bittern, blue-winged teal, ruddy duck, marsh hawk, Virginia rail, common gallinule, American coot.

Little Beach Island: Laughing gull, black skimmer.

Sandy Hook State Park: Common egret, green heron, black-crowned night heron, black duck, mallard, wood duck, osprey, sparrow hawk, bobwhite, clapper rail, sora, semipalmated plover, killdeer, American woodcock, semipalmated sandpiper, great black-backed gull, herring gull, laughing gull, common tern, least tern, mourning dove, great horned owl, whippoorwill, belted kingfisher, yellow-shafted flicker, songbirds.

DELAWARE

Bombay Hook National Wildlife Refuge: Pied-billed grebe, green heron, black-crowned night heron, least bittern, American bittern, Canada goose, mallard, black duck, pintail, gadwall, green-winged teal, blue-winged teal, shoveler, wood duck, ruddy duck, turkey vulture, bald eagle, marsh hawk, other hawks, pheasant, bobwhite, clapper rail, Virginia rail, common gallinule, American coot, killdeer, American woodcock, willet, black-necked stilt, black tern, mourning dove, owls, songbirds.

Source: Adapted from Heppner and Gould 1973.

Table B-5

Marine Mammals in Study Area

Species	Pilson and Goldstein 1973	Wass et al. 1972	Delaware List[a]	New Jersey List[a]	Burt and Grossenheider 1964
Walrus	X				
Harbor seal	X	X		X	X
Gray seal	X			X	X
Harp seal	X			X	X
Hooded seal	X			X	X
Manatee	X				
Right whale	X	X	X	X	X
Gray whale	X				
Minke whale	X				
Sei whale	X	X	X		X
Fin whale	X	X	X		X
Blue whale	X		X	X	X
Hump-backed whale	X	X	X	X	X
Rough-tooth dolphin	X	X			
Bottle-nosed dolphin	X	X			X
Risso's dolphin	X				X
White-beaked dolphin	X				
White-sided dolphin	X				
Spotted dolphin	X	X			
Striped dolphin	X				
Common dolphin	X	X			X
False killer whale	X				
Pilot whale	X	X			X
Short-finned pilot whale	X	X			X
Killer whale	X				X
Harbor porpoise	X				X
White whale	X				
Sperm whale	X	X	X		X
Pigmy sperm whale	X	X			X
Dwarf sperm whale	X				Not listed
North Sea beaked whale	X				
Antillean beaked whale	X				Not listed
True's beaked whale	X				X
Dense-beaked whale	X				
Goose-beaked whale	X	X			X
North Atlantic bottle-nosed whale	X				
Bowhead whale			X		

a. Rare, threatened, or endangered species according to individual state list.

Of the various groups of organisms discussed, the marine mammals are probably the least well known. There is a need to clarify the nomenclature, both scientific and common names, and the natural history of many species. In order to effectively protect this long-exploited group of animals, many of which are now endangered, a great deal of additional research needs to be done.

APPENDIX C

SUPPLEMENTARY TABLES PROVIDING ADDITIONAL INFORMATION ON THE IMPACT OF PETROLEUM WASTES

The eleven tables presented in this section summarize current information on the effects of actual oil spills on biological communities (Table C-1), information on the toxicity of petroleum substances to various marine organisms (Tables C-2 through C-10), and information on U.S. Department of the Interior petroleum-related environmental research that is now in progress (Table C-11).

Table C-1. A Summary of Several Major Oil Spills Followed by Studies of Their Biological Impact

Date of Spill	Source and Location	Type and Amount of Oil (barrels)	Shoreline Affected (mi)	Localities Studied	Species Identified	Sampling Method	Biological Damage	Reference
March 1957	*Tampico Maru*, Baja California, Mexico	Diesel oil 60,000	2	Intertidal and subtidal	Larger visible plants and animals	Qualitative, quantitative macrocystis counts	Nearly total devastation immediately, luxuriant growth of seaweed developed within months; biota 90% restored after 3 or 4 years, although relative abundance of certain species still somewhat changed after 12 years	North *et al.*, 1964; Mitchell *et al.*, 1970
July 1962	*Argea Prima*, Guayanilla Harbor, Puerto Rico	Crude oil 70,000		Mangrove shores; intertidal and subtidal	Blue-green algae	Qualitative	Extensive damage: high mortalities among many shallow water and shore-dwelling organisms, including a wide variety of vertebrates; also extensive damage to intertidal and sublittoral algae and mangrove habitat	Diaz-Piferrer, 1962
Jan. 1967	*Chryssi P. Goulandris*, Milford Haven, England	Crude oil >1,800		Intertidal salt marsh; intertidal rocky shore	Grasses	Semiquantitative rocky shore transect; quantitative studies of grasses	Most damage to intertidal organisms; gastropod molluscs badly affected, also barnacles and sea anemones on a number of shores; no apparent damage to algae	Cowell, 1969; Nelson-Smith, 1968
March 1967	*Torrey Canyon*, S.W. England	860,000[a]		Intertidal rocky shores and sand beach	Larger visible animals only	Semiquantitative rocky shore transects; qualitative beach and subtidal surveys; quantitative algal counts	Very high mortalities of intertidal shore life, mostly due to use of toxic emulsifiers; many invertebrates and algae killed on shores; fisheries and plankton apparently unaffected; estimated 10,000 birds killed	Bellamy *et al.*, 1967; Smith, 1968
Sept. 1967	*R. C. Stoner*, Wake Island	Aviation gas, J-P4 jet fuel, A-1 turbine oil, and Bunker C oil 126,000		Intertidal and subtidal	Large visible invertebrates	Qualitative	Many dead fish stranded on shores; also abundant dead molluscs, sea-urchins, and crabs	Gooding, 1968
March 1968	*Ocean Eagle*, San Juan Harbor, Puerto Rico	Crude oil 83,000		Intertidal rocky shore	15 large sp.	Qualitative	Many subtidal and intertidal organisms killed or damaged by oil or oil and emulsifier, including molluscs, crustaceans, and algae, although subsequent recovery good; 10 species of fish found dead or in state of stress	Cerame-Vivas, 1968
April 1968	*Esso Essen*, S. Africa	Crude oil 20,000-28,000		Intertidal and subtidal	No species identifications, observations on larger organisms	Qualitative	High mortalities of sandhoppers (amphipods) but otherwise little damage on shores; high bird mortalities	Stander and Ventner, 1968

Table C-1. A Summary of Several Major Oil Spills Followed by Studies of Their Biological Impact (Cont.)

Date of Spill	Source and Location	Type and Amount of Oil (barrels)	Shoreline Affected (mi)	Localities Studied	Species Identified	Sampling Method	Biological Damage	Reference
Dec. 1968	*Witwater*, Galeta Island, Canal Zone	Diesel and Bunker C oil 20,000		Rocky intertidal, coral reef, sandy intertidal mangroves	*Uca*, mangrove species, four coral species	One quantitative sand sample for meiofauna; otherwise qualitative	On rocky shores, extensive mortality of supralittoral vegetation and tide pool life; on sandy beaches, great population decreases among meiofauna, especially crustaceans; many young mangroves killed in swamp areas, also algae and many invertebrates; coral reefs apparently unharmed	Rutzler and Sterrer, 1970
Jan. 1969	Well A-21, Santa Barbara Channel	Crude oil 33,000[a]	40	Intertidal and subtidal	Subtidally: selected polychaete families, ophiuroids, and molluscs not including smaller polychaetes and amphipods; intertidally: visible rocky shore species and 195 sp. retained by 1.5-mm screens in sandy areas	Grab sample, qualitative at species level; quantitative for biomass line transects on rocky shores; 1/100 m^3 samples on beaches	High mortalities of intertidal organisms covered with oil; about 3,600 birds killed; no apparent effects on fish and plankton; no directly attributable damaging effects of oil on large marine mammals or on benthic fauna; area recovering well within a year	Cimberg *et al.*, 1973; Fauchald, 1971; Foster *et al.*, 1971a,b; Nicholson and Cimberg, 1971; Straughan, 1972
Sept. 1969	*Florida*, West Falmouth, Mass.	No. 2 fuel oil 4,500[a]	3	Intertidal mud and sand flats; subtidal to 10 mm	All animals 0.247 mm, excluding nematodes, copepods; ostracods and unicellular organisms, including smaller polychaetes and amphipods	Quantitative transects	Severe pollution of sublittoral zone, with 95% kill of all fauna, including many fish, worms, molluscs, crabs, lobsters, and other crustaceans and invertebrates; local shellfish industry severely affected; Wild Harbor still closed to shellfish fishing in May 1974	Blumer and Sass, 1972; Blumer *et al.*, 1970a,b
Feb. 1970	*Arrow*, Chedabucto Bay	Bunker C 108,000[a]	12	Intertidal rocky shore; intertidal lagoon	Common visible species on rocky shore and species 74 mm in lagoon samples	Semiquantitative transects; 2 samples in lagoon	Localized damage to intertidal life, where most mortalities were crabs, limpets, and algae, probably killed by smothering; local fish catches normal; about 2,300 birds killed; 5 months after spill, subtidal flora and fauna healthy; fishing and lobstering normal	Thomas, 1973; Navships, 1970
Jan. 1971	*Arizona Standard* and *Oregon Standard*, San Francisco Bay	Bunker C 20,000[a]	60	Intertidal and subtidal rocky shore; intertidal sand beach	31 larger sp.	Quantitative transect counts	Some damage to shore life, mainly to acorn barnacles, limpets, mussels, and striped shore crabs; 3,600 birds killed; area nearly normal within 1 year	Chan, 1973
Feb. 1971	*Wafra*, Cape Aulhas, S. Africa	Crude oil 445,000	10	Intertidal rocky shores	Larger intertidal rocky shore species	Qualitative	Little damage to intertidal life; 1,135 black footed penguins found oiled	Day *et al.*, 1971
April 1971	March Point Dock Facility, Anacortes, Washington	No. 2 fuel oil 5,000	20	Intertidal beaches, rocky shores, subtidal	Animals 4 mm in subtidal samples, visible epifauna in intertidal areas; fauna identified to major taxa only	Quantitative grabs; quantitative intertidal transects	Some oil on shores, damaging shellfish, limpets, crabs, clams and oysters; about 1,000 birds involved	Watson *et al.*, 1971; Woodin *et al.*, 1973
Jan. 1972	*General M.C. Meigs*, Wreck Cove, Washington Coast	Navy special oil 3,000[a]	300-500 yd	Intertidal rocky shores	37 sp. algae, sp. animals not including smaller polychaetes and amphipods	Quantitative transects	Urchins affected; plant community showed less of fronds and bleached thalli	Clark *et al.*, 1973

SOURCE: NAS 1975: 74-75.

TABLE C-2. SUMMARY OF TOXIC RESPONSES FOR MARINE FLORA

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Phyto-Plankton	Dinobryon Sp. Peridinum Sp.	FIELD (freshwater pond, June-October)	M.S.O. crude 4.5 1/6 diam. test area (film on surface)		117 days (whole experiment)	growth suppressed	Kauss, et al (1972)	
"	Tabellaria Sp. Ankistrodesmus spirales	"	"		"	growth stimulated	"	
"	Fragillaria Sp. Ankistrodesmus falcatus	"	"		"	no response	"	volatilization & bacterial degradation
"	Chlorococcum Sp.	LABORATORY	Soluble extract from 50 ml in 1 liter water 0, 25, 50, 75, 100% "saturation	1-5 ppm 100% "saturation"	10 days	no response	"	
"	Cosmarium Sp.	"	"	"	12 days	growth inversely proportional to % saturation	"	
"	Chlorella vulgaris	"	Soluble extract from 50 ml "Gulf" crude in one liter water 0, 10, 25, 50, 75, 90% "saturation"	"	10 days	growth suppressed	"	suppression attributed to a decrease caused by oil
"	"	"	Benzene	25-500 ppm 500-1744 ppm	10 days 10 days	initial inhibition for 2 days, then growth lethal toxicity	"	4 day $LD_{50} \cong$ 650 ppm (our estimate from Kauss data)
"	"	"	Tuluene	25-250 ppm 500 ppm	10 days 10 days	slight inhib. lethal toxicity	"	4 day $LD_{50} \cong$ 175 ppm (our estimate from Kauss data)
"	"	"	O-Xylene	25-50 ppm	10 days	slight inhib. lethal toxicity	"	4 day $LD_{50} \cong$ 70 ppm
"	?	"	7 Alberta crudes concentrations unknown		10 days	2 day inhibition then stimulation	"	
"	Chlorella vulgaris	"	Bailey Colville (an Alberta crude) soluble extract		10 days	slight inhibition over 10 day period	"	

TABLE C-2. SUMMARY OF TOXIC RESPONSES FOR MARINE FLORA (CONT.)

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Phyto Plankton	Numerous Species	Laboratory	"oil" .00001-1.0 ml/l; most used .001-1. ml/l	(.01-1000. ppm)	5 days	death 1 ml/l. (1000 ppm) delayed cell division 1.0-.001 ml/l no effect .01-.001 ml/l (10-.01 ppm)	Mironov (1970)	does not describe oil used or whether concentrations quoted are soluble or not
Intertidal plants surf grass	Phyllospadix torreyii	incident Santa Barbara	weathered crude heavy coating		one tidal cycle	death through coating & abrasion (smothering)	Foster, et al (1971)	
Green algae (mid & high intertidal)	Enteromorpha intestinalis	"	heavy coating various coatings			slight damage except where completely coated	"	
	Chaetomorpha aerea	"	heavy coating various coatings					most intertidal algae have a mucous coat which sheds oil; high intertidal plants, where oil dried were damaged, season important- i.e. blooms, subtidal plants not affected
	Ulva californica	"	heavy coating various coatings			U. californica recovered in 4 months		
Brown algae	Egregia laevigata	"	various coatings			little damage		
Red algae	Porphyra sp.	"	"			killed-holds oil		
Kelp	Macrocystis angustifolia	"	heavy coating			no damage-mucous coat		
"	"	Tampico Maru Laboratory	diesel fuel .01%-1% emulsion	1-100 ppm	7 days	loss of photosynth. ability	North et al (1964)	Tampico Maru spill resulted in kills to members all phyla.
Salt marsh grasses	Spartina townsendii	incidents: Milford Haven & Torrey Canyon	fresh crude		20 min. (M.H.) after spill	75-100% killed	Cowell (1971)	many other marsh plants studied but not summarized here
	Puccinellia maritima	weathered crude (& dispersants)			8 days (T.C.)			
Macrophytic algae		incident: Torrey Canyon	weathered crude & dispersants			algae increased coverage of rocks	Bellamy et al (1967)	oil & dispersants killed herbivores, so algae overgrew rocks

TABLE C-2. SUMMARY OF TOXIC RESPONSES FOR MARINE FLORA (CONT.)

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Phytoplankton	Prasinophyceae Halosphaera sp. Pterosperma sp.	incident: Torrey Canyon	crude slick			lethal toxicity (reduced population)	Smith (1968)	Cysts (reprod cells) of these were disrupted by oil, since they float near surface
"	various species	Laboratory	BP 1002 emulsifier without kerosene	1.2×10^{-3} ppm 1.2 ppm		generation time & lag phase lengthened below 1.2 ppm lethal toxicity at 1.2 ppm	"	brackish water species better able to withstand membrane damage caused by emulsifier (sol'n in lipid layer)
Salt marsh grasses	various species	Field experiment (Milford Haven)	fresh crudes (Kuwait)			see p.31 of Cowell annuals most susceptible, perennials most resistant	Baker (1971)	germination in annuals inhibited seasonally dependent
Kelp	Macrocystic angustifolia	Laboratory	benzene n-hexane toluene	10 ppm 10 ppm 10 ppm	96 hrs. 96 hrs. 96 hrs.	slight photosynth. inhib. no effect visible injury, 75% reduction in photosynth.	Wilber (1968)	

SOURCE: MIT 1973: 216-218.

TABLE C-3. SUMMARY OF TOXIC RESPONSES OF FINFISH

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Atlantic Salmon	Salmo salar	Laboratory	Corexit 8666 1-10,000 mg/1 complete emulsion		7-14 days	4 day LD_{50} >10,000 mg/1	Sprague & Carson (1970)	authors point out probability of sublethal-long-term effects of oil dispersant at lower conc.
"	"	"	1-10,000 mg/1 complete emulsion BP1100 B BP 1100 Gulf agent 1009 Naphtha gas Dispersant 88 Dispersol SD BP1002 XZIT x-1-11	2-2000 ppm	7-14 days	4 day LD_{50} 1-100 mg/1		authors believe Corexit is microbially degraded; the byproducts of this process, either from Corexit or waste from microbes, are toxic after 7 day's building in test tank.
"	"	"	1-10,000 mg/1 temporary emulsion Bunker C	0-1 ppm	7-14 days	4 day LD_{50} >10,000 mg/1 7 day LD_{50} ~ 2000 mg/1		
"	"	"	Bunker C & Corexit 8666		"	4 day 7 day } LD_{50} ≥100-1000 mg/1		
Flounder (winter)	Pseudopleuronectes americanus	"	Bunker C & Corexit 8666		"	4 day LD_{50} >10,000 mg/1 7 day LD_{50} ~1000 mg/1		
fresh water fish	Mugil saliens Sargus annularis Crenilabrus tenca	Laboratory	"oil" .25 ml/1		"many days" "several days"	no effect	Mironov (1970)	emulsion more toxic than film
Flaice	Rhombus maeoticus	Laboratory	"oil" 10^{-4}-10^{-5} ml/1		2 days	lethal toxicity to eggs	"	
Shad	Alosa sapidisuima	Laboratory	Gasoline #2 Diesel fuel Bunker C			LD_{50} 24 48 96 Gas 91 91 - #2 204 167 - C - 2,417 1,952	Tagatz (196)	loss of toxicity by evaporation
Mullet	Mugil cephalus Micropogon undulatus	Laboratory	#2 Diesel oil .01-10% emulsified	.002-2 ppm	LD_{50} (48 hr.) 420 ppm (acute) LD_{50} (chronic) 42 ppm	LD_{50} (48 hr.) ~420 ppm (acute) LD_{50} (chronic) 42 ppm	Texas Instruments (1971)	safe at 4.2 ppm

TABLE C-3. SUMMARY OF TOXIC RESPONSES OF FINFISH (CONT.)

ORGANISM COMMON NAME	ORGANISM SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Roach	Rutilus sp.	Laboratory	cyclohexane benzene methylcyclohexane	10 ppm 10 ppm 10 ppm	3-4 hrs.	lethal toxicity	Nelson-Smith (1970)	
Sunfish		"	Phenanthrene Naphthalene Xylene, toluene benzene, ethylene	4-5 ppm 4-5 ppm 22-65 ppm	1 hr.	lethal toxicity	Wilber (1968)	
Thread herring	Ophistonema onglinum	incident: Ocean Eagle San Juan	crude oil & emulsifiers			95% of schools near spill had lesions	Cerame-Vivas (1968)	

SOURCE: MIT 1973: 219-220.

TABLE C-4. SUMMARY OF TOXIC EFFECTS OF OILS ON LARVAE AND EGGS OF MARINE ORGANISMS

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Plaice	Rhombus maeoticus	Laboratory	"oil" 10^{-4} - 10^{-5} ml/l			40 to 100% hatched pre-larvae perished	Mironov (1968)	no information on experimental methods
Barnacle	Balanus sp.					Larvae 100 times more sensitive than adults	"	"
Cod and Flounder		Laboratory	Bunker C film - 100 ppm	~0	96 hours	35% pulled in stagnant water, not affected in running water	James (1926) reported in Kuhnhold (1970)	"
Black Sea Turbot		Laboratory	10-100 ppm dispersion of Russian crude	.01 - 1 ppm	2-3 days	100% eggs killed	Mironov (1967) reported in Kuhnhold (1970)	"
Herring		Laboratory	10^3 and $2x10^4$ppm film		2.5-3.5 days	100% eggs killed	Kuhnhold (1969) reported in Kuhnhold (1970)	"
Cod	Gadus morrhua	Laboratory	extract of Venezuelan oil in water 10^4ppm 10^2ppm extracts of Iranian crude 10^4ppm 10^3ppm 10^2ppm control	 .10ppm .1ppm 10ppm 1ppm .1ppm	100 hours	40% higher mortality than control 10-20% increase in mortality 99% killed 63% killed 33% killed 21% killed	Kuhnhold (1970)	Libyan (high paraffin content) did not cause increases in mortality; 10 day old larvae less sensitive
Cod	Gadus morrhua	Laboratory	extracts of Iranian Crude in water 10^4ppm 10^3ppm 10^2ppm 10^3plus 10-100ppm Correxit 7664 10-100ppm Correxit 7664	 10ppm 1ppm .1ppm control 100-1000ppm ~0	1-10 days 4.2 days 8.4 days 14 days 14 days 3 to 6 hours no effect	Time to death for larvae exposed for 1 day	"	Young larvae less resistant than embryo; Herring less resistant; Plaice more resistant; Libyan crude affected larvae more than embryos.

TABLE C-4. SUMMARY OF TOXIC EFFECTS OF OILS ON LARVAE AND EGGS OF MARINE ORGANISMS (CONT.)

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Plaice	Pleuronectas platessa	Laboratory	0 - 10ppm BP1002	0 - 2ppm	1 - 30 days	10ppm BP1002 killed 100%; 2.5ppm BP1002 reduced survival by 50%	Wilson (1970)	see original article for considerable more detail; some mortality delayed due to effects on feeding and larval development
Barnacle	Elminius modestus	Laboratory	0 - 100ppm BP1002 1000ppm Kuwait	0 - 20ppm 1ppm	various	0 - 3ppm BP1002 increase mortality some reduction of activity	Corner, et al. (1968)	original article contains much more data on other dispersants and other tests; adults resistant up to 100ppm BP1002
Pilchard	Sardine pikhardus	Torrey Canyon Incident	Kuwait and emulsifiers			50-90% of eggs in plankton tows dead	Smith (1968)	
Lobsters	Homarus americanus	Laboratory	.001 - .1ml/1 Venezuelan crude	(.01-1ppm)	24 - 96 hours	$96LD_{50}$ = .03 - 002ml/1	Wells (1972)	.001ml/1 had little effect; .1ml/1 very toxic
Sea Urchin	Strongylocentrotus purpuratus	Laboratory	extracts of 25ml crude and bunker C oils in 500ml sea water 6.25% - 50% dilutions	(.1-1ppm)		fertilization not affected; lowest dilutions interfere with fertilized egg development	Allen (1971)	Urchins generally very sensitive
Polychaete	Sabellaria spinulosa	Laboratory	.5 - 1ppm BP1002	.1 - .2ppm	several hours to several days	1ppm caused 100% mortality; .5ppm caused abnormal development	Wilson (1968)	death definitely due to kerosene solvent in BP1002
Crustaceans	several	Laboratory	1 - 10ppm BP1002	.2 - 2ppm		1ppm BP1002 lethal	Portmann & Connor (1968)	Larvae 10-100 times as sensitive as adults
Oysters	Crassostrea gigas	Laboratory	various detergents 0 - 3ppm	0 - .5ppm	24 hours	3ppm of all detergents toxic	Smith (1968)	also similar results for many other marine invertebrate larvae

SOURCE: MIT 1973: 221-222.

TABLE C-5. SUMMARY OF TOXIC RESPONSES TO OILS OF PELAGIC CRUSTACEANS

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Copepod	several species	Laboratory	.001-.1 ml/l "oil"	(possibly 1-100 ppm)		insensitive to .001 ml/l, 100% death with .1 ml/l	Mironov(1969), cited in Mironov (1970)	experimental methods not described
Shrimp	Penaeus sp. Palaemonetes sp.	Laboratory	crude oil plus emulsifiers (1-100 ppt)	(1-100 ppm)		48LD$_{50}$ = 1-40 ppt crude oil 48LD$_{50}$ = .5-5 ppt crude plus Corexit	Mills and Culley (1971)	see reference for detailed breakdown; oils with higher proportion of aromatics most toxic
Copepod	Calanus finmarchicus	Laboratory	1-50 ppm BP 1002 Gamlen Dasic Molyslip Houghton Solvent 112	.2-10 ppm	1 hour-3 days	50 ppm detergent caused 100% mortality in an hour; 5-10 ppm detergents caused high mortality in 3 days; 1 ppm was injurious	Smith (1968)	
Copepod	Acartia clausi	Laboratory	5-100 ppm BP 1002 Dasic	1-20 ppm	10-1000 minutes	lethally toxic at all concentrations	"	BP 1002 5 times as toxic as Dasic; Acartia much less resistant than Calanus; suggests small animals toxicity is related to size
Pink Shrimp	Pandalus montagui	Laboratory	BP1002		48 hr. LD$_{50}$ = 5.8 ppm	Portmann and Connor (1968)		

SOURCE: MIT 1973: 223.

TABLE C-6. SUMMARY OF TOXIC RESPONSES OF GASTROPODS

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Dog Whelk Periwinkle	Nucella lapidus Littorina littorea	Incident	"dispersants"			more resistance than crustaceans	Shelton (1971)	Gastropods can produce copious mucus secretion
Periwinkle	Littorina littorea	Incident: Arrow	Bunker C			ingestion of oil- no effect	Scarratt et al (1970)	intertidal contact with oil-oil passed through digestive system unmodified - no uptake in other organs
Periwinkle	Littorina littorea		fresh crude oil			"sensitive"	Nelson-Smith (1967)	
Limpets	Acmea sp.	Incident: Santa Barbara	weathered crude oil	heavy coat		little damage	Foster, et al (1971)	limpets appeared to be feeding on oil
Periwinkle " Limpet Dogwhelk	Littorina neritoides Littorina saxatilis Patella vulgata Thais lapillus Gibbula umbilicalis Littorina obtusata	Field	Kuwait crude (fresh) Kuwait crude (weathered) DP 1002 (single in combination) ∿ 2 liters/m²		5 min.-6 hrs.	general relative toxicity to gastropods BP 1002 > fresh ≫ weathered	Crapp in Cowell (1971)	data difficult to summarize by species; experiments were small scale and contained many uncontrolled variables, making quantification of results difficult
same 6 species as above		Laboratory	BP 1002 BP 1100			toxicity dependent on season: least toxic in winter (water temp. 10°C) highest in summer (water temp. 18°C) BP 1002 much more toxic than BP 1100	"	same comments as above
Limpet Periwinkle Periwinkle	Patella vulgata Littorina littorea Littorina littoralis	Laboratory	various crudes		sprayed on for 1 hr. then washed	1-89% mortality for L. littoralis L. littorea very resistant. P. vulgata very sensitive	Ottway in Cowell (1971)	high mortality correlates with asphaltenes & low boiling compounds (aromatics, especially).

TABLE C-6. SUMMARY OF TOXIC RESPONSES OF GASTROPODS (CONT.)

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Periwinkle	Littorina littorea	Laboratory	BP 1002		24 hrs.	LD_{50} ~100 ppm	Smith (1968)	intertidal species periwinkles may recover from 100 ppm all detach from substrate before dying
Dog Whelk	Nucella lapillus		0-100 ppm	0-20 ppm	"	LD_{50} ~100 ppm		
Top-shell	Monodonta lineata					LD_{50} = 100 ppm		
Limpet	Patella vulgata					LD_{50} = 5 ppm		
Limpet	Patella vulgata	Laboratory	BP 1002			96h LD_{50} = 5 ppm	Perkins in Carthy & Arthur (1968)	data supports Ottway's conclusions
			0-200 ppm	0-400 ppm				
Periwinkle	Littorina littoralis	Laboratory	BP 1002			24h LD_{50} = 250 ppm		
Periwinkle	L. littorea	"	"			24h LD_{50} =2000 ppm		
Periwinkle	L. littorea	"	crude oil weathering BP 1002			weathered oil less toxic than oil & BP 1002.		oil weathered for 24h in lab. simulated tidal washing in lab.

SOURCE: MIT 1973: 224-225.

TABLE C-7. SUMMARY OF TOXIC EFFECTS OF OIL ON MARINE BIVALVES (SHELLFISH)

ORGANISM		EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
COMMON NAME	SCIENTIFIC NAME							
Cockles	Cardium edule	Laboratory	detergents	0-20 ppm	variable	$48LD_{50}$ for BP1002 81ppm	Portmann & Connor (1968)	$48LD_{50}$ for many detergents given
Mussel	Modiolus modiolus	Field (Arrow Spill)	Bunker C			oil content 100-125 μg/gm	Scarratt, et al. (1970)	incorporation of Bunker C after Arrow Spill
Mussel	Mytilus edulis	Laboratory	BP1002	∿.4ppm		$24LD_{50}$ = 90ppm $48LD_{50}$ = 2ppm	Perkins (1968)	
Cockle	Cardium edule	Laboratory	BP1002	∿.4ppm		$24LD_{50}$ = 20ppm	Perkins (1968)	
Mussel	Mytilus edulis	Laboratory	0-100ppm BP1002	0-20ppm	24 hours	5ppm BP1002 not lethal in 24 hours; 10ppm BP1002 lethal	Smith (1968)	Also obtained information on sublethal concentrations
			1000ppm crude emulsion	∿60ppm	24 hours	no deaths, but mussels could not attach properly		
Razor clam	Ensis siligua	Laboratory	BP 1002			24 hrs. LD_{50} = 0.5 ppm	"	subtidal species
Queen scallop	Chlamys opercularis					24 hrs. LD_{50} = 1 ppm		
Oysters		Laboratory	BP1002	∿2-20ppm		10-100ppm BP1002 lethal	Simpson (1968)	
Cockles	Cardium edule		phenol			$48LD_{50}$ = 500ppm	Nelson-Smith & Hepple(1971)	
Mussel	Mytilus edulis	Laboratory	"laboratory" weathered (24 hours) Arabian crude plus Correxit or Dispersol approximately .5ml/cm^2 + 10% dispersant		4 tidal cycles	no toxicity for crude oil only; 50% mortality with Dispersol plus oil		simulated tidal conditions

TABLE C-7. SUMMARY OF TOXIC EFFECTS OF OIL ON MARINE BIVALVES (SHELLFISH) (CONT.)

ORGANISM		EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTIONS	DURATION	RESPONSE	REFERENCE	REMARKS
COMMON NAME	SCIENTIFIC NAME							
Mussels	Mytilus californianus	Laboratory	0-10^5 ppm Santa Barbara crude (as surface film)	0-100ppm	34 days	10^4 and 10^5 ppm caused significant mortality	Kanter, Straughan, and Jessee (1971)	individual from area (Coal Point) subject to natural seeps possibly less susceptible than those from other areas; data not conclusive
Mussels	Mytilus edulis	Laboratory	1000mg/l mineral oil (paraffin only)	0	up to 6 days	no mortality	Lee (1972)	primarily an experiment to investigate uptake and incorporation
			1-8mg/l heptadecane	0	up to 6 days	no mortality		
			100ppm tetralin	100ppm	up to 6 days	toxic		
			1ppm toluene, napthalene, 3,4-benzpyrene	1ppm	up to 6 days	not toxic		

SOURCE: MIT 1973: 226-227.

TABLE C-8. SUMMARY OF TOXIC EFFECTS OF OIL ON MARINE BENTHIC CRUSTACEANS

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Shrimp	Crangon crangon	Laboratory	various emulsifiers	~1ppm	48 hours	48LD$_{50}$ for BP1002=5.8ppm	Portmann and Connor (1968)	
Shore crab	Carcinus maenas	Laboratory	various emulsifiers	~3ppm	48 hours	BP1002 48LD$_{50}$=15ppm		
Lobster	Homarus gammarus	Laboratory	various emulsifiers	~4ppm	48 hours	BP1002 24LD$_{50}$=20ppm		
Barnacles	Elminius modestus	Laboratory	1-100ppm BP1002	0-20ppm	48 hours	100% mortality with 100ppm; 5ppm shows sub lethal effect	Corner, et al. (1968)	
			100ppm film of Kuwait	.1ppm	24 hours	some inhibition of cirral beat		
Lobsters	Homarus americanus	Laboratory	Bunker C and various dispersants		7-14 days	4 day LD$_{50}$ for Bunker C > 10,000 ppm	Scarratt et al (1970)	lobster fishery of Chedabucto Bay not damaged by Arrow spill; lobsters considered very resistant
Barnacles	Balanus balanoids	Laboratory	BP 1002	2 ppm		100% survival at 10ppm	Perkins (1968) in Carthy & Arthur (1968)	
Hermit Crab	Eupagurus bernhardus	Laboratory	BP 1002	1ppm		96 hours LD$_{50}$ = 5ppm		
Crab	Carcinus maenas	Laboratory	BP 1002	6ppm		96 LD$_{50}$ = 30ppm		
Crab	Cancer pagures	Laboratory	BP 1002	2ppm		24LD$_{50}$ = 10ppm	Smith (1968)	
Shrimp	Crangon vulgaris	Laboratory	BP 1002	4ppm		24LD$_{50}$ = 2ppm		
	Carcinus maenas	Laboratory	BP 1002	5ppm		24LD$_{50}$ = 25ppm		
Hermit Crab	Diogenes pugilator	Laboratory	BP 1002	5ppm		24LD$_{50}$ = 25ppm		
Barnacle	Balanus balanoides	Laboratory	crude oil	2ppm		2% is toxic	Nelson-Smith in Hepple (1971)	
many species		Field	Kuwait BP 1002				Crapp in Cowell (1971)	many field experiments and data which is difficult to summarize; data indicates little toxic response of most species to weathered kuwait.

SOURCE: MIT 1973: 228.

TABLE C-9. SUMMARY OF TOXIC EFFECTS OF OIL ON OTHER BENTHIC INVERTEBRATES

ORGANISM COMMON NAME	SCIENTIFIC NAME	EXPERIMENT TYPE	SUBSTANCE & REPORTED AMOUNT	ESTIMATED HYDROCARBONS IN SOLUTION	DURATION	RESPONSE	REFERENCE	REMARKS
Polychaete annelid	Arenicola marina	Laboratory	BP 1002	6 ppm		96 hr. LD_{50} = 30ppm	Perkins in Carthy & Arthur (1968)	
"	Nereis diversicolor	"	BP 1002	5 ppm		24 hr. LD_{50} = 25ppm	Smith (1968)	
starfish	Asterias rubens	"	BP 1002	6-8 ppm		24 hr. LD_{50} = 40 ppm 96 hr. LD_{50} = 30 ppm	Perkins in Carthy & Arthur (1968)	
Anemones	2 species	"	"	5-10 ppm		24 hr. LD_{50} = 25-50ppm	Smith (1968)	
starfish	A. rubens	"	"	5 ppm		24 hr. LD_{50} = 25 ppm	"	
Brittlestar	Ophiocomina nigra	"		1 ppm		24 hr. LD_{50} = 5ppm	"	
Coelenterate	Tubularia crocea	"	crude 0.1-5%			"quickly lethal"	Nelson-Smith in Hepple (1971)	
"	Calliactis parasitica	"	BP 1002	5 ppm		24 hr. LD_{50} = 25	Smith (1968)	
Sandworm	Nereis virens	"	"BP"			96 hr. LD_{50} = 165ppm	LaRoche et al (1970)	only code names of 10 dispersants are given. Sandworm is one of most valuable marine products in New England
"	"	"	"crude oil B"	0		96 hr LD_{50} = 6100ppm		
Polychaete annelids	Cirriformia tentaculata	Incident: shore terminal spill	fresh fuel oil coating on mud surface			little damage	George (1970)	Mucus secretions of worms and inability of oil to penetrate mud may have prevented toxicity
"	"	"	fuel oil & Essolvene			high mortality	"	oil may have been dispersed into mud by emulsifier and ingested by worms
"	"	Laboratory	BP 1002 Essolvene Corexit 7664		24 hr. LD_{50} (ppm) BP / Essolvene / Corexit C. tentaculata 30 / 63 / 100,000 C. cirratus 129 / 162 / 100,000 24 hrs.			
Coral	several species	Laboratory	Corexit (0-500 ppm) crude oil 0-500 ppm (slick) & mixtures			harmful at 100-500 ppm (not necessarily completely in solution) dispersant more toxic than oil	Lewis (1971)	crude oil concentrations given were not completely dissolved

Table C-10. Evaluation of Experiments and Observations of the Sublethal Effects on Organisms Both of Pollution and of Other Associated Activities of the Petroleum Industry

Group	Species	Reference	Type of Petroleum Product	Concentration	Effects and Evaluation
A. Reproduction					
1. Fecundity					
Crustacea	*Pollicipes polymerus*	Straughan, 1971	Crude oil, Santa Barbara blowout field study		Inverse relationship between the fraction of adults brooding and the amount of oil on the adults (p 0.5); heavily and moderately oiled areas had no recruitment whereas settlement was recorded from all unoiled samples
Mollusca	*Mytilus edulis*	Blumer *et al.*, 1971	No. 2 fuel oil, West Falmouth spill field observations		Gonads of mussels failed to develop in affected areas
2. Fertilization and Development					
Marsh grass	*Festuca rubra*	Baker, 1971	Kuwait ("fresh," 10% distillate and 90% residue)	Seeds soaked in 5 ml of various oils for 1 h	Germination almost completely inhibited; experiments limited in scope, but related to field situation
Polychaeta	*Capitella capitata*	Bellan *et al.*, 1972	Detergent ("low" toxicity polyethylene-glycol fatty acid)	0.01–10 ppm	Survival of young decreased; reduction in number of females laying eggs; most complete study of sublethal effects on reproduction; laboratory strain of this hardy species probably reflects extreme tolerance conditions
Fish	*Gadus morrhua*	Kuhnhold, 1970	Iranian crude extracts (paraffin based)	Aqueous extracts from 10^4, 10^3, 10^2 ppm total oil (author estimates 10^4 yields 10 ppm soluble hydrocarbons, 1 ppm may be more likely)	*Eggs:* "Some cases" were sublethal but embryos and larvae did not survive, apparently, 10^2 ppm does not differ from control. *Larvae:* "Showed typical behavior symptoms in oil extracts: increased activity was followed by a reduction of swimming activity, which finally stopped ... which slowly deepened until the 'critical point' when no responses of the larvae were obtained even by touching or prodding"; time to "critical point" varies with age of larvae and amount of oil: 10^2 ppm not different from control (14–5.5 days for 1–10-day-old larvae); 10^3 ppm (8.4–4.5); 10^4 ppm (4.2–0.5); "herring larvae were less, and plaice larvae more, resistant than cod"; "chemoreceptors seemed to be blocked very quickly at the first contact with oil"; insufficient quantification; no measure of uncertainty; no chemical analysis
	Pleuronectes platessa	Wilson, 1970	BP1002	0–10 ppm	*Larvae:* "1/50 of 100 C_{50} (0.04–0.2 ppm BP1002) disrupt photoactic and feeding behavior (the ability of the larvae to capture prey items was significantly impaired)"; recovery in uncontaminated seawater in 1–3 days; ranges for control in photoactic response experiments not given; feeding results not documented
Lobster	*Homarus americanus*	Wells, 1972	Venezuelan crude	0.1, 1, 6, 10, and 100 (emulsions)	100 ppm lethal to all larval stages; 10 ppm; stages 1–3 more sensitive than stage 4. *Long-term experiments with newly hatched larvae:* 10 ppm: 9-day mean survival time; 6 ppm: longer time to 4th, longer than at lower concentrations; concentrations at which development was prolonged are too high to be important in the field

Table C-10. Evaluation of Experiments and Observations of the Sublethal Effects on Organisms Both of Pollution and of Other Associated Activities of the Petroleum Industry (Cont.)

Group	Species	Reference	Type of Petroleum Product	Concentration	Effects and Evaluation
B. Growth					
Phytoplankton	Several diatoms and dinoflagellates	Mironov, 1970		Concentrations of oil mixed with seawater (1.0–0.001 ml/l); effective concentration *may be* 0.1 ppm–0.1 ppb	No cell division or delayed cell division, compared with controls; dinoflagellates generally more susceptible than diatoms; no mention of type of oil in this work; no measure of concentration of soluble hydrocarbons; concentrations reported seem unrealistically low
	Unspecified microalgae, *Asterionella japonica*	Aubert *et al.*, 1969	Kerosene	3 ppm; 38 ppm	Depression of growth rate; concentration of soluble hydrocarbons unknown
	Phaeodactylum tricornutum	Lacaze, 1967; Nelson-Smith, 1973	Kuwait crude	1% extracts, effective concentration may be 1 ppm	Depression of growth rate; concentration of soluble hydrocarbons unknown
	Chlorella vulgaris	Kauss *et al.*, 1973	Aqueous extracts of several crude oils and outboard motor oil; 90% solutions of aqueous extracts used	1 part oil to 20 parts water	Inhibition of growth varied from 5 to 41% after 2 days of exposure; after 10 days, cell yields were close to controls, suggesting inhibiting substance was eventually lost. After 2 days of cell growth, cell numbers were significantly lower in 25, 50, and 90% oil extracts than in control; concentrations of water-soluble hydrocarbons and comparison of oils unknown
				25–500 ppm solutions of benzene; 25–250 ppm solutions of toluene; 100 ppm solutions of xylene; 3–27 ppm naphthalene	Inhibition of growth of 1–2 days' duration (volatization eventually reduced effect); minimum concentrations tested had an effect but are unrealistically high; lower concentrations should have been tested
	Monochrysis lutheri	Strand *et al.*, 1971	Kuwait crude; dispersant (holl. chem. 622) emulsions	20–100 ppm	Inhibition of growth during 6 days of experiment at all concentrations tested; lowest concentrations had an effect, therefore, lower concentrations should have been studied; effect of crude-dispersant emulsion difficult to relate to other information
	Phaesdactylum tricornutum, Skeletonema costatum, Chlorella sp., *Chlamydomonas* sp.	Nuzzi, 1973	Extracts of outboard motor oil, No. 6 fuel oil, No. 2 fuel oil	1 ppm	Inhibition of growth during 10–12 days incubation with No. 2 fuel oil only at 20% of extracted medium, stimulation of growth by crude and motor oil extracts; concentration of water-soluble hydrocarbons not determined, therefore, it is difficult to compare oils
Plants	*Distichlis maritima, Festuca rubra*	Baker, 1971	Kuwait atmospheric residues		Treatment / Apply: 4/23/70 Harv.: 6/10/70 / Apply: 7/11/69 Harv.: 8/27/69 Unoiled: 5.4 ± 0.8 / 2.9 ± 0.4 4 l/m^2: 7.8 ± 1.4 / 2.9 ± 0.7 8 l/m^2: 11.7 ± 0.7 / 1.6 ± 0.5 *Results:* increase in dry weight (g/25 cm quadrat); similar for *F. rubra* but stimulation not observed with *Spartina anglica*; experiments with "fresh" Kuwait reduce growth; numerous additional experiments reported; results not reported systematically, statistical significance included
Mollusca	*Crassostrea virginica*	Mackin and Hopkins, 1961	Locally produced crude	Spray	Sprayed directly on oysters weekly for 6 months; no effect on growth or survival of adult oysters or spat
			Heavy loss of crude by wild well; Port Sulfur, La.; started 1/17/56, oil not evident by 3/72		No effect on growth, nor any difference in growth between experiment and controls for all size oysters

Table C-10. Evaluation of Experiments and Observations of the Sublethal Effects on Organisms Both of Pollution and of Other Associated Activities of the Petroleum Industry (Cont.)

Group	Species	Reference	Type of Petroleum Product	Concentration	Effects and Evaluation
B. Growth (Continued)					
Mollusca (Continued)	*Crassostrea virginica*	Mackin and Hopkins, 1961	Bleedwater		Oysters in trays and bags at varying distances from outfall; *Effect:* mortality at 50–75 ft; reduced growth and glycogen content at 75–150 ft; none beyond 150 ft
	Littorina littorea	Perkins, 1970	BP1002	30 ppm	Significant inhibition of growth
C. Metabolism					
1. Photosynthesis					
Phytoplankton	Mixed natural samples	Gordon and Prouse, 1973	Venezuelan crude No. 2 and No. 6 fuel oil	10–200 μg/l (ppb)	Concentrations below 10–30 μg/l were found to stimulate photosynthesis, while at concentrations between 60 and 200 μg/l, were somewhat suppressed below controls for all but No. 2 fuel oil which depressed photosynthesis to approximately 60% of controls at concentrations between 100 and 200 μg/l; environment in Bedford Basin: 0.5–60 μg/l; highest content (under slick): 800 μg/l
	Monochrisis lutheri	Strand *et al.*, 1971	Kuwait crude; dispersant (holl. chem. 622) emulsions	1–1,000 ppm	Significant reduction of bicarbonate uptake at concentrations 50 ppm; effect of crude-dispersant emulsion difficult to relate to other information; only observations recorded; no data presented in this preliminary report
	Chlamydomonas angulosa	Kauss *et al.*, 1973	Naphthalene	3–24 ppm	Almost complete reduction of bicarbonate uptake at concentrations as low as 3 ppm in stoppered flasks; when volitization permitted uptake rebounds; lowest concentration tested produced reduction; therefore, experiments at lower, probably more realistic, concentrations should have been conducted
Kelp	*Marcocystis pyrifera*	North, 1965			
Lichen	*Lichen pygmaea*	Brown, 1972	Kuwait crude BP1002	0.1–100 ppm	Total ^{14}C fixation was affected by emulsifier at concentrations of 1 ppm and greater; 50% fixation below control at 100 ppm and near 0 fixation at 50% emulsifier—at higher concentrations tested, there is also an increase in carbohydrate leakage to the seawater from the lichen—also conducted experiments to test effects of aging oil and/or emulsifier but results gave either no difference or they were unclear; oil and emulsifier gave same response as emulsifier and seawater, so oil was not the important toxicant; cites field studies which confirm lab results in that emulsifier and not oil kills lichens; concludes that since aging didn't increase the toxicity of PB1002, then it is the surfactant and not the volatile solvent that is of significance in toxicity
2. Respiration					
Fish	*Cyprinodon variegatus, Lagodon thomboides, Micropogon undulatus*	Steel and Copeland, 1967	Petrochemical wastes	0.2–2.0 ppm in addition 0.4–4.0 phenol	Claims respiratory inhibition at low concentration, then stimulation approaching TL 48 as general pattern; only 1 of the 3 species fit this pattern; insufficient acclimation; too high concentrations

Table C-10. Evaluation of Experiments and Observations of the Sublethal Effects on Organisms Both of Pollution and of Other Associated Activities of the Petroleum Industry (Cont.)

Group	Species	Reference	Type of Petroleum Product	Concentration	Effects and Evaluation
	Lagodon rhomboides	Wohlschlag and Cameron, 1967	Petrochemical wastes	50% of wastewater	Depression of respiration much more severe at near-lethal temperatures than intermediate ones; water collected from Corpus Christi turning basin then diluted to ½; so achievable in the field; lack of confidence intervals
Molluscs	*Mytilus edulis, Modiólus demissus*	Gilfillan, 1973	Extract of midcontinent sweet crudes	1% emuslion	Differential effects of salinity and oil on filtering rate and respiration; normal salinity: increasing oil produces erratic stimulation of respiration; depression of filtering rate above 1% extract; 21 ppt salinity increases respiration and increases filtering rate up to 10% extract, then a very rapid dropoff at higher concentrations of oil. 11 ppt: shutdown of activity; no additional effect of oil
Fish	Juvenile *Onchorhynchus tshanytsha* (salmon) and *Morone saxatilis* (striped bass)	Brocksen and Bailey, 1973	Benzene	5 and 10 ppm changed every 48 h	Respiratory rate was increased during the early (24–48-h) period of exposure to both 5 and 10 ppm of benzene; after longer periods, respiration decreases back to near-control levels; when tested at daily intervals after exposure, found both fish species returned to control levels
D. Behavior					
Fish	*Ictalurus natalis*	Todd, 1972			Feeding unaffected; social behavior altered after 1–3 days and returned to normal in about 1 week; second additions after return to normal again disrupted social behavior
	Notemigonus crysoleucas				No apparent effect on social behavior and/or feeding
Crustacea	*Homarus americanus*	Atema and Stein, 1972	La Rosa crude and extracts thereof		Change in feeding times (doubling of waiting time) and behavior caused by addition of 1:100,000 parts crude oil to water; soluble fractions giving same oil/water ratio had no effect; light and electron microscopy showed no change in morphology of odor receptors; response similar over 5-day period, although hydrocarbons' characteristics did change by "weathering"; experimentally good as possible, but long-term effects and recovery not considered; very difficult problem
Gastropoda	*Nassarius obsoletus*	Jacobson and Boylan, 1973	Kerosene extract	1–4 ppb	Significant reduction in attraction to oyster extract (0.31 ppm); significant reduction in attraction to scallop extract (3 ppm); analytically and statistically sound; experimental concentrations realistic to chronically polluted harbors and spill-affected areas
Crustacea	*Pachygrapsus crassipes*	Kittredge, 1971	Crude oil (Sisquoc sand in California) dilutions (as low as 1:100) of diethyl ether extracts		Inhibition of chemically mediated feeding and 6 pheromone responses in the presence of dilutions of crude oil extracts; response recovery in 3–6 days; quantification less than adequate, not statistically tested; method of extract preparation of questionable validity; concentration of hydrocarbons not known
	Uca pugnax	Krebs, 1973	No. 2 fuel oil, West Falmouth spill, heavily and moderately oiled marshes		Results were that male and females exhibited breeding display colors, and males exhibited threat posture even though the breeding season had been over; mortality was heavy in these areas; interpretations based on observational information only; little quantification and adequate control areas lacking

Table C-10. Evaluation of Experiments and Observations of the Sublethal Effects on Organisms Both of Pollution and of Other Associated Activities of the Petroleum Industry (Cont.)

Group	Species	Reference	Type of Petroleum Product	Concentration	Effects and Evaluation
D. Behavior (Continued)					
Fish	*Onchorhynchus gorbuschka* (salmon)	Rice, 1973	Prudhoe Bay crude oil		Small fry are much more tolerant of oil and avoid it at much higher concentrations than large fry; large fry: TL_m 48–110 ppm, avoidance at 1.6 ppm. The speculation that this avoidance could disrupt migrations may be reasonable since such an effect has been reported for zinc pollution on Atlantic salmon
E. Histological Changes					
Fish	*Menidia menidia*	Gardner, 1972	Texas-Louisiana crude oil	1 l w/40 l seawater, then separate fractions (soluble and insoluble); exposed for 168 h	Various types of histological abnormalities exhibited after exposure to both the soluble and insoluble fractions; largely chemoreceptor structures studies but also ventricular myocardium; no analyses of concentrations seen by fish; technique seems good, but tissue and water content of hydrocarbons needed
Clam Fish	*Mya arenaria* *Menidia menidia*	Gardner *et al.*, 1973	Texas-Louisiana crude oil and No. 2 fuel	600 ppm	0.95 l crude oil mixed with 37.85 l seawater; after settling, oil on top (water-insoluble fraction) at 600 ppm used to expose *Menidia*, also water layer (water-soluble fraction) at 126 ml/l used on other groups of *Menidia*; some histological damage to chemoreceptors of fish but concentrations seen by fish not known; *Mya arenaria* collected and sectioned 4 months after a spill of No. 2 fuel oil showed an increased incidence of gonadal tumors, compared with those collected from control area; all results indicative of possibly good technique but effect not well quantified and neither was content of hydrocarbons; other causes for tumors possible
Mollusca	*Crassostrea virginica*	St. Amant, 1970	Dredging, etc., associated with petroleum extraction in marshes of Louisiana coast		Activities have caused increased incursion of higher salinity water into marshes that formerly had lower salinity; decreased oyster production
Benthos Zooplankton Neuston		Mackin, 1971	Brine effluents from 5 different oil fields; volume and characteristics differ widely		Over a radius of approximately 400 ft, the effluence from Trinity Bay and Fisher's Reef fields affects the size and diversity of benthic communities; no other effect from other distances, other fields, or the zooplankton or neuston was found. A quite complete coverage of species and conducted over a 1-year period; would be good if had hydrocarbon concentration data
Benthos		Reish, 1965	Refinery effluent		Bottom of L.A. harbor that received wastes from refineries was either uninhabited or inhabited only by *Capitella capitata*; after a part of region dredged, number of species increased, then rapidly declined again; correlated increase of carbon in the sediment; region studies limited to only a mile of narrow channel near the source of the effluents; in addition, this part of the harbor received wastes from many other sources; not certain that the oil was actually responsible, nor how far and to what dilutions severe damage extended

Table C-10. Evaluation of Experiments and Observations of the Sublethal Effects on Organisms Both of Pollution and of Other Associated Activities of the Petroleum Industry (Cont.)

Group	Species	Reference	Type of Petroleum Product	Concentration	Effects and Evaluation
		Reish, 1971	Refinery effluent		By 1970, all L.A. refineries ceased discharging wastes or eliminated the oxygen depleting fraction; number of benthic species increased from 0 in 1954 at the four most heavily polluted stations to 4, 6, 10, 11 in November 1970; work sketchy, but does demonstrate that oil wastes definitely were responsible for the impoverished benthic fauna before abatement; no samples from greater distances to suggest the extent of the effect by refinery wastes
Marsh	*Spartina anglica* community	Baker, 1971	Refinery effluent hydrocarbon; characteristics not specified	About 2 ppm phenols	*S. anglica* gradually killed over 20-year period, probably by repeated coating by thin oil films; in creek blue-green algae have replaced filamentous greens (*S. anglica* will grow in soil samples and effluent water samples)
Marsh grasses		Baker, 1971	Successive spillage of Kuwait crude		Results, ranking from least to most tolerant species: (1) shallow rooted plants with no or small food reserves (*Suaeda maritima, Salicornia* sp.); (2) shrubby perennials (*Halimione portulacoides*); (3) filamentous green algae (*Ulothrix* sp., *Baucheria* sp.); (4) perennials (*Spartina townsendi, Juncus maritima, Puccinellia maritima, Festuca rubra, Agrostis stonifera*); (5) perennials of rosette habit with large food reserves (*Cochlearia* sp., *Glaux maritima, Artemisia maritima*)
Various	Various	Crapp, 1971	Benthic Kuwait crude emulsifier BP1002		Communities, hard substrates, Milford Haven: (a) same shores compared after 7–9 years, only species changing were also changed elsewhere due to temperature changes over a large area; (b) field experiments crude oil had little detectable effect, but emulsifiers reduced herbivorous molluscs with the result that inner tidal alga increased; (c) stranded weathered crude, mechanical smothering of some inner tidal animals
		Crapp, 1971; Baker, 1973	Refinery effluents: phenol oils, etc.		Effluents poorly described, only "oil," "phenols," etc.; grazing snails reduced in numbers, particularly small ones, nearer (27 m) vs. further (1960 m) from outfall; fucoid algae more abundant at nearer stations; prior to this refinery, the shore had few algae, mostly barnacles and limpets; same situation in 1970, 1972
Invertebrates		Nicholson and Cimberg, 1971	Santa Barbara crude and natural seep		Coal Oil Point had a less varied invertebrate fauna than other comparable areas along the coast of Southern California; suggested that chronic exposure to the nearby natural seep might account for the low diversity by eliminating sensitive kinds; sampling along single line transects inappropriate for assessing the variety of organisms that inhabit a locality; Onuf added 21 more species to their list of 24 in 1½ h
Mussels	*Mytilus californianus*	Kanter *et al.*, 1971	Crude	1,000, 10,000, 100,000 ppm	Coal Oil Point mussels were more resistant than ones from other areas, suggesting that chronic exposure leads to selection for tolerant forms; alternative that inherent physiological variability between populations may account for differences in oil tolerance is not eliminated and is suggested by the 10–100-fold difference in tolerance of mussels from 2 nonseep area samples

Table C-10. Evaluation of Experiments and Observations of the Sublethal Effects on Organisms Both of Pollution and of Other Associated Activities of the Petroleum Industry (Cont.)

Group	Species	Reference	Type of Petroleum Product	Concentration	Effects and Evaluation
D. Behavior (Continued)					
Fish	Gulf of Mexico sp.	Bechtel and Copeland, 1970	Petrochemical wastes	Different % Houston Ship Channel water	Claims that percent polluted water is a good predictor of species diversity; unfounded because confounded with salinity; to convincingly demonstrate that oil pollution responsible for decreased diversity, compare with samples covering a similar range of salinites in an unpolluted control bay
Fish Shrimp	Gulf of Mexico sp.	Spears, 1971	Oil field wastes	~ 18 ppm	Yields of harvestable fisheries products less in every case in the one creek receiving oil field wastes than in 5 nearby relatively undisturbed creeks: 4–30 times fewer shrimp, 2–25 times fewer blue crabs, 5–16 times fewer game fish, 1.4–11 times fewer forage fish; adverse effects may extend to the bay receiving the oil filled waters; on average, half as many stations on state tracts yielded harvestable organisms in the bay receiving oil field wastes; study useful because it does incorporate reasonable controls; drawbacks in applying to other situations: the brine is at least as toxic as the soil, control bay is not so variable in salinity, and rate of dilution in the receiving bay is undetermined

SOURCE: NAS 1975: 76-82.

Table C-11

U.S. Department of the Interior Petroleum-Related Environmental Research Now in Progress

Type of Study	Area Studied
1. Monitoring studies on the OCS to assess local effects of oil and gas exploration activities addressing impacts, fates, and effects of materials associated with rig operations	Mississippi, Alabama, Florida
2. Baseline study to delimit natural communities and to establish ambient levels of hydrocarbons and trace metals in water, sediments, organisms, and on particulates	California Bight
3. Delineation of natural communities to establish ambient levels of hydrocarbons and trace metals in the water column, organisms and on particulates; baseline survey of geological and geophysical properties; physical oceanography of the region, development of a water circulation model, oil spill trajectory model, expansion of MARMAP Program	Mid-Atlantic
4. Baseline multidisciplinary investigations of marine, littoral, onshore biota, chemistry, physical oceanography, geology, meteorology, ice,	Gulf of Alaska, Southeast Bering Sea, Beaufort Sea

Table C-11 (Cont.)

Type of Study	Area Studied
5. Baseline studies of geology, biology, chemistry field and lab studies, summaries of historical data on physical oceanography, zooplankton, ichthyoplankton, fisheries biology	South Texas
6. Baseline study of Mississippi-Alabama-Florida Deep	Mississippi, Alabama, Florida
7. Baseline monitoring studies	North Atlantic, South Atlantic, Northern California, Alaska
8. Environmental inventory of the deep Atlantic shelf and slope	Georges Bank to Cape Hatteras
9. Environmental and socioeconomic inventory of the North Atlantic	Sandy Hook to Bay of Fundy
10. Environmental and socioeconomic inventory of the South Atlantic	Cape Hatteras to Cape Kennedy
11. Socioeconomic inventory of the Mid-Atlantic	Sandy Hook to Cape Hatteras
12. Update of CICAR volumes for environmental data	Gulf of Mexico

Table C-11 (Cont.)

Type of Study	Area Studied
13. Environmental and socioeconomic inventory	Gulf of Alaska
14. Environmental and socioeconomic inventory	Southern California Bight
15. Development of program plan, quality control analysis, data management scheme, and laboratory analysis requirements documents	
16. Survey of topographic highs	Western Gulf of Mexico
17. Investigation of the long-term effects of No. 6 oil spill in Casco Bay, Maine	Casco Bay, Maine
18. Analysis of hydrocarbons in selected benthic organisms in Mississippi, Alabama, and Florida	Mississippi, Alabama, Florida
19. Preparation of bathymetric maps with lease block overlays	
20. Trace metal quality control analysis	
21. Hydrocarbon quality control analysis	

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Table C-11 (Cont.)

Type of Study	Area Studied
22. Modelling of circulation patterns	Gulf of Mexico
23. Summary of hydrographic data	Eastern Gulf of Mexico
24. Seismic surveys	Deep Gulf of Mexico
25. Cultural resource survey	Louisiana and Texas OCS
26. Cultural resource survey	Bering Land Bridge
27. Delta front sediment stability	
28. Multivariate analysis of water column data	Eastern Gulf of Mexico
29. Survey of outer shelf and upper slope organisms	Gulf of Mexico
30. Socioeconomic study	Kenai Peninsula, Alaska
31. Economic study of impact of oil and gas production	OCS
32. Study of tourism and recreational uses of the coastal areas	Mid-Atlantic
33. Bathymetric map preparation - contination of 1975 program	

Table C-11 (Cont.)

Type of Study	Area Studied
34. Continuation of long-term effects of a No. 6 fuel oil spill in Casco Bay, Maine - third and final year	Casco Bay, Maine
35. Data archiving for all OCS areas except Alaska	
36. Trace metals quality control for baseline programs	
37. Modelling of current patterns	Gulf of Mexico
38. Literature surveys	Central and Northern California, Washinton, and Oregon
39. Hydrocarbons quality control for baseline programs	
40. Delta front sediment stability - continuation of 1975 program	
41. Bering Sea Land Bridge - continuation	Bering Sea
42. South Texas wildlife survey	South Texas
43. Update of previously completed literature surveys (11 areas)	

Table C-11 (Cont.)

Type of Study	Area Studied
44. Faunal succession of fishes and biofouling organisms on production rigs	
45. Cultural resource surveys including literature searches, field surveys, and map preparation - continuation	Gulf of Mexico, Southern California, Atlantic Coast
46. Toxicity studies:	
(a.) resuspension of heavy metals in sediments;	
(b.) surface activity of clay minerals and organic matter with regard to trace metals;	
(c.) bioassays of selected endemic species exposed to crude oils and products;	North Atlantic, South Atlantic, South Texas, South California, Mississippi, Alabama, Florida
(d.) preliminary investigations of the accumulation of petroleum hydrocarbons in selected species of birds and mammals; and	Mid-Atlantic, North Atlantic, South Texas, Louisiana
(e.) physiological partitioning of trace metals in marine and nearshore organisms	

Table C-11 (Cont.)

Type of Study	Area Studied
47. Determine the persistence of drilling muds additives and drill cuttings in the area around rigs	
48. Determine the effects and rate of recovery associated with pipeline burial in coastal wetlands, nearshore, and offshore	
49. Evaluation of the temporal changes in the Louisiana marshlands over the past 25 years in response to OCS development. Changes in cultural and land-use patterns included.	
50. Offshore recreational and commercial fish study - effects of OCS development	Gulf of Mexico
51. Historical survey of oil spills in Mid-Atlantic area	Montauk Point to Cape Hatteras
52. Resource use conflict between fishing industry and OCS development	North Atlantic, Mid-Atlantic, South Atlantic, South California
53. Attraction and avoidance of marine birds, mammals, and fish to oil slicks	

Table C-11 (Cont.)

Type of Study	Area Studied
54. Refinery investment analysis	
55. Analysis of the social services in Yakatat, Alaska area	Yakatat, Alaska
56. Development of methodology for assessing onshore impacts of OCS development	
57. Application of an I-O model utilizing Leontief's matrix analysis of the interdependence between the various sectors of the U.S. economy allocated at the county level	
58. Effects of declining OCS production on the economics of Louisiana and Texas	Louisiana and Texas
59. Socioeconomic studies of OCS development	Alaska

Working Paper #3

Oil Spill Risk Assessment for OCS Oil and Gas Processing Facilities and Deepwater Ports

Prepared for OTA
by the BDM Corp.

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WORKING PAPER #3:

OIL SPILL RISK ASSESSMENT FOR OCS OIL AND GAS DEVELOPMENT AND DEEPWATER PORTS

1.0 INTRODUCTION

Oil spills are an inevitable aspect of all offshore petroleum activities. Yet the risk of spills is not as great for some offshore oil technologies as for others--an important point for decision-makers comparing alternative ways to meet the petroleum needs of regions such as the mid-Atlantic area.

This working paper estimates the oil spill risks associated with three offshore petroleum technologies: the present system of importing oil in small tankers capable of entering mid-Atlantic ports, the combination of very large tankers and a deepwater port, and developing the mid-Atlantic region's OCS oil and gas reserves and transporting the petroleum to shore via underwater pipeline.

A statistical technique known as "risk analysis" was used in making these oil spill estimates. Risk analysis essentially is a way of estimating how likely problems are to occur in the future, based on an analysis of what problems have occurred in the past. In this case it says, in effect, that if past trends on oil spills continue, then we can predict how much oil will be spilled in the future. Major improvements in petroleum technology or operating procedures could make future oil spills less likely than these estimates indicate.

The body of the working paper is divided into three main sections:

-- OCS oil spills. Key findings on OCS-related spills and those of the small tanker alternative system are presented.

-- Deepwater port oil spills. Key findings on supertanker/deepwater port spills and those of the small tanker alternative are presented.

-- Third, details of the methodology, assumptions, and data for this study are presented.

2.0 KEY FINDINGS

2.1 OCS Oil Spills

FIGURE 1 summarizes the estimated spills for the projected thirty years of mid-Atlantic OCS oil and gas development operations. The figure also compares these estimates with the estimated spills for small tankers carrying an equivalent amount of oil over the same length of time. The "small tanker" case would be basically a continuation of the existing system that is used to bring petroleum into this region.

According to the analysis, the small tanker import alternative would result in more spillage in ports, harbors, and entrances within the region, and would mean more overall spillage in the Northwest Atlantic. Most of the OCS spills would be at the rigs, some fifty to one hundred miles offshore, where there is a better chance of its not reaching shore. Within the region out to fifty miles off the New Jersey and Delaware shores, OCS operations would spill more oil than small tanker operations. But the tankers would spill so much oil farther out to sea that overall OCS operations would spill only about one seventh the total oil that the small tankers would. FIGURES 2, 3, and 4 expand on these points by presenting estimates on the sizes and numbers of the estimated spills.

Two recovery scenarios -- high and median -- and three catagories of estimates -- expected, pessimistic, and optimistic -- are included in these figures. The high recovery scenario assumes that 4.6 billion barrels (190 billion gallons) of oil will be recovered from the Mid-Atlantic OCS over a thirty year period. The median scenario assumes that 1.8 billion barrels (76 billion gallons) is recovered. Lifetime estimates are for a period of 30 years. The comparison with small tankers is based on equivalent amounts of petroleum delivered over the same years.

HIGH RECOVERY SCENARIO						
	EXPECTED		PESSIMISTIC		OPTIMISTIC	
	OCS	TANKER	OCS	TANKER	OCS	TANKER
INSHORE	*	4.4M	*	18.6M	*	.6M
WITHIN 50 MI	1.9M	.1M	6.0M	.8M	.9M	0
NEAR 50 MI	7.7M	**	34.4M	**	2.7M	**
REGION SUBTOTAL	9.6M	4.5M	40.4M	19.4M	3.6M	.6M
BEYOND 50 MI	-	59.7M	-	170.4M	-	15.0M
NW ATLANTIC TOTAL	9.6M	64.2M	40.4M	189.8M	3.6M	15.6M

Median Recovery Scenario						
	EXPECTED		PESSIMISTIC		OPTIMISTIC	
	OCS	TANKER	OCS	TANKER	OCS	TANKER
INSHORE	*	2.0M	*	9.6M	*	.3M
WITHIN 50 MI	.8M	.1M	3.1M	.4M	.3M	0
NEAR 50 MI	3.6M	**	17.2M	**	1.2M	**
REGION SUBTOTAL	4.4M	2.1M	20.4M	10.0M	1.5M	.3M
BEYOND 50 MI	-	27.3M	-	97.2M	-	7.5M
NW ATLANTIC TOTAL	4.4M	29.4M	20.4M	107.2M	1.5M	7.8M

(M - MILLIONS OF GALLONS)

* SOME SPILLAGE FROM ONSHORE PIPELINES COULD BE EXPECTED, BUT TOO LITTLE TO EFFECT THE ESTIMATES SIGNIFICANTLY.

** SOME SMALL PORTION OF THE COASTAL SPILLAGE MAY OCCUR NEAR 50 MILES OFFSHORE.

Figure 1 Comparative Geographic Distribution of OCS and Small Import Tanker Spillage Life Cycle Estimates

HIGH RECOVERY SCENARIO							
SIZE RANGE	TYPICAL SIZE	EXPECTED		PESSIMISTIC		OPTIMISTIC	
		NO.	VOLUME	NO.	VOLUME	NO.	VOLUME
>10M	12M	0	0	.22	2.64M	0	0
1-10M	2M	1.77	3.54M	14.14	28.28M	0	0
100K-1M	200K	9.57	1.91M	24.74	4.95M	.11	.02M
42-100K	50K	6.46	.32M	.90	.04M	.89	.18M
LARGE SPILLS		17.80	5.77M	40.0	35.91M	1.0	.2 M
SMALL SPILLS		17K	2.1 M	20K	2.5 M	15K	1.85M
WASTE WATER			1.7 M		2.0 M		1.5 M
TOTALS			9.57M		40.41M		3.55M

Median Recovery Scenario							
SIZE RANGE	TYPICAL SIZE	EXPECTED		PESSIMISTIC		OPTIMISTIC	
		NO.	VOLUME	NO.	VOLUME	NO.	VOLUME
>10M		0	0	.11	1.32M	0	0
1-10M	2M	.79	1.58M	7.11	14.22M	0	0
100K-1M	200K	4.26	.85M	13.28	2.66M	0	0
42-100K	50K	2.85	.14M	.50	.03M	0	0
LARGE SPILLS		7.90	2.57M	21.0	18.23M	-	-
SMALL SPILLS		7.5K	1.0 M	9K	1.2 M	6K	.8M
WASTE WATER			.8 M		1.0 M		.7M
TOTALS			4.37M		20.43M		1.5M

(M - MILLIONS OF GALLONS, K - THOUSANDS OF GALLONS AND SPILLS)

FIGURE 2. OCS Oil Spill Risk Estimates-Life Cycle Estimates, 30 years

SIZE* RANGE	TYPICAL SIZE	EXPECTED NO.	EXPECTED VOLUME	PESSIMISTIC NO.	PESSIMISTIC VOLUME	OPTIMISTIC NO.	OPTIMISTIC VOLUME
IN OCS REGION							
>10M	-	-	-	-	-	-	-
1-10M	1.2M	.7	.82M	11.5	13.8M	0	0
100K-11M	350K	7.9	2.87M	10.1	3.5M	.1	.04M
10-100K	14,50K	9.6	.31M	48.2	1.3M	1.4	.07M
LARGE SPILLS		18.2	3.9 M	69.8	18.6M	1.5	.11M
SMALL SPILLS		2K	.6 M	2.3K	.8M	1.8K	.5 M
TANK CLEANING		-	-	-	-	-	-
TOTALS			4.5 M		19.4M		.6 M
AT SEA IN THE NW ATLANTIC							
>10M	12M	1.2	14.4M	11.75	141.0M	0	0
1-10M	7M	3.6	25.2M	.24	1.7M	0	0
100K-1M	350K	0	0	.24	.1M	0	0
10-100K	4,50K	1.0	.1M	11.75	.6M	0	0
LARGE SPILLS		5.8	39.7M	24.0	143.4M	-	-
SMALL SPILLS		-	-	-	-	-	-
TANK CLEANING			20.0M		27.0M		15M
TOTALS			59.7M		170.4M		15M
TOTAL FOR NW ATLANTIC AREA							
>10M	12M	1.2	14.4M	11.75	141.0M	0	0
1-10M	7M	4.3	26.0M	11.74	15.5M	0	0
100K-1M	350K	7.9	2.8M	10.34	3.6M	.1	.04M
10-100K	14,50K	10.6	.4M	60.0	1.9M	1.4	.07M
LARGE SPILLS		24.0	43.6M	93.8	162.0M	1.5	.11M
SMALL SPILLS			.6M		.8M		.5 M
TANK CLEANING			20.0M		27.0M		15.0 M
TOTALS			64.2M		189.8M		15.6 M

FIGURE 3. Small Import Tanker Spill Risk Estimates High Recovery Equivalent Life Cycle Estimates, 30 years

SIZE RANGE*	TYPICAL SIZE	EXPECTED NO.	EXPECTED VOLUME	PESSIMISTIC NO.	PESSIMISTIC VOLUME	OPTIMISTIC NO.	OPTIMISTIC VOLUME
IN OCS REGION							
>10M	-	-	-	-	-	0	0
1-10M	1.2M	.3	.37M	6.0	7.20M	0	0
100K-1M	350K	3.6	1.25M	5.3	1.85M	0	0
10-100K	14,50K	4.3	.14M	24.7	.67M	0	0
LARGE SPILLS		8.2	1.76M	36.0	9.72M	-	-
SMALL SPILLS		900	.3 M	1000	.3 M	800	.3M
TANK CLEANING			-		-		-
TOTALS			2.06M		10.02M		.3M
AT SEA IN THE NW ATLANTIC							
>10M	12M	.54	6.48M	6.86	82.32M	0	0
1-10M	7M	1.54	10.78M	.14	.98M	0	0
100K-1M	350K	0	0	.14	.05M	0	0
10-100K	50K	2.1	.11M	6.86	.34M	0	0
LARGE SPILLS		4.18	17.37M	14.0	83.69M	-	-
SMALL SPILLS			-		-		-
TANK CLEANING			10.0 M		13.5 M		7.5M
TOTALS			27.37M		97.19M		7.5M
TOTAL NW ATLANTIC							
>10M	12M	.54	6.48M	6.86	82.32M	0	0
1-10M	1.2M	1.84	11.15M	6.14	8.18M	0	0
100K-1M	350K	3.6	1.25M	5.44	1.90M	0	0
10-100K	14,50K	6.4	.25M	31.56	1.01M	0	0
LARGE SPILLS		12.38	19.13M	50.0	93.41M	-	-
SMALL SPILLS		900	.3 M	1000	.3 M	800	.3M
TANK CLEANING			10.0 M		13.5 M		7.5M
TOTALS			29.43M		107.21M		7.8M

FIGURE 4. Small Import Tanker Spill Risk Estimates Median Recovery Equivalent Life Cycle Estimates, 30 years

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There is a large difference between the pessimistic and optimistic estimates. The way the pessimistic spillage was estimated was by assuming that we would have the number of spills such that there seems to be a ninety-five percent chance that we would actually have fewer spills. On top of that it was assumed that the size of those spills would average the size, such that there seems to be a ninety-five percent chance that the average spill size would really be smaller. If these were solidly based statistical estimates, we could expect, with 97.5 percent confidence, that we would not get more spillage than the pessimistic estimates. On the other hand, we could only be 2.5 percent confident of seeing the optimistic volumes spilled. The estimates are not nearly solid enough to be sure of that kind of statement, so these outside estimates are simply called pessimistic or optimistic.

The numbers of spills need explaining. We could get one or two spills of 1 to 10 million gallons, but how could we get 1.77 spills? These numbers are expected values. They mean that if we were going to have a large number of tries at Baltimore Canyon OCS operations, and if we were to average out the number of spills and their sizes, we could expect to average 1.77 spills of an average size of two million gallons. Another way to look at that number is that we are somewhat more likely to get two spills in that size range than we are to get one. If we did have two spills we would have to expect four million gallons of spillage rather than 3.54 million.

One conclusion that has to be drawn is that we are very unlikely to see exactly the expected value of spillage. On the other hand, we are much more likely to see spillage close to the expected value than very

far away from it, given the data and assumptions of the analysis.

Another important point to examine is the thirty year time frame of the spills, as well as their geographic location. Assuming that Baltimore Canyon OCS operations could start by, say, 1980, it would take until the 1990's to reach peak production. During the start-up period, the production volumes would be low, as would the expected spillage. Both would increase into the mid-1990's and then decline, tapering off during the first decade of the twenty-first century, as FIGURES 5 and 6 show.

There are two implications of this time distribution. First, the spillage numbers and volumes in FIGURES 1 through 4 are life cycle spillage estimates. That spillage would be spread out over thirty years. Second, the chances of major accidental spills would not be near their peak for fifteen years. Providing that we as a society plan carefully for either type of operation and pursue spill prevention improvements persistently, there is reason to believe that the "expected" spill volumes need not be encountered.

FIGURES 5 through 8 lay out the time frames in ten year periods, by operation, and by spill size. To estimate average annual spillage during any phase, simply move the decimal point in a spill's or volume value one place to the left; for the period 1990-1999, that will give a fairly good approximation of the yearly spillage. For the 1980-1989 or 2000-2009 period, those values are likely to be more accurate in the middle of the period. Closer to the 1990's, they will be low and further from the 1990's, these annual estimates will be high.

SPILL SIZE RANGE (GALLONS)	TYPICAL SPILL SIZE	1980-89 TOTALS				1990-99 TOTALS				2000-09 TOTALS				LIFE CYCLE TOTALS			
		RIGS	PIPELINES	SPILLS	VOLUME	RIGS	PIPELINES	SPILLS	VOLUME	RIGS	PIPELINES	SPILLS	VOLUME	RIGS	PIPELINES	SPILLS	VOLUME
EXPECTED VALUES																	
1-10M*	2M	.42	.42	.44	.88M	.85	.04	.89	1.78M	.42	.02	.44	.88M	1.69	.08	1.77	3.54M
100K-1M	200K	1.72	.65	2.37	.47M	3.50	1.33	4.83	.97M	1.72	.65	2.37	.47M	6.94	2.63	9.57	1.91M
42-100K	50K	.46	1.13	1.59	.08M	.95	2.33	3.28	.16M	.46	1.13	1.59	.08M	1.87	4.59	6.46	.32M
TOTALS		2.6	1.8	4.4	1.43M	5.3	3.7	9.0	2.91M	2.6	1.8	4.4	1.43M	10.5	7.3	17.8	5.77M
PESSIMISTIC VALUES																	
>10M	12M	.06	-	.06	.72M	.10	-	.10	1.2 M	.06	-	.06	.72M	.22	-	.22	2.64M
1-10M	2M	3.66	.20	3.86	7.72M	6.10	.32	6.42	12.84M	3.66	.20	3.86	7.72M	13.42	.72	14.14	28.28M
100K-1M	200K	2.28	4.55	6.83	1.37M	3.80	7.28	11.08	2.22M	2.28	4.55	6.83	1.37M	8.36	16.38	24.74	4.95M
42-100K	50K	-	.25	.25	.01M	-	.40	.40	.02M	-	.25	.25	.01M	-	.90	.90	.04M
TOTALS		6.0	5.0	11.0	9.82M	10.0	8.0	18.0	16.28M	6.0	5.0	11.0	9.82M	22.0	18.0	40.0	35.91M
OPTIMISTIC VALUES																	
1-10M	2M	-	0	-	-	-	0	-	-	-	-	-	-	-	-	-	-
100K-1M	200K	0	0	0	0	.11	0	.11	.02M	0	0	0	0	.11	0	.11	.02M
42-100K	50K	0	0	0	0	.89	0	.89	.18M	0	0	0	0	.89	0	.89	.18M
TOTALS		0	0	0	0M	1.0	0	1.0	.2 M	0	0	0	0M	1.0	0	1.0	.2 M

*M - MILLIONS, K - THOUSANDS OF GALLONS

FIGURE 5. OCS Major Oil Spill Estimates - High Recovery Scenario

SPILL SIZE RANGE (GALLONS)	TYPICAL SPILL SIZE	1980-89 TOTALS				1990-99 TOTALS				2000-09 TOTALS				LIFE CYCLE TOTALS			
		RIGS	PIPELINES	SPILLS	VOLUME	RIGS	PIPELINES	SPILLS	VOLUME	RIGS	PIPELINES	SPILLS	VOLUME	RIGS	PIPELINES	SPILLS	VOLUME
EXPECTED VALUES																	
1-10M*	2M	.19	.01	.20	.40M	.37	.02	.39	.78M	.19	.01	.20	.40M	.75	.04	.79	1.58M
100K-1M	200K	.79	.29	1.08	.22M	1.52	.58	2.10	.42M	.79	.29	1.08	.22M	3.10	1.16	4.26	.85M
42-100K	50K	.22	.50	.72	.04	.41	1.0	1.41	.07M	.22	.50	.72	.04M	.85	2.00	2.85	.14M
TOTALS		1.20	.80	2.00	.66	2.30	1.6	3.90	1.27M	1.20	.80	2.00	.66M	4.70	3.20	7.90	2.57M
PESSIMISTIC VALUES																	
>10M	12M	.03	-	.03	.36M	.05	-	.05	.60M	.03	-	.03	.36M	.11	-	.11	1.32M
1-10M	2M	1.83	.12	1.95	3.90M	3.05	.16	3.21	6.42M	1.83	.12	1.95	3.90M	6.71	.40	7.11	14.22M
100K-1M	200K	1.14	2.73	3.87	.77M	1.90	3.64	5.54	1.11M	1.14	2.73	3.87	.77M	4.18	9.10	13.28	2.66M
42-100K	50K	-	.15	.15	.01M	-	.20	.20	.01M	-	.15	.15	.01M	-	.50	.50	.03M
		3.0	3.0	6.0	5.04M	5.0	4.0	9.0	8.14M	3.0	3.0	6.0	5.04M	11.0	10.0	21.0	18.23M
OPTIMISTIC VALUES																	
1-10M	2M	NO MAJOR SPILLS															
100K-1M	200K																
42-100K	50K																

*M - MILLIONS, K - THOUSANDS OF GALLONS

FIGURE 6. OCS Major Oil Spill Estimate - Median Recovery Scenario

SPILL SIZE RANGE (GALLONS)	TYPICAL SPILL SIZES*	1980-89,2000-09 (EACH) VESSEL CASUALTIES TOTALS					1990-99 VESSEL CASUALTIES TOTALS					LIFE CYCLE VESSEL CASUALTIES TOTALS				
		TRANSFERS	INSHORE	COASTAL	SPILLS	VOLUME	TRANSFERS	INSHORE	COASTAL	SPILLS	VOLUME	TRANSFERS	INSHORE	COASTAL	SPILLS	VOLUME
EXPECTED VALUES																
1-10M	N,1.2M,N	0	.17	0	.17	.20M	0	.34	0	.34	.41M	0	.68	0	.68	.82M
100K-1M	N,350K,N	0	1.96	0	1.96	.69M	0	3.99	0	3.99	1.40M	0	7.91	0	7.91	2.77M
10-100K	14K,50K,	1.27	.67	.51	2.40	.08M	2.43	1.37	1.04	4.84	.15M	4.87	2.71	2.06	9.64	.31M
TOTALS		1.22	2.80	.51	4.53	.97M	2.43	5.70	1.04	9.17	1.96M	4.87	11.30	2.06	18.23	3.90M
PESSIMISTIC VALUES																
1-10M	N,1.2M,N	0	3.00	0	3.00	3.60M	0	5.50	0	5.50	6.60M	0	11.56	0	11.50	13.80M
100K-1M	N,350K,N	0	2.64	0	2.64	.92M	0	4.84	0	4.84	1.69M	0	10.12	0	10.12	3.54M
10-100K	14K,50K	7.8	.36	4.2	12.36	.27M	15	.66	7.8	22.46	.63M	30.6	1.38	16.2	48.18	1.31M
TOTALS		7.8	6.0	4.2	18.00	4.79M	15.0	11.0	7.8	32.80	8.92M	30.6	23.0	16.2	69.8	18.65M
OPTIMISTIC VALUES																
1-10M	N,1.2M,N	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
100K-1M	N,350K,N	0	0	0	0	0	0	.12M	0	.12	.04M	0	.12	0	.12	.04M
10-100K	14K,50K	0	0	0	0	0	0	1.40	0	1.40	.07M	0	1.40	0	1.40	.07M
TOTALS		0	0	0	0	0	0	1.52	0	1.52	.11M	0	1.52	0	1.52	.11M

* TYPICAL SIZES IN SIZE RANGE FOR TRANSFERS, INSHORE AND COASTAL VESSEL CASUALTIES RESPECTIVELY.
N - NOT APPLICABLE
M - MILLIONS
K - THOUSANDS OF GALLONS
** SPILLS FROM SHIPS, BARGES, AND FACILITIES DURING TRANSFER OPERATIONS PLUS NON-CASUALTY VESSEL SPILLS IN INSHORE AREAS.

FIGURE 7. Regional Major Oil Spills - Small Tanker Imports - High Recovery Equivalent

SPILL SIZE RANGE (GALLONS)	TYPICAL SPILL SIZE*	1980-89,2000-09 (EACH) VESSEL CASUALTIES TOTALS					1990-1999 VESSEL CASUALTIES TOTALS					LIFE CYCLE VESSEL CASUALTIES TOTALS				
		TRANSFERS**	INSHORE	COASTAL	SPILLS	VOLUME	TRANSFERS	INSHORE	COASTAL	SPILLS	VOLUME	TRANSFERS	INSHORE	COASTAL	SPILLS	VOLUME
EXPECTED VALUES																
1-10M	N,1.2M,N	0	.08	0	.08	.10M	0	.15	0	.15	.18M	0	.31	0	.31	.37M
100K-1M	N,350K,N	0	.91	0	.91	.32M	0	1.75	0	1.75	.61M	0	3.57	0	3.57	1.25M
10-100K	14K,50K	.56	.31	.24	1.01	.04M	1.08	.60	.46	2.14	.07M	2.20	1.22	.94	4.36	.14M
TOTALS		.56	1.30	.24	2.0	.46M	1.08	2.50	.46	4.04	.86M	2.20	5.10	.94	8.24	1.76M
PESSIMISTIC VALUES																
1-10M	N,1.2M,N	0	1.50	0	1.50	1.80M	0	3.0	0	3.0	3.60M	0	6.0	0	6.0	7.2 M
100K-1M	N,350K,N	0	1.32	0	1.32	.46M	0	2.64	0	2.64	.92M	0	5.28	0	5.28	1.85M
10-100K	14K,50K	4.20	.18	2.4	6.78	.19M	7.2	.36	3.6	11.16	.30M	15.6	.72	8.4	24.72	.67M
TOTALS		4.2	3.0	2.4	9.60	2.45M	7.2	6.0	3.6	16.8	4.82M	15.6	12.0	8.4	36.0	9.72M
OPTIMISTIC VALUES																
1-10M	N,1.2M,N	ALL ZEROS														
100K-1M	N,350K,N															
10-100K	14K,50K															
TOTALS																

* TYPICAL SIZE RANGE FOR TRANSFERS, INSHORE AND COASTAL VESSEL CASUALTIES, RESPECTIVELY. (N - NOT APPLICABLE, M - MILLIONS, K - THOUSANDS)

** SPILLS FROM SHIPS, BARGES AND FACILITIES DURING TRANSFER OPERATIONS, PLUS NON-CASUALTY VESSEL SPILLS IN INSHORE AREAS.

FIGURE 8. Regional Major Oil Spills, Small Tanker Imports Median Recovery Equivalent

Occasionally, some mention may be made of hazards to OCS or tanker operations from earthquakes, tidal waves, falling aircraft or other external factors. The projected OCS region is not prone to either earthquakes or tsunamis. There is little danger of aircraft impacts to installations more than five miles from an airport. One external risk obviously worth examining is the probability of a vessel collision with an oil rig, thereby causing loss of control and a major spill from the rig or, if the vessel is a tanker, from the ship. This possibility is included in the risk estimates. Alternatively, one could conceive of vessels attempting to use the rigs' warning lights or horns as navigation aids, thereby increasing the risk of a tanker collision spill. This was examined briefly in the alternative analysis. Assuming that, if a collision occurs fifty miles offshore, the chances of it being induced by a rig are one chance in a thousand, or even one chance in a hundred, the resulting spill expectation does not affect the risk estimates.

In general, including all externally caused accidents other than a ship collision with the rig (which is included) the risks would not change the estimated spill volume by a significant amount. This is not to say that no such risks exist. Rather, they are too small relative to the risks internal to the OCS operations to make any difference.

2.2 Deepwater Port Oil Spills

The 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 1,400,000 barrels. The high estimates include the pessimistic assumption of a major tanker accident. Thus, 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 is used to move oil instead of small tankers. The resulting oil spill estimates for the deepwater port system are summarized in FIGURE 9.

3.0 METHODOLOGY, ASSUMPTIONS, DATA AND DETAILED FINDINGS

3.1 The Statistical Approach

There are several ways of producing spillage estimates, depending on the specific objectives of an analysis. In cases where a specific operation under unified control is being planned with a limited set of well-defined hardware, such as a single oil company's plan for producing offshore oil from a given field with specific oil rig and pipeline, designs and locations, then engineering and system safety analyses may be the most appropriate method. These are the techniques used so successfully in the space program. Conversely, in a case where almost nothing is known about similar past operations and the hardware designs are mainly conceptual, then polling of expert opinion may be the best approach. Policy decisions on oil operations generally demand a statis-

	EXPECTED		PESSIMISTIC		OPTIMISTIC	
	DWP	SMALL TANKER	DWP	SMALL TANKER	DWP	SMALL TANKER
INSHORE	1.6	12.5	10.5	55.8	-	1.4
COASTAL	4.8	.6	19.7	2.1	2.1	0
REGIONAL (INSHORE PLUS COASTAL)	6.4	13.1	30.2	57.9	2.1	1.4
AT-SEA	111.2	150.9	422.1	362.0	49.9	49.9
TOTAL	117.6	164.0	452.3	419.9	52.0	51.3

	REGIONAL		AT-SEA		TOTAL	
	DWP	ALL SMALL TANKER	DWP	ALL SMALL TANKER	DWP	ALL SMALL TANKER
EXPECTED VALUES						
>10M	-	-	10.4	30.6	10.4	30.6
1-10M	.9	3.9	38.0	57.5	38.9	61.4
100K-1M	2.0	6.9	-	-	2.1	6.9
< 100K	.7	.9	-	-	.9	.9
ALL MAJOR	3.6	11.7	48.4	88.1	52.0	99.8
SMALL SPILLS	2.8	1.4	2.8	2.8	5.6	4.2
TANK CLEANING	-	-	50.0	60.0	60.0	60.0
TOTAL	6.4	13.1	111.2	150.9	117.6	164.0
PESSIMISTIC VALUES						
>10M	-	-	262.0	233.0	262.0	233.0
1-10M	11.4	45.0	63.3	31.6	74.7	76.6
100K-1M	9.6	8.1	1.5	2.1	11.1	10.2
<100K	4.2	2.7	.3	.3	4.5	3.0
MAJOR	25.2	55.8	327.1	267.0	352.3	322.8
SMALL	5.0	2.1	5.0	5.0	10.0	7.1
TANKS	-	-	90.0	90.0	90.0	90.0
TOTAL	30.2	57.9	422.1	362.0	452.3	419.9
OPTIMISTIC VALUES						
>10M	-	-	-	-	-	-
1-10M	-	-	-	-	-	-
100K-1M	.06	.03	-	-	.06	.03
<100K	.12	.18	-	-	.12	.18
MAJOR	.18	.21	0	0	.18	.12
SMALL	1.90	1.14	1.9	1.9	3.8	3.0
TANKS	-	-	48.0	48.0	48.0	48.0
TOTAL	2.1	1.35	49.9	49.9	52.0	51.2

FIGURE 9. Deepwater Port and All Small Tanker Import Spillage Comparisons, One DWP - Fifteen Year Totals (Millions of Gallons) (42 Gallons = 1 Barrel)

tical approach because there are too many hardware designs to analyze in detail, and there is enough objective data so that one need not fall back on purely subjective methods.

Statistical estimation of oil spills has been attempted only recently, because spills had not been regarded as a significant problem until the Torrey Canyon and Santa Barbara incidents were widely publicized in the late 1960's. Thus, little data was collected on the problem and what was available was of questionable accuracy. The mid-70's are a time of transition for attacking the statistical spill estimation problem. Better, more controlled and more complete data are being collected, and more is being learned about the statistical properties of spill data. On the other hand, the available amounts of data tend to be small, their precision is suspect, and relatively little is known about the theoretical properties of their probability distributions.[1/]

3.2 Assumptions Used in the Study

The amounts and quantities of oil spill data available are not sufficient, in themselves, to establish how they should be described statistically. This means that the results of any such analysis are very dependent on the assumptions made in the study.

Three general assumptions must be made for each analysis regarding:

(1) Sufficiency of data

(2) Increasing, decreasing or stable risk, and

(3) Relevance of data.

1/ National Academy of Sciences, "Petroleum in the Marine Evironment," (Washington D.C., 1975)

3.2.1 Sufficiency of Data

Whether the available data are sufficient to provide a reasonable description of the overall process of oil spillage or reveal only a small part of the total possible spill experience must be decided. If the spill experience to date can be considered representative of the full range of experience we are likely to encounter in the future, then we want to make our estimates as tight and descriptive of the data as possible. If we consider the experience to be very slight, then we want to allow for considerable uncertainty in our estimates.

Consider estimation of flood height instead of oil spills. Having observed five years of floods, could we reasonably predict floods for the next thirty years? If we happened to have had a 200-year flood in our five-year sample, then we would be better off to restrict our mathematical description of floods to what was experienced, preventing vast over-expenditures on overly high dikes. If our five year sample did not even include a ten-year flood, we would be better off to spread our mathematical description of floods so as to avoid underestimating the risks. With only five years data, however, we simply would not know what sort of sample we had.

This dilemma is easily resolved if we can assume that the data sample is random. If so, it is far more likely that any given five-year sample of data would not contain an extreme value (say, an exceptionally large oil spill) than that it would contain one. Thus it may be preferable to spread the mathematical distribution of possible oil spill sizes rather than to restrict it.

There is a rationale available, however, for thinking that the oil spill data samples available may not be random, but skewed toward large spills. For one thing, larger spills are more likely to be reported. Moreover, it was precisely the occurrence of several unusually large spills which led to the current concern. Because both offshore oil production and tanker operations had been around for many years prior to Santa Barbara and the Torrey Canyon, there is considerable reason to beleive that earlier years' spill size experience was less dramatic and occurred in areas where the damage was less severe.

The parallel with floods can be very misleading in another way. Because flooding results, in general, from spring rains combined with the melting of winter snow--or alternatively, from seasonal major storms, it is very reasonable to relate flood data to the number of years of experience available to determine the adequacy of the sample. Applying the same rationale to oil spills would lead us to suspect that we had a very small sample indeed. There is no reason to expect that our exposure to oil spills is based on seasonal or time factors. It relates more logically to the volume of oil handled or transported. If that is the case, then the relevant question is whether the volumes of oil handled in our sample are large or small relative to the amounts that are planned to be handled in the operation for which the predictions are being made.

In this study these assumptions are made regarding the sufficiency of data:

-- OCS assumption 1. For purposes of this OCS study, the volumes of oil handled in the experience data (historical data) were

considered to be sufficiently large relative to those planned for specific phases of the Baltimore Canyon OCS operations, and that the range of spill experience in the data represents fairly well the range to be expected.

-- DWP assumption 1. The spill data available and the limited comparable exposure experience necessitate considerable extrapolation for the predictions required.

3.2.2 Trend of Spill Risks with Time

The second key judgment is whether oil spillage is a static process. On the one hand there are indications that it is increasing. As noted previously, the very fact that oil spillage has only recently come to be considered a societal problem relates to the occurrence of a few very large spills, apparently exceeding any in previous experience. In the case of tankers, it is apparent that the size of a spill from a single tanker cannot exceed the capacity of that tanker, and tanker sizes have increased dramatically over the past twenty or more years.

On the other hand, there are also two indications that spillage in the small tanker operations of interest for this analysis are pretty well bounded by recent experience. These operations are limited to tanker operations in importing foreign oil to U.S. east coast ports. These ports have water depths limited to about forty-five to fifty-five feet. The largest vessels capable of entering these ports have been doing so during the sample period. Conceivable the mix of tankers importing oil may change so that more large and fewer small tankers are being used or wider tankers with similar drafts may come into service. Neither of

these factors is likely to increase the spill sizes encountered dramatically. As to tanker spill frequency, the safety effects of slight increases in port traffic could be offset by vessel traffic systems planned and authorized under the Ports and Waterways Safety Act of 1972 (P.L. 92-340).

Spills from OCS and deepwater port operations are not bounded by any firm limiting factor such as vessel size, but there are several factors that mitigate against ever-larger spills. First, let us consider alternative possible trends that oil spills data could reflect. Theory A might be that the randomness of nature defeats any attempt to limit oil spill sizes. Inexorably over a period of time and as increasing volumes of oil have been produced, some new, unanticipated type of accident occurs which produces a larger spill than those previously encountered. In fact, the major spill hazards are well recognized. Theory A could also be true if neither oil companies nor society at large reacted to limit oil spillage. Up to the late sixties that may have been consedered the case; certainly we are reacting now.

Theory B-1 might be that spill sizes approach a limit of acceptable risk and level off as additional safety features and governmental controls are introduced. In fact, three separate trends tend to limit the increase of spill sizes. First, the increasing price and scarcity of oil increases the dollar loss to oil companies from major spills, thus increasing the incentive to employ improved technology and operating procedures to avoid such losses. Second, societal reaction to major oil spills has produced additional economic penalties and liabilities, further

motivating the oil companies to try to limit spillage. Third, increasing experience and improving technology enhance the capability to limit oil spillage.

Theory B-2 might be that the reaction to excessive oil spillage only sets in after the acceptable risk limit has been clearly exceeded and/or that the occurrence of a few large spills reduces the previous tolerance of even small ones. This, in fact, appears to be the case. The same factors work as in Theory B-1 to limit the spillage. It decreases to a point at which the perceived costs to governments and to the oil companies become disproportionate to the benefits of further reducing the spillage. The same rationale applies to both frequency and size of spills.

In this study these assumptions are made regarding the trend of spill risks over time:

-- OCS assumption 2. For the purposes of the OCS part of this study, it was assumed that the acceptable spill risk level is below the level experienced in the available historical data and that future spill experience will be a stable continuation of recent experience or, experience and technology permitting, the spill risks will decrease.

-- DWP assumption 2. The trend of large tanker and single point mooring-type (SPM) deepwater port spill frequencies is highly uncertain, as is the trend of SPM spill sizes. The trend of tanker spill sizes is increasing.

The OCS oil spill analysis was aided by the existence of a U.S. data base fairly closely pertinent to the contemplated operations. The data

systems are relatively new and have several potentials for inaccuracy. Much of available data is reconstructed from reports not originally intended for such a use. More data would be desirable but what is available is relevant.

In the deepwater port case, the small tanker data is relevant, but that is about all. Supertankers have not operated on U.S. routes and no vessel is currently sailing of the largest sizes contemplated. No SPM is currently operational in the United States and no proper data set is available from any location.

3.2.3 Adequacy of Data for Supporting Predictions

The third key judgment underlying a statistical oil spill risk analysis is whetyer to select data as relevant as possible to the specific operations studied or to increase calculated statistical confidence by using all available data. Because deepwater port operations in the U.S. are merely contemplated, it is apparent that no specifically relevant data are available.

With respect to tanker spill data, there are far more numerous data, including data directly from the New Jersey-Delaware region being studied. Although world wide data are available, they may be rejected both because other areas of the world do not have the tanker size restriction of U.S. ports and because hazards vary among trade routes. On the other hand it is judged that the major spill experience specific to the New Jersey-Delaware region is insufficient, whereas tanker import operations along the entire U.S. east coast are sufficiently similar to provide a consistent and comparable data base.

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In this study these assumptions are made regarding the adequacy of the data for supporting predictions:

-- OCS assumption 3. For the purposes of this OCS study, it is assumed that available U.S. OCS oil spill data are adequate to predict Atlantic OCS operations and that regional small tanker oil spill data are adequate and well suited to predict spillage in similar tanker operations in that region.

-- DWP assumption 3. Such data as can be used to make the deepwater port spillage estimates are not specifically relevant to the contemplated mid-Atlantic deepwater port operations. Whether they reflect experience similar to that to be expected off New Jersey and Delaware is simply unknown.

One point should be made about this last deepwater port assumption and the two earlier DWP assumptions as well. Given the limited credibility of any analysis of historical data which uses such assumptions, it might appear that the proper and most reliable course would be to make no predictions at all about deepwater port oil spills. Nonetheless, a reasoned analysis will provide at least a perspective and a rationale in which to clarify qualitative judgments about the spillage to be expected and the means of analysis available to narrow the uncertainties.

3.2.4 Study Objectives and Their Impact on Method

The main objective of this analysis was to provide as realistic an estimate as feasible of the oil spill experience to be expected in OCS operations in the mid-Atlantic region over the 1980-2010 period. Secondary objectives were to describe the expected spill frequencies by size range

and geographically in rough terms of spill distance from the coast. Comparable estimates for the alternative of importing comparable amounts of oil by current tanker practices also were needed.

The major bounding condition in terms of the objectives is to provide realistic estimates. Many risk studies are slanted toware positive assurance against underestimating the risks. This can result in including one conservative assumption after another until the worst conceivable case appears to be likely rather than improbable. Conversely, the proponents of a risky activity may frequently minimize or overlook risks.

The nature of oil spill statistics themselves makes it easy to adopt or support an extreme position. The vast majority of consistently recorded oil spills are very small, frequently between one and one hundred gallons. If these spills are not promptly contained and cleaned up, they may be as environmentally damaging as the much rarer very large spills, but they do not tend to be a major concern to the general public. Conversely, the fact that oil spills may run into the millions, or even tens of millions of gallons, is indisputable, and the potential for such a spill may overshadow its rarity or the fact that even if such a spill occurs, it may neither reach shore nor cause detectable environmental damage.

Somewhere between a focus on the worst case and casual dismissal of the risk, there lies a ground on which a careful consideration must be made of the need for oil, alternative ways of getting it, and the potential for harmful spills.

There are also alternative ways of describing the variability of oil spill data in terms of statistical probability distributions. One approach is to use the familiar "bell-shaped curve" or normal probability distribution. That describes many sets of data quite well, where the data group around a central value such as school grades with about as many students well below average as the number well above average. Because most spills are very small and a very few are very large, the normal distribution does not appear applicable.

A 1975 Rennselear Polytechnic Institute paper[2/] points out that very good descriptions of U.S. Coast Guard oil spill data can be obtained by applying stable law distributions. These are mathematically somewhat complex, but have the advantage of describing large extreme values, far removed from the mean of a distribution, better than conventional distributions. The major problems are that the methods of estimating the three parameters of such distributions have not been fully resolved, the stable laws have no finite variance, and they are somewhat complex to compute.

Analysts at Massachusetts Institute of Technology (MIT)[3/] approached the problem in two parts--estimating the frequency of occurrence of spills independently of the sizes of the spills. Because spill frequencies,

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2/ Paulson, A.S., Schumaker, A.D., and Wallace, W.A., "A Risk-Analytic Approach to Control of Large Volume Oil Spills," Proceedings 1975 Conference on Prevention and Control of Oil Pollution.

3/ Massachusetts Institute of Technology, "Analysis of Oil Spill Statistice," Council on Environmental Quality Report, OCS Oil and Gas - An Environmental Assessment (Washington, D.C.: U.S. Government Printing Office, April 1974.)

disregarding size, are fairly stable, a Poisson distribution was considered. This distribution is widely used for accidents or other events where the frequencies of the events of interest are small relative to the exposure. Because the Poisson distribution has only one parameter and spill rates are not definitely known, it is best to allow the parameter to vary. Assuming that the mean spill rate of the Poisson distribution varies as a gamma distribution with both parameters equal to zero leads to the negative binomial probability distribution, which is simple to compute and consistent with our experience of oil spills. The MIT analysts assumed the exposure variable to be volume of oil handled.

In order to estimate spill sizes, the MIT team considered the gamma distribution, which for low values of its shape parameter describes distributions highly skewed toward low values. Paralleling the reasoning used for spill frequencies, they noted that with small amounts of spill data the gamma parameters cannot be estimated confidently. For this reason, they developed a variable parameter distribution termed a gamma hyperpoisson. There are two key difficulties with use of that distribution. The computational procedure is quite complex and has not been developed for general use and allowing the parameters to vary tends to spread the distribution at the high end. This is consistent with the assumption that our experience is very limited relative to our contemplated exposure, and is appropriate for a generalized analysis based on worldwide data, which was the case in the MIT analysis.

In another recent oil spill study[4/], Oceanographic Institute of Washington (OIW) analysts adopted the negative binomial distribution for spill frequencies. They also tested tanker trips and volume handled as alternative exposure variables. Both appeared consistent with available data, although "trips" was the more appropriate choice for their study. It is fortunate that volume handled was also found to be an appropriate exposure measure, because a comparative study of, say, deepwater port throughput and small tanker operations requires a common exposure variable. Translation from tanker trips to volume adds uncertainty to an analysis unless the ship sizes contemplated and also in the experience data are both fairly well known.

To deal with the spill size distribution problem, OIW selected the exponential distribution as a convenient engineering approximation to the gamma. (The exponential is a special case of the gamma, having a gamma shape parameter of 1.)

For the present study, none of the above methods was suitable. There were too many different operations with different spillage characteristics to be analyzed, many of which could not be appropriately described as an exponential. In a similar vein, it was postulated that not only would different operations have different oil spill patterns, but also that the patterns might be different for different spill size ranges in the same operation. A flexible and analytically convenient distribution, the gamma was assumed and in its cumulative form was fitted to each individual data set.

4/ Oceanographic Institute of Washington, Offshore Petroleum Transfer Systems for Washington State: A Feasibility Study. A report to 44th Legislative, State of Washington by the Oceanographic Commission of Washington, 16 December 1974.

3.3 Data Used in the Study

The following pages present data on oil spills from OCS operations, deepwater ports, and small tanker operations.

OCS and other spill risk estimates tend to appear to be complex probability functions until reduced to concrete form by specifying the planned exposure. In the case of OCS operations, the volumes planned to be produced in the Baltimore Canyon OCS operations were used both to assess the OCS spill risk and the comparable risk from importing equivalent volumes by current tanker practices. FIGURE 10 summarizes the values.

The first experience data set required was spills and volumes for OCS operations. The relevant subdivision is between the oil rigs themselves and the undersea pipelines which carry the oil ashore. No better source of data on large spills was found than that in the MIT analysis reproduced in FIGURES 11 and 12. Because Gulf Coast OCS operations have generally been conducted with pipelines lying on the ocean floor, those pipes have occasionally been ruptured by vessel anchors or propellers. The significance of this danger is recognized, and it is assumed that all Atlantic OCS pipelines will be buried under the ocean floor to avoid this problem. Some vessel risk will remain due to:

(1) Bottom sand shifting

(2) Occasional line exposure for inspection and maintenance, and

(3) Any bridging of gullys and valleys in the ocean floor.

Nonetheless, burying the lines will so significantly reduce this risk that those accidents were deleted from the experience base. The residual risk from this cause is considered covered by the variances of the size

TIME FRAME	HIGH RECOVERY	MEDIAN RECOVERY
1980-1989	48 B GALLONS (1,142 M BARRELS)	22 B GALLONS (521.6 M BARRELS)
1990-1999	98.2 B GALLONS (2,337 M BARRELS)	42.8 B GALLONS (1,019 M BARRELS)
2000-2009	48 B GALLONS (1,142 M BARRELS)	22 B GALLONS (521.6 M BARRELS)

(B - BILLIONS, M - MILLIONS)

FIGURE 10. Planned Exposure-OCS Production Volumes

LOCATION	CAUSE	AMOUNT
LOUISIANA, WEST DELTA	ANCHOR DRAGGING*	6,600,000
PERSIAN GULF**	BREAK	4,000,000
LOUISIANA, COASTAL CHANNEL	TUG PROPELLER*	1,050,000
CHEVRON MP 299	UNKNOWN	310,000
LOUISIANA, GULF ST 131	ANCHOR DRAGGING*	250,000
LOUISIANA, COASTAL CHANNEL	EQUIPMENT FAILURE	160,000
LOUISIANA, COASTAL WATERS	LEAK	155,000
TEXAS, COASTAL CHANNEL	LEAK	42,000
LOUISIANA, COASTAL CHANNEL	LEAK	42,000

EXPOSURE OBSERVED: 3,169 M BARRELS = 1.33×10^{11} GALLONS

* REJECTED AS IMPROBABLE WITH BURIED LINES

** REJECTED AS NON-U.S.

FIGURE 11. United States Offshore Pipeline Spills Over 42,000 Gallons, 1967-1972

RIG	CAUSE	AMOUNT
UNION "A", SANTA BARBARA	BLOWOUT	3,250,000
LA, SHELL ST 26 "B"	FIRE	2,200,000
LA, CHEVRON MP 41 "C"	FIRE	1,300,000
LA, MP GATHERING NET AND STORAGE	STORM	512,000
SIGNAL SS 149 "B"	HURRICANE	210,000
PLATFORM, 15 MILES OFFSHORE	-	168,000
CONTINENTAL EI 208 "A"	COLLISION	108,000
MOBIL SS 72	STORM	105,000
TENNECO SS 198 "A"	HURRICANE	67,000

EXPOSURE OBSERVED: 3,927 M BARRELS = 1.65×10^{11} GALLONS

SOURCE: MIT, "ANALYSIS OF OIL SPILL STATISTIC," PAGES 88, 89, 94

FIGURE 12. United States Offshore Oil Rig Spills Over 42,000 Gallons, 1964-1972

and frequency distributions. On the other hand, if, for some reason Atlantic pipelines are not buried, the spill risk should be carefully re-evaluated.

No similarly conclusive rationale for adjusting major spill risks was found for the oil rigs or tanker operations. Certainly, one would hope that improved drilling and navigation technology, tighter government controls, and increased economic motivation would occur and reduce oil rig and tanker spill risks. However, no known plans reduce the physical possibility of those accidents in a manner comparable to the burying of pipelines.

For spills smaller than 42,000 gallons, which would be unlikely to be covered in other than a comprehensive reporting system, the U.S. Coast Guard Pollution Incident Reporting System was used in the MIT analysis which is discussed later in this working paper. Both because the occurrence frequencies of small spills are much higher than for major spills (leading to tighter estimates) and because the numerous spills in this range contribute very little to the overall spill volume expectations, no attempt was made to improve on the MIT results.

The breakout of OCS spillage between oil rigs and pipelines serves both a functional and geographic distinction. The Baltimore Canyon oil production platforms would be predominantly about fifty to one hundred miles offshore, with the pipelines running inward to the coast and overland to the refineries. No estimates were made for the onshore portions of the pipelines because there is no indication that land pipeline spills are a major concern in the study region. FIGURE 13 shows spill frequencies from published Materials Transportation Bureau (formerly

NO. OF SPILLS	1968	1969	1970	1971	1972	1973	1974
DELAWARE	0	0	0	0	0	0	0
NEW JERSEY	6	2	3	4	2	1	0
NEW YORK	3	3	1	1	1	2	0
PENNSYLVANIA	17	28	13	11	12	9	1
NATIONAL	499	403	347	308	309	273	256
EST. CRUDE SPILLS (BASED PERCENT CRUDE SPILLS IN NATIONAL TOTAL)							
DELAWARE	0	0	0	0	0	0	0
NEW JERSEY	4	1	2	2	1	.57	0
NEW YORK	2	2	.62	.56	.58	1	0
PENNSYLVANIA	11	17	8	6	7	5	.65
NATIONAL VOLUMES (GALLONS)							
CRUDE SPILLED	9.3M	7.3M	16.1M	4.9M	9.8M	8.8M	7.1M
NO. OF SPILLS	322	246	216	172	180	155	156
AVG. VOLUME*	29K	29.8K	74.5K	28.3K	54.5K	56.5K	42.7K
VOLUME HANDLED ($\times 10^{11}$)	1.1	1.2	1.2	1.2	1.3	1.3	
(SOURCE: ASSOCIATION OF OIL PIPELINES)							

* BASED ON GENERAL KNOWLEDGE OF OIL SPILLS, A PREPONDERANCE OF THE SPILLS WILL HAVE MUCH LOWER VOLUMES AND AN OCCASIONAL SPILL WILL HAVE MUCH HIGHER VOLUME THAN THIS AVERAGE.

SOURCE: DOT MATERIALS TRANSFER BUREAU, SUMMARY OF LIQUID PIPELINE ACCIDENTS REPORTED DOT FORM 7000-1 FROM JANUARY 1, 19XX THROUGH DECEMBER 31, 19XX (ANNUAL) **

** FORMERLY PUBLISHED BY THE OFFICE OF HAZARDOUS MATERIALS, THEN BY THE OFFICE OF PIPELINE SAFETY.

FIGURE 13. Onshore Pipeline Spill Data

Office of Pipeline Safety) reports.[5/] Comparable regional spill volume and exposure volume data was not available for these spills. National volumes handled were obtained from the Association of Oil Pipelines.[6/]

The deepwater port system envisioned in this study would be located about 30 miles offshore, would receive crude oil from VLCC's, pump it through a buried undersea pipeline to shore storage and through a land pipeline to refineries. Oil could be spilled at any point in the system. The refinery and tank farm spillages are not estimated here because they make no difference in resolving the policy issues. Equivalent amounts of storage will be needed for the given volume in any case. Furthermore, because storage tanks are diked to catch the spillage from any single tank rupture, the environmental threat is relatively minor and is localized. Again, onshore pipeline date is shown in FIGURE 13.

No better source of undersea pipeline data was found than that in the MIT analysis which is reproduced in FIGURE 11. Because Gulf Coast OCS operations have been conducted with pipelines lying on the ocean floor, those pipes have occasionally been ruptured by vessel anchors or propellers. The significance of this danger is recognized and pipelines from deepwater ports to shore are to be buried to avoid this problem.

5/ Department of Transportation, Materials Transfer Bureau, "Summary of Liquid Pipeline Accidents Reported on DOT Form 7000-1 from January 1, 19xx, Through December 31, 19xx" Reports for 1968-1974. Compiled by the Office of Hazardous Materials and the Office of Pipeline Safety. Washington, D.C., various dates.

6/ Association of Oil Pipelines, Press Release of June 2, 1975, "Shifts in Petroleum Transportation." Washington, D.C.

Some vessel risk will remain due to:

(1) Bottom sand shifting

(2) Occasional line exposure for inspection, maintenance, and

(3) Any necessary bridging of gullys or valleys in the ocean floor.

Nonetheless, burying the lines will so significantly reduce this risk that those accidents were deleted from the experience base. The residual risk from this cause is considered covered by the variances of the size and frequency distributions.

No similarly conclusive rationale for adjusting major spill risks was found for the tanker operations. Certainly, one would hope that improved navigation technology, tighter government controls, and increased economic motivation would reduce tanker spill risks. No known plans reduce the physical possibility of those accidents in a manner comparable to the burying of pipelines, however.

For spills smaller than 42,000 gallons, which would be unlikely to be covered in other than comprehensive reporting system, the U.S. Coast Guard Pollution Incident Reporting System was used in the MIT analysis. Both because the occurrence frequencies of small spills are much higher than of major spills (leading to tighter estimates) and because the numerous spills in this range contribute very little to the overall spill volume expectations, no attempt was made to improve on the MIT results. They are taken from the adaptation of the MIT study at the end of the working paper and are shown in FIGURES 14 and 15.

Comparable tanker data are more complex to analyze geographically. Several categorizations of vessel accident locations are available, but

SPILL SIZE RANGE	MEAN	VOLUME LANDED INTERVAL	0-10,500 M	10,500-21,000 M	21,000 - 31,500 M	31,500 - 42,000 M	42,000 M
		MIDPOINT	5,250 M	15,750 M	26,250 M	36,750 M	63,000 M
		PROBABILITY	.57	.25	.10	.05	.03
10 M	20 M	.02	.0114	.0050	.0020	.0010	.0006
1-10 M	4 M	.48	.2736	.1200	.0480	.0240	.0144
100K-1 M	.35	.38	.2166	.0950	.0380	.0190	.0114
42-100K	.067M	.12	.0684	.0300	.0120	.0060	.0036

SPILL VOLUME EXPECTATION BY SIZE OVER ALTERNATIVE VOLUME LANDED INTERVALS

			(WORLD)	(REGOPM)
E (SPILL 10M)	=4.3E-5 + 6.3E-6 + 1.5E-6 + 5.4E-7 + 1.9E-7	=	5.2E-5	2.6E-5
E (SPILL 1-10 M)	=2.1E-4 + 3.0E-5 + 7.3E-6 +2.6E-6 +9.1E-7	=	2.5E-4	1.3E-4
E (SPILL 100K-1 M)	=1.4E-5 + 2.1E-6 + 5.1E-7 +1.8E-7 +6.3E-8	=	1.7E-5	8.4E-6
E (SPILL 42-100K)	=8.7E-7 + 1.3E-7 +3.1E-8 +1.1E-8 +3.8E-9	=	1.0E-6	5.0E-7
E (SPILL 42K)	=(624 X 318)/(1412E6 X 42)	=	(6.6E-6)	3.3E-6
TANK CLEANING	=1/2 LOT SPILLING 2.7E-4 AND 1/2 SEGREGATED BALLAST W/SLOP RECEPTION	=	1.4E-4	0
	TOTAL EXPECTATION		4.6E-4	1.6E-4

FIGURE 14. Joint Distribution of Equivalent Import Tanker Spill Size Interval by Volume Landed (Volume in Gallons) (Data from MIT Analysis)

SPILL SIZE RANGE	MEAN	PRODUCTION VOLUME INTERVAL	0-10,500 M	10,500 - 21,000 M	21,000 - 31,500 M	31,500 - 42,000 M	42,000 M
		MIDPOINT	5,250 M	15,750 M	26,250 M	36,750 M	63,000 M
		PROBABILITY	.46	.22	.13	.08	.11
10 M	15 M	.03	.0138	.0066	.0039	.0024	.0033
1-10 M	2 M	.37	.1702	.0814	.0481	.0296	.0407
100K-1 M	.2 M	.36	.1656	.0792	.0468	.0288	.0396
42-100K	.05 M	.24	.1104	.0528	.0312	.0192	.0264

Spill Expectation by Spill Size Over Alternate Production Volume Spill Intervals

		(Base)	(Revised)
E (Spill 10 M)	= 3.9E-5 + 6.3E-6 + 2.2E-6 + 9.8E-7 + 7.8E-7 =	4.9E-5	1.2E-5
E (Spill 1-10 M)	= 6.5E-5 + 1.0E-5 + 3.7E-6 + 1.6E-6 + 1.3E-6 =	8.2E-5	4.1E-5
E (Spill 100K-1 M)	= 6.3E-6 + 1.0E-6 + 3.6E-7 + 1.6E-7 + 1.3E-7 =	8.0E-6	6.0E-6
E (Spill 42-100K)	= 1.0E-6 + 1.7E-7 + 5.9E-8 + 2.6E-8 + 2.1E-8 =	1.3E-6	1.3E-6
E (Spill 42K)	= (1182 X 201 + 159 X 94)/(1230E6 X 42) [Values from MIT Analysis]=	4.9E-6	4.9E-6
	Total Expectation	1.4E-4	6.5E-5

FIGURE 15. Joint Distribution of Pipeline Major Spill Size and Spill Interval by Production Volume (Volume in Gallons) (Data from MIT Analysis)

are somewhat ambiguous for inshore areas such as ports, harbors, entrances, channels, rivers, and docks. The categorization adopted for this study was:

(1) Inshore--all incidents categorized as entrances or inside of harbor entrances,

(2) Coastal--from entrances out to 50 miles, and

(3) At-sea--beyond 50 miles.

The inshore data are broken down into transfer operations (all inshore spills not resulting from a vessel casualty) and inshore vessel casualties. The transfer operations data are from the U.S. Coast Guard Pollution Incident Reporting System (PIRS). FIGURE 16 shows those spills over 1,000 gallons from onshore bulk cargo transfer facilities plus those from ships or barges where the cause is specified as a personnel or equipment failure plus those from unknown sources and causes. Only spills involving heavy oils such as crudes or residuals are used because these are frequently imported and thus involve operations similar to those contemplated. Lubricants are included because they are heavy and cannot be distinguished from light crudes in the early PIRS data.

The coastal spills shown in FIGURE 17 are also taken from the 1971-1974 PIRS data. Although the majority of the spills are listed as source unknown, most spills in the coastal area not identified to a land source are likely to be from vessels, especially when the oil can be identified as crude or residual. Reporting in the coastal area is weak because the federal jurisdiction for spill reporting enforcement only extends to the three-mile limit of U.S. territorial waters.

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VOLUME SPILLED	MATERIAL SPILLED	SOURCE	YEAR	CAUSE
1,000	CRUDE	UNKNOWN	1973	UNKNOWN
1,000	HEAVY	UNKNOWN	1973	UNKNOWN
1,000	CRUDE	FACILITY	1974	DEFECTIVE FLANGE
1,050	LUBE	SHIP	1972	UNKNOWN
1,500	UNKNOWN	UNKNOWN	1972	UNKNOWN
1,500	UNKNOWN	SHIP	1974	UNKNOWN
1,680	RESIDUAL	BARGE	1971	UNKNOWN
1,680	RESIDUAL	SHIP	1971	PERSONNEL FAULT
2,000	CRUDE	SHIP	1974	FLANGE FAILURE
2,000	CRUDE	SHIP	1974	FLANGE FAILURE
2,000	MIXTURE	FACILITY	1974	SATURATED/GROUND
2,100	CRUDE	FACILITY	1973	IMPROPER VALUE OPERATION
2,100	UNKNOWN	BARGE	1971	MISC. EQUIPT. FAILURE
2,200	MIXTURE	SHIP	1974	IMPROPER VALUE OPERATION
3,000	UNKNOWN	FACILITY	1974	PIPELEAK-PERSONNEL FAULT
3,150	CRUDE	SHIP	1971	MISC. EQUIPT. FAILURE
3,940	UNKNOWN	UNKNOWN	1972	UNKNOWN
4,200	RESIDUAL	SHIP	1972	IMPROPER VALUE OPERATION
4,200	RESIDUAL	UNKNOWN	1972	UNKNOWN
4,200	CRUDE	SHIP	1973	LOADING ARM OVERPRESSURED
4,200	CRUDE	BARGE	1971	PIPE RUPTURE
8,400	RESIDUAL	BARGE	1972	LINE LEAK
10,000	CRUDE	SHIP	1973	DEFECTIVE HOSE
15,000	LT. CRUDE, LUBE	UNKNOWN	1972	UNKNOWN
16,800	RESIDUAL	SHIP	1971	MISC. EQUIPT. FAILURE
90,000	RESIDUAL	FACILITY	1973	UNKNOWN

FIGURE 16. Ship Conventional Transfer Operations, Spills Over 1,000 Gallons, New York Harbor and Delaware Bay and River

VOLUME SPILLED	MATERIAL SPILLED	SOURCE	YEAR	CAUSE
1,000	RESIDUAL	SUSPECTED VESSEL	1973	UNKNOWN
1,500	CRUDE	UNKNOWN	1974	UNKNOWN
1,800	UNKNOWN	UNKNOWN	1974	UNKNOWN
4,000	RESIDUAL	UNKNOWN	1973	UNKNOWN
53,000	RESIDUAL	UNKNOWN	1972	UNKNOWN

SOURCE: U.S. COAST GUARD POLLUTION INCIDENT REPORTING SYSTEM

FIGURE 17. Tanker Coastal Spills Over 1,000 Gallons Heavy Oils, New York/New Jersey Area, 1971-1974

Comparable volume handled date for FIGURES 16 and 17 were extracted from "Waterborne Commerce of the United States",[7/] an annual report of the Department of the Army Corps of Engineers. All non-internal inbound shipments of crude, residual, and lubricants are reflected in the volumes shown in FIGURES 18 and 19. Data from 1964-1973 were used to form a basis for a semilogarithmic linear regression estimate of the 1974 value. (The b parameter of that estimate, indicates an average annual growth rate in heavy oils handled of about 4 percent for New York ports and 5 percent for the Delaware Bay area.) Volume data were converted from short tons to gallons using the relationship:

Data (ST) x 2000/2240 x 300 gallons/LT,

where ST - short tons, 2000 pounds, and

LT - long tons, 2240 pounds.

Except for the coastal area, the PIRS reports reflect very few major vessel casualty spills. A computer listing was obtained from the Coast Guard of 1969-1973 polluting vessel casualties[8/] compiled from a variety of sources, those used in this study being from Lloyds Weekly Casualty Reports. Spill casualties were initially selected if they occurred north of the Tropic of Cancer and west of 30° W longitude in the Atlantic Ocean. The Lloyds reports were consulted to eliminate casualties associated with

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7/ Department of the Army, Corps of Engineers, Waterborne Commerce of the United States, 19xx. Annual reports from 1964 through 1973. (New Orleans: District Engineer, U.S. Army Engineer District.)

8/ U.S. Coast Guard, Memo to File G-MMT-1/82, 5943 21 May 1974, Subject, "1973 Tanker Casualty Data." 1969-1970, and 1973 data compiled by U.S. Coast Guard, 1971-1972 data compiled by J.J. Henry Company, Inc , for the U.S. Coast Guard (Washington, D.C.)

TEN-YEAR HISTORY

YEAR	HEAVY* OILS HANDLED ($\times 10^{10}$)
1964	1.4097
1965	1.4947
1966	1.5488
1967	1.6742
1968	1.7994
1969	1.8001
1970	1.9530
1971	1.9588
1972	1.8661
1973	2.0449

1971 - 1974 EXPOSURE ($\times 10^{10}$)

1971	1.9588
1972	1.8661
1973	2.0449
1974	2.1670
	8.0368×10^{10}
	$\approx 8.04 \times 10^{10}$

REGRESSION ESTIMATE

1974	2.1670

$\ln y = a + b x$

$a = 0.3375$

$b = 0.0396$

$r^2 = 0.9202$

* HEAVY OILS TAKEN AS CRUDE PETROLEUM, PLUS RESIDUAL FUEL OIL, PLUS LUBRICATING OILS AND GREASES

SOURCE: DEPARTMENT OF THE ARMY, CORPS OF ENGINEERS WATERBORNE COMMERCE OF THE UNITED STATES

FIGURE 18. New York Harbor Volume Histories for Heavy Oils, 1964-1973, Estimate of 1974

TEN-YEAR HISTORY			
YEAR	HEAVY* OILS HANDLED ($\times 10^{10}$)		
1964	1.2988		
1965	1.2621		
1966	1.2084		
1967	1.4451		
1968	1.5367	1971	1.5937
1969	1.5720	1972	1.8661
1970	1.6247	1973	1.6670
1971	1.5937	1974	1.7468
1972	1.5799		6.8736×10^{10}
1973	1.6670		
REGRESSION ESTIMATE			
1974	1.7468		
$y = a + bx$			
$a = 1.2109$			
$b = 0.0487$			6.87×10^{10}
$y = 1.7468$			
$r^2 = 0.768$			$+ NY\ 8.04 \times 10^{10}$
			$DB + NY = 1.49 \times 10^{11}$

SOURCE: DEPARTMENT OF THE ARMY, CORPS OF ENGINEERS WATERBORNE COMMERCE OF THE UNITED STATES

FIGURE 19. Delaware Bay Volume Histories for Heavy Oils, 1964-1973, Estimate for 1974

Canada or the Bahamas as opposed to the U.S. east coast and to identify the type of oil spilled where possible. In cases where the oil was not identified it is listed in FIGURES 20 and 21 as "Heavy". Cases involving light oils or spills other than tanker cargoes were eliminated where identified.

Lloyds Weekly Casualty Reports seldom report spill volumes. These were estimated by various compilers of teh listing based on information in the report, from supplemental documentation, or from calls to companies involved in the incidents. Volume data were converted from the long tons in the listing to gallons using the estimating relationships:

Crude--315 gallons/LT,

Heavy--300 gallons/LT, and

Residual--280 gallons/LT.

Finally, inshore data in FIGURE 20 were selected based on locations: entrances, ports, harbors. The remainder of the selected spills, at-sea casualties, are in FIGURE 21.

Comparable volume exposure data required a compilation of data for oceangoing inbound shipments of crude, residual, and lubricants or all major east coast ports from 1969-1973. The data are shown in FIGURE 22.

None of the data sources above addressed chronic pollution from tanker tank cleaning operations. These values were taken from the University of Oklahoma study[9/] and included in FIGURE 14.

9/ Kash, Don E. and White, Irvin L., et al., Energy Under the Oceans: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations. (Norman, Oklahoma: University of Oklahoma Press, 1973).

VOLUME SPILLED	MATERIAL SPILLED	VESSEL	YEAR	TYPE CASUALTY	FLAG
60,000	HEAVY*	ATLANTIC PRESTIGE	1972	GROUNDING	U.S.
102,000	HEAVY	HELENA VENIZEL	1973	GROUNDING	LIBERIAN
135,000	RESIDUAL	BATISSA	1972	GROUNDING	BRITISH
150,000	HEAVY	ALGOL	1969	GROUNDING	LIBERIAN
225,000	HEAVY	ESSO GETTYSBURG	1970	GROUNDING	U.S.
238,000	RESIDUAL	PENNANT	1973	GROUNDING	LIBERIAN
249,000	HEAVY	DELTAN APPOLON	1970	GROUNDING	GREEK
285,000**	HEAVY	LALIBELLA	1973	RAMMING	ITHIOPIAN
300,000**	HEAVY	HILDA	1969	RAMMING	LIBERIAN
465,000	HEAVY	ESSO SALISBURY	1970	GROUNDING	BRITISH
476,000	RESIDUAL	REGENT LIVERPOOL	1969	RAMMING	BRITISH
756,000	CRUDE	MOBIL ENDURANCE	1969	GROUNDING	BRITISH
900,000	HEAVY	WILLIAM LARMARNE	1973	GROUNDING	LIBERIAN
986,000	RESIDUAL	TAMANO	1972	GROUNDING	NORWEGIAN

*OILS ASSUMED "HEAVY" UNLESS SPECIFIED AS CRUDE, RESIDUAL, OR A LIGHT OIL IN LLOYDS.
**LLOYD'S REPORTS NOT FOUND.

SOURCE: U.S. COAST GUARD, SPILLAGE ESTIMATES FROM INCIDENTS REPORTED IN LLOYD'S WEEKLY CASUALTY REPORTS

FIGURE 20. Inshore Tanker Spills Over 10,000 Gallons Heavy Oils, U.S. East Coast, 1969-1973

VOLUME SPILLED	MATERIAL SPILLED	VESSEL	YEAR	TYPE CASUALTY	FLAG
12,600	HEAVY*	ADAMANTIOS	1971	STRUCTURAL FAILURE	LIBERIAN
12,600	HEAVY	ADAMANTIOS	1972	STRUCTURAL FAILURE	LIBERIAN
12,600	HEAVY	APODIMOS	1972	STRUCTURAL FAILURE	GREEK
13,230	CRUDE	LAMYRA	1969	STRUCTURAL FAILURE	LIBERIAN
30,000	HEAVY	OLYMPIC STAR	1970	STRUCTURAL FAILURE	LIBERIAN
52,500	HEAVY	DON MANUEL	1973	STRUCTURAL FAILURE	LIBERIAN
1,789K	CRUDE	GAFTON	1969	STRUCTURAL FAILURE	BRITISH
5,876K	HEAVY	NELSON	1973	STRUCTURAL FAILURE	CYPRIAN
8,274K	RESIDUAL	TEXACO OKLAHOMA	1971	STRUCTURAL FAILURE	U.S.
9,002K	HEAVY	KEO	1969	STRUCTURAL FAILURE	LIBERIAN
9,365K	HEAVY	CHRYSSI	1970	STRUCTURAL FAILURE	PANAMANIAN
9,515K	HEAVY	GOLDEN DRAKE	1972	EXPLOSION	LIBERIAN

*OILS ASSUMED "HEAVY" UNLESS SPECIFIED AS CRUDE, RESIDUAL OR A LIGHT OIL IN LLOYD'S.

SOURCE: U.S. COAST GUARD SPILLAGE ESTIMATES FROM INCIDENTS REPORTED IN LLOYD'S WEEKLY CASUALTY REPORTS

FIGURE 21. At-Sea Tanker Spills Over 10,000 Gallons Heavy Oils, U.S. East Coast Routes, 1969-1973

	1969	1970	1971	1972	1973
PORTLAND, ME	22,555,214	24,912,067	26,430,027	25,743,339	24,025,107
PORTSMOUTH, NH	639,648	784,085	909,014	751,264	862,460
BOSTON, MA	7,818,521	8,222,845	6,400,539	7,201,688	7,873,515
PROVIDENCE, RI	2,634,372	2,501,661	2,006,529	2,363,544	2,562,650
NEW LONDON, CO	1,061,474	2,034,631	1,883,094	2,391,405	2,696,265
CONN. RIVER,CO	1,881,336	1,607,737	1,430,352	1,487,491	1,760,061
NEW HAVEN,CO	2,472,422	2,944,738	2,904,729	3,552,221	3,527,823
BRIDGEPORT, CO.	1,494,389	1,854,462	1,644,402	1,582,443	1,419,492
NEW YORK, N.Y.	46,445,111	51,149,955	47,310,806	42,131,169	46,875,386
HUDSON RIVER, N.Y.	1,328,121	2,297,478	2,559,001	3,000,657	2,879,322
DELAWARE RIVER	59,043,789	60,437,698	59,548,235	58,496,680	62,236,372
BALTIMORE, MD.	4,101,277	5,304,347	5,052,129	5,704,680	6,399,710
POTOMAC RIVER	902,208	1,611,785	2,416,102	2,564,229	3,193,394
HAMPTON ROADS, VA.	4,035,148	5,411,374	6,262,740	6,774,985	7,367,151
YORK RIVER, VA.	2,288,590	1,865,750	1,878,270	2,619,438	2,631,444
WILMINGTON, NC	698,063	1,055,974	1,109,951	1,961,035	2,725,480
CHARLESTON, S.C.	1,249,945	1,583,265	1,564,165	1,696,929	2,599,638
SAVANNAH, GA.	1,099,215	1,388,503	1,648,845	1,691,661	2,043,167
JACKSONVILLE, FL.	2,768,598	2,883,826	2,903,843	4,067,828	4,252,917
CANAVERAL, FL.	653,737	764,059	920,354	1,002,814	1,045,255
PORT EVERGLADES, FL.	1,485,566	1,792,334	1,758,355	2,041,323	2,153,061
MIAMI, FL.	820,577	815,327	739,640	968,082	1,125,816
	1.6748E8	1.8217E8	1.7928E8	1.7980E8	1.9226E8

1969 - 73 GRAND TOTAL = 9.01×10^{8} TONS = 2.41×10^{11} GALLONS

FIGURE 22. Atlantic Coast Foreign and Domestic Receipts of Heavy Oil of Short Tons

The tank cleaning discharge rate for load-on-top (LOT) tankers is estimated as 270 barrels per million barrels carried. It was assumed for this study that over the time period contemplated about half of the tankers would be of the load-on-top type and the other half would be of the more modern segregated ballast type. It was further assumed that slop reception facilities would be provided for discharge of their cargo tank residues. These assumptions reduce the effective chronic pollution rate to 135 barrels per million barrels produced. Geographically, this spillage is allocated to the at-sea area beyond 50 miles.

Data on large tanker spills used is also contained in the MIT analysis. It was obtained from Engineering Computer Optecnomics, compiled from a variety of sources, mainly Lloyd's Weekly Casualty Reports. The MIT spill size description, using their gamma hyperpoisson distribution was used directly in the present analysis. Spillage and exposure volumes from the same chart were used for frequency estimation (FIGURE 23). These data are from a variety of worldwide trade routes and are not specifically indicative of U.S. routes. The spill size distribution has sufficient variance to include spills of the full capacity of the largest tankers contemplated for this study. All of this large tanker spillage is assigned to the at-sea area both because Lloyd's shows virtually no major spills in the U.S. east coastal area and because careful traffic control will be required in teh vicinity of any U.S. deepwater port.

The deepwater port is expected to be of the single point moor (SPM) type using monobuoys. A list of 51 SPM spill incidents was obtained from

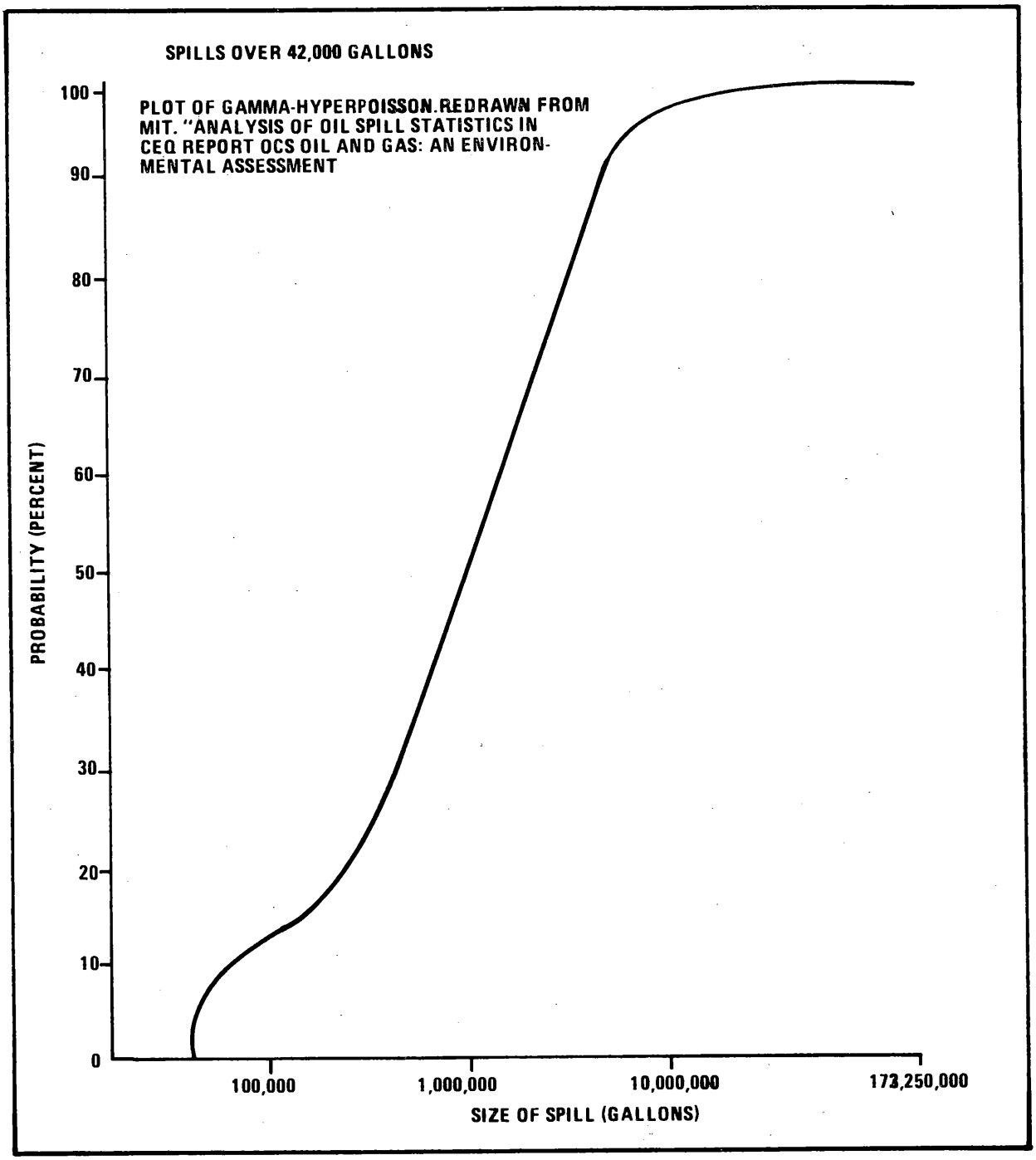

FIGURE 23. Cumulative Probability of Spill Size $\leq$ X for Large Tankers

Engineering Computer Optecnomics (ECO). The ECO principals have assembled that data from all available sources and consider it to be as reliable a data set as can be currently assembled. In many contacts with ship and port operators, they have found a consensus that spill experience with a modern well-run SPM should be comparable.

Of the 51 spills, ten occurred at loading SPM's which would have different spill experience from the discharge SPM's of interest for the deepwater port. The remaining 41 spills are listed in FIGURE 24. Most of the data was obtained by ECO from the SPM Forum. This data is very useful for estimating spill size distributions, but without comparable volume handled data it does not indicate spill frequency.

Reference 2 lists most of those spills and also data presented to the House of Lords hearings on a proposed deepwater port at Angelsey, 1 October 1971. The latter data, listing spills by size range and comparable volume handled, was useful for spill frequency estimation. It includes spills from an SPM at Durban which has been exceptionally plagued with problems. In that sense, the data is conservative, but spills well in excess of the 9000 gallon upper bound implied by the data have obviously occurred.

3.4 Spill Frequency Estimation

As discussed previously, spill frequencies are considered to follow a Poisson-type distribution where the intensity varies as a gamma distribution with both parameters equal to zero. This results in the negative binomial probability distribution. Given an experience base consisting of number of spills observed and exposure observed, this distribution can

VOLUME (GALLONS)	LOCATION	CAUSE	REPORTING PERIOD
25,200	HUELVA, SPAIN	FLOATING HOSE FAILURE	1971-72
25,200	TETNEY, U.K.	TANKER HIT BUOY	1971-72
21,000	KOSHIBA, JAPAN	FISHING VESSEL OVERRAN FLOATING HOSE DURING PUMPING	1967-72
8,400	DURBAN, SOUTH AFRICA	UNDERBUOY HOSE TWISTED	1971-72
7,140	PORT DICKSON, MALAYSIA	UNDERBUOY HOSE FAILED	1971-72
3,000	SINGAPORE	FLOATING HOSE FAILURE	1970
2,500	CHIBA, JAPAN	MOORING BUOY TORE LOOSE, UNDERBUOY HOSES PARTED	1970-72
2,100	KAWASAKI, JAPAN	VESSEL HIT BUOY	1970-72
1,680	DURBAN	FLOATING HOSE FAILED	1971-72
1,260	BOTANY BAY, AUSTRALIA	EXPANSION PIECE ON MOORING BUOY FAILED	1970
1,000	SINGAPORE	FLOATING HOSE FAILED	1970
1,000	SUBIC BAY, PHILIPPINES	FLOATING HOSE FAILED	1970-72
1,050	JAVA, INDONESIA	SWIVEL SEAL LEAKAGE	1971-72
840	WULSAN, NEW ZEALAND	FLOATING HOSE FAILED	1970-72
840	KAWASAKI, JAPAN	FLOATING HOSE FAILED	1970-72
840	HUELVA, SPAIN	FLOATING HOSE FAILED	1971-72
800	KOSHIBA, JAPAN	FLOATING HOSE FAILED	1967-72
800	PORT DICKSON, MALAYSIA	FLOATING HOSE FAILED	1971-72
630	WULSAN, NEW ZEALAND	FLOATING HOSE FAILED	1971-72
600	WULSAN, NEW ZEALAND	FLOATING HOSE FAILED	1971-72
600	CHIBA, JAPAN	FLOATING HOSE FAILED	1970-72
600	MIRI, MALAYSIA	FLOATING HOSE FAILED	1970-72
500	PORT BALEO, ECUADOR	FLOATING HOSE FAILED	1972
460	KOSHIBA	FLOATING HOSE FAILED	1972
420	WULSAN, NEW ZEALAND	FLOATING HOSE FAILED	1971-72
420	HUELVA, SPAIN	FLOATING HOSE FAILED	1971-72
420	DURBAN	FLOATING HOSE FAILED	1971-72
400	TETNEY, U.K.	FLOATING HOSE FAILED	1971-72
400	MIRI, MALAYSIA	SWIVEL JOINT LEAKED	1970-72
400	SUBIC BAY, PHILIPPINES	MOORING BUOY FAILED	1970-72
400	ST. JOHN'S, CANADA	CHAFED UNDERBUOY HOSE	1970-72
400	CHIBA, JAPAN	FLOATING HOSE FAILURE	1970-72
400	JAVA, INDONESIA	SWIVEL SEAL LEAK	1971-72
400	PORT DICKSON, MALAYSIA	FLOATING HOSE FAILED	1970-72
300	PORT BALEO, ECUADOR	FLOATING HOSE FAILED	1972
200	TETNEY, U.K.	FLOATING HOSE FAILED	1971-72
200	JAVA, INDONESIA	FLOATING HOSE FAILED	1971-72
200	KAWASAKI, JAPAN	FLOATING HOSE FAILED	1970-72
200	PORT DICKSON, MALAYSIA	FLOATING HOSE FAILED	1970-72
200	ST. JOHN'S, CANADA	CHAFED UNDERBUOY HOSE	1970-72
200	ST. JOHN'S, CANADA	CHAFED UNDERBUOY HOSE	1970-72

FIGURE 24. Discharge SPM Spills (Data from Engineering Computer)

be used to compute either interspill production volume distributions or number of spill distributions for a fixed production volume. Given the volume-planned estimates used in the scenarios, the distribution of number of spills by time frame was desired.

In the OCS analysis, it is assumed that the planned volume of production over time is symmetrical, with peak production occurring within the 1990-1999 time frame and the remaining production equally divided between a 1980-1989 start-up phase and a 2000-2009 wind down phase. This ten year breakout allows convenient translation from annual spillage to phase or life cycle spillage, although spills in the early and late phases will be distributed more toward the peak period than away from it.

Calculations were made for major spills for each operation of interest: pipelines, rigs, marine transfers, inshore, coastal, and at-sea vessel casualties. The latter data are separated by size category into spills of 10,000 to 1 million gallons and spills over one million gallons; both categories having the same negative binomial distributions of frequencies.

The data inputs for the calculations were taken directly from the previous section. Four distributions were calculated for each operation to provide start-up/wind-down and peak-production phase estimates for both the high and low recovery scenarios.

DWP calculations were made for major spills for each operation of interest: pipelines, SPM operations, transfers, inshore, coastal, and at-sea vessel casualties. The latter data are separated by size category into spills of 10,000 to 1 million gallons and spills over one million

gallons, with both categories having the same negative binomial distributions of frequencies.

The computation formula used in both the OCS and DWP analyses is displayed in FIGURE 25.

In addition to the major spill frequency estimates, small SPM spill frequencies were also calculated using the negative binomial distribution. Other small spill estimates were calculated as a fraction of volume handled using the coefficients of FIGURES 14 and 15.

Relative to the two Assumptions 1 of the analyses, it should be observed that exposure volumes observed ranges from 8.04×10^{10} gallons to 2.41×10^{11} gallons, while volumes planned ranges from 2.2×10^{10} gallons to 9.8×10^{10} gallons. Thus, comparable or larger volumes have been observed in the data base relative to those for which frequencies are calculated. While more exposure data would be desirable, that available appears adequate to provide credible distributions.

To aid in visualising the distributions produced, FIGURE 26 shows the plots of these cumulatives for marine transfer spills in the high recovery scenario. Tabular data are more convenient to use for the application of the values to spillage estimation. FIGURES 27-32 show the spill frequencies calculated.

3.5 Spill Size Estimation

The estimation of spill sizes varies slightly in this analysis from that used in other recent reports. The gamma distribution was selected to describe each spill size data set. Because only the cumulative distribution is used in the analysis, the data were hand-fitted directly

- THE PROBABILITY OF x SPILLS OCCURRING WHILE PRODUCING A VOLUME Vp OF OIL IS ASSUMED TO BE GIVEN BY NEGATIVE BINOMIAL DISTRIBUTION:

$$f(x) = \binom{x + SO-1}{SO-1} p^{SO} (1-p)^{x}$$

WHERE,

VO = EXPOSURE VOLUME OBSERVED

SO = NUMBER OF SPILLS OBSERVED IN PRODUCING VO

Vp = VOLUME PLANNED

p = VO/(VO + Vp)

x = NUMBER OF SPILLS

- THE PROBABILITY OF x OR FEWER SPILLS OCCURRING WHILE PRODUCING VOLUME Vp OF OIL, DENOTED BY F(x), IS GIVEN BY

$$F(x) = \sum_{i=o}^{x} f(i)$$

FIGURE 25. Spill Probability Distributions

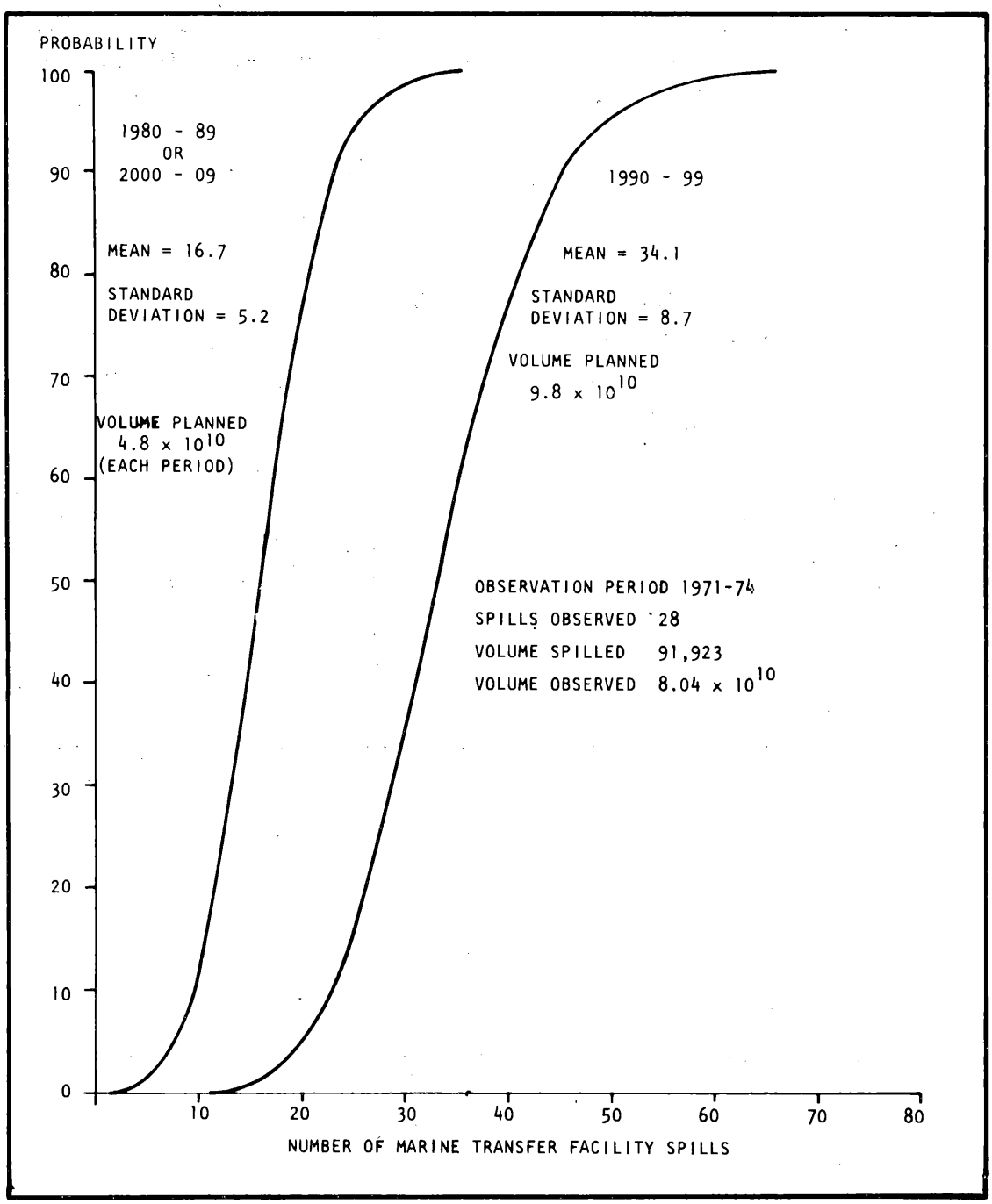

FIGURE 26. Cumulative Probabilities of Marine Transfer Spills Small Import Tanker Equivalent-High Recovery Scenario

HIGH RECOVERY: 1980-89, 2000-09 VOLUME = 4.8×10^{10} 1990 -99 VOLUME = 9.8×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY	NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.214		0	.063	
1	.284	.498	1	.134	.197
2	.226	.724	2	.171	.368
3	.140	.864	3	.169	.537
4	.074	.938	4	.143	.681
5	.035	.974	5	.110	.790
			6	.077	.868
MEAN = 1.8			7	.052	.920
STANDARD DEVIATION = 1.57			8	.033	.952

MEAN = 3.68

STANDARD DEVIATION = 2.53

LOW RECOVERY: VOLUME = 2.2×10^{10} VOLUME = 4.28×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY	NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.465		0	.248	
1	.330	.795	1	.302	.550
2	.141	.936	2	.220	.770
3	.047	.982	3	.125	.895
			4	.061	.956

MEAN = .83

STANDARD DEVIATION = .98

MEAN = 1.61

STANDARD DEVIATION = 1.46

FIGURE 27. Pipeline (Less Anchor, Propeller Incidents) Spills Over 42,000 Gallons Negative Binomial Probabilities and Cumulatives Spills Observed = 5 Exposure Observed = 1.33×10^{11}

NEGATIVE BINOMIAL PROBABILITIES AND CUMULATIVES

SPILLS OBSERVED = 9			EXPOSURE OBSERVED = 1.65×10^{11}		
1980 - 89, 2,000-09			1990 - 99		
HIGH RECOVERY: VOLUME = 4.8×10^{10}			VOLUME = 9.8×10^{10}		
NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY	NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.100		0	.015	
1	.204	.304	1	.050	.066
2	.230	.534	2	.094	.160
3	.190	.723	4	.144	.423
4	.128	.852	5	.139	.571
5	.075	.927	6	.121	.692
6	.040	.966	8	.072	.861
			10	.034	.946
MEAN = 2.6 STANDARD DEVIATION = 1.8			MEAN = 5.3 STANDARD DEVIATION = 2.9		
LOW RECOVERY: VOLUME = 2.2×10^{10}			VOLUME = 4.28×10^{10}		
NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY	NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.324		0	.125	
1	.343	.667	1	.233	.358
2	.202	.869	2	.240	.598
3	.087	.956	3	.181	.778
4	.031	.987	4	.112	.890
			5	.060	.950
MEAN = 1.2 STANDARD DEVIATION 1.2			MEAN = 2.3 STANDARD DEVIATION = 1.7		

FIGURE 28. Oil Rig Spills Over 42,000 Gallons

SPILLS OBSERVED = 12
1980 - 89, 2,000 - 09
HIGH RECOVERY: VOLUME = 4.8×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.004	
2	.040	.059
4	.097	.225
6	.123	.464
7	.117	.582
9	.087	.774
11	.051	.893
13	.025	.955

MEAN = 7.2
STANDARD DEVIATION = 3.4

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	7×10^{-5}	
6	.024	.054
8	.044	.132
10	.062	.248
12	.072	.387
14	.071	.531
16	.063	.662
20	.037	.850
25	.013	.958

MEAN = 14.6
STANDARD DEVIATION = 5.7

LOW RECOVERY: VOLUME = 2.2×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.055	
1	.141	.196
2	.198	.394
3	.198	.592
4	.160	.752
5	.110	.861
6	.067	.928
7	.037	.965

MEAN = 3.3
STANDARD DEVIATION = 2.0

VOLUME = 4.28×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.006	
1	.025	.031
2	.056	.087
4	.119	.300
6	.130	.558
8	.096	.770
10	.054	.898
12	.025	.960

MEAN = 6.4
STANDARD DEVIATION = 3.1

FIGURE 29. Marine Transfer Spills Over 1,000 Gallons Negative Binomial Probabilities and Cumulatives

NEGATIVE BINOMIAL PROBABILITIES AND CUMULATIVES

SPILLS OBSERVED = 14

1980 -89 2000 - 09

HIGH RECOVERY: VOLUME = 4.8×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.079	
1	.183	.262
2	.228	.484
3	.202	.691
4	.142	.834
5	.085	.919
6	.045	.963

MEAN = 2.8

STANDARD DEVIATION = 1.8

VOLUME = 9.8×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.008	
1	.034	.043
3	.114	.230
4	.140	.370
5	.146	.516
6	.133	.649
8	.084	.843
10	.039	.942

MEAN = 5.7

STANDARD DEVIATION = 2.8

LOW RECOVERY: VOLUME = 2.2×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.294	
1	.345	.639
2	.216	.855
3	.096	.952
4	.034	.986

MEAN = 1.3

STANDARD DEVIATION = 1.2

VOLUME = 4.28×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.101	
1	.214	.316
2	.242	.558
3	.195	.752
4	.125	.877
5	.068	.945

MEAN = 2.5

STANDARD DEVIATION = 1.7

FIGURE 30. Inshore Tanker Spills Over 10,000 Gallons

NEGATIVE BINOMIAL PROBABILITIES AND CUMULATIVES

SPILLS OBSERVED = 5 1980-89,2000-09			EXPOSURE OBSERVED = 8.04×10^{10} 1990-99		
HIGH RECOVERY: VOLUME = 4.8×10^{10}			VOLUME = 9.8×10^{10}		
NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY	NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.096		0	.019	
1	.180	.276	1	.051	.070
2	.202	.478	3	.108	.262
3	.176	.654	5	.117	.497
4	.132	.786	6	.107	.605
5	.089	.874	7	.093	.697
6	.055	.925	9	.061	.834
7	.032	.962	11	.035	.916
			13	.018	.959
MEAN = 3.0 STANDARD DEVIATION = 2.2			MEAN = 6.1 STANDARD DEVIATION = 3.7		
LOW RECOVERY: VOLUME = 2.2×10^{10}			VOLUME = 4.28×10^{10}		
NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY	NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.298		0	.118	
1	.321	.619	1	.206	.324
2	.207	.826	2	.214	.538
3	.104	.929	3	.174	.712
4	.045	.974	4	.121	.833
5	.017	.991	5	.075	.908
			6	.044	.952
MEAN = 1.4 STANDARD DEVIATION = 1.3			MEAN = 2.7 STANDARD DEVIATION = 2.0		

FIGURE 31. Tanker Coastal Spills Over 1,000 Gallons

NEGATIVE BINOMIAL PROBABILITIES AND CUMULATIVES

SPILLS OBSERVED = 6
1980-89,2000-09

EXPOSURE OBSERVED = 2.41×10^{11}

HIGH RECOVERY: VOLUME = 4.8×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.336	
1	.335	.671
2	.195	.866
3	.086	.953

MEAN = 1.2
STANDARD DEVIATION = 1.2

VOLUME = 9.8×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.129	
1	.224	.353
2	.227	.580
3	.175	.754
4	.114	.868
5	.066	.933
6	.035	.968

MEAN = 2.4
STANDARD DEVIATION = 1.9

LOW RECOVERY: VOLUME = 2.2×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.592	
1	.297	.889
2	.087	.976
3	.019	.995

MEAN = .5
STANDARD DEVIATION = .8

VOLUME = 4.28×10^{10}

NUMBER OF SPILLS	PROBABILITY	CUMULATIVE PROBABILITY
0	.375	
1	.339	.714
2	.179	.893
3	.072	.965

MEAN = 1.1
STANDARD DEVIATION = 1.1

FIGURE 32. Tanker Spills Over 1 Million Gallons Or 10,000 - 1 Million Gallons

to the incomplete gamma function, $\gamma(r, x)$, where r is the gamma shape parameter and x is the spill size for which the probability that a spill will be less than or equal to x is desired. Because the incomplete gamma is a single parameter distribution, the data were inspected to find a unit scaling factor (same spill size) such that when all data points were divided by that size, a reasonable fit to some incomplete gamma function could be found.

The approximate formulation given in the exhibit avoids the need for numerical integration and is computationally convenient, but it is accurate over the full distribution only when r is an integer. For decimal values of r the approximation is good in the middle probability ranges (about .30 - .70), but loses accuracy toward the low and high tails. To compensate, decimal r distributions were compared to a graph of the cumulative gamma with integer r curves plotted[10/] and the tails were adjusted to reasonable values from .05 to .95.

FIGURES 33-40 provide spill size summaries, observed cumulative percentages, and corresponding values of the fitted cumulative gamma. FIGURES 41-48 display the resulting curves, which are used in the remainder of the analysis. Observed cumulative data points are plotted to indicate roughly how well the data fits the distribution. In all cases, however, there is too little data to establish whether the cumulative gamma fits the data better than some alternative distribution. Furthermore, the predictive accuracy has not been tested. The fits shown, therefore, are

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10/ Schlaifer, R., Probability and Statistics for Business Decisions: An Introduction to Management Economics Under Uncertainty, McGraw-Hill, New York, 1959.

NO.	SPILLS VOLUME (GALLONS)	VOLUME (500,000 GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r=1.0
1	67,000	.134		
1	105,000	.210	.22	.18
1	108,000	.216		
1	168,000	.34	.44	.29
1	210,000	.42	.55	.34
1	512,000	1.02	.67	.63
1	1,300,000	2.60	.78	.92
1	2,200,000	4.40	.89	.99
1	3,250,000	6.50		~.9999
9	7,920,000			

EXPOSURE OBSERVED: 1.65E11 GALLONS

SOURCE: MIT, "ANALYSIS OF OIL SPILL STATISTICS," IN CEQ OCS OIL AND GAS: AN ENVIRONMENTAL ASSESSMENT

FIGURE 33. Offshore Oil Rig Spills > 42,000 Gallons, United States, 1964-1972

NO.	SPILLS VOLUME (GALLONS)	VOLUME (500,000 GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r=.9
1	60,000	.12	.07	.16
1	102,000	.20	.14	.24
1	135,000	.27	.21	.30
1	150,000	.3	.28	.33
1	225,000	.45	.36	.44
1	238,000	.48	.43	.46
1	249,000	.50	.5	.48
1	285,000	.57	.57	.52
1	300,000	.6	.64	.54
1	465,000	.93	.71	.69
1	476,000	.95	.78	.70
1	756,000	1.51	.86	.86
1	900,000	1.8	.93	.92
1	986,000	1.97	-	.93
14	5,327,000			

EXPOSURE OBSERVED: 2.41×10^{11} GALLONS

SOURCE: U.S. COAST GUARD SPILL ESTIMATES BASED ON INCIDENTS REPORTED IN LLOYD'S WEEKLY CASUALTY REPORTS

DEPARTMENT OF THE ARMY CORPS OF ENGINEERS WATERBORNE COMMERCE OF THE UNITED STATES

FIGURE 34. Inshore Tanker Spills > 10,000 Gallons, U.S. East Coast, 1969-1973

NO.	SPILLS VOLUME (GALLONS)	VOLUME (7300 GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r = 1.0
4	1,000	.14	.15	.13
2	1,500	.21	.23	.19
2	1,680	.23	.31	.21
3	2,000	.27	.42	.24
3	2,150	.30	.54	.26
2	3,000	.41	.62	.33
1	3,940	.54	.65	.41
4	4,200	.58	.81	.44
1	8,400	1.15	.85	.68
1	10,000	1.37	.88	.74
1	15,000	2.05	.92	.87
1	16,800	2.30	.96	.90
1	90,000	12.33	-	.99994
26	189,750			

FIGURE 35. Inshore Marine Transfer Operations, Spill Sizes Over 1,00 Gallons, Small Tanker Oil Imports

NO.	SPILLS VOLUME (GALLONS)	VOLUME (10,000 GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r=.8
1	1,000	.10	.2	.19
1	1,500	.15	.4	.25
1	1,800	.18	.6	.28
1	4,000	.40	.8	.51
1	53,000	5.3	-	~.9999
5	61,300			

EXPOSURE OBSERVED: 8.04×10^{10} GALLONS

SOURCE: U.S. COAST GUARD POLLUTION INCIDENT REPORTING SYSTEM

DEPARTMENT OF THE ARMY CORPS OF ENGINEERS WATERBORNE COMMERCE OF THE UNITED STATES

FIGURE 36. Tanker Coastal Spills > 1,000 Gallons

SPILLS 10,000-1,000,000 GALLONS

NO.	SPILLS VOLUME (GALLONS)	VOLUME (50K GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r=.7
3	12,600	.25	.5	
1	13,230	.26	.67	.51
1	30,000	.60	.83	.79
1	52,500	1.05	-	.99
6	133,530			

SPILLS >1,000,000 GALLONS

NO.	SPILLS VOLUME (GALLONS)	VOLUME (9M GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r=.95
1	1.789M	8.20	.17	.21
1	5.876M	.65	.33	.52
1	8.274M	.91	.50	.65
1	9.002M	1.00	.67	.67
1	9.365M	1.04	.83	.68
1	9.515M	1.05	-	.68
6	43.821M			

EXPOSURE OBSERVED: 2.41×10^{11} GALLONS

SOURCE: U.S. COAST GUARD SPILL ESTIMATES BASED ON INCIDENTS REPORTED IN LLOYD'S WEEKLY CASUALTY REPORTS

FIGURE 37. DEPARTMENT OF THE ARMY CORPS OF ENGINEERS WATERBORNE COMMERCE OF THE UNITED STATES

NO.	SPILLS VOLUME (GALLONS)	VOLUME (100,000 GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r=1.0
2	42,000	.42	.4	.34
1	155,000	1.55		
1	160,000	1.60	.8	.78
1	310,000	3.10	-	.95
5	709,000			

EXPOSURE OBSERVED: 1.33×10^{11} GALLONS

SOURCE: MIT, "ANALYSIS OF OIL SPILL STATISTICS," IN CEQ OCS OIL AND GAS: AN ENVIRONMENTAL ASSESSMENT

FIGURE 38. Offshore Pipeline Spills > 42,000 Gallons Less Anchor, Propeller Incidents, United States, 1967-1972

NO.	SPILLS VOLUME	VOLUME (10,000 GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r=2.0
1	7,140	.71	.20	.160
1	8,400	.84	.40	.206
1	21,000	2.10	.60	.620
2	25,000	2.50	---	.713
5	61,540			

FIGURE 39. Discharge SPM Spill Sizes Over 5,000 Gallons

150 TO 1,000 GALLONS

NO.	SPILLS VOLUME (GALLONS)	VOLUME (500 GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r = .85
6	200	.40	.21	.45
1	300	.60	.25	.59
10	420	.84	.61	.71
1	460	.92	.64	.74
1	500	1.00	.68	.78
4	630	1.25	.82	.86
5	840	1.68	—	.95
28	13,380			

1 TO 5,000 GALLONS

NO.	SPILLS VOLUME (GALLONS)	VOLUME (1,500 GALLON UNITS)	OBSERVED CUMULATIVE PERCENTAGE	CUMULATIVE GAMMA r = .95
3	1,000	.67	.37	.53
1	1,260	.84	.50	.61
1	1,680	1.12	.62	.72
1	2,100	1.40	.75	.79
1	2,500	1.67	.87	.85
1	3,000	2.00	-	.90
8	11,540			

FIGURE 40. Discharge SPM Spill Sizes

79-065 O - 76 - 33

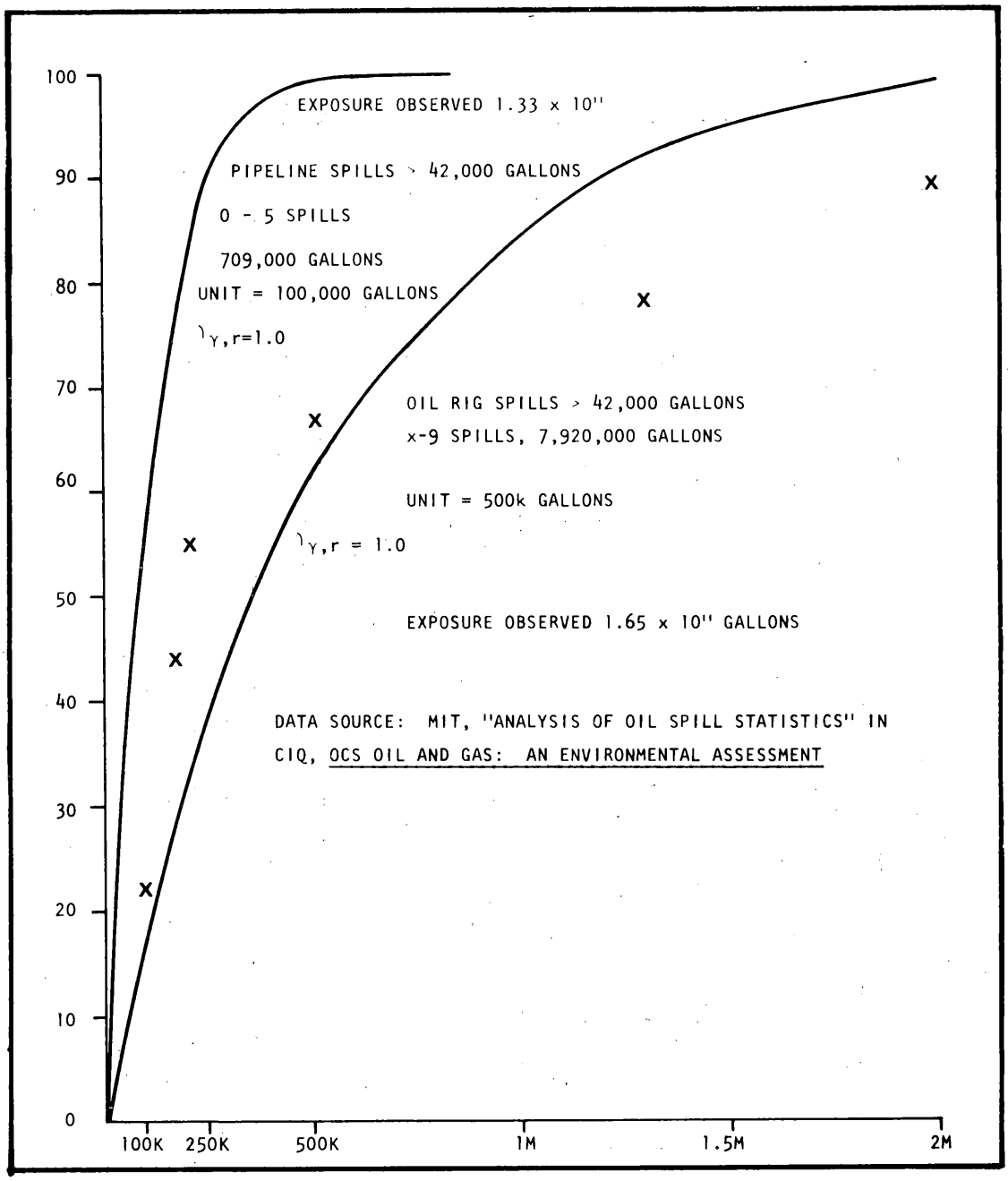


FIGURE 41. Cumulative Probability of Spill <X for Offshore Pipelines and Oil Rigs

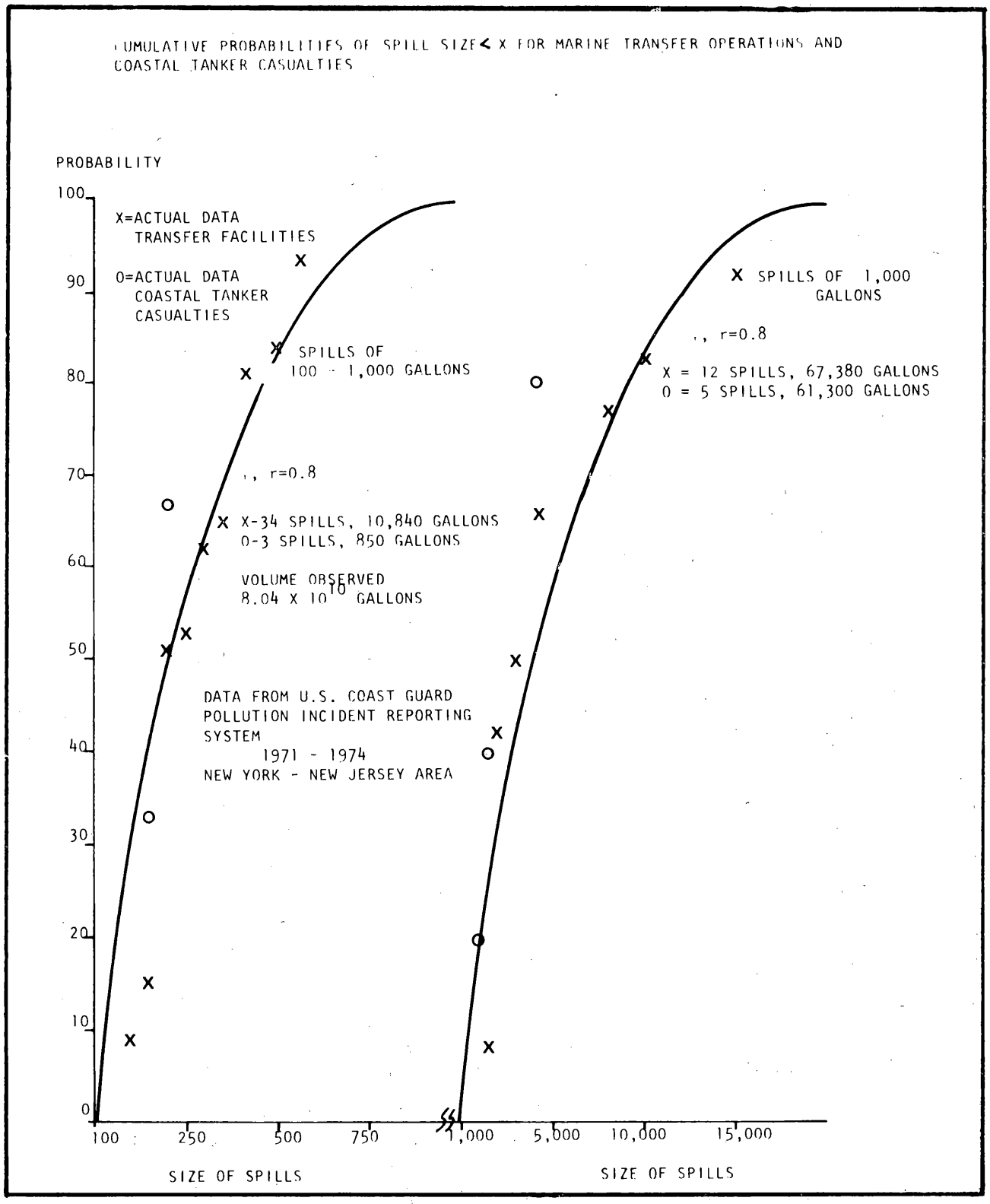


FIGURE 42. Cumulative Probabilities of Spill Size < X for Marine Transfer Operations and Coastal Tanker Casualties

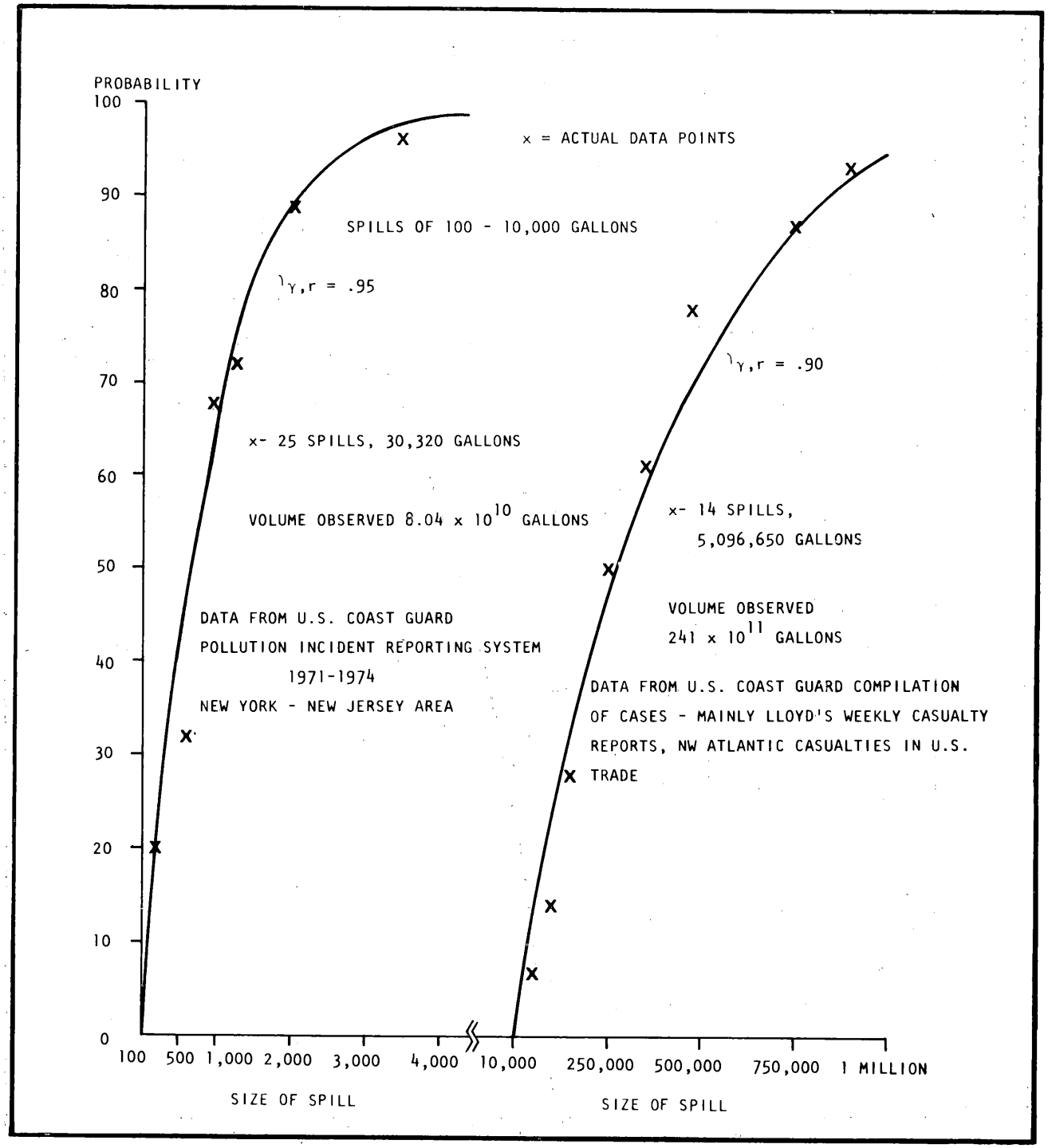


FIGURE 43. Cumulative Probabilities of Spill Size <X for Inshore Tanker Casualties

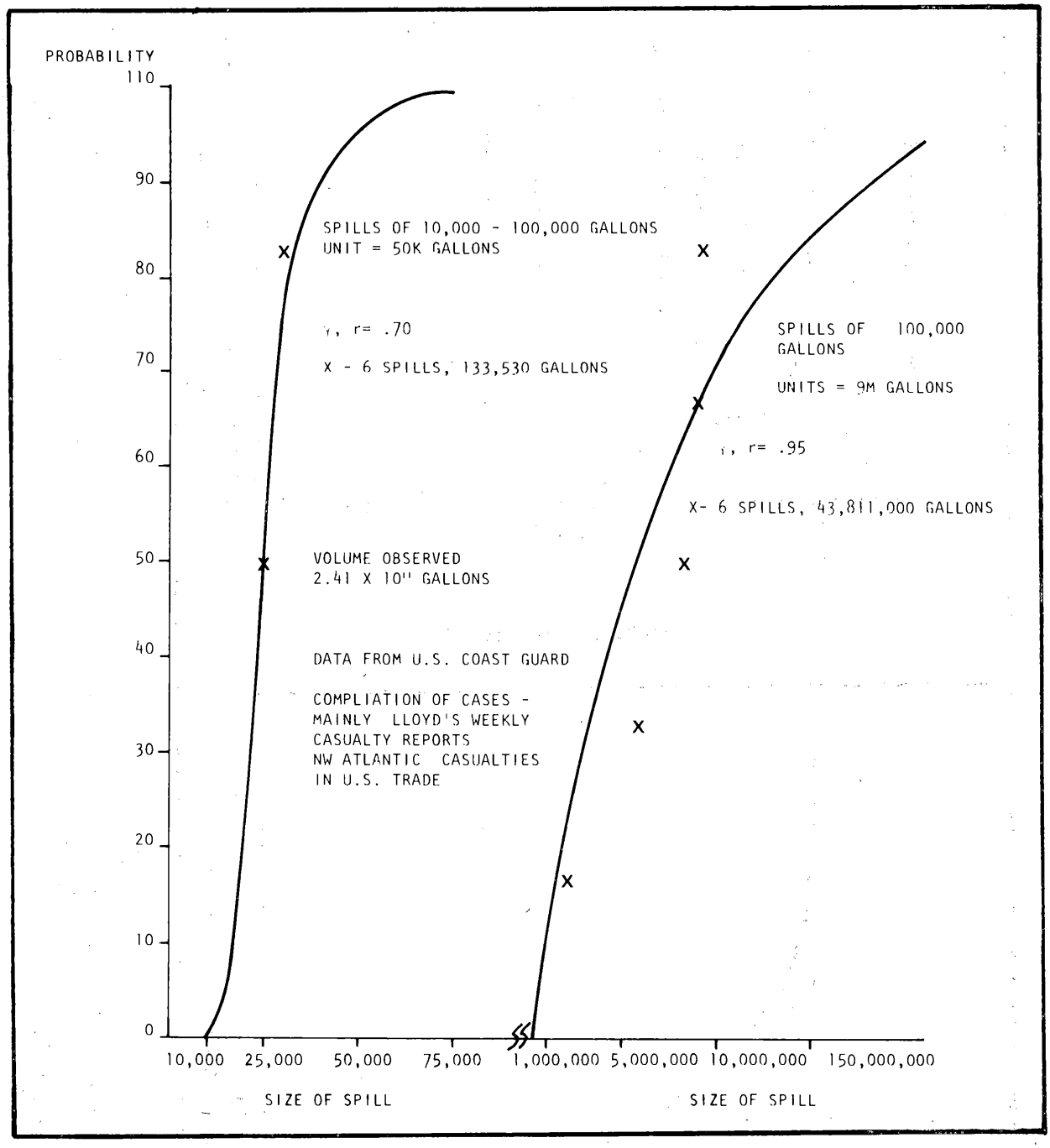
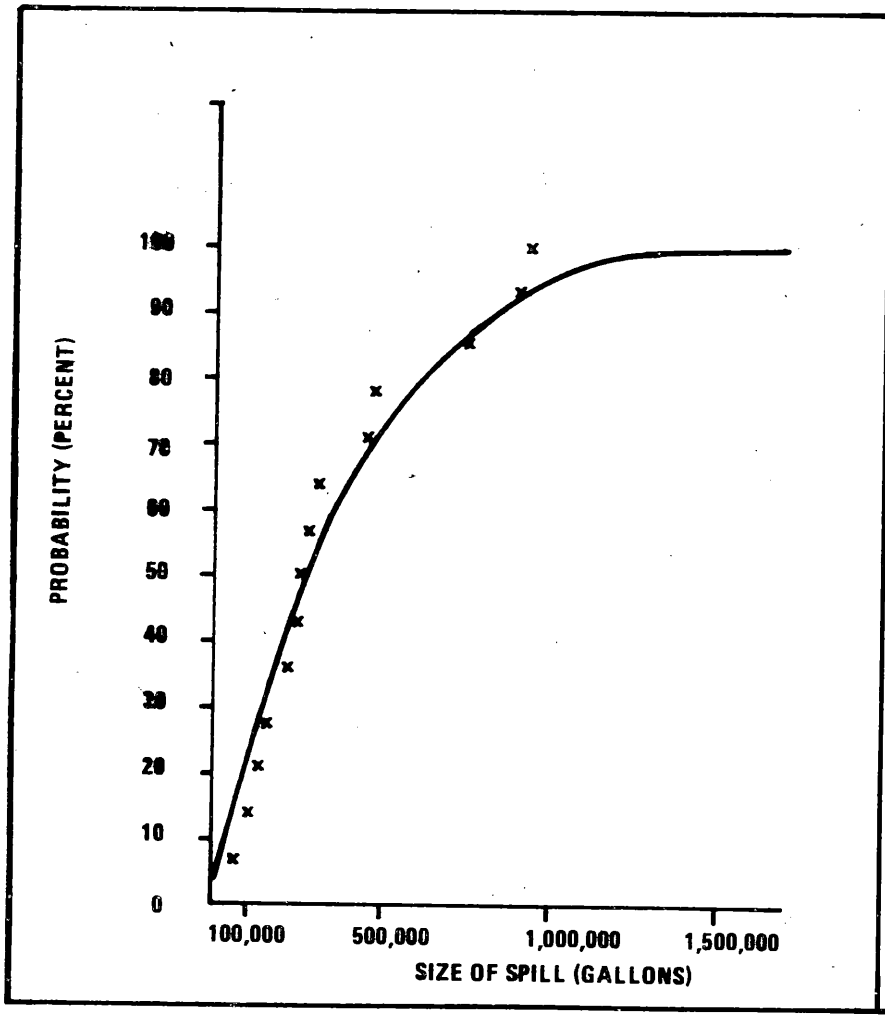


FIGURE 44. Cumulative Probabilities of Spill Size X for Tanker Casualties at Sea in the Northwest Atlantic



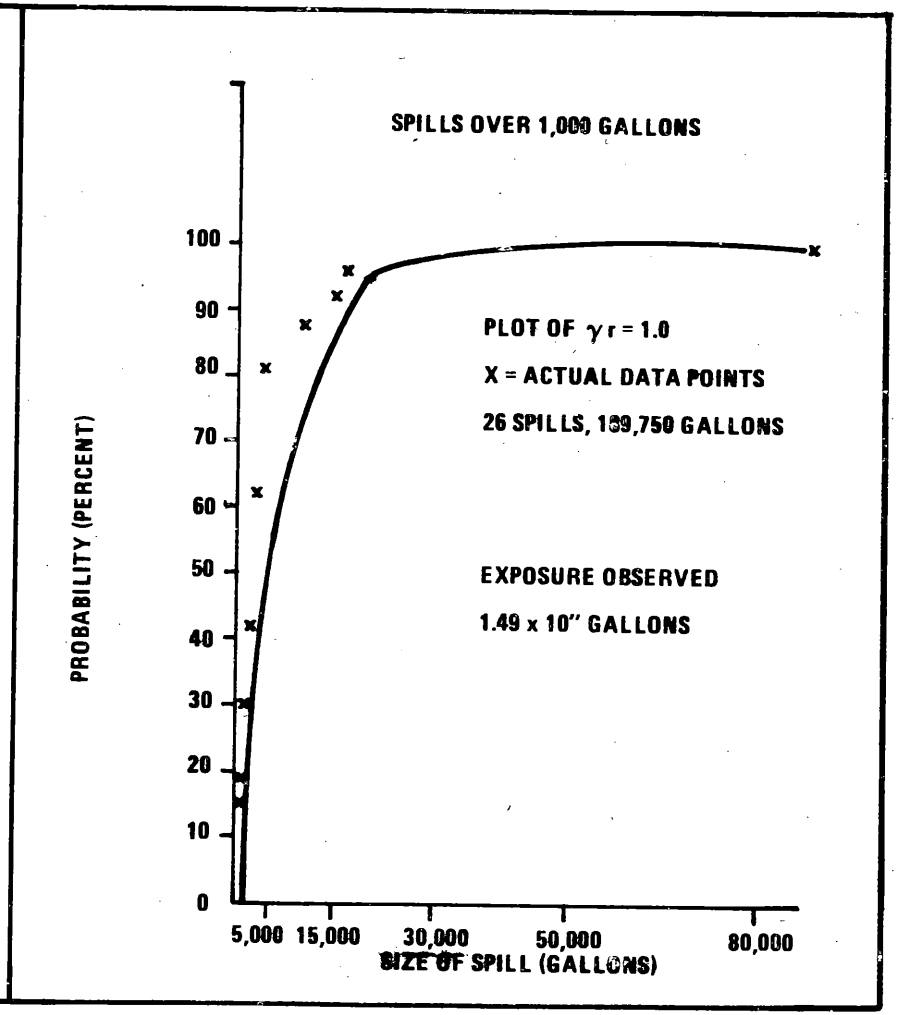


FIGURE 45. Cumulative Probability of Spill Size X for Inshore Tanker Casualty Spills

Exhibit VI-30. Cumulative Probability of Spill Size X for Inshore Marine Transfer Operations

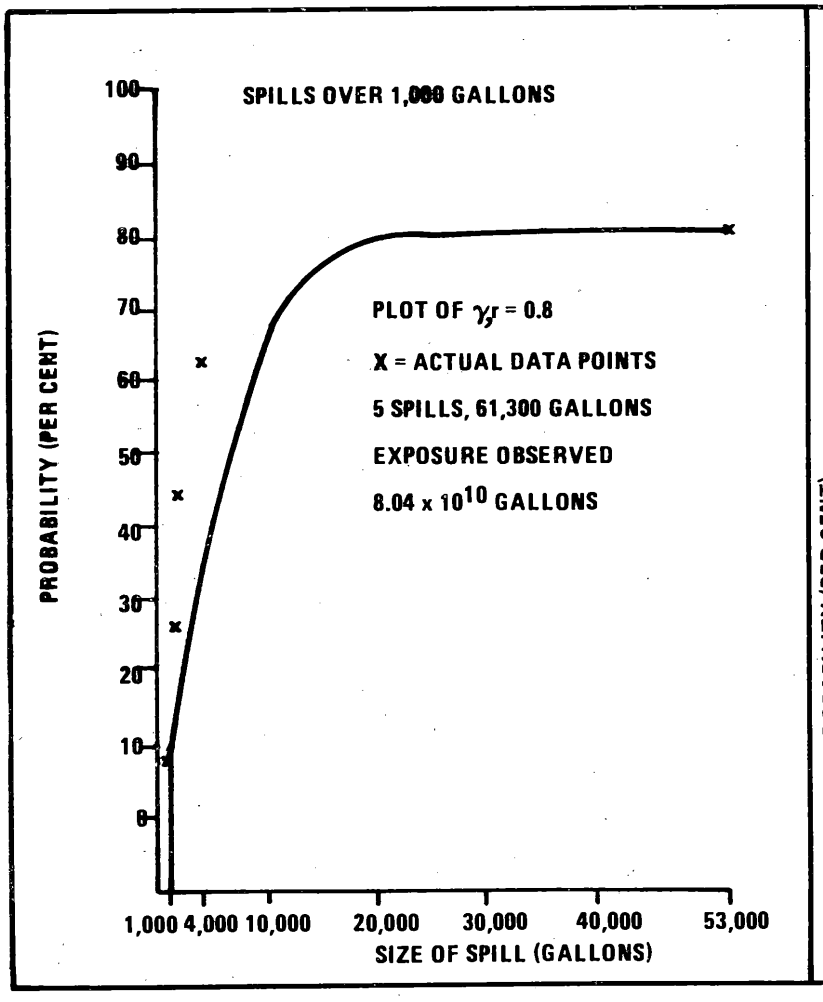


FIGURE 46. Cumulative Probability of Spill Size ≤ X For Small Tanker Coastal Spills

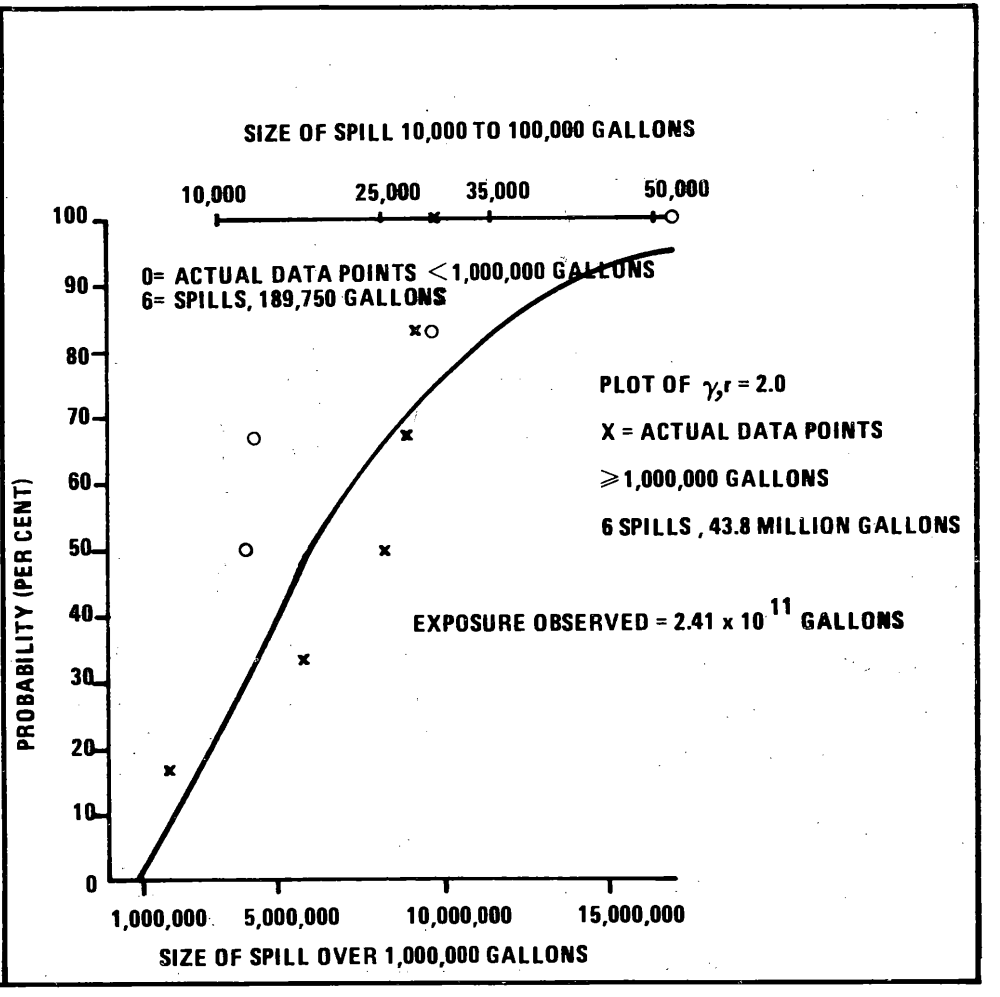


Exhibit VI-32. Cumulative Probability of Spill Size ≤ X For Small Tanker At-Sea in U.S. East Coast Trade

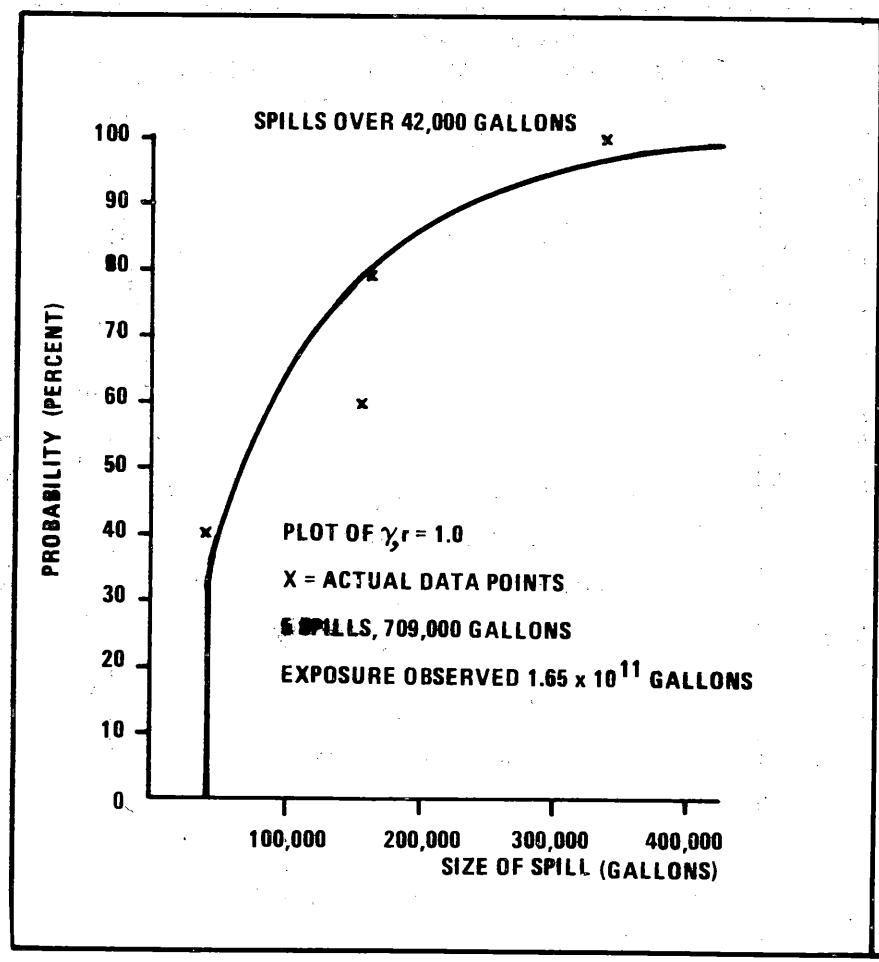


FIGURE 47. Cumulative Probability of Spill Size ≤X For Undersea Pipelines

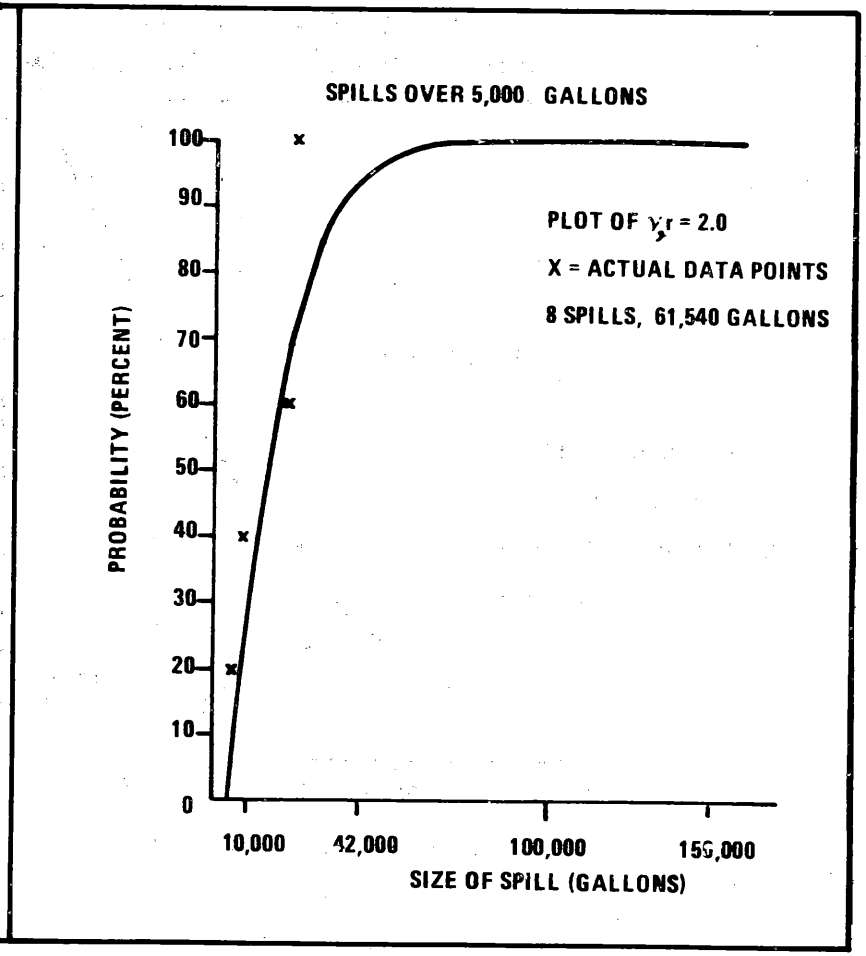


Exhibit VI-34. Cumulative Probability of Spill Size ≤X For Discharge SPMS

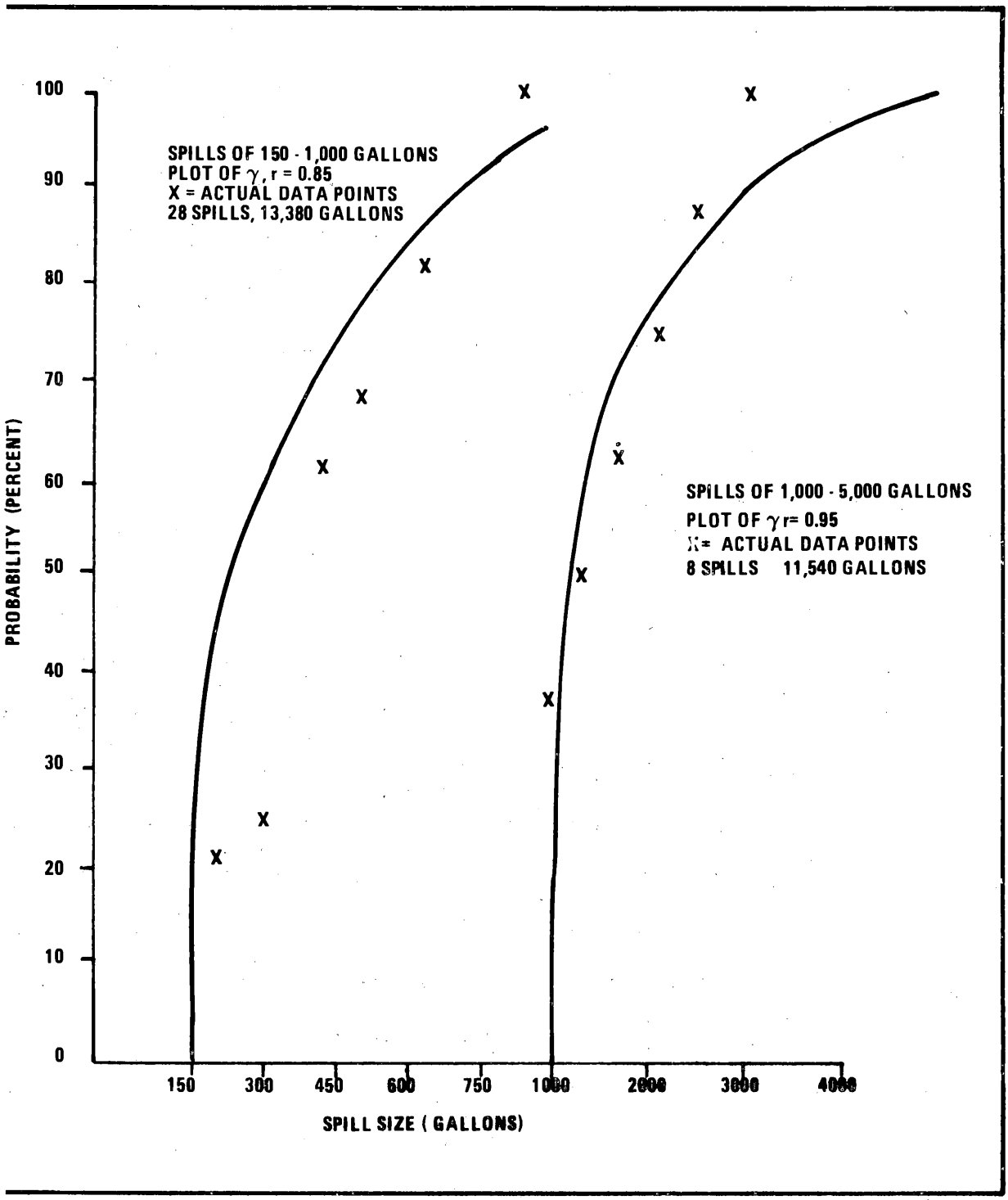


FIGURE 48. Cumulative Probability Of Spill Size ≤X For Discharge SPMS

only roughly descriptive of the data, and of undetermined predictive capability. Use of these distributions represents one assumption of the analysis.

3.6 Expectation Tables for Prediction

At this point, in one respect, the spill risk estimation task is complete in that the sizes and frequencies of spills are reasonable described in mathematical terms encompassing the variability revealed by the data in a manner consistent with the assumptions of the study. Confidence in limits computed on the distributions would be misleading because the data are not sufficient to estimate them accurately.

The task is slightly complicated here because the spill frequency and spill size estimates have to be combined. A non-rigorous, but reasonable, device is the formulation of expectation tables for number of spills by size range, scenario, phase, and operation, assuming the spill size is independent of frequency.

Rather than imply a confidence limit, the predictions are simply termed expected, pessimistic and optimistic. For each OCS scenario and phase, three values are selected for spill frequency and size. FIGURES 49 through 54 display the resulting values.

Spill frequencies consequently represent the mean of the appropriate negative binomial distributions, the number of spills having a cumulative probability of at least 95 percent, and the number of spills having a cumulative probability of 5 percent.

For each set of spill frequency values, there is a corresponding set of spill size values by size range. The expected value probabilities are

EXPECTED NUMBER OF SPILLS				
RECOVERY TIME PERIOD	HIGH 1980-89, 2000-09	HIGH 1990-1999	LOW 1980-89, 2000-09	LOW 1990-99
SPILL MEAN NO. =	1.8	3.7	0.8	1.6
SIZE PROBABILITY				
1-10M .01	.02	.04	.01	.02
100K-1M .36	.65	1.33	.29	.58
42-100K .63	1.13	2.33	.50	1.0
PESSIMISTIC NUMBER OF SPILLS				
95% NO. =	5	8	3	4
SIZE PROBABILITY				
1-10M .04	.20	.32	.12	.16
100K-1M .91	4.55	7.28	2.73	3.64
42-100K .05	.25	.40	.15	.20
OPTIMISTIC NUMBER OF SPILLS				
5% NO. =	0	0	0	0
SIZE PROBABILITY				
1-10M *	0	0	0	0
100K-1M .10	0	0	0	0
42-100K .90	0	0	0	0

* NEGLIGIBLE

FIGURE 49. Expectation Tables: Pipeline Spills Over 42,000 Gallons

EXPECTED NUMBER OF SPILLS					
RECOVERY TIME PERIOD		HIGH		LOW	
		1980-89,2000-09	1990-99	1980-89,2000-09	1990-99
SPILL	MEAN NO. =	2.6	5.3	1.2	2.3
SIZE	PROBABILITY				
1-10M	.16	.42	.85	.19	.37
100K-1M	.66	1.72	3.50	.79	1.52
42-100K	.18	.46	.95	.22	.41
PESSIMISTIC NUMBER OF SPILLS					
	95% NO. =	6	10	3	5
SIZE	PROBABILITY				
>10M	.01	.06	.10	.03	.05
1-10M	.61	3.66	6.10	1.83	3.05
100K-1M	.38	2.28	3.80	1.14	1.90
42-100K	*	-	-	-	-
OPTIMISTIC NUMBER OF SPILLS					
	5% NO.	0	1	0	0
SIZE	PROBABILITY				
1-10M	*	-	-	-	-
100K-1M	.11	0	.11	0	0
42-100K	.89	0	.89	0	0

*NEGLIGIBLE

FIGURE 50. Expectation Tables: Oil Rig Spills Over 42,000 Gallons

EXPECTED NUMBER OF SPILLS					
RECOVERY		HIGH		LOW	
TIME PERIOD		1980-89,2000-09	1990-99	1980-89,2000-09	1990-99
SPILL SIZE	MEAN NO. = PROBABILITY	7.2	14.6	3.3	6.4
>100K	*	-	-	-	-
10-100K	.17	1.22	2.43	.56	1.08
1-10K	.83	5.98	12.17	2.74	5.32
PESSIMISTIC NUMBER OF SPILLS					
SIZE	95% NO. = PROBABILITY	13	25	7	12
>100K	*	-	-	-	-
10-100K	.60	7.8	15	4.2	7.2
1-10K	.40	5.2	10	2.8	4.8
OPTIMISTIC NUMBER OF SPILLS					
SIZE	5% NO. = PROBABILITY	2	6	0	2
10-100K	*				
1-10K	.50	1	3	0	1

* NEGLIGIBLE

FIGURE 51. Expectation Tables: Marine Transfer Spills Over 1,000 Gallons

EXPECTED NUMBER OF SPILLS					
RECOVERY		HIGH		LOW	
TIME PERIOD		1980-89,2000-09	1990-99	1980-89,2000-09	1990-99
SPILL SIZE	MEAN NO. = PROBABILITY	2.8	5.7	1.3	2.5
>10M	*				
1-10M	.06	.17	.34	.08	.15
100K-1M	.70	1.96	3.99	.91	1.75
10-100K	.24	.67	1.37	.31	.60
PESSIMISTIC NUMBER OF SPILLS					
SIZE	95% NO. = PROBABILITY	6	11	3	6
>10M	*				
1-10M	.50	3	5.5	1.5	3
100K-1M	.44	2.64	4.84	1.32	2.64
10-100K	.06	.36	.66	.18	.36
OPTIMISTIC NUMBER OF SPILLS					
SIZE	5% NO. = PROBABILITY	0	2	0	0
1-10M	*	-	-	-	-
100K-1M	.06	0	.12	0	0
10-100K	.70	0	1.40	0	-
<10K	.24	0	.48	0	0

* NEGLIGIBLE

FIGURE 52. Expectation Tables: Inshore Tanker Spills > 10,000 Gallons

EXPECTED NUMBER OF SPILLS					
RECOVERY		HIGH		LOW	
TIME PERIOD		1980-89,2000-09	1990-99	1980-89,2000-09	1990-99
SPILL SIZE	MEAN NO. = PROBABILITY	3.0	6.1	1.4	2.7
>100K	*	-	-	-	-
10-100K	.17	.51	1.04	.24	.46
1-10K	.83	2.49	5.06	1.16	2.24
PESSIMISTIC NUMBER OF SPILLS					
SIZE	95% NO. PROBABILITY	7	13	4	6
>100K	*	-	-	-	-
10-100K	.60	4.2	7.8	2.4	3.6
1-10K	.40	2.8	5.2	1.6	2.4
OPTIMISTIC NUMBER OF SPILLS					
SIZE	5% NO. PROBABILITY	0	0	0	0
10-100K	*	0	0	0	0
1-10K	.50	0	0	0	0

* NEGLIGIBLE

FIGURE 53. Expectation Tables: Tanker Coastal Spills Over 1,000 Gallons

EXPECTED NUMBER OF SPILLS					
RECOVERY		HIGH		LOW	
TIME PERIOD		1980-89,2000-09	1990-99	1980-89,2000-09	1990-99
SPILL SIZE	MEAN NO. = PROBABILITY	1.2*	2.4	.5	1.1
>10M	.25	.3	.6	.13	.28
1-10M	.75	.9	1.8	.37	.82
100K-1M	**	-	-	-	-
10-100K	∿1.0	1.2	2.4	.5	1.1
PESSIMISTIC NUMBER OF SPILLS					
SIZE	95% NO. = PROBABILITY	3	6	2	3
>10M	.98	2.94	5.88	1.96	2.94
1-10M	.02	.06	.12	.04	.06
100K-1M	.02	.06	.12	.04	.06
10-100K	.98	2.94	5.88	1.96	2.94
OPTIMISTIC NUMBER OF SPILLS					
SIZE	5% NO. = PROBABILITY	0	0	0	0
>10M	**	0	0	0	0
1-10M	∿1.0	0	0	0	0
100K-1M	**	0	0	0	0
10-100K	∿1.0	0	0	0	0

* NUMBER OF SPILLS APPLY INDEPENDENTLY TO SPILLS GREATER OR LESS THAN ONE MILLION GALLONS

FIGURE 54. Expectation Tales: At-Sea Tanker Spills Over One Million Gallons and 10,000 - 1 Million Gallons

read directly from FIGURES 41 to 48. The pessimistic estimates are derived by selecting the spill size under the 95 percent probability intersection on each curve, shifting it to the 50 percent intersection and recomputing the scale of sizes accordingly. At this point the probabilities can be read directly. The process is repeated by shifting the original 50 percent size to the 50 percent position and reading the optimistic probabilities.

Multiplying these marginal probabilities yields the expected pessimistic, and optimistic numbers of spills by size category. However, the size data within ranges are lost. Because the variability is now expressed within the probability distributions of size ranges, we can use single point estimates of a typical size for each range, for each operation. These are, approximately, the means of the various data sets used, rounded for computational convenience. FIGURES 55 and 56 contain the typical spill size values used.

3.7 Spill Predictions

The FIGURES of the previous section provide all of the data required to compile estimates of the major oil spill experience which may result from the contemplated operations, subject to the assumptions of the analysis. It only remains to arrange them in a form from which it is convenient to assemble the answers to questions bearing on policy decisions.

FIGURES 57 through 60 display the analytic results for OCS and small tanker operations with all relevant subdivision of operations, scenario, phase, spill size range, and subtotals. Annual spill data with a given phase may be read simply by shifting the decimal point left one position. If volume data are desired by operation, the appropriate number of spill

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	>10M	1-10M	100K-1M
PIPELINES	NA	2M	.2M
OIL RIGS	12M	2M	.2M
MARINE TRANSFER	NA	NA	NA
INSHORE TANKER	NA	2M	.4M
TANKER COASTAL	NA	NA	NA
AT-SEA TANKER	12M	7M	.35M
	42-100K	10-100K	SMALL SPILLS
PIPELINE	.05M	NA	190 GALLONS
OIL RIGS	.05M	NA	100 GALLONS
MARINE TRANSFER	NA	.014M	NA
INSHORE TANKER	NA	.05M	320
TANKER COASTAL	NA	.05M	320
AT-SEA TANKER	NA	.02M	320

NA - NOT APPLICABLE

M - MILLIONS OF GALLONS

FIGURE 55. Typical Spill Sizes

	OVER 10M	1-10M	100K-1M	
PIPELINES	NA	2M	.2M	
SPMS	NA	NA	.15M	
INSHORE TRANSFER	NA	NA	.12M	
INSHORE CASUALTY	NA	2M	.4M	
TANKER COASTAL	NA	NA	NA	
LARGE TANKER AT-SEA	20M	7M	.35M	
SMALL TANKER AT-SEA	12M	7M	.35M	
	42-100K	**10-100K**	**SMALL SPILLS**	
PIPELINES	.05M	NA	190 GALLONS	
SPMS	.075M	NA	NA	
INSHORE TRANSFER	NA	.014M	NA	
INSHORE CASUALTY	NA	.05M	320 GALLONS	
TANKER COASTAL	NA	.05M	320 GALLONS	
LARGE TANKER AT-SEA	.075M	NA	320 GALLONS	
SMALL TANKER AT-SEA	NA	.02M	320 GALLONS	
	5-42K	**1-5K**	**150-1K**	**UNDER 150 GALLONS**
SPMS	.012M	1.5K	500 GALLONS	30 GALLONS

FIGURE 55. Typical Spill Sizes

SPILL SIZE RANGE (GALLONS)	TYPICAL SPILL SIZE	1980-89				1990-99				2000-09				LIFE CYCLE			
		RIGS	PIPE-LINES	TOTALS SPILLS	TOTALS VOLUMES	RIGS	PIPE-LINES	TOTALS SPILLS	TOTALS VOLUME	RIGS	PIPE-LINES	TOTALS SPILLS	TOTALS VOLUME	RIGS	PIPE-LINES	TOTALS SPILLS	TOTALS VOLUME
EXPECTED VALUES																	
1-10M*	2M	.42	.02	.44	.88M	.85	.04	.89	1.78M	.42	.02	.44	.88M	1.69	.08	1.77	3.54M
100K-1M	200K	1.72	.65	2.37	.47M	3.50	1.33	4.83	.97M	1.72	.65	2.37	.47M	6.94	2.63	9.57	1.91M
42-100K	50K	.46	1.13	1.59	.08M	.95	2.33	3.28	.16M	.46	1.13	1.59	.08M	1.87	4.59	6.46	.32M
	TOTALS	2.6	1.8	4.4	1.43M	5.3	3.7	9.0	2.91M	2.6	1.8	4.4	1.43M	10.5	7.3	17.8	5.77M
PESSIMISTIC VALUES																	
>10M	12M	.06	--	.06	.72M	.10	--	.10	1.2M	.06	--	.06	.72M	.22	--	.22	2.64M
1-10M	2M	3.66	.20	3.86	7.72M	6.10	.32	6.42	12.84M	3.66	.20	3.86	7.72M	13.42	.72	14.14	28.28M
100K-1M	200K	2.28	4.55	6.83	1.37M	3.80	7.28	11.08	2.22M	2.28	4.55	6.83	1.37M	8.36	16.38	24.74	4.95M
42-100K	50K	--	.25	.25	.01M	--	.40	.40	.02M	--	.25	.25	.01M	--	.90	.90	.04M
	TOTALS	6.0	5.0	11.00	9.82M	10.00	8.0	18.00	16.28M	6.0	5.0	11.0	9.82M	22.0	18.0	40.0	35.91M
OPTIMISTIC VALUES																	
1-10M	2M	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
100K-1M	200K	0	0	0	0	.11	0	.11	.02M	0	0	0	0	.11	0	.11	.02M
42-100K	50K	0	0	0	0	.89	0	.89	.18M	0	0	0	0	.89	0	.89	.18M
	TOTALS	0	0	0	0	1.0	0	1.0	.2M	0	0	0	0M	1.0	0	1.0	.2M

* M - MILLIONS, K - THOUSANDS OF GALLONS

FIGURE 57. OCS Major Oil Spill Estimates - High Recovery Scenario

SPILL SIZE RANGE (GALLONS)	TYPICAL SPILL SIZE	1980-89				1990-99				2000-09				LIFE CYCLE			
		RIGS	PIPE-LINES	TOTALS SPILLS	TOTALS VOLUMES	RIGS	PIPE-LINES	TOTALS SPILLS	TOTALS VOLUME	RIGS	PIPE-LINES	TOTALS SPILLS	TOTALS VOLUME	RIGS	PIPE-LINES	TOTALS SPILLS	TOTALS VOLUME
EXPECTED VALUES																	
1-10M*	2M	.19	.01	.20	.40M	.37	.02	.39	.78M	.19	.01	.20	.40M	.75	.04	.79	1.58M
100K-1M	200K	.79	.29	1.08	.22M	1.52	.58	2.01	.42M	.79	.29	1.08	.22M	3.10	1.16	4.26	.85M
42-100K	50K	.22	.50	.72	.04	.41	1.0	1.41	.07M	.22	.50	.72	.04M	.85	2.00	2.85	.14M
		1.20	.80	2.00	.66	2.30	1.6	3.90	1.27M	1.20	.80	2.00	.66M	4.70	3.20	7.90	2.57M
PESSIMISTIC VALUES																	
>10M	12M	.03	---	.03	.36M	.05	---	.05	.60M	.03	---	.03	.36M	.11	---	.11	1.32M
1-10M	2M	1.83	.12	1.95	3.90M	3.05	.16	3.21	6.42M	1.83	.12	1.95	3.90M	6.71	.40	7.11	14.22M
100K-1M	200K	1.14	2.73	3.87	.77M	1.90	3.64	5.54	1.11M	1.14	2.73	3.87	.77M	4.18	9.10	13.28	2.66M
42-100K	50K	---	.15	.15	.01M	---	.20	.20	.01M	---	.15	.15	.01M	---	.50	.50	.03M
		3.0	3.0	6.0	5.04M	5.0	4.0	9.0	8.14M	3.0	3.0	6.0	5.04M	11.0	10.0	21.0	18.23M
OPTIMISTIC VALUES																	
10-10M	2M	NO MAJOR SPILLS															
100K-1M	200K																
42-100K	50K																

* M - MILLIONS, K - THOUSANDS OF GALLONS

FIGURE 58. OCS Major Oil Spill Estimates - Median Recovery Scenario

SPILL SIZE RANGE (GALLONS)	TYPICAL SPILL SIZES*	1980-89,2000-09 (EACH)					1990-99					LIFE CYCLE				
		VESSEL CASUALTIES					VESSEL CASUALTIES					VESSEL CASUALTIES				
		TRANS-FER	IN-SHORE	COASTAL	TOTALS SPILLS	TOTALS VOLUME	TRANS-FER	IN-SHORE	COASTAL	TOTALS SPILLS	TOTALS VOLUME	TRANS-FER	IN-SHORE	COASTAL	TOTAL SPILLS	TOTAL VOLUME
		EXPECTED VALUES														
1-10M	N,1.2M,N	0	.17	0	.17	.20M	0	.34	0	.34	.41M	0	.68	0	.68	.82M
100K-1M	N,350K,N	0	1.96	0	1.96	.69M	0	3.99	0	3.99	1.40M	0	7.91	0	7.91	2.77M
10-100K	14K,50K,50K	1.22	.67	.51	2.40	.08M	2.43	1.37	1.04	4.84	.15M	4.87	2.71	2.06	9.64	.31M
	TOTALS	1.22	2.80	.51	4.53	.97M	2.43	5.70	1.04	9.17	1.96M	4.87	11.30	2.06	18.23	3.90M
		PESSIMISTIC VALUES														
1-10M	N,1.2M,N	0	3.00	0	3.00	3.60M	0	5.50	0	5.50	6.60M	0	11.50	0	11.50	13.80M
100K-1M	N,350K,N	0	2.64	0	2.64	.92M	0	4.84	0	4.84	1.69M	0	10.12	0	10.12	3.54M
10-100K	14K,50K,40K	7.8	.	4.2	12.36	.27M	15	.66	7.8	22.46	.63M	30.6	1.38	16.2	48.18	1.31M
	TOTALS	7.8	6.0	4.2	18.00	4.79M	15.0	11.0	7.8	32.80	8.92M	30.6	23.0	16.2	69.8	18.65M
		OPTIMISTIC VALUES														
1-10M	N,1.2M,N	ALL ZEROES					0	0	0	0	0	0	0	0	0	0
100K-1M	N,350K,N						0	.12	0	.12	.04M	0	.12	0	.12	.04M
10-100K	14K,50K,50K						0	1.40	0	1.40	.07M	0	1.40	0	1.40	.07M
	TOTALS						0	1.52	0	1.52	.11M	0	1.52	0	1.52	.11M

* TYPICAL SIZES IN SIZE RANGE FOR TRANSFERS, INSHORE AND COASTAL VESSEL CASUALTIES RESPECTIVELY. (N - NOT APPLICABLE, M - MILLIONS, K - THOUSANDS OF GALLONS)

** SPILLS FROM SHIPS, BARGES AND FACILITIES DURING TRANSFER OPERATIONS, PLUS NON-CASUALTY VESSEL SPILLS IN INSHORE AREAS.

FIGURE 59 Regional Major Oil Spills - Small Tanker Imports - High Recovery Equivalent

SPILL SIZE RANGE (GALLONS)	TYPICAL SPILL SIZES*	1980-89, 2000-09 (EACH) VESSEL CASUALTIES TRANS-FER**	IN-SHORE	COASTAL	TOTALS SPILLS	TOTALS VOLUME	1990-99 VESSEL CASUALTIES TRANS-FER	IN-SHORE	COASTAL	TOTALS SPILLS	TOTALS VOLUME	LIFE CYCLE VESSEL CASUALTIES TRANS-FER	IN-SHORE	COASTAL	TOTAL SPILLS	TOTAL VOLUME
EXPECTED VALUES																
1-10M	N,	0	.08	0	.08	.10M	0	.15	0	.15	.18M	0	.31	0	.31	.37M
100K-1M	1.2M, N	0	.91	0	.91	.32M	0	1.75	0	1.75	.61M	0	3.57	0	3.57	1.25M
10-100K	N, 350K, N	.56	.31	.24	1.01	.04M	1.08	.60	.46	2.14	.07M	2.20	1.22	.94	4.36	.14M
	14K, 50K, 50K															
	TOTALS	.56	1.30	.24	2.0	.46M	1.08	2.50	.46	4.04	.86M	2.20	5.10	.94	8.24	1.76M
PESSIMISTIC VALUES																
1-10M	N,	0	1.50	0	1.50	1.80M	0	3.0	0	3.0	3.60M	0	6.0	0	6.0	7.2M
100K-1M	1.2M, N	0	1.32	0	1.32	.46M	0	2.64	0	2.64	.92M	0	5.28	0	5.28	1.85M
10-100K	N, 350K, N	4.20	.18	2.4	6.78	.19M	7.2	.36	3.6	11.16	.30M	15.6	.72	8.4	24.72	.67M
	14K, 50K, 50K															
	TOTALS	4.2	3.0	2.4	9.6	2.45M	7.2	6.0	3.6	16.8	4.82M	15.6	12.0	8.4	36.0	9.72M
OPTIMISTIC VALUES																
1-10M	N,	ALL ZEROES														
100K-1M	1.2M, N															
10-100K	N, 350K, N															
	14K, 50K, 50K															
	TOTALS															

* TYPICAL SIZES IN SIZE RANGE FOR TRANSFERS, INSHORE AND COASTAL VESSEL CASUALTIES RESPECTIVELY. (N - NOT APPLICABLE, M - MILLIONS, K - THOUSANDS OF GALLONS

** SPILLED FROM SHIPS, BARGES AND FACILITIES DURING TRANSFER OPERATIONS, PLUS NON-CASUALTY VESSEL SPILLS IN INSHORE AREAS.

FIGURE 60 Regional Major Oil Spills - Small Tanker Imports - Median Recovery Equivalent

data can be read and multiplied by the typical spill size corresponding to each size range.

Although major spills have the major impact on policy, small spills and chronic pollution should also be considered for completeness. Also, while regional tanker spillage is most relevant to the OCS oil spillage, current tanker practice comparison and at-sea tanker spills should not be ignored. FIGURES 61 through 63 provide life cycle estimates of numbers of OCS and small tanker spills by size range and corresponding volumes, by scenario and by major alternative. The small and chronic spill estimates are taken from an adaptation of the MIT analysis, described in the next section. The variances on these estimates are simply judgments reflecting the relatively small variabilities to be expected in these types of spillage.

FIGURES 64 through 70 provide spill estimates for deepwater port operations and the small tanker imports alternative.

3.8 Alternative OCS Estimates--An Adaptation of the MIT Analysis of Oil Spill Statistics

The analytic methods and spill risk estimates in a given study are dependent on the assumptions made. What if, however, the reader wishes to reject those assumptions or at least to see what difference they make in the analysis? In this case, fortunately, it is possible to clarify the issue. The MIT "Analysis of Oil Spill Statistics"[11/] addressed these same issues (on a less localized scale in the case of tankers). Not only

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11/ Massachusetts Institute of Technology, "Analysis of Oil Spill Statistics," Council on Environmental Quality Report, OCS Oil and Gas - An Environmental Assessment (Washington, D.C.: U.S. Government Printing Office, April 1974.)

LIFE CYCLE ESTIMATES
HIGH RECOVERY SCENARIO

SIZE RANGE	TYPICAL SIZE	EXPECTED NO.	EXPECTED VOLUME	PESSIMISTIC NO.	PESSIMISTIC VOLUME	OPTIMISTIC NO.	OPTIMISTIC VOLUME
>10M	12M	0	0	.22	2.64M	0	0
1-10M	2M	1.77	3.54M	14.14	28.28M	0	0
100K-1M	200K	9.57	1.91M	24.74	4.95M	.11	.02M
42-100K	50K	6.46	.32M	.90	.04M	.89	.18M
LARGE SPILLS		17.80	5.77M	40.0	35.91M	1.0	.2M
SMALL SPILLS		17K	2.1M	20K	2.5M	15K	1.85M
WASTE WATER			1.7M		2.0M		1.5M
	TOTALS		9.57M		40.41M		3.55M

MEDIAN RECOVERY SCENARIO

SIZE RANGE	TYPICAL SIZE	EXPECTED NO.	EXPECTED VOLUME	PESSIMISTIC NO.	PESSIMISTIC VOLUME	OPTIMISTIC NO.	OPTIMISTIC VOLUME
>10M		0	0	.11	1.32M		
1-10M	2M	.79	1.58M	7.11	14.22M		
100K-1M	200K	4.26	.85M	13.28	2.66M	ALL ZEROES	
42 -100K	50K	2.85	.14M	.50	.03M		
LARGE SPILLS		7.90	2.57M	21.0	18.23M	--	--
SMALL SPILLS		7.5K	1.0 M	9K	1.2M	6K	.8M
WASTE WATER			.8M		1.0M		.7M
	TOTALS		4.37M		20.43M		1.5M

(M - MILLIONS OF GALLONS, K - THOUSANDS OF GALLONS AND SPILLS)

FIGURE 61 OCS Oil Spill Risk Estimates

HIGH RECOVERY EQUIVALENT
LIFE CYCLE ESTIMATES

SIZE* RANGE	TYPICAL SIZE	EXPECTED NO.	EXPECTED VOLUME	PESSIMISTIC NO.	PESSIMISTIC VOLUME	OPTIMISTIC NO.	OPTIMISTIC VOLUME
IN OCS REGION							
>10M	--	--	--	--	--	--	--
1-10M	1.2M	.7	.8	11.5	13.8M	0	0
100K-1M	350K	7.9	2.8M	10.1	3.5M	.1	.04M
10-100K	14,50K	9.6	.3M	48.2	1.3M	1.4	.07M
LARGE SPILLS		18.2	3.9M	69.8	18.6M	1.5	.11M
SMALL SPILLS		2K	.6M	2.3K	.8M	1.8K	.5M
TANK CLEANING		--	--	--	--	--	--
TOTALS			4.5M		19.4M		.6M
AT SEA IN THE NW ATLANTIC							
>10M	12M	1.2	14.4M	11.75	141.0M		
1-10M	7M	3.6	25.2M	.24	1.7M		
100K-1M	350K	0	0	.24	.1M	ALL ZEROES	
10-100K	50K	1.0	.1M	11.75	.6M		
LARGE SPILLS		5.8	39.7M	∿24.0	143.4M	--	--
SMALL SPILLS		--	--	--	--	--	--
TANK CLEANING			20.0M		27.0M		15.M
TOTALS			59.7M		170.4M		15.M
TOTALS FOR NW ATLANTIC AREA							
>10M	12M	1.2	14.4M	11.75	141.0M	0	0
1-10M	7M	4.3	26.0M	11.74	15.5M	0	0
100K-1M	350K	7.9	2.8M	10.34	3.6M	.1	.04M
10-100K	14,50K	10.6	.4M	60.0	1.9M	1.4	.07M
LARGE SPILLS		24.0	43.6M	93.8	162.0M	1.5	.11M
SMALL SPILLS			.6M		.8M		.5M
TANK CLEANING			20.0M		27.0M		15.0M
TOTALS			64.2M		189.8M		15.6M

(M - MILLIONS, K - THOUSANDS OF GALLONS PER SPILL)

FIGURE 62 Small Import Tanker Spill Risk Estimates (High Recovery Equivalent Life Cycle Estimates)

MEDIAN RECOVERY EQUIVALENT
LIFE CYCLE ESTIMATES

SIZE* RANGE	TYPICAL SIZE	EXPECTED NO.	EXPECTED VOLUME	PESSIMISTIC NO.	PESSIMISTIC VOLUME	OPTIMISTIC NO.	OPTIMISTIC VOLUME
IN OCS REGION							
>10M	--	--	--	--	--	--	--
1-10M	1.2M	.3	.37M	6.0	7.20M		
100K-1M	350K	3.6	1.25M	5.3	1.85M	ALL ZEROES	
10-100K	14,50K	4.3	.14M	24.7	.67M		
LARGE SPILLS		8.2	1.76M	36.0	9.72M		
SMALL SPILLS		900	.3M	1000	.3M	800	.3M
TANK CLEANING		--	--	--	--	--	--
TOTALS			2.06M		10.02M		.3M
AT SEA IN THE NW ATLANTIC							
>10M	12M	.54	6.48M	6.86	82.32M		
1-10M	7M	1.54	10.78M	.14	.98M		
100K-1M	350K	0	0	.14	.05M	ALL ZEROES	
10-100K	50K	2.1	.11M	6.86	.34M	---	---
LARGE SPILLS		4.18	17.37M	14.0	83.69M		
SMALL SPILLS			--		--		--
TANK CLEANING			10.0 M		13.5 M		7.5M
TOTALS			27.37M		97.19M		7.5M
TOTALS FOR NW ATLANTIC AREA							
>10M	12M	.54	6.48M	6.86	82.32M		
1-10M	1.2M	1.84	11.15M	6.14	8.18M		
100K-1M	350K	3.6	1.25M	5.44	1.90M	ALL ZEROES	
10-100K	14,50K	6.4	.25M	31.56	1.01M		
LARGE SPILLS		12.38	19.13M	50.0	93.41M		
SMALL SPILLS		900	.3M	1000	.3M	800	.3M
TANK CLEANING			10.0M		13.5M		7.5M
TOTALS			29.43M		107.21M		7.8M

(M - MILLIONS, K - THOUSANDS OF GALLONS PER SPILL)

FIGURE 63 Small Import Tanker Spill Risk Estimates (Median Recovery Equivalent Life Cycle Estimates)

SPILL SIZE RANGE	TYPICAL SPILL SIZES*	HIGH SCENARIO SPMS	HIGH SCENARIO PIPE-LINES	HIGH SCENARIO TOTAL NO.	HIGH SCENARIO TOTAL VOLUME	MEDIUM SCENARIO SPMS	MEDIUM SCENARIO PIPE-LINES	MEDIUM SCENARIO TOTAL NO.	MEDIUM SCENARIO TOTAL VOLUME
1-10M	N, 2M	0	.24	.24	.48M	0	.20	.20	.41M
100K-1M	.15,.2M	.29	8.75	9.04	1.81M	.25	7.56	7.80	1.54M
42-100K	.075,.05M	7.22	15.65	22.87	1.31M	6.16	13.25	19.41	1.12M
TOTALS		7.52	24.60	32.12	3.60M	6.45	21.0	27.4	3.1M
1-10M	N, 2M	0	1.90	1.90	3.83M	0	1.64	1.64	3.28M
100K-1M	.15,.2M	31.4	43.6	75.0	13.45M	25.4	37.20	62.6	11.5M
42-100K	.075,.05M	83.8	2.4	86.1	6.40M	71.5	2.05	73.5	5.45M
TOTALS		115.0	48.0	163.0	23.68M	96.9	40.9	137.7	20.2M
1-10M	N, 2M	0	0	0	0	0	0	0	0
100K-1M	.15,.2M	0	.64	.64	.13M	0	.5	.5	.11M
42-100K	.075,.05M	0.32	5.75	6.07	.32M	.3	4.8	5.2	.27M
TOTALS		0.32	6.4	6.72	.45M	0.3	5.3	5.7	.38M

* TYPICAL SIZES IN SIZE RANGE FOR SPMS AND UNDERSEA PIPELINES RESPECTIVELY
(N - NOT APPLICABLE, M = MILLIONS, K = THOUSANDS OF GALLONS)

FIGURE 64 Regional Deepwater Port Major Oil Spill Estimates - Fifteen Year Total Throughput

SPILL SIZE RANGE	TYPICAL SPILL SIZES*	HIGH SCENARIO VESSEL CASUALTIES								MEDIUM SCENARIO VESSEL CASUALTIES							
		TRANSFERS		INSHORE		COASTAL		TOTALS		TRANSFERS		INSHORE		COASTAL		TOTALS	
		NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.
1-10M	N, 2M, N	0	-	.84	.79M	0	-	.84	.79M	0	-	.84	.79M	0	-	.84	.79M
100K-1M	N, .4M, N	0	-	3.2	1.3M	0	-	3.2	1.3M	0	-	3.2	1.3M	0	-	3.2	1.3M
10-100K	.014, .05, .05M	3.78	.12M	1.10	.04M	.87	.04M	5.75	.20M	3.78	.12M	1.10	.04M	.87	.04M	5.75	.2M
TOTALS		3.78	.12M	5.14	2.13M	.87	.04M	9.8	2.3M	3.78	.12M	5.14	2.13M	.87	.04M	9.8	2.3M
1-10M	N, 2M, N	0	-	5.9	11.9M	0	-	5.9	11.9M	0	-	5.9	11.9M	0	-	5.9	11.9M
100K-1M	.12M, .4M, N	.83	.08M	5.1	2.05M	0	-	5.9	2.1M	.83	.08M	5.1	2.05M	0	-	5.9	2.1M
10-100K	.014, .05, .05M	19.1	.28M	.83	.04M	9.5	.48M	29.4	.80M	19.1	.28M	.83	.04M	9.5	.48M	29.4	.8M
TOTALS		19.9	.36M	11.8	14.0M	9.5	.48M	41.2	14.8M	19.9	.36M	11.8	14.0M	9.5	.48M	41.2	14.8M
1-10M	N, 2M N	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
100K-1M	N, .4M, N	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10-100K	.014, .05 .05M	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

* TYPICAL SIZE RANGE FOR TRANSFERS, INSHORE AND COASTAL VESSEL CASUALTIES, RESPECTIVELY (N - NOT APPLICABLE, M - MILLIONS, K - THOUSANDS OF GALLONS)

** SPILLS FROM SHIPS, BARGES AND FACILITIES DURING TRANSFER OPERATIONS, PLUS ALL OTHER NON-CASUALTY VESSEL-RELATED SPILLS IN INSHORE AREAS

FIGURE 65 Regional Major Spill Estimates from Supplemental Small Tanker Imports, Fifteen Year Total Throughput

SPILL SIZE RANGE	TYPICAL SPILL SIZE*	** TRANSFERS		HIGH SCENARIO VESSEL CASUALTIES INSHORE		HIGH SCENARIO VESSEL CASUALTIES COASTAL		TOTALS		TRANSFERS		MEDIUM SCENARIO VESSEL CASUALTIES INSHORE		MEDIUM SCENARIO VESSEL CASUALTIES COASTAL		TOTALS	
		NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.
1-10M	N, 2M, N	0	-	3.34	6.9M	0	-	3.35	6.9M	0	-	3.0	6.0M	0	-	3.0	6.0M
100K-1M	N, .4M, N	0	-	29.4	11.7M	0	-	29.4	11.7M	0	-	25.4	10.4M	0	-	25.4	10.4M
10-100K	.014, .05, .05M	33.6	.84M	10.3	.56M	19.9	1.03M	63.8	2.43M	29.1	.4M	9.0	.5M	12.0	.56M	50.1	1.5M
TOTALS		33.6	.84M	43.1	19.2M	19.9	1.03M	96.6	21.0M	29.1	.4M	37.4	16.9M	12.0	.56M	78.5	17.9M
1-10M	N, 2M, N	0	-	34.4	69.0M	0	-	34.4	69.0M	0	-	29.8	59.5M	0	-	29.8	59.5M
100K-1M	.12M .4M, N	5.4	.06M	52.0	20.9M	0	-	57.4	21.0M	14.7	.06M	45.1	18.1M	0	-	49.8	18.2M
10-100K	.014, .05, .05M	124.8	1.74M	4.8	.29M	91.6	4.6M	221.2	6.6M	108.0	1.51M	4.2	24M	79.4	3.9M	191.6	5.7M
TOTALS		130.2	1.8M	91.2	90.2M	91.6	4.6M	313.0	96.6M	112.7	1.6M	79.1	77.8M	79.4	3.9M	271.0	83.4M
1-10M	N, 2M, N	0	-	0	-	0	-	0	-	0	-	0	-	0	-	0	-
100K-1M	N, .4M, N	0	-	.19	.19M	0	-	.19	.19M	0	-	.16	.08M	0	-	.16	.08M
10-100K	.014, .05, .05M	0	-	13.2	.65M	0	-	13.2	.65M	0	-	11.4	.56M	0	-	11.4	.56M
TOTALS		0	-	13.4	.8M	0	-	13.4	0.8M	0	-	11.6	.6M	0	-	11.6	.6M

* TYPICAL SIZE RANGE FOR TRANSFERS, INSHORE AND COASTAL VESSEL CASUALTIES, RESPECTIVELY (N - NOT APPLICABLE, M - MILLIONS, K - THOUSANDS OF GALLONS)

** SPILLS FROM SHIPS, BARGES AND FACILITIES DURING TRANSFER OPERATIONS, PLUS ALL OTHER NON-CASUALTY VESSEL-RELATED SPILLS IN INSHORE AREAS

FIGURE 66 Regional Oil Spill Estimates for All Small Tanker Imports, Instead of Deepwater Ports, Fifteen Year Total Throughput

SPILL SIZE RANGE	TYPICAL SPILL SIZE*	HIGH SCENARIO								MEDIUM SCENARIO							
		DWP LARGE TANKERS		SUPPLY SMALL TANKERS		DWP TOTAL		ALL SMALL TANKERS		DWP LARGE TANKERS		SUPPLY SMALL TANKERS		DWP TOTAL		ALL SMALL TANKERS	
		NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.
OVER 10M	20, 12M	.44	8.75M	.48	5.5M	.9	14.3	2.48	29.7M	.4	7.5M	.48	5.5M	0.9	13.0M	2.14	25.7M
1-10M	7M	9.0	63.0M	1.58	3.2M	10.6	66.2	14.1	98.8M	7.7	53.5M	1.58	3.2M	9.3	56.7M	12.2	85.5M
50K-1M	.35M	7.15	2.48M	.04	-	7.2	2.5M	.36	.09M	6.1	2.1M	.04	-	6.1	2.1M	.3	.08M
10-100K*	.075, .02M	2.39	.16M	2.0	-	4.4	.2M	18.1	.37M	2.0	.14M	2.0	-	4.0	.1M	15.6	.32M
TOTALS		19.0	74.5M	4.1	8.7M	23.1	83.2	35.1	129.0M	16.2	63.2M	4.1	8.7M	20.3	71.9M	30.2	111.6M
OVER 10M	20, 12M	14.9	298.0M	6.4	76.5M	21.3	374.5	28.7	344.0M	12.7	254.0M	6.4	76.5M	19.1	330.5	24.0	298.0M
1-10M	7M	12.8	89.5M	1.5	3.2M	14.3	92.7M	6.7	47.0M	10.9	76.5M	1.5	3.2M	12.4	79.7	5.8	40.7M
100K-1M	.35M	3.91	1.3M	2.1	.8M	6.0	2.1M	9.2	3.17M	3.3	1.1M	2.1	.8M	5.4	1.9	8.0	2.7M
10-100K*	75, .02M	3.91	.33M	5.8	.4M	9.7	.7M	26.2	.56M	3.3	.3M	5.8	.4M	9.1	.7	22.7	0.5M
TOTALS		35.5	389.1M	15.8	80.9M	51.3	490.0	70.8	394.8M	30.2	331.9M	15.8	80.9M	46.0	412.8	61.3	341.9M
OVER 10M	20, 12M	0	-	0	-	0	-	0	-	0	-	0	-	0	-	0	-
1-10M	7M	0	-	0	-	0	-	5.6	39.0M	0	-	0	-	0	-	4.8	33.8M
100K-1M	.35M	.33	.08M	0	-	.3	.08M	0	-	.3	.075M	0	-	.5	.08M	0	-
10-100K*	.075, .02M	3.0	.25M	0	-	3.0	.25M	5.6	.09M	2.5	.2M	0	-	2.5	.2M	4.8	.08M
TOTALS		3.3	.3M	0	-	3.3	.3M	13.2	39.1M	2.9	.3M	0	-	2.8	.3M	9.6	33.9M

* TYPICAL SPILL SIZES IN SIZE RANGE FOR LARGE (UP TO 550 DWT) AND SMALL TANKERS, RESPECTIVELY, IF DIFFERENT. LARGE TANKER SPILL SIZES UNDER 100K RANGE FROM 42-100K IN THE DATA USED; WHEREAS, SMALL TANKER SPILLS RANGE FROM 10-100K (M - MILLIONS, K - THOUSANDS OF GALLONS)

FIGURE 67 At-Sea (Northwest Atlantic) Tanker Major Spill Estimates Comparing DWP Operations To All Small Tanker Imports, Fifteen Year Total Throughput

SPILL SIZE RANGE	TYPICAL SPILL SIZE	DWP		PIPELINE		DWP OPERATIONS - REGIONAL SPILLS							
						VESSEL CASUALTIES							
						TRANFERS		INSHORE		COASTAL		TOTAL DWP	
		NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.
EXPECTED VALUES													
OVER 10M	20, 12M	0	-	0	-	0	-	0	-	0	-	0	-
1-10M	7, 2M	0	-	.05	.1M	0	-	.10	.2M	0	-	.15	.3M
100K-1M	.15, .2, .12, .4, .35	.05	.01M	1.66	.33M	0	-	.82	.33M	0	-	2.52	.67M
UNDER 100K	.075, .05 .015, .02	1.35	.10M	2.90	.14M	.96	.01M	.28	.01M	.22	.01M	5.71	.27M
TOTALS		1.40	.11M	4.60	.6M	.96	.01M	1.20	.5M	.22	.01M	8.4	1.2M
PESSIMISTIC VALUES													
OVER 10M	20, 12M	0	-	0	-	0	-	0	-	0	-	0	-
1-10M	2, 7M	0	-	.40	.80M	0	-	1.50	3.0M	0	-	1.90	3.8M
100K-1M	.15, .2, .12, .4, .35	5.9	.88M	9.10	1.82M	.21	.02M	1.29	.52M	0	-	16.50	3.2M
UNDER 100K	.075, .05 .014, .02	15.8	1.18M	.50	.20M	4.83	.07M	.21	.01M	2.40	.12M	23.74	1.4M
TOTALS		21.7	2.1M	10.0	2.6M	5.04	.1M	3.0	3.5M	2.40	.12M	42.1	8.4M
OPTIMISTIC VALUES													
OVER 10M		0	-	0	-	0	-	0	-	0	-	0	-
1-10M		0	-	0	-	0	-	0	-	0	-	0	-
100K-1M		0	-	.10	.02M	0	-	0	-	0	-	.1	.02M
UNDER 100		.05	-	.90	.04M	0	-	0	-	0	-	5.9	.04M
TOTALS		.05	-	1.0	.06M	0	-	0	-	0	-	6.0	.06M

FIGURE 68

REGIONAL SMALL TANKER SPILLS								AT-SEA SPILLS					
VESSEL CASUALTIES								ALL SMALL TANKERS		DWP SMALL TANKERS		DWP LARGE TANKERS	
TRANFERS		INSHORE		COASTAL		TOTALS							
NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.	NO.	VOL.
0	-	0	-	0	-	-	-	.85	10.2M	.12	1.4M	.1	2.0M
0	-	.66	1.3M	0	-	.66	1.3M	2.75	19.2M	.4	.8M	1.7	11.90M
0	-	5.64	2.3M	0	-	5.75	2.3M	.07	-	.01	-	1.3	0.41M
6.50	.09M	1.99	.1M	1.51	.08M	10.0	.1M	3.53	-	.51	-	.4	-
6.5	.09M	8.3	3.7M	1.51	.08M	16.3	3.7M	7.2	29.4M	1.0	2.2M	3.5	14.3M
0	-	0	-	0	-	0	-	6.48	77.8M	1.62	19.4M	3.4	68.M
0	-	7.5C	15.0M	0	-	7.5	15.0M	1.52	10.6M	.38	.8M	2.9	20.3M
1.11	.13M	6.45	2.6M	0	-	7.6	2.7M	2.08	.7M	.42	.2M	.9	.3M
25.53	.34M	1.05	.05M	10.8	.54M	37.4	.9M	5.92	.1M	1.48	-	.9	.1M
26.64	.5M	15.0	17.6M	10.8	.5M	5.25	18.6M	16.0	89.2M	4.0	20.4	8.1	88.7M
0	-	0	-	0	-	0	-	0	-	0	-	0	-
0	-	0	-	0	-	0	-	0	-	0	-	0	-
0	-	.02	.01M	0	-	.02	.01M	0	-	0	-	0	-
0	-	1.24	.06M	0	-	1.24	.06M	0	-	0	-	0	-
0	-	1.26	.07M	0	-	1.26	.07M	0	-	0	-	0	-

FIGURE 69 **Regional and At-Sea Major Spill Estimates DWP Operations and Small Tankers - Each Five Years**

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SPILL SIZE RANGE	TYPICAL SPILL SIZE	HIGH SCENARIO		MEDIUM SCENARIO		LOW SCENARIO	
		NUMBER	VOLUME	NUMBER	VOLUME	NUMBER	VOLUME
5-42K	12K	86.3	1038K	73.8	885K	64.4	773K
1-5K	1.5K	150.0	224K	128.0	193K	112.0	168K
150-1K	500	188.0	94K	160.5	81K	140.0	70K
UNDER 150	30	1024	34K	960.0	29K	840.0	25K
TOTALS		1448	1.390M	1322.3M	1.188M	1156	1.89M

FIGURE 70

Minor Spill Estimates - SPMs Expected Values

was their tanker data base worldwide, but also their gamma hyperpoisson distribution of oil spill sizes spread the variances more than the conventional gamma used in the analysis previously discussed.

The result is more in line with Theory B-1, mentioned in the assumptions section. That is that oil spill experience may be approaching an upper bound, but that limit has not yet been reached and significantly larger spills than any previously experienced may still occur. In the case of worldwide tanker operations, that is very likely. As long as ever-larger tankers are built, a spill of the maximum capacity of the largest tanker is possible. Indeed, given enough ship-years of operation and inadequate structural inspection and maintenance, it is virtually inevitable.

If we apply the same rationale to current tanker practices and to Baltimore Canyon OCS operations then we must expect more spillage; although the supporting rationale for such assumptions in those cases is not readily apparent.

The results of the MIT analyses for tanker shipments of oil, offshore platforms, and offshore pipelines provide cumulative probability curves for spill incidents as a function of volume produced and, separately, for volume of individual spills. Expectation values by spill size range are not provided, apparently due to the author's recognition that single point estimates are not valid when standard deviations are large relative to the mean of a distribution.

The MIT cumulative probabilities for large spill incidents and volume were broken down to create joint distribution tables, as in FIGURES 71 through 73. It is recognized that this procedure entails the assumption

Spill Size Range	Mean	Production Volume Interval	0-10,500 M	10,500 - 21,000 M	21,000 - 31,500 M	31,500 - 42,000 M	42,000 M
		Mid point	5,250 M	15,750 M	26,250 M	36,750 M	63,000 M
		Probability	.40	.26	.11	.08	.15
10 M	15 M	.01	.004	.0026	.0011	.0008	.0015
1-10 M	2 M	.35	.140	.0910	.0385	.0280	.0525
100K-1 M	.2 M	.43	.172	.1118	.0473	.0344	.0645
42-100K	.05 M	.21	.084	.0546	.0231	.0168	.0315

Spill Volume Expectation by Size over Alternate Production Volume Spill Intervals

E (Spill 10M) = 1.1E-5 + 2.5E-6 + 6.3E-7 + 3.3E-7 + 3.6E-7 =	1.5E-5
E (Spill 1-10 M) = 5.3E-5 + 1.2E-5 + 2.9E-6 + 1.5E-6 + 1.7E-6 =	7.1E-5
E (Spill 100K-1 M) = 6.6E-6 + 1.4E-6 + 3.6E-7 + 1.9E-7 + 2.0E-7=	8.8E-6
E (Spill 42-100K) = 8.0E-7 + 1.7E-7 + 4.0E-8 + 2.3E-8 + 2.5E-8 =	1.3E-6
E (Spill 42K) = (3051 X 104)/(1230E6 X 42) [Values from MIT Analysis] =	6.1E-6
Wastewater Spill Rate [from Kash et al Energy Under the Oceans]=	9.0E-6
Total Expectation	1.1E-4

FIGURE 71 **Joint Distribution of OCS Platform Major Spill Size Interval by Production Volume (Volume in Gallons) (Data from MIT Analysis)**

Spill Size Range	Mean	Production Volume Interval	0-10,500 M	10,500 - 21,000 M	21,000 - 31,500 M	31,500 - 42,000 M	42,000 M
		Midpoint	5,250 M	15,750 M	26,250 M	36,750 M	63,000 M
		Probability	.46	.22	.13	.08	.11
10 M	15 M	.03	.0138	.0066	.0039	.0024	.0033
1-10 M	2 M	.37	.1702	.0814	.0481	.0296	.0407
100K-1 M	.2 M	.36	.1656	.0792	.0468	.0288	.0396
42-100K	.05 M	.24	.1104	.0528	.0312	.0192	.0264

Spill Expectation by Spill Size over Alternate Production Volume Spill Intervals

		(Base)	(Revised)
E (Spill 10M)	= 3.9E-5 + 6.3E-6 + 2.2E-6 + 9.8E-7 + 7.8E-7 =	4.9E-5	1.2E-5
E (Spill 1-10 M)	= 6.5E-5 + 1.0E-5 + 3.7E-6 + 1.6E-6 + 1.3E-6 =	8.2E-5	4.1E-5
E (Spill 100K-1 M)	= 6.3E-6 + 1.0E-6 + 3.6E-7 + 1.6E-7 + 1.3E-7 =	8.0E-6	6.0E-6
E (Spill 42-100K)	= 1.0E-6 + 1.7E-7 + 5.9E-8 + 2.6E-8 + 2.1E-8 =	1.3E-6	1.3E-6
E (Spill 42K)	= (1182 X 201 + 159 X 94)/(1230E6 X 42) [Values from MIT Analysis] =	4.9E-6	4.9E-6
	Total Expectation	1.4E-4	6.5E-5

FIGURE 72 **Joint Distribution of OCS Pipeline Major Spill Size and Spill Interval by Production Volume (Volume in Gallons) (Data from MIT Analysis)**

Spill Size Range	Mean	Volume Landed Interval	0-10,500 M	10,500 - 21,000 M	21,000 - 31,500 M	31,500 - 42,000 M	42,000 M
		Midpoint	5,250 M	15,750 M	26,250 M	36,750 M	63,000 M
		Probability	.57	.25	.10	.05	.03
10 M	20 M	.02	.0114	.0050	.0020	.0010	.0006
1-10 M	4 M	.48	.2736	.1200	.0480	.0240	.0144
100K-1 M	.35 M	.38	.2166	.0950	.0380	.0190	.0114
42-100K	.067M	.12	.0684	.0300	.0120	.0060	.0036

Spill Volume Expectation by Size over Alternative Volume Landed Intervals

			(World)	(Region)
E (Spill 10M)	= 4.3E-5 + 6.3E-6 + 1.5E-6 + 5.4E-7 + 1.93-7	=	5.2E-5	2.6E-5
E (Spill 1-10 M)	= 2.1E-4 + 3.0E-5 + 7.3E-6 + 2.6E-6 + 9.1E-7	=	2.5E-4	1.3E-4
E (Spill 100K-1 M)	= 1.4E-5 + 2.1E-6 + 5.1E-7 + 1.8E-7 + 6.3E-8	=	1.7E-5	8.4E-6
E (Spill 42-100K)	= 8.7E-7 + 1.3E-7 + 3.1E-8 + 1.1E-8 + 3.8E-9	=	1.0E-6	5.0E-7
E (Spill 42K)	= (624 X 318)/(1412E6 X 42)	=	(6.6E-6)	3.3E-6
Tank Cleaning	= 1/2 LOT Spilling 2.7E-4 and 1/2 Segregated Ballast w/slop reception	=	1.4E-4	0
	Total Expectation		4.6E-4	1.6E-4

FIGURE 73 **Joint Distribution of Equivalent Import Tanker Spill Size Interval by Volume Landed (Volume in Gallons) (Data from MIT Analysis)**

that spill size probabilities are independent of incident frequency per volume produced, which may or may not be true. Subdividing an already small data sample defeats any effort to compute a credible variance of the spill expectation by size of spill. It can also be misleading with respect to the expected spill volume. For example, the "average" OCS spill volume in the one to ten million gallon spill range would be about two million gallons. Over a large number of spills, several may be less than the average and few over five million gallons. If only a few spills occur, but include one or two toward the high end of the range, then the average experienced could be two or three times the long term mean expectation.

Production volume return frequencies were assumed linear for the ranges shown, so that midpoint values were used (in M gallons): 5,250, 15,750, 26,250, 36,250, and 63,000, respectively. (The representative value over 1,000 million was chosen as 1,500 M barrels.)

In general, near mean typical values for the respective spill size ranges were used. In the OCS case, T=2M, 200K, and 50K for 1-10M, 100K-1M, and 42-100K ranges, respectively.

Next, for each size range, an expected value for frequency as a function of volume was estimated as the probability of spill size and production volume times typical spill, divided by production range mid-point. For example, the expectation component for platform spills of one to ten million gallons and production 0 to 250 million barrels is:

$$.14 \times 2 / 5{,}250 = 5.3E - 5 = 5.3 \times 10^{-5}$$

For successive production volumes the figures are: 5.3E-5 + 1.2E-6 + 2.9E-6 + 1.5E-6 + 1.7E-6. Thus, summing, the expected value of a spill

of 1 to 10 M gallons, average 2M, over all production volumes is 7.1E-5; similarly for other size ranges over 42,000 gallons.

For spills under 42,000 gallons, "typical" sizes were selected in rough accord with the experience means and the expectation was computed as spills observed X T gallons/(Production observed in gallons). For platform spills the value is:

3051 x 104 / (1230E6 x 42) = 6.1E-6

Waste water spillage for platforms was based on Energy Under the Oceans, pages 291-292, 9E-6.[12/] Tank cleaning spillage for load-on-top (LOT) tankers was taken from page 294 as 270 / 1.E6 = 2.7E-4.[13/]

The result of this process is a set of spill risk factors which can be applied to any assumed production volume to estimate spill frequencies by size range for any production scenario. FIGURE 74 gives the risk factors for tankers, platforms, and pipelines, the base figures based on the MIT results, and the revised figures being adjusted for burying the pipelines.

For OCS production transfer, it was assumed, in accordance with Energy Under the Oceans, that ninety-seven percent would be transported by pipeline and three percent by barge. Barges were assumed to have segregated ballast and slop reception facilities. Tanker value for accidental spills up to 1M gallons in FIGURE 74 were used.

For other vessel spills, it was assumed (lacking data) that, given that a tanker spill occurs, there is one chance in 1,000 that it is

---

12/ Kash, Don E. and White, Irvin L., et al., Energy Under the Oceans: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations. (Norman, Oklahoma: University of Oklahoma Press, 1973).

13/ Ibid.

Spill Size Range	Pipelines (97%)		Barges 3%	OCS Transport Total		Rigs	OCS Totals		Tankers	
	Base	Revised		Base	Revised		Base	Revised	World	Region*
10 M	4.8E-5	1.2E-5	-	4.8E-5	1.2E-5	1.5E-5	6.3E-5	2.7E-5	5.2E-5	2.6E-5
1-10 M	8.0E-5	4.0E-5	-	8.0E-5	4.0E-5	7.1E-5	1.5E-4	1.1E-4	2.5E-4	1.3E-4
100K-1M	7.8E-6	5.8E-6	2.5E-7	8.0E-6	6.0E-6	8.8E-6	1.7E-5	1.5E-5	1.7E-5	8.4E-6
42-100K	1.3E-6	1.3E-6	1.5E-8	1.3E-6	1.3E-6	1.3E-6	2.6E-6	2.6E-6	1.0E-6	5.0E-7
42K	4.8E-6	4.8E-6	1.0E-7	4.9E-6	4.9E-6	6.1E-6	1.1E-5	1.1E-5	6.6E-6**	3.3E-6
Chronic	-	-	-	-	-	9.0E-6	9.0E-6	9.0E-6	1.4E-4	0
Total	1.4E-4	6.5E-5	3.7E-7	1.4E-4	6.5E-5	1.1E-4	2.53E-4	1.75E-4	4.67E-4	1.68E-4

* Regional values generally assumed to be half of world values.
** Assumed double regional value.

FIGURE 74 **Oil Spill Volume Per Volume Produced/Landed (Expected Value Coefficients) (from MIT Analysis)**

induced by OCS operations. Thus, this expectation is 4.6E-7. That is probably a high estimate, but it is so small compared to the other factors that it does not influence the overall risk estimates.

The MIT report shows that about fifty-eight percent of tanker spillage worldwide occurs on the high seas. Allocating thirty of the remaining forty-two percent to the delivery region yields the regional spill factors shown.

If these estimates are used for tabulations similar to FIGURES 56 through 59, the result is FIGURES 75 through 78, which have not been disaggregated by operation or location. Such disaggregations are not supported by the MIT analysis, which addressed the general problem, rather than the specific issues of this study.

Nonetheless, utilizing the data from FIGURES 75 through 78 expected composite spillage estimates roughly comparable to those in FIGURES 55 through 60 of the main analysis were produced. These results are displayed in FIGURES 79 and 80. As indicated in the footnote to FIGURE 79, the pessimistic and optimistic values were not computed, but were judgmental within spill size ranges. Because these estimates do not allow for the shifts of spill frequencies among size ranges, only the expected values can be compared to the results of the main analysis.

3.9 A Final Note on the Reliability of the Estimates

To the extent that the data tell us reasonable things aobut the comparative environmental safety of the major options, things that are supportable by qualitative judgment--the numbers are useful. It may be difficult to visualize relationships without numerical comparisons, with their simplistic clarity, to guide the qualitative logic.

SPILL SIZE RANGE	TYPICAL SPILL SIZE	START-UP, PHASE-OUT INCIDENTS 1980-89, 2000-09 20 YEARS @ 114.2 Mb/year TOTAL 2,284 Mb					PEAK PRODUCTION INCIDENTS 1990-1999 10 YEARS @ 233.7 Mb/year TOTAL 2,337 Mb					LIFE CYCLE INCIDENTS AND VOLUME		
(GALLONS)	(GALLONS)	RIG	TRANS-PORT*	OTHER VESSEL **	TOTAL	PER YEAR	RIG	TRANS-PORT*	OTHER VESSEL **	TOTAL	PER YEAR	TOTAL INCIDENTS	TOTAL VOLUME (GALLONS)	PERCENT OF VOLUME BY SIZE
>10M	15M	0.1	0.08	.0001	0.18	0.009	0.1	0.08	.0001	0.18	0.02	0.36	5.4M	15.9%
1-10M	2M	3.4	1.9	.003	5.3	0.265	3.5	1.9	.003	5.4	0.54	10.7	21.4M	62.9%
100K-1M	200K	4.2	2.9	.002	7.1	0.355	4.3	3.0	.002	7.3	0.73	14.4	2.9M	8.5%
MAJOR SPILL SUBTOTAL		7.7	4.88	.005	12.6	0.629	7.9	4.98	.005	12.9	1.3	25.5	29.7M	87.3%
42-100K	50K	2.5	2.5	.0007	5.0	0.25	2.6	2.6	.0007	5.2	0.5	10.2	0.5M	1.5%
<42K#	100,190	5856	2476	.99	8333	417	5990	2533	1.0	8554	855	16,887	2.1M	6.2%
WASTE WATER		CONTINUOUS					CONTINUOUS						1.7M	5.0%
		Percent of Total Production Spilled = 0.0175% = 1756/Mb										TOTALS	34.0M	100.%

* ASSUMES 97% OF OIL TRANSPORTED BY PIPELINE AND 3% BY BARGE

** ASSUMES 1 CHANCE IN 1000 THAT A VESSEL CASUALTY IN THE OCS REGION IS INDUCED BY OCS OIL OPERATIONS

\# TYPICAL SPILL SIZE IN THE RANGE UNDER 42K IS 100 GALLONS FOR RIGS AND 190 GALLONS FOR PIPELINES

FIGURE 75 High Recovery OCS Spill Expectation: Incidents by Size, Volumes (from MIT Analysis)

SPILL SIZE RANGE	TYPICAL SPILL SIZE	START-UP, PHASE-OUT INCIDENTS 1981-90, 2000-09 20 YEARS @ 52.2 Mb/YEAR TOTAL 1,043 Mb					PEAK PRODUCTION INCIDENTS 1991-1999 9 YEARS @ 113.2 Mb/YEAR TOTAL 1,019 Mb					LIFE CYCLE INCIDENTS AND VOLUME		
(GALLONS)	(GALLONS)	RIG	TRANS-PORT*	OTHER VESSEL **	TOTAL	PER YEAR	RIG	TRANS-PORT*	OTHER VESSEL **	TOTAL	PER YEAR	TOTAL INCIDENTS	TOTAL VOLUME (GALLONS)	PERCENT OF VOLUME BY SIZE
>10M	15M	0.04	0.04	--	0.08	0.004	0.04	0.04	--	0.08	0.01	0.16	2.4M	15.7%
1-10M	2M	1.55	0.88	0.0014	2.43	0.122	1.51	0.86	0.0014	2.37	0.26	4.80	9.6M	62.8%
100K-1M	200K	1.93	1.31	0.0011	3.24	0.162	1.89	1.28	0.0011	3.17	0.35	6.41	1.3M	8.5%
MAJOR SPILL SUBTOTAL		3.52	2.23	0.0025	5.75	0.288	3.44	2.18	0.0025	5.62	0.62	11.4	13.3M	87.0%
42-100K	50K	1.14	1.12	0.0003	2.26	0.113	1.11	1.09	0.0003	2.20	0.24	4.46	0.2M	1.3%
<42K#	100,190	2672	1130	0.45	3802.5	190.1	2611	1104	0.44	3715.4	413	7518	1.0M	6.5%
WASTE WATER		CONTINUOUS					CONTINUOUS					--	0.8M	5.2%
												TOTALS:	15.3M	100.0%

* ASSUMES 97% OF OIL TRANSPORTED BY PIPELINE AND 3% BY BARGE

** ASSUMES 1 CHANCE IN 1000 THAT A VESSEL CASUALTY IN THE OCS REGION IS INDUCED BY OCS OIL OPERATIONS

\# TYPICAL SPILL SIZE IN THE RANGE UNDER 42K IS 100 GALLONS FOR RIGS AND 190 GALLONS FOR PIPELINES

FIGURE 76 Median Recovery OCS Spill Expectation: Incidents by Size, Volumes (from MIT Analysis)

SPILL SIZE (GALLONS)	TYPICAL SIZE (GALLONS)	1980-89, 2000-09 INCIDENTS 114.2 Mb/YR 2,284 Mb	1990-99 INCIDENTS 233.7 Mb/YR 2,337 Mb	WORLDWIDE			REGIONAL VOLUME (MILLIONS OF GALLONS)
				TOTAL INCIDENTS	TOTAL VOLUME (MILLIONS OF GALLONS)	PERCENT OF VOLUME BY SPILL SIZE	
>10M	20M	0.25	0.26	0.51	10.2	11.3	
1-10M	4M	6.0	6.1	12.1	48.4	53.4	
100K-1M	350K	4.6	4.8	9.4	3.3	3.6	
MAJOR SPILL SUBTOTAL		10.85	11.16	22.01	61.9	68.3	18.6
42-100K	67K	1.4	1.5	2.9	0.2	0.2	0.1
<42K	320	1,978	2,024	4,002	1.3	1.5	0.7
TANK CLEANING*		REGULAR		--	27.2	30.0	0**
				TOTALS:	90.6	100.	19.4

PERCENT OF VOLUME LAND SPILLED = 0.467%
= 4676/Mb

* ASSUMES 1) TANKERS ARE HALF LOAD-ON-TOP (LOT) AND HALF SEGREGATED BALLAST
2) SEGREGATED BALLAST TANKERS HAVE ACCESS TO SLOP RECEPTION FACILITIES

** ASSUMES NO TANK CLEANING DISCHARGES WITHIN 50 MILES OF THE COAST

FIGURE 77 High Recovery Equivalent: Import Tanker Spills, World and Regional (from MIT Analysis)

SPILL SIZE (GALLONS)	TYPICAL SIZE (GALLONS)	1980-89, 2000-09 INCIDENTS 52.2 Mb/YR 1,043 Mb	1990-99 INCIDENTS 113.2 Mb/YR 1,019 Mb	WORLDWIDE			REGIONAL VOLUME (MILLIONS OF GALLONS)
				TOTAL INCIDENTS	TOTAL VOLUME (MILLIONS OF GALLONS)	PERCENT OF VOLUME BY SPILL SIZE	
> 10M	20M	0.11	0.11	0.22	4.4	10.7	
1-10M	4M	2.7	2.7	5.4	21.6	52.6	
100K-1M	350K	2.1	2.1	4.2	1.5	3.6	
MAJOR SPILL SUBTOTAL		4.9	4.9	9.8	27.5	66.9	8.3
42-100K	67K	0.65	0.64	1.3	0.9	2.2	0.5
<42K	320	903	883	1,786	0.6	1.5	0.3
TANK CLEANING*		REGULAR		--	12.1	29.4	0**
				TOTALS:	41.1	100.0	9.1

* ASSUMES 1) TANKERS ARE HALF LOAD-ON-TOP (LOT) AND HALF SEGREGATED BALLAST
2) SEGREGATED BALLAST TANKERS HAVE ACCESS TO SLOP RECEPTION FACILITIES

** ASSUMES NO TANK CLEANING DISCHARGES WITHIN 50 MILES OF THE COAST

FIGURE 78 Median Recovery Equivalent: Import Tanker Spills, World and Regional (from MIT Analysis)

HIGH RECOVERY					
SIZE RANGE	TYPICAL SIZE	EXPECTED INCIDENTS	VOLUME (MILLIONS OF GALLONS)		
			OPT MISTIC*	EXPECTED	PESSIMISTIC*
>10M	15M	0.4	0	5.4	20
1-10M	2M	10.7	14	21.4	43
100K-1M	.2M	14.4	2	2.9	6
MAJOR SPILLS		25.5	16	29.7	69
42-100K	.05M	10.2	0.3	0.5	2
< 42K	150	17,000	2	2.1	2.5
WASTE WATER			1.5	1.7	2.0
		TOTALS:	∿ 20	34	∿ 75

MEDIAN RECOVERY					
>10M	15M	0.2	0	2.4	10
1-10M	2M	4.8	6	9.6	19
100K-1M	.2M	6.4	.9	1.3	2.5
MAJOR SPILLS	—	11.4	6.9	13.3	31.5
42-100K	.05M	4.5	0.1	0.2	1
< 42K	150	7,500	0.9	1.0	1.3
WASTE WATER	—		0.7	0.8	1.2
		TOTALS:	∿ 8.5	15.3	35M

* THESE ESTIMATES ARE NOT STATISTICAL, BUT JUDGMENTAL, BASED ON THE FOLLOWING RATIONALE: (1) IN GENERAL, THE POSSIBILITY OF GREATER VOLUME SPILLAGE IS WIDER THAN THAT OF LOWER VOLUMES, (2) WHERE SMALL NUMBERS OF INCIDENTS ARE EXPECTED, ONE SPILL WELL ABOVE THE EXPECTED AVERAGE SIZE COULD EASILY INCREASE THE SPILLAGE IN THAT RANGE BY TWO OR MORE TIMES. FOR THE TOTAL SPILLAGE TO BE LESS THAN EXPECTED, ALL SPILLS EXPERIENCED WOULD HAVE TO BE AT OR BELOW THE AVERAGE SIZE.

FIGURE 79 Expected Baltimore Canyon OCS Spills (from MIT Analysis)

HIGH RECOVERY EQUIVALENT						
SIZE RANGE	TYPICAL SIZE	EXPECTED INCIDENTS	VOLUME (MILLIONS OF GALLONS)			REGIONAL EXPECTED
			OPTIMISTIC	EXPECTED	PESSIMISTIC	
> 10M	20M	0.5	0	10.2	40	
1-10M	4M	12.1	32	48.4	97	
100K-1M	350K	9.4	2	3.3	7	
MAJOR SPILLS		22.0	34	61.9	144	18.6
42-100K	67K	2.9	0.1	0.2	0.8	0.1
< 42K	320	4002	1.2	1.3	1.5	0.7
TANK CLEANING		—	24	27.2	32	0
			59	90.6	178	19.4

MEDIAN RECOVERY EQUIVALENT						
> 10M	20M	0.2	0	4.4	20	
1-10M	4M	5.4	13.5	21.6	43	
100K-1M	350K	4.2	1	1.5	3	
MAJOR SPILLS		9.8	14.5	27.5	66	8.3
42-100K	67K	1.3	0.4	0.9	4	0.5
< 42K	320	1,786	0.5	0.6	8	0.3
TANK CLEANING		—	10.6	12.1	18	0
			26	41.1	86	9.1

FIGURE 80 Equivalent Import Tanker Spillage (from MIT Analysis)

On the other hand, spillage estimates of this degree of mathematical unreliability ought not to be accepted merely because they clarify apparent relationships. The fact that the results are generated systematically, and with a great deal of computation, says absolutely nothing about their validity.

For instance, let us use the top part of FIGURE 9 on deepwater ports as an example and explore its credibility. Perhaps the most striking first impression is that the majority of regional DWP spillage is coastal rather than inshore, presumably indicating a plus for the deepwater ports. The numerical results are logical. Small tankers travel into the ports and harbors where there is a significantly greater opportunity for collisions, rammings, and groundings than exests in the coastal area. Their transfers and transfer spills occur inshore. But that is not the whole story. It is also true that spillage reporting in the coastal area is very poor relative to the inshore area. There is a greater chance of avoiding detection of spillage and the legal jurisdiction of the spill reporting system extends only three miles out. Perhaps there appear to be greater inshore risks only because we know more about those spills. In fact, that is unlikely to explain the difference. Chronic (intentional) pollution might be so concealed, but major accidents taking a vessel out of commission for repairs would be difficult to conceal. Further, there would appear to be little motivation to claim that a spill outside U.S. jurisdiction had actually occurred in port. Liability considerations would create the opposite motivation. Thus, despite the data weakness, qualitative logic appears to support the numerical relationship.

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Conversely, of course, because the deepwater port facility and pipelines will lie in coastal waters, it is inevitable that the predominant spillage would be attributed there. In fact, the only spillage attributed inshore is from the supplemental small tanker operations. This may understate the deepwater port inshore spillage. Some undersea pipeline spills may occur at the shore or at an inland waterway. Land segments of the pipelines do sometimes spill into inshore waters. Nonetheless, while the numbers and proportions may be a little off target, it appears reasonable that the actual deepwater port spillage would be predominantly offshore.

Another notable feature is that the at-sea spillage is so much greater than the regional spillage. This is reasonable and is consistent with the Lloyds data. Vessel total losses are far more likely from structural failures, which predominantly occur at sea, than from other accident types occurring in or near shore. In such cases, the entire contents may go into the spill. Typically, in a collision or grounding (particularly if not followed by a fire), cargo loss is limited to the tanks directly damaged. If the vessels sinks, it is likely to rest on the bottom and assistance and salvage resources, enhances the potential for saving the vessel, the remaining oil and particularly the crew.

Another paradox in FIGURE 9 is that deepwater port total spill volumes are smaller with one exception than the small tanker option in the expected and optimistic cases, but larger in the pessimistic estimate. This is due to the spill size probability distributions assumed. In all operations except large tanker casualties spill sizes are described by

fixed parameter gamma distributions. In the exception, the gamma hyper-poisson distribution randomizes the gamma parameters, thus spreading the size range of the estimates. It was used in this case because of the need for considerable extrapolation to allow for the increasing trend of tanker sizes. The relationship follows directly from input assumptions selected on the criterion of reasonable judgment. The credibility of this output is tied to the credibility of the specific assumption.

At this point, an inferential process can be traced to enhance the credibility of the deepwater port numerical estimates--which were assumed to be of uncertain validity. Referring back to the discussions of assumptions it may be noted that the data base for small tanker imports can be assumed stable and specifically relevant to the analysis. The exposure volumes observed are not large relative to the volumes contemplated so that the numerical outputs may be less tightly bounded than for the OCS analysis, but the outputs would not be biased by this uncertainty.

If one can accept the assumption that the small tanker estimates are reasonable credible and, further, that the deepwater port-small tanker relationships are directionally correct, then it follows that the deepwater estimates must be in the right ballpark. Of course, due to the wide variances between the expected and extreme values, the estimates have a large ballpark to fit into. Nonetheless, it is plausible to conclude by this rationale that both the deepwater port and small tanker spillage are more likely to fall in the vicinity of the expected values than close to either extreme, always subject to assumptions made in the process of the analysis.

Working Paper #4

Air and Water Quality Impacts of Oil and Gas Processing Facilities

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SECTION I

INTRODUCTION

This working paper is intended to provide supplementary material to the main report on Coastal Effects of Offshore Energy Systems. It is an expansion of those sections dealing with petroleum processing and refining facilities which may be built in conjunction with developing either offshore oil and gas or deepwater ports.

The petroleum industry can logically be divided into production, refining, and marketing. Production includes locating and drilling of oil wells, pumping and preheating the crude oil, recovering gas condensate, and shipping these raw products to the refineries, or distribution center. Refining is the conversion of crude to a finished salable product. Marketing involves the distribution and sale of the finished products. This chapter deals primarily with refining aspects of the petroleum industry.

The petroleum refinery is an assortment of aggregated processing units which are engaged in the conversion of crude oil into a variety of petroleum intermediate products and finished products. Although a modern refinery is a complex system of many processes, the entire operation can be divided into three major steps: separating, converting and blending. The crude oil is first separated into selected fractions, i.e. gasoline, kerosene, fuel oil, etc. Because the relative volumes of each fraction produced by separating (distilling) the crude may not conform to market demands for each fraction, some of the products, such as heavy nephtha, are converted to products of greater sale value, such as gasoline. This conversion is accomplished by splitting (cracking), uniting (isomerization,

polymerization), or rearranging (reforming) the original molecules. The final step is blending of the refined base stocks with each other and with various additives to meet final product specification. The various unit processes involved at a petroleum refinery will be discussed in the following sections.

A. Processes Employed

The components of a typical petroleum refinery are diagramed in FIGURE 1. This process flow chart shows the general relationship between units in a petroleum refinery.

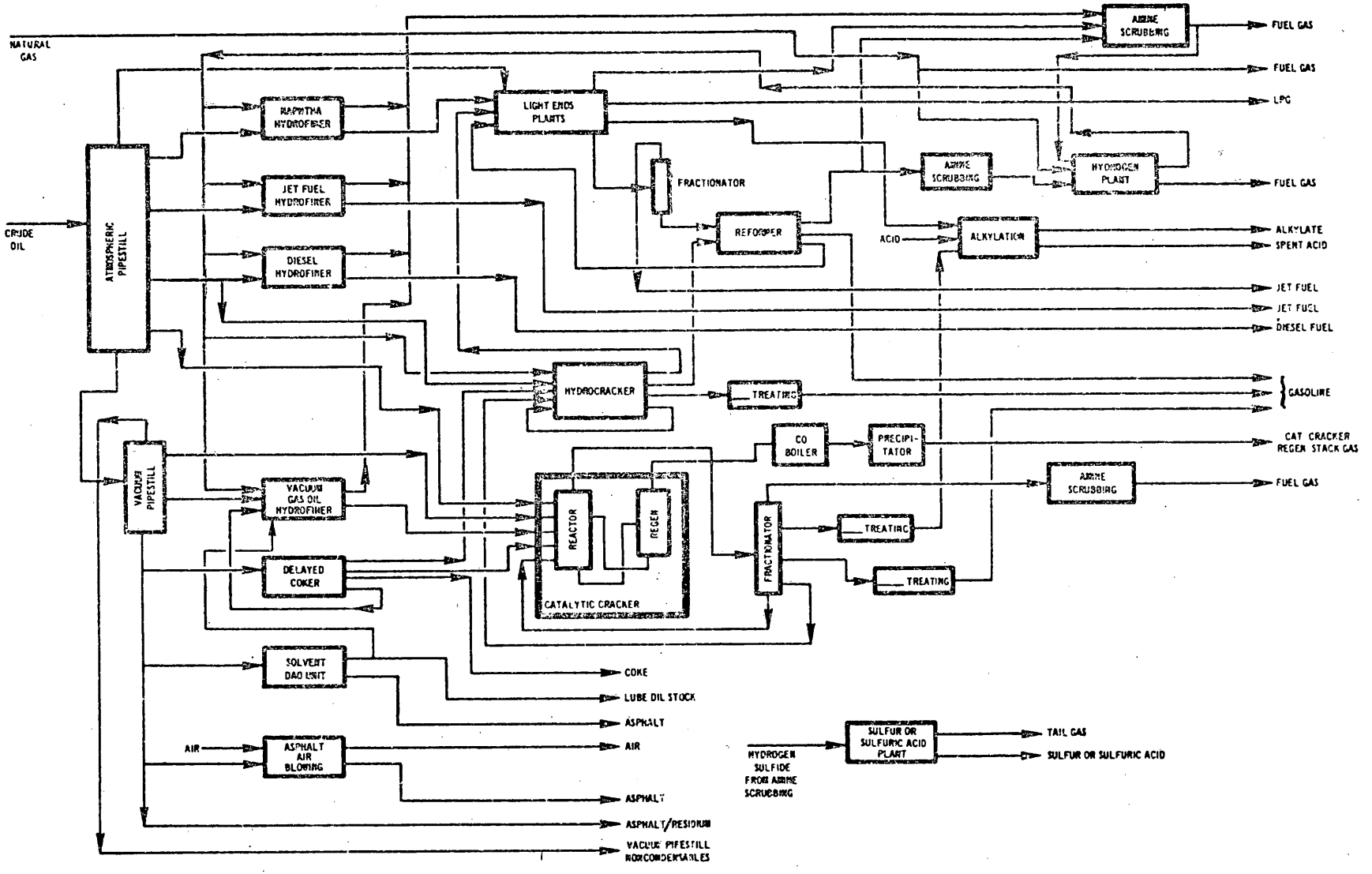


Figure 1 Basic flow diagram of petroleum refinery. (12)

These processing units are listed below with their purposes explained and their nature described.

1. Crude Desalting

If the salt content of the crude oil is greater than 10 lb/1000 bbl (expressed as NaCl), the crude requires desalting to minimize fouling and corosion caused by salt deposition or heat transfer surfaces, and acids formed by decomposition of the chloride salts. In addition, some metals which can cause catalyst deactiviation in catalytic processing units are partially rejected in the desalting process.

2 Crude Distillation

Crude distillation is the first major processing unit in a refinery. It is used to separate crude oil into intermediate fractions of specific boiling point ranges. Typical fraction out points and boiling ranges of crude oil is given in Table 1. Each fraction is then routed to downstream units as feedstocks or is considered a final product. Higher efficiencies and lower costs are achieved if the crude oil separation is accomplished in two steps: First, by fractionating the total crude oil at essentially atmospheric pressure; then, by feeding the high-boiling bottoms fraction from the atmospheric still to a secondary still operating at a high vacuum. Atmospheric distillation breaks the heated crude oil into (1) light overhead products of C5 or lighter, (2) sidestream distillate cuts of kerosene, heating and gas oil, and (3) residual or reduced crude oil. Vacuum distillation operating at sub-atmospheric pressure separates heavy petroleum distillates from reduced crude or atmospheric distillation tower bottoms. Vacuum fractionation is employed to avoid excessive temperatures that would be encountered in producing heavy distillates by atmospheric fractionation alone.

Table 1: Boiling of Typical Crude Oil Fractions

Fraction	Boiling Range, ASTM(oF)
Butane and lighter ends	
Light straight-run gasoline (LSR)	90-220
Naphtha (heavy straight-run gasoline)	180-400
Kerosene	330-540
Light as oil (LGO)	420-640
Atmospheric gas oil	550-830
Vacuum gas oil	750-1050
Vacuum reduced crude-residue	1000+

An initial vacuum stage produces well-fractioned, lube oil base stocks plus residue for subsequent propane de-asphalting. A second vacuum stage fractionates surplus atmospheric bottoms not applicable for lube production, and surplus initial stage residuum not required for desaphalting. This stage adds the capability of removing catalytic cracking stock from surplus bottoms to the distillation unit. Figure 2 shows a typical crude distillation unit.

3 Hydrotreating

Hydrotreating petroleum stocks catalytically converts organic compounds of sulfur, nitrogen, and oxygen into hydrocarbons and removable ammonia, sulfide, and water. Its principal function is to purify, cleanse, and improve the quality of the feed stock. The process employes hydrogen and a catalyst. Figure 3 illustrates the typical flow diagram of a hydrotreating unit.

Normally petroleum fractions are hydrotreated separately because of varying sulfur limits placed on various fuels, and of the wide range of catalysts and reaction conditions required to hydrotreat the various petroleum fractions. Naphtha hydrotreating is used for the denitrogenation and desulfuration of naphtha feed

Figure 2.(Ref.2) Typical Crude Distillation Unit

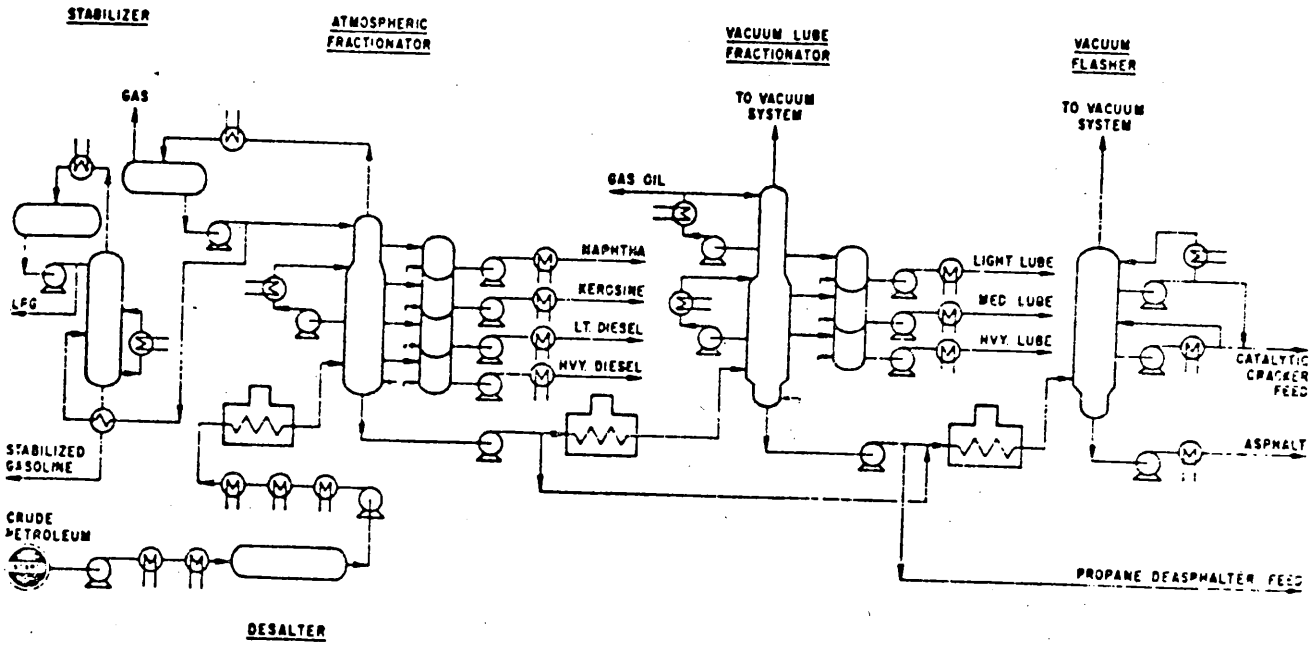
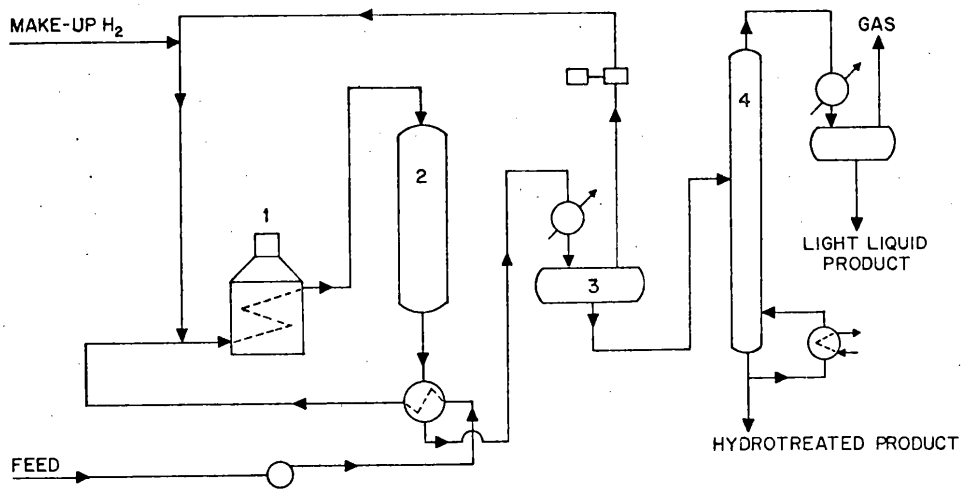


Figure 3 (Ref. 1) A Representative Hydrotreating Unit



stocks to isomerization units, catalytic reforming units, and other processing units. The high product quality required of naphtha fuels in conjunction with the extreme susceptibility of catalysts to sulfur and nitrogen poisoning necessitates the removal of approximately all of the sulfur and nitrogen present in the naphtha feed stock. Distillate hydrotreating is used in the desulfurization, denitrogenation, and stabilization of distillate gas oils which includes vacuum distillates. Residual hydrotreating units are used in the desulfurization and stabilization of both atmospheric and vacuum residues.

4 Alkylation

For the production of a gasoline blending component, alkylation means the chemical combination of isobutane with any one or a combination of propylene, butylenes and amylenes to form a mixture of highly branched paraffin that has high octane and good stability. The alkylation is accomplished with the catalytic aid of hydrofluoric or sulfuric acid to produce a gasoline having octane numbers in the range of 93-95 (Reference 6). Figure 4 represents a flow diagram of a hydrofluoric alkylation unit.

5 Catalytic Reforming

The purpose of catalytic reforming is to rearrange or reform the molecular structure of hydrocarbons catalytically, The objective of catalytic reforming is to upgrade naphthas having poor antiknock characteristics to premium-quality motor fuels or produce aromatics, notably benzene, toluene, and C_8 aromatics from selected naphtha fractions. These high octane aromatic products are used in gasoline blending and as feedstocks to aromatic plants. Figure 5 illustrates a typical catalytic reforming unit.

Figure 4 (Reference 2)

Flow Diagram of a Hydrofluoric Alkylation Unit

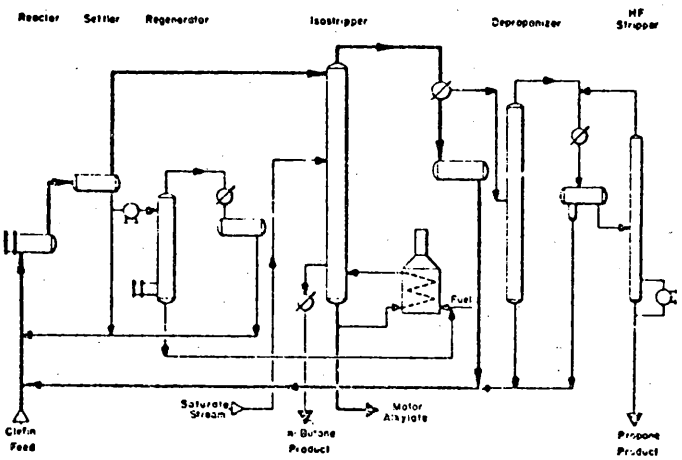
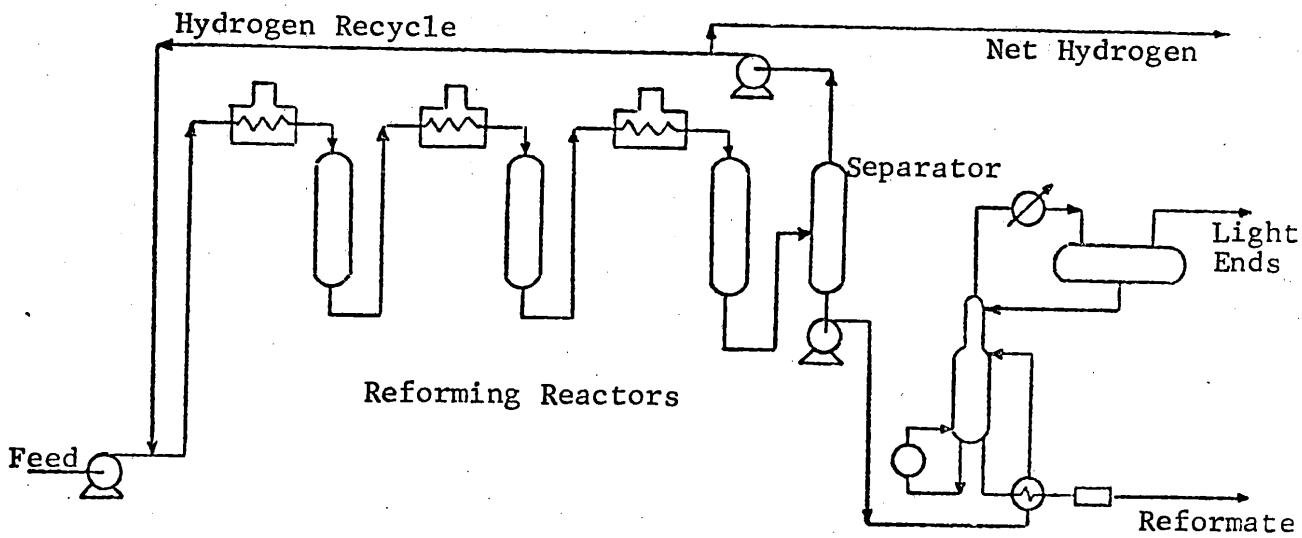


Figure 5 (Reference 2) Typical
Catalytic Reforming Unit (Chevron Research Co.)



6 Catalytic Cracking

In petroleum technology, cracking denotes reactions in which a hydrogen molecule is fractured or broken into two smaller fragments. The purpose of catalytic cracking is to convert heavy distillate oil into gasoline as the primary product, with accompanying production of light hydrocarbons and distillate fuels that are lighter than the feedstock. The product will contain olefinic hydrocarbons. Catalytic cracking is performed at temperatures in the region of 455-540°C, at pressures only slightly above atmospheric, and in the presence of a catalyst which, basically, is composed of silica and alumina (Reference 1). Figure 6 shows a typical catalytic cracking process.

There are several types of catalytic cracking processes, and they differ by the mode in which catalyst-oil contact and reaction are achieved. The three major catalytic cracking processes are fixed bed, thermofor catalytic cracking (TCC), and fluid catalytic cracking (FCC)(Reference 16). Of these processes, fluid catalytic cracking in which catalyst transfer between reactor and regenerator is accomplished by a combination of gravity and fluidized catalyst transport is dominant in the petroleum industry today.

7 Isomerization

Isomerization can be defined as the rearrangement of the structural configuration of a molecule without changing its molecular weight. Isomerization processes are used to increase the octaine rating of light straight run gasoline by catalytically rearranging the straight-chained C_5 (pentane) and C_6 (hexane) paraffins into branched paraffins. Straight-channel C_4 paraffins are converted into isobutane by isomerization, and used for alkylation with olefins in the production of motor fuels. Isomerization also is applied in a much lesser extent to C_8 aromatic hydrocarbons. Figure 7 diagrams a C_5/C_6 isomerization unit.

Figure 6 (Reference 2) Typical Catalytic Cracking Process

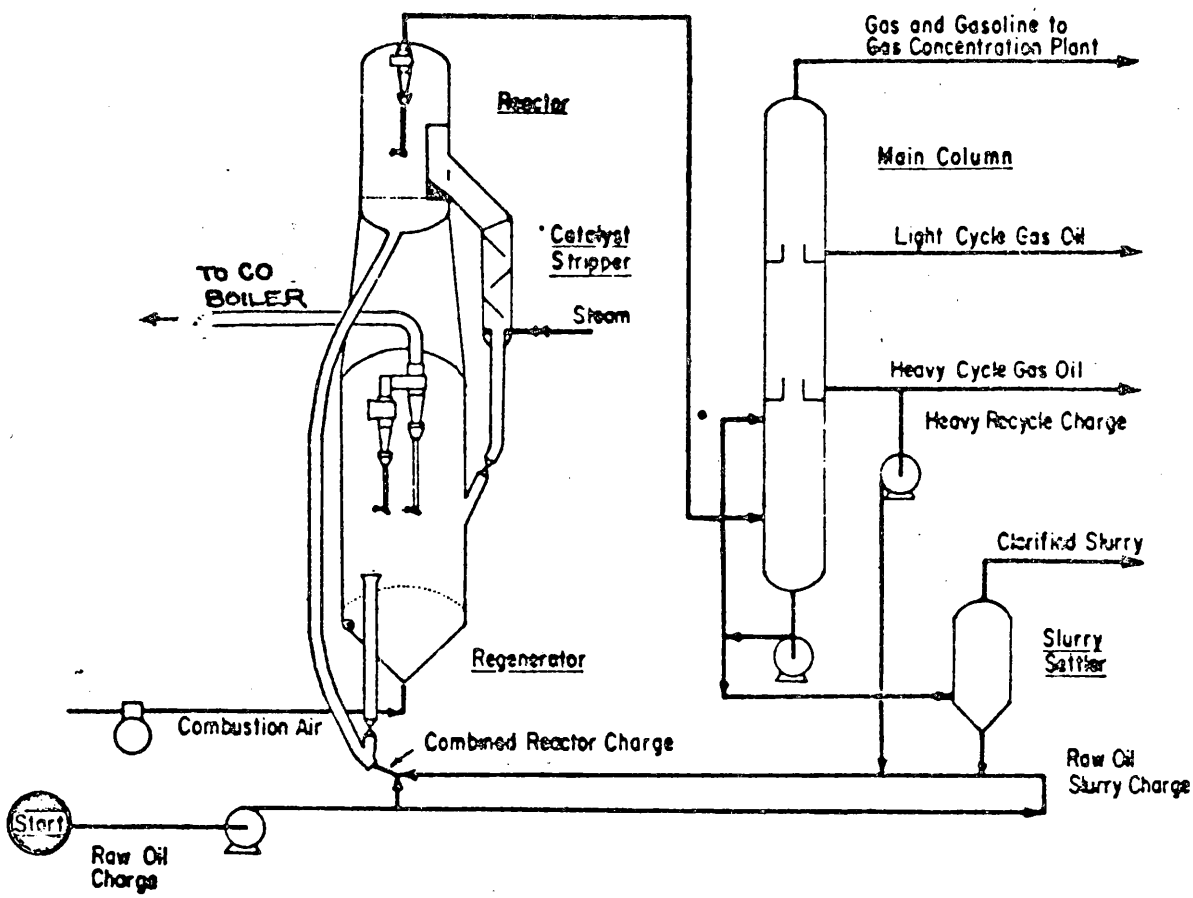
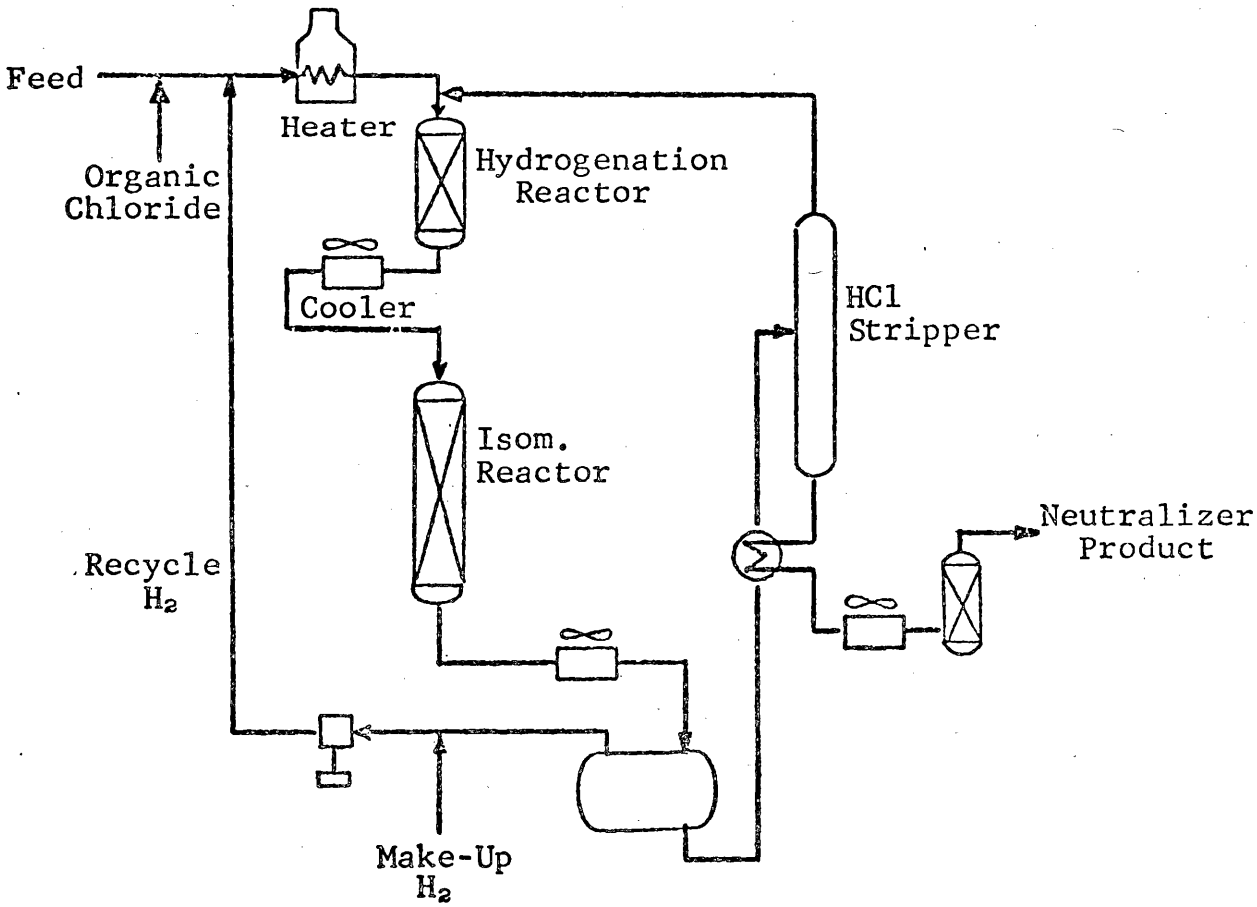


Figure 7 (Ref. 2)

C_5/C_6 Isomerization Unit



8 Thermal Cracking

Thermal cracking is used principally in coking and viscosity breaking to convert non-distillate residues into more valuable products. The pitch and residuums, as produced by most vacuum-flashing units, is two vicious to be marketed as a heavy fuel oil without further processing. In some refineries, the pitch is processed further in a thermal cracking unit to reduce its viscosity. This process which is commonly referred to as coking produces coke as a by-product.

9 Catalytic Hydrocracking

Catalytic hydrocracking differs from catalytic cracking in that it uses a different catalyst and an environment of hydrogen. Although there are hundred of simultaneous chemical reactions occurring in hydrocracking, the mechanisms of hydrocracking is that of catalytic cracking with hydrogenation superimposed. Hydrocracking reactions are normally carried out at average catalyst temperatures between 550° and 750° F and at reaction pressures between 1200 and 2000 psig (Reference 3). Two major reasons why the use of hydrocracking is justified in a modern petroleum refinery are: (1) hydrogen at low cost and in large amounts is available as a catalytic reforming byproduct, and (2) there is a higher demand for gasoline petroleum products.

10 Vapor Recovery

Light ends recovery involves the separation of refinery gases by absorption and/or distillation. The majority of the refinery gases discharged to the vapor recovery unit are from the distillation, hydrotreater, catalytic cracking and reforming, thermal cracking and hydrocracking units. A typical recovery process utilizing an absorption-fractionation technique would yield the following light products (4):

a. ethane and lighter off gas
b. propane - propylene
c. butane-butylene

These products will be used further in petrochemical processes, i.e., ethane or lighter off gas, propane, and propylene to produce ethylene, propylene and bytadiene, in petroleum processes, i.e., butane in gasoline blending, or become commercial available as final products, i.e., butylene. Figure 8 shows a flow diagram of a vapor recovery process.

11 Ethlyene Plant

An ethylene plant upgrades the low molecular weight straight-chain paraffins such as ethane, propane, normal butane, light straight-run naphtha, and reformer raffinate. The process products, in addition to ethylene, include hydrogen, methane, propylene, bytadiene (C_4), pyrolysis gasoline and a cracked fuel oil. Hydrogen is used in the hydrotreating unit while methane is used as a refinery fuel. Pyrolysis gasoline and cracked fuel oil are blended into other refinery products. The finished products from the ethylene plant are ethylene, propylene, and bytadiene. Figure 9 diagrams the flow scheme of an ethylene plant.

12 Hydrogen Plant

Hydrogen plants utilize steam-hydrocarbon reforming to produce hydrogen. Hydrocarbons (methane to light distillate oils) and steam are catalytically reacted at 1700°F in a reactor (5), and then are cooled by water and/or condensate quenching.

Figure 8 (Ref. 2)

Vapor Recovery Process

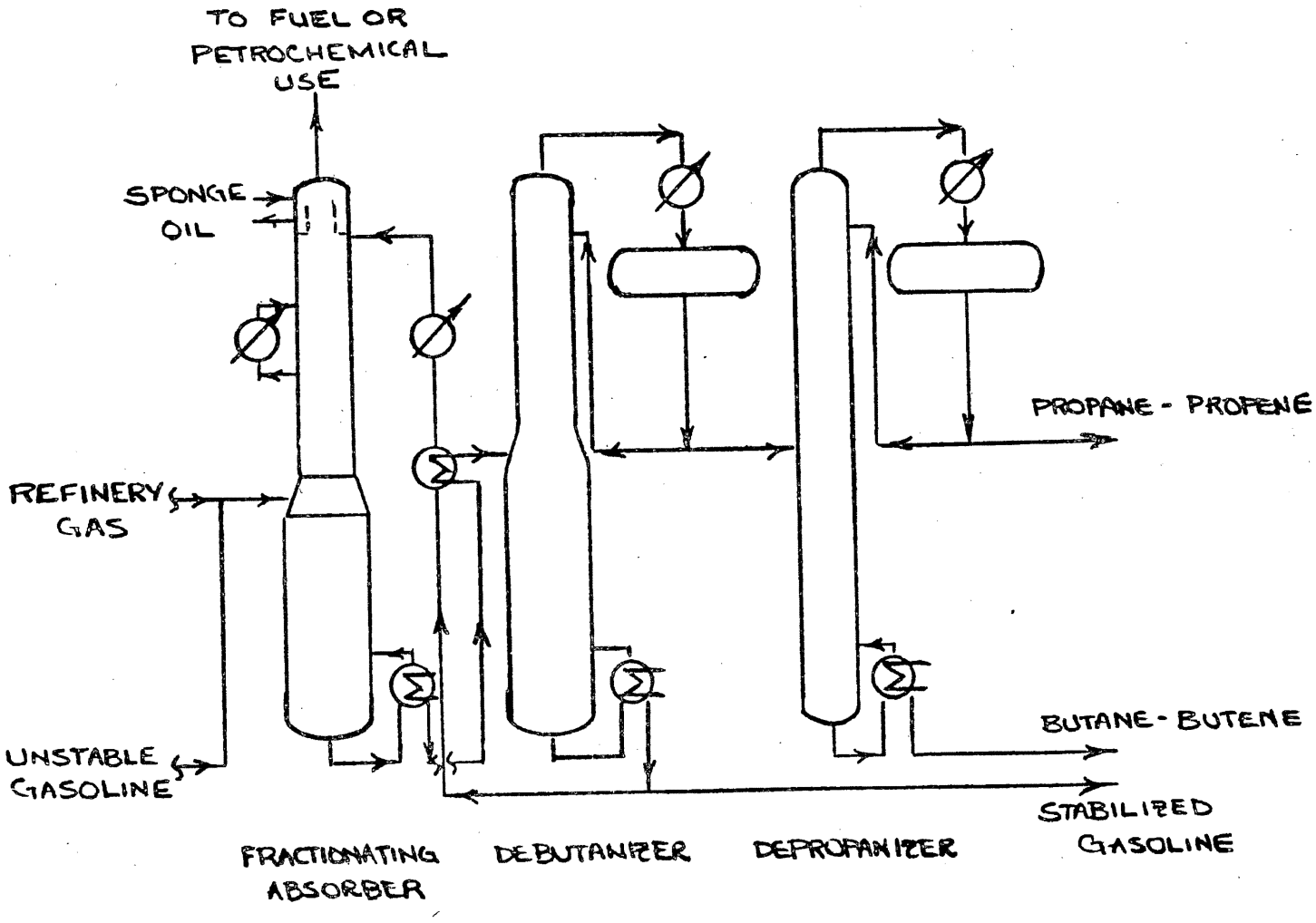
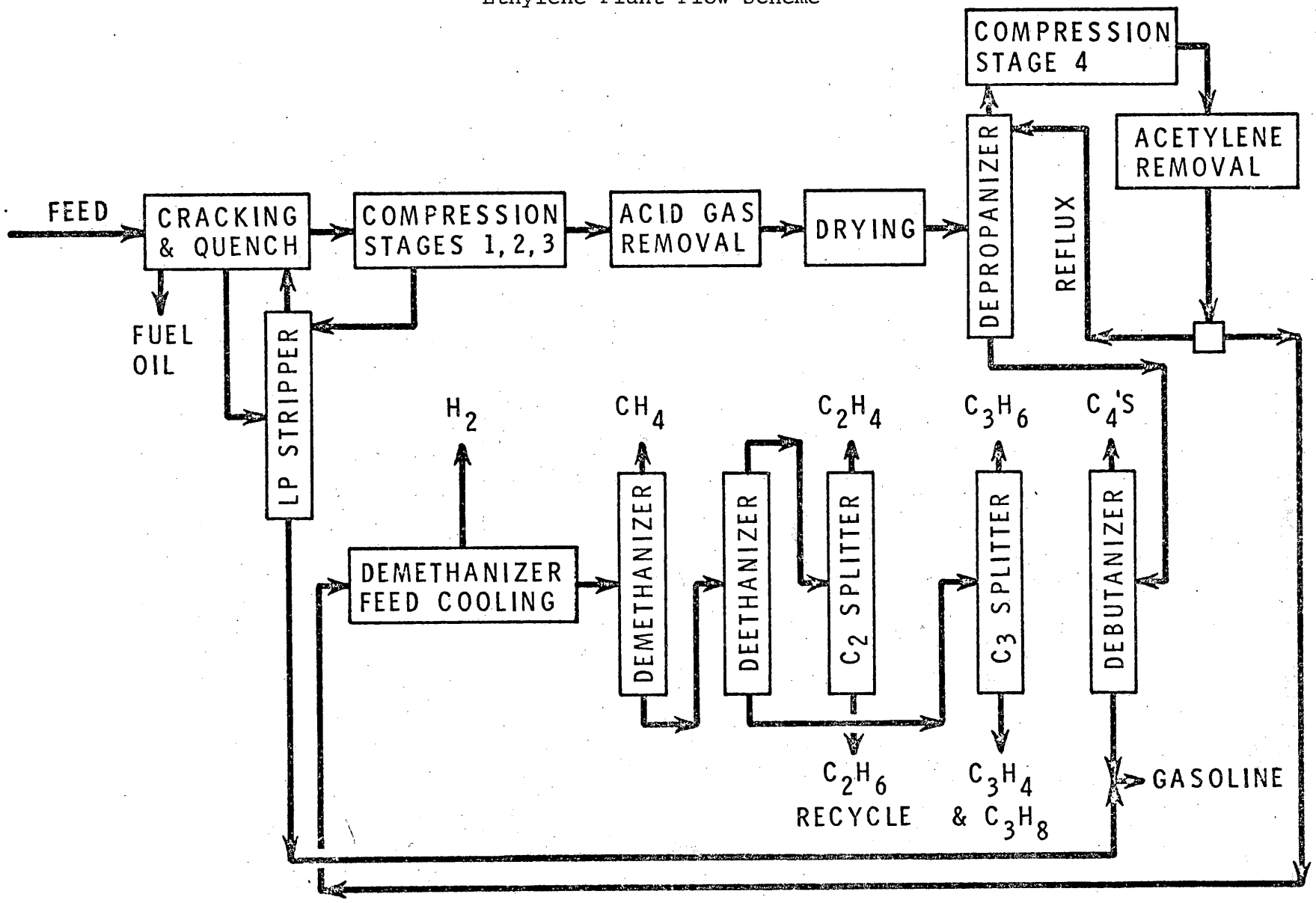


Figure 9 (Ref. 2)
Ethylene Plant Flow Scheme



The product then undergoes CO conversion, and is distributed to a number of refinery processes including the hydrotreater, isomerization, and catalytic reformer units.

13 Asphalt Plant

The purpose of this complex is to produce various grades of asphalt for use in paving and roofing. Vacuum flahser bottoms blended to the proper viscosity with heavy flashed distillate form the basic raw material for asphalt manufacture. Heavy gas oil having a boiling range of 343-566°C, and nondistillable residue pitch is subjected to vacuum flashing or vacuum distillation if several fractions are desired (6).

B. Process-Related Facilities

1) Sulfur Plants and Sour Water Stripper

The Sour Water Stripper and the Sulfur Plants minimize emissions of pollutants to the air and water. Sour water, or water containing acids, is collected from various refinery process units, particularly from the wash water systems in the hydrotreaters, and mixed with spent caustic, which contains chemically bound hydrogen sulfide. This mixture is fed through a stripper to remove hydrogen sulfide and ammonia. These contaminants are gassified, and passed into a sulfur Plant where elemental sulfur is recovered and approximately all ammonia is converted to gaseous nitrogen and water vapor. Figure 10 and 11 show the flow diagrams for a claus sulfur recovery process and a sour water stripper, respectively. A more detailed description of a Sulfur Recovery Plants and Tail Gas Systems is contained in Chapter 3 - Natural Gas Processing, Processes Employed.

Figure 10 (Ref. 2)
Claus Sulfur Recovery Process

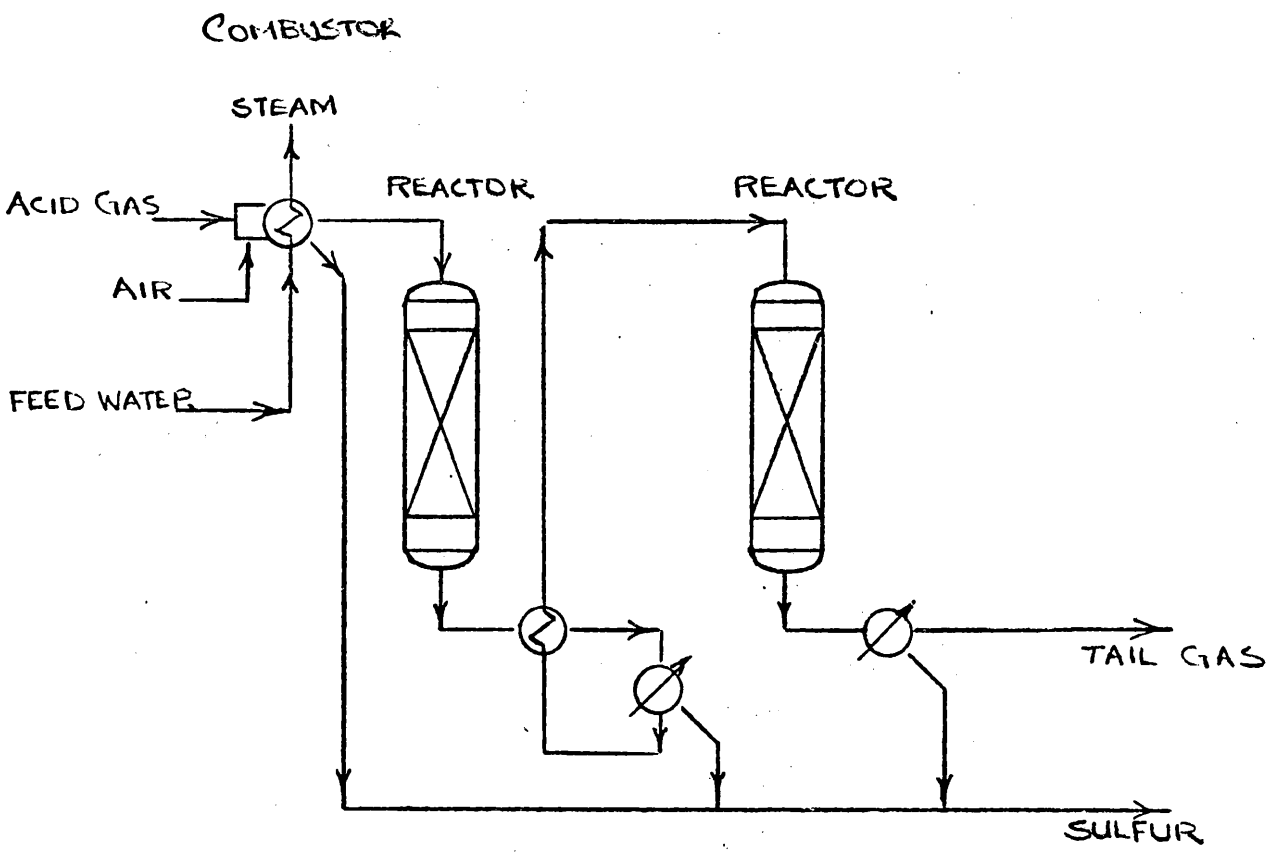
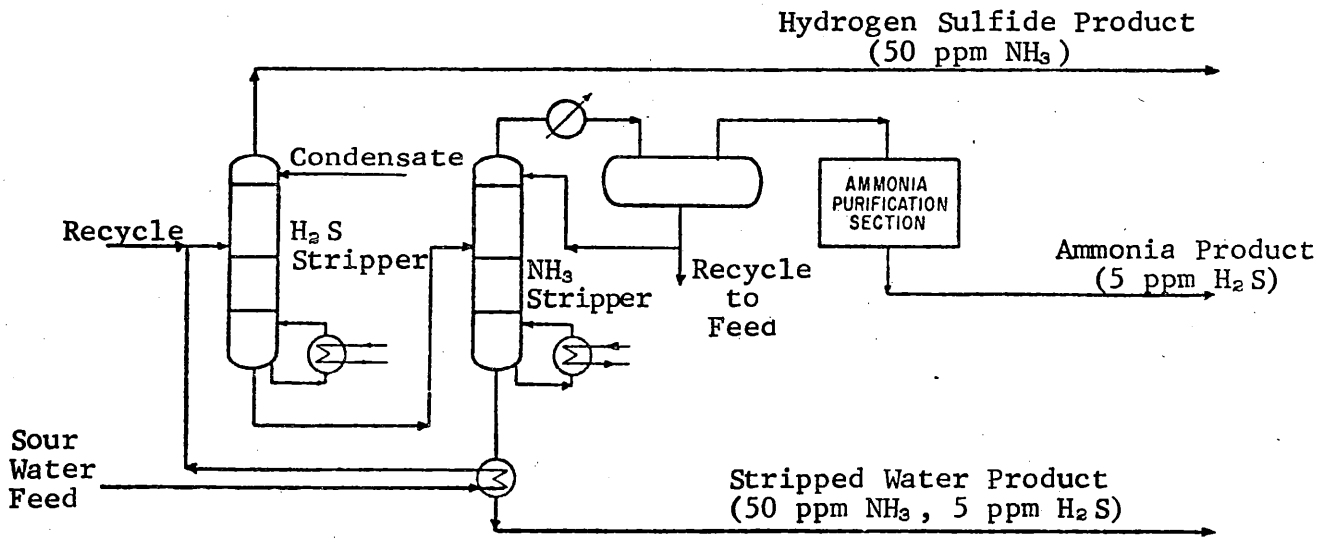


Figure 11 (Ref. 2)

Sour Water Stripper
(Chevron Research Co.)



2) Vent Gas Incineration

The ground-level incinerator is a large, low cylinder in which vented gases are burned. It is designed to minimize noise, light, and smoke. As the gases enter the base of the cylinder, they are burned in a number of flame jets. The ground-level incinerator will handle all but the most severe refinery upsets

Major upsets, including those which might result from the loss of outside electrical service or from the loss of cooling water circulation can be controlled with a conventional elevated incinerator. This elevated incinerator can be equipped with steam injection to promote smokeless burning.

3) CO Waste Heat Boiler

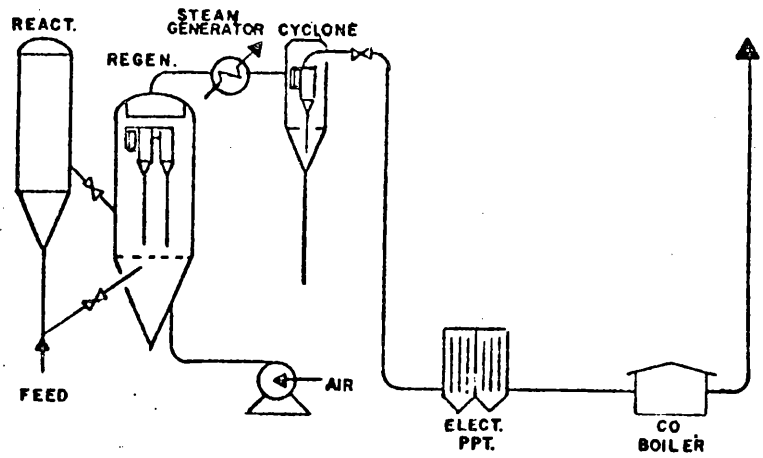
Carbon monoxide (CO) and other pollutants are discharged in normal operation from a catalytic cracking unit, i.e., the FCC regenerator. A CO boiler or furnace (Figure 12) is used to control these CO emissions from a catalyst generator. The flue gas from the generator after particulate removal is used as a furnace fuel. The CO content of the flue gas is combusted and is utilized to provide process heat or generate steam.

4) Gas Treating Plant

Refinery gases withdrawn from various processing units contain a variety of acid gas constitutents including hydrogen sulfide, mercaptans, carbonyl sulfides, carbon disulfide, and carbon dioxide. Refinery processes which produce substantial quantities of these acid gases include crude distillation, hydrotreating, catalytic cracking, thermal cracking, and hydrocracking treatment usually involves adsorption by some

Figure 12 (Ref. 2)

Typical CO Boiler and its Interrelationship With A FCC Unit



aqueous, regenerative sorbent. A more detailed description of this type of treatment process, i.e., amine sweetening process is contained in Chapter 3 Natural Gas Processing, Processes Employed, Sweetening Process.

5) Waste Water Treatment Plant

The purpose of a waste water treatment plant is to upgrade the quality of water effluents so that they can be released to the environment, or reused within the refinery. A waste water treatment facility depending on the amount and volume of waste being processed may include pretreatment, primary, secondary, and/or teritary treatment.

Inplant pretreatment processes include those that treat specific aqueous waste streams. For example, such processes as sour water stripping, spent caustic oxidizers, and chlorination of sanitary wastes are considered inplant pretreatment processes. Another pretreatment process involves the segregation of effluent steams into specific type ie clean water, reused water, highly contaminated water, and special treatment water. This technique reduces the cost and increases the efficiency of the treatment facility.

Primary wastewater treatment involves the physical upgrading of aqueous effluents prior to discharge or secondary treatment. The oil-water separator is a commonly used primary waste treatment process. This unit allows for the continuous gravity separation of oil, oily sludge, and grit from incoming waste water. Suspended solids or oil are removed in settling chambers and clarifiers (gravity separators), air floatation systems, coagulation, and flocculation systems. Also, alkali and acidic waste are neutralized in this process step.

BOD and COD are removed from waste waters as a result of secondary treatment. In biological secondary treatment processes, microorganisms are used to consume soluble organic wastes in the water and convert them to CO_2 and H_2O. Another form of biological wast treatment is anaerobic digestion in which micro-organisms in the absence of oxygen convert soluble organic wastes to CO_2 and methane.

Tertiary treatment processes are additive to primary and secondary treatment. Activiated carbon adsorption is effective in removing soluble organics not removed in secondary treatment, and improving the taste, odor, and color of treated waste water. Other tertiary treatment processes include ion exchange, reverse osmosis, and evaporation.

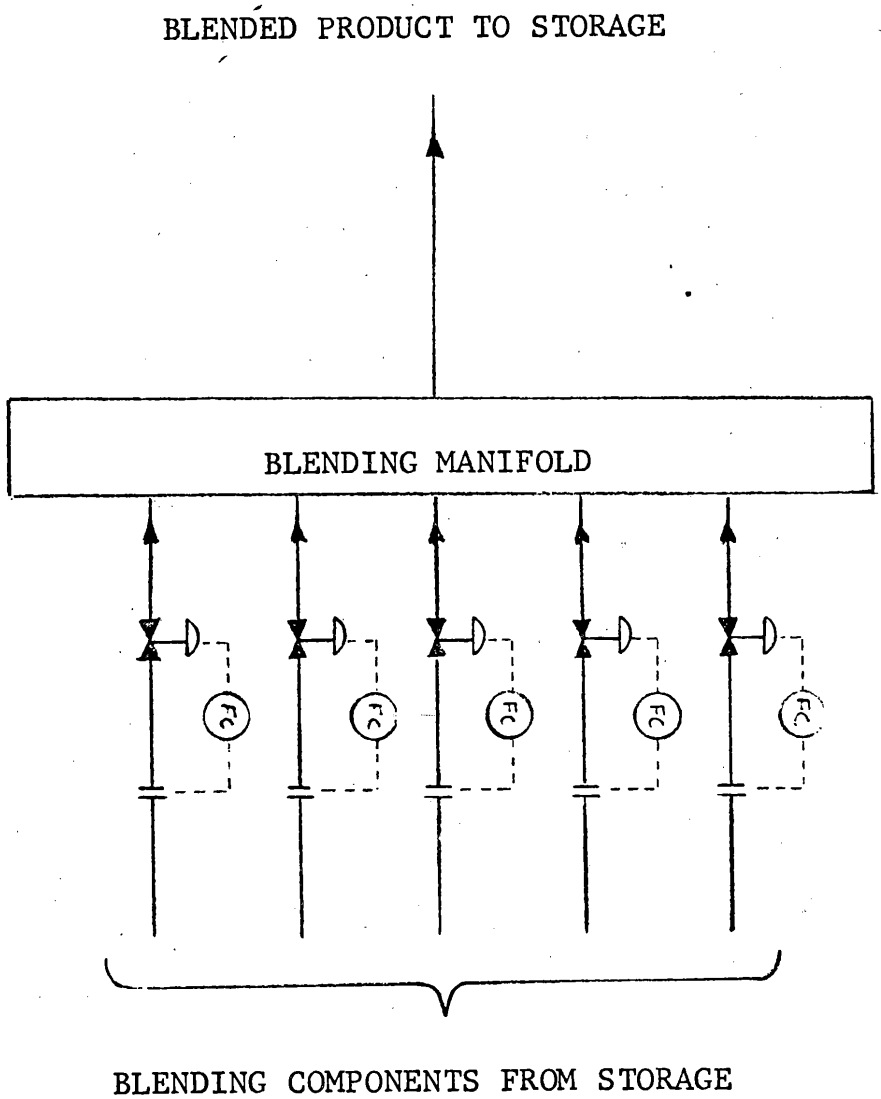
6) Blending

The most common blending operation in petroleum refining involves the blending of gasoline components. Components such as cat gasoline, reformate, alkylate, isomerate, butane, lead, etc. are mixed in a specific proprotion to meet gasoline specifications. Blending is conducted in a mixing manifold diagrammed in Figure 13.

7) Miscellaneous Unit

Within a refinery, there are numerous process heaters or furnaces, boilers, and compressors. These units are powered by several fuels including natural gas, fuel oil, refinery gas, and refinery feeds (residual, distillate, naphtha, etc.).

Figure 13 (Ref. 2)
Typical Refinery Blending Operation



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A blowdown recovery system is also a crucial functional unit of a petroleum refinery. This system is designed to permit safe disposal of excess gases and liquids in case operational difficulties occur.

C. Emission Sources and Factors

1) Air Pollutant Sources

The air emissions from a petroleum refinery can be broken down into five major categories: crude distillation, converting, treating, blending and miscellaneous. These various emission sources in each category will be briefly discussed in the following sub-sections.

a. Distillation:

The main source of emissions from crude oil distillation is the barometric condenser on the vacuum distillation column. The condenser, while maintaining a vacuum on the tower, often allows non-condensable light hydrocarbons and H_2S to pass through to the atmosphere. Vapor recovery systems reduce these emissions to negligible amounts.

b. Converting:

1) Catalytic Cracking

Air emissions from the cracking unit regenerators consist of particulates (coke and catalyst fines), hydrocarbons, sulfur oxides, carbon monoxide, adehydes, ammonia, and nitrogen oxides in the combustion gases. Control systems commonly used on regenerators consist of cyclones and electrostatic precipitators to remove particulates and energy-recovery combustors to reduce carbon monoxide emissions.

2) Hydrocracking

Waste gas from the hydrocracker containes large amounts of H_2S, which can be processed for the removal of sulfur which occurs at the sulfur recovery plant.

3) Catalytic Reforming

There are approximately no emissions from reforming processes.

4) Alkylation and Isomerization

These processes, including regeneration of any catalysts, form essentially closed systems and have no unique, major source of atmospheric emissions.

c. Treating:

1) Hydrotreating

The hydrogen sulfide produced in a hydrotreating unit is removed from the hydrogen stream via extraction and converted to elemental sulfur or sulfuric acid. When present in small quantities, the H_2S is burned to SO_2 in a flare or boiler firebox. Another potential source of emissions is from catalyst regeneration. Regeneration gases consist of catalyst fines, oil mists, hydrocarbons, ammonia, sulfur, chlorides, cyanides, nitrogen oxides, and carbon monoxide. These emissions are not of significant quantity since catalysts need only be regenerated twice a year.

2) Sweetening Process

Emissions from the sweetening process are not significant However, malodorous substances such as mercaptains may escape from the process. A more detailed discussion of emissions from a gas sweetening process is contained in Chapter III: Natural Gas Processing - Emission Sources

3) Sulfur Plant

The sulfur plant will usually consist of a Claus unit plus some type of Claus tail-gas control unit for sulfur recovery. Emissions from the treatment process is primarily SO_2. Pollutant concentrations depend primarily on the sulfur removal efficiency of the treatment processes applied. A more detailed discussion of the emissions from sulfur recovery plants is included in Chapter III: Natural Gas Processing - Emission Sources.

d. Blending

Emissions associated with this operation are hydrocarbons that leak from storage vessels, values, and pumps. Vapor recovery systems and specialized designed storage tanks minimize these emissions.

e. Miscellaneous Operations

1) Process Heater, Boilers and Compressor

A process heater, boiler or compressor is probably involved with most every major processing unit in a refinery. Emissions

depend on fuel type, fuel sulfur content, size or equipment, method of firing, crude charge rate, and maintenance. The primary air pollutants emitted from process heaters are CO, NO_x, hydrocarbons, SO_2 and particulates. Air emissions from the boilers may be controlled through combustion techniques ie low excess air firing, water or steam injection, two-stage combustion, and discriminate fuel selection ie low sulfur fuel.

2) Miscellaneous Hydrocarbon Emissions

Many refinery processes emit minimal amounts of hydrocarbons by may be considered as one large major source of hydrocarbons. Among these processes are included cooling tower, vacuum jet-vapor recovery, blowdown, and air blowing units. There are also miscellaneous hydrocarbon leaks from points such as pump seals, valve stems, and flanges due to high temperature and pressure used in processing unit. The best method for controlling these emissions is the effective repair, maintenance, and replacement of pump seals, valve caulking, and pipe-joint sealer. However, maintenance and replacement of parts usually constitutes an economic more than an environmental control question.

2) Air Pollutant Emission Factors

Table 1 summarizes the air pollutant emission factors for a typical petroleum refinery. The table lists individual pollutant sources and in certain cases, recommended control devices (12, 18).

Table 1. EMISSION FACTORS FOR PETROLEUM REFINERIES

Type of process	Particulates	Sulfur oxides (SO_2)	Carbon monoxide	Hydro-carbons	Nitrogen oxides (NO_2)	Alde-hydes	Ammonia
Boilers and process heaters[a] lb/10^3 bbl oil burned	800	8400s[a]	2	140	2,900	25	Neg
lb/10^3 ft^3 gas burned	0.02	2s[d]	Neg[b]	0.03	0.23	0.003	Neg
Fluid catalytic cracking units Uncontrolled lb/10^3 bbl fresh feed	242 (93 to 340)[oc]	493 (313to525)	13,700	220	71.0 (37.1to145.0)	19	54
Electrostatic pre-cipatator and CO boiler lb/10^3 bbl fresh feed	44.7 (12.5 to 61.0)	493 (313 to 525)	Neg	220	71.0 (37.1to145.0)	19	54
Fluid coking units Uncontrolled lb/10^3 bbl fresh feed	523	NA[e]	Neg	Neg	Neg	Neg	Neg
Electrostatic pre-cipatator lb/10^3 bbl fresh feed	6.85	NA	Neg	Neg	Neg	Neg	Neg
Compressor internal combustion engines lb/$10^3 ft^3$ gas burned	Neg	2s	Neg	1.2	0.9	0.1	0.2

TABLE 1: EMISSION FACTORS FOR PETROLEUM REFINERIES

Miscellaneous	Sulfur Oxides (SO_2)	Carbon Monoxide (CO)	Hydro Carbons	Nitrogen Oxides (NO_2)	Alde-Hydes	Ammonia	Particulates
Vapor Recovery System or flaring lb/10^3bbl refinery	Neg	Neg	5	Neg	Neg	Neg	Neg
Cooling Towers lb/10^6gal cooling water	Neg	Neg	6	Neg	Neg	Neg	Neg
Pipeline valves, flanges, vessel relief valves, pump-seals, blowdown system, drains compression seals, air blowing, sampling, lb/10^3bbl crude	Neg	Neg	150	Neg	Neg	Neg	Neg
Catalyst Regeneration lb/10^3bbl charge	500	13700	220	63	Neg	Neg	With precipitation 61
Barometric Condensers lb/1000lb charge to vacuum distillation tower	Neg	Neg	130	Neg	Neg	Neg	Neg

a. S= Fuel oil sulfur content; factors based on 100 percent combustion of sulfur to SO_2 and assumed density of 336 lb/bbl.

b. negligible emission.

c. numbers in parenthesis indicate range or values observed.

d. S= refinery gas sulfur content (lb/100ft^3); factors based on 100 percent combustion of sulfur to SO_2

e. not available

3) Water Pollutant Sources

The significant waste water constituents of a pretroleum refinery are Biological Oxygen Demand (BOD), Total Organic Carbon (TOC), total suspended solids, oil and grease, phenolic compounds, ammonia (Nitrogen), sulfides, and heavy metals (chronium and zinc). The major pollutants and their sources are discussed below under selected refinery pollution parameters.

a. Oxygen Demand Parameters (BOD)

Waste waters from petroleum refineries exert a significant and sometimes major oxygen demand. The primary sources are soluble biodegradable hydrocarbons and inorganic sulfur compounds. Crude distillation, catalytic cracking, and product finishing operations are the major contributors of BOD. In addition, the combination of small losses that occur throughout a refinery complex can produce principal BOD pollution.

b. Total Suspended Solid (TSS)

In refineries, the major sources of suspended matter are crude storage, alkylation , crude desalting and finishing operations. Quenching and removal operations in the production of coke can also contribute significant amounts of suspended matter to the refinery effluent.

c. Oil and Grease

In the petroleum industry, oily water streams can result from refinery process facilities, including desalter blowdown, cooling tower blowdown, sour water strippers, pump and compressor bases, and miscellaneous drains.

d. Ammonia

Ammonia is commonly found in overhead condensates from distillation, and results from cracking and desalting processes.

e. Phenolic Compounds

Catalytic cracking, crude distillation, and product finishing and treating are the major sources of phenolic compounds. Solvent refining processes use phenol as a solvent and although it is salvaged by recovery processes, losses result.

f. Sulfides

In the petroleum industry, major sources of sulfide wastes are crude desalting, crude distillation and cracking processes. Sulfides appear in the sour condensate waters of these processes. Hydrotreating processes can be used to remove sulfides in the feed stock. Most recovered sulfide is processed to produce sulfuric acid or elemental sulfur.

g. Chromium and Zinc

Chromium can be used as a catalyst in refining processes, and chromate compounds are frequently added to cooling water for corosion control. Zinc compounds are also used as corosion inhibitors for cooling water. In addition, zinc is produced in the combustion of fossil fuels and may find its way into refinining waters by leaching processes.

h. Miscellaneous Pollutants

Other pollutants which can be found in refinery waste waters are: total dissolved solids , cyanide, PH, heat, various metallic ions, chloride, flouride and phosphate. Dissolved solids in refinery waste waters consist mainly of carbonates, chlorides, and sulfates. The dissolved solid concentration in the waste effluent depends on process recycle and the quality of the process raw water. Most refinery waste waters are alkaline due to the presence of ammonia and the use of caustic for sulfur removal. Cracking (thermal and catalytic) and crude distillation are the principal sources of alkaline discharges. Alkylation and polymerization utilize acids as catalysts and produce acidity wastes. Crude desalting, distillation, and cracking units contribute substantial thermal waste loads. This effluent must be treated ie cooling tower before being released to the environment. Metallic ions found in refinery effluents are usually from the crude itself and corosion products. Copper chloride may be used in a sweetening process and aluminum chloride in catalytic isomerization. These products may also find their way into waste streams. Alkaline units, when hydrofluoric acid is used, can contribute flouride ion to the waste chemicals and contained in the cooling systems.

4) Water Effluent Composition

It is assumed that (1) the petroleum refinery waste waters will vary in quantity and quality and will be treated by different waste water treatment processes to reach an acceptable effluent [1/] and (2) waste waters from the various sources will not require the same degree of treatment and will be segregated in a multiple sewer system to the appropriate handling and treatment facility before being released to a receiving stream. These assumptions

1/ as designated by Federal and State statutes and regulations for petroleum refinery effluent.

are viable with current petroleum refinery waste water treatment technology as stated in the Chevron Oil, Mobil Oil, Shell Oil and Radian Corporation petroleum refinery environmental impact statements (13, 14, 15, 2).

Table 2 lists the concentration range of pollutants in raw refinery waste water and the concentration of the same pollutants in raw municipal waste water (17). The pollutant concentrations are typical of a high cracking petroleum plant where greater than 50 percent of the fresh feed is cracked or hydro processed. The concentration range of pollutants in raw waste water depends on the product mix, the processes involved, and the operating capacity of the refinery. Noteworthy, as the complexity of refinery operations increase ie lube, petrochemical production, the pollutant concentrations in the raw waste water will increase. It is also assumed that the waste water treatment plant will be the major treatment facility at the refinery and all major waste water streams will be processed at the treatment plant before entering the environment ie receiving stream.

TABLE 2: TYPICAL CONCENTRATIONS OF SELECTED POLLUTANTS IN A HIGH CRACKING PETROLEUM REFINERY AND MUNICIPAL RAW WASTE WATER (17)

Waste Water Parameter	Refinery Raw Waste Water Load - mg/l	Municipal Raw Waste Water Load - mg/l
BOD	100 - 600	100 - 300
COD	150 - 400	200 - 400
TOC	50 - 500	50 - 250
Total Suspended Solids	20 - 100	100 - 300
Oil and Grease 1/	30 - 300	Variable 2/
Ammonia as Nitrogen	2 - 200	Variable
Phenolic Compounds	0 - 100	Variable
Sulfides	0 - 20	Variable
Total Chromium	0.02 to 0.26 3/	0.05 4/
Zinc	0.04 to 1.84 3/	0.1 to 1.0 5/
Total Disolved Solids	400 - 700 3/	1000 6/
Cyanides	0.0 to 0.18	0.01 4/
Chlorides	57 - 712 3/	Variable
Total Phosphate	0.096 to 9.49 3/	Variable

1. Freon Extractables as Oil and Grease
2. Concentration dependent on water source
3. Concentration in refinery effluent
4. USPHS Drinking Water Standard (in 1962 for Total Chromium)
5. Toxicity to fish
6. Domestic water supply level that will not interefere with beneficial use

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2. Final Report: A Program to Investigate Various Factors in Refinery Siting, Radian Corporation Contract Number 100-029, submitted to the Council on Environmental Quality and Environmental Protection Agency. 15 February, 1974.

3. Gary, James H. and Handwerk, Glenn E., Petroleum Refining-Technology and Economics, Marcel Dekker, Inc., N.Y., 1975.

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14. Environmental Report on the Proposed Moderization of the Paulsboro Refinery, submitted by Mobil Oil Corporation to the State of New Jersey, Department of Environmental Protection, April 1974.

15. Shell Oil Company Proposed Refinery Environmental Impact Statement for Logan Township, New Jersey, submitted to the State of New Jersey, Department of Environmental Protection, 1973.

16. Reference 2, pg 111.

17. Reference 10.

18. Environmental Impact Assessment Guidelines for Selected New Source Industries, U.S. Environmental Protection Agency, Washington, D. C., October 1975.

SECTION II

OIL STORAGE FACILITIES

The tank farm is part of an integrated system for the receipt, intramural movement, temporary storage, blending, and shipment of petroleum raw materials, petroleum products, and other substances. Generally, the tank farm will encomPass three general areas where 75 to 90 steel storage tanks (Reference 4) will be clustered. Tanks in one section will be designed to receive crude oil from ships or pipeline and recovered oil from refinery water treatment systems. These tanks are designed for surge capacity i.e., extra storage for liquids or gases that may accumulate during a refinery shut-down or the like. In another section, tanks will be provided to store intermediate refinery products. Tanks in the third section will be used to accumulate, hold, and blend finished products. Other tanks, some of which will be grouped in the farm, will store gasoline blending components, chemicals for process operations, water-treatment chemicals, and ballast water.

The tank farm for a refinery complex may be located inside or outside the refinery paramter. The storage vessels contained in a tank farm may be characterized as closed-storage or open storage tanks. Fixed-roof tanks, pressure tanks, floating-roof tanks and conservation tanks are examples of closed-storage vessels, while ope tanks, reservoirs, pits and ponds are considered open-storage facilities.

A. Storage Vessels

1. Pressure Tanks and Fixed-Roof Tanks

Pressure tanks are specific examples of fixed-roof tanks that are designed to operate at greater than atmospheric pressure. Pressure tanks can be spheric, plain and noded spheroids, and noded hemispheroids in shape as seen in Figure 1. Maximum capacities of these pressure tanks are as much as 30,000 barrels and can be operated up to 217 psi (Reference 1).

The fixed-roof storage tank at approximately atmospheric pressure, may have a flat, recessed flat, conical or domed roof. Some of these tanks have free vents open to the atmosphere or conservative vents that open at very slight positive pressures. Other tanks may have gauging hatches, sample hatches, relief vents, or foam mixers that may operate improperly and result in vapor leaks. A vertical, cylindrical, fixed-roof tank is pictured in Figures 2 and 3.

2. Floating-Roof Tanks

Floating-roof tanks are used to store volatile materials with vapor pressures in the lower explosive range. They are also used to store volatile materials that do not boil at atmospheric pressures or less, or at storage temperatures or below. The floating roof may be subdivided into three types: pan, pontoon, or double-deck floating-roof tanks, and are illustrated in Figure 4.

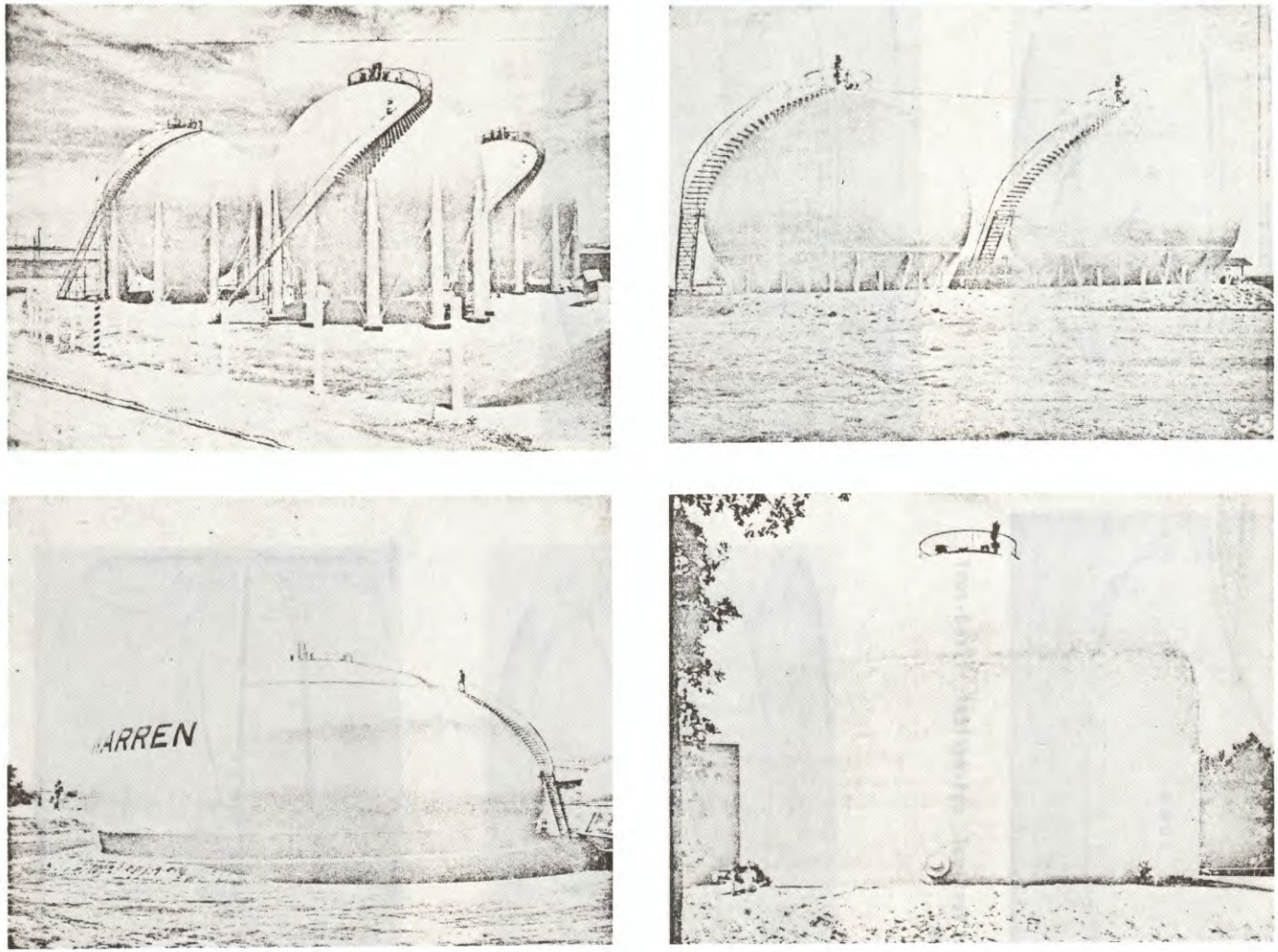

Figure 1(1): Types of pressure vessels: (upper left) 51-foot-diameter spheres (Butane is stored in these spheres at a petroleum refinery in California. Capacity of each is 15,000 barrels, diameter is 54 feet 9 inches and design working pressure is 35 pounds per square inch.); (upper right) two 5,000-barrel spheroids designed for 20-psi pressure; (lower left) large noded spheroids, each designed for 100,000-barrel capacity and 15-psi pressure; (lower right) a 20,000-barrel noded hemispheroid designed for 2-1/2-psi pressure (Chicago Bridge and Iron Company (1959).

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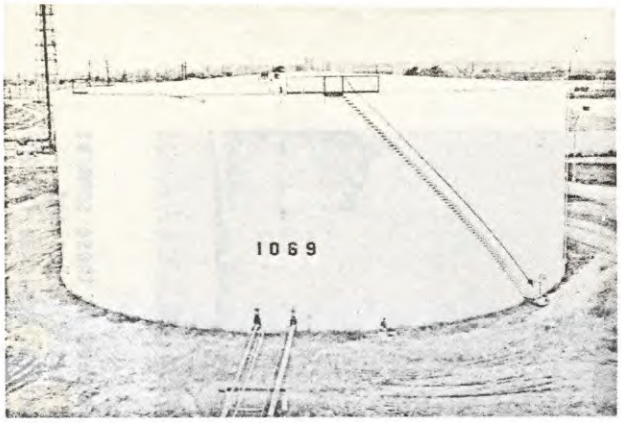
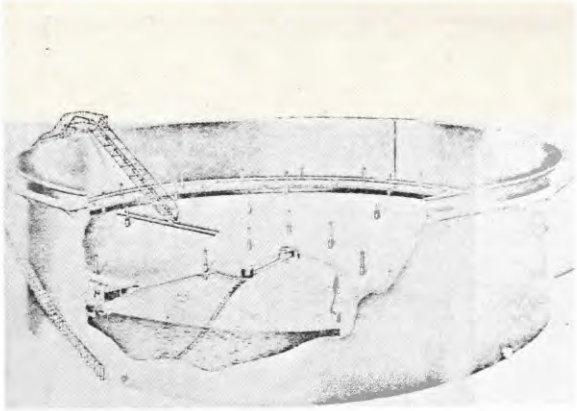
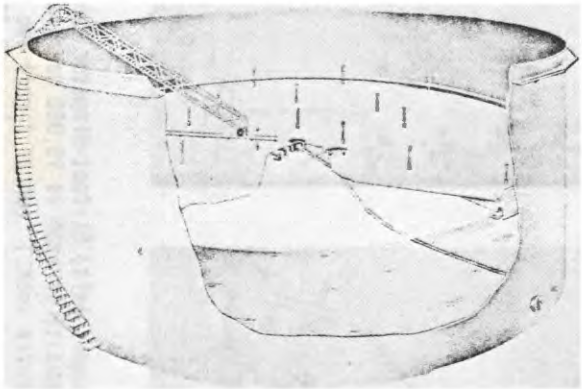
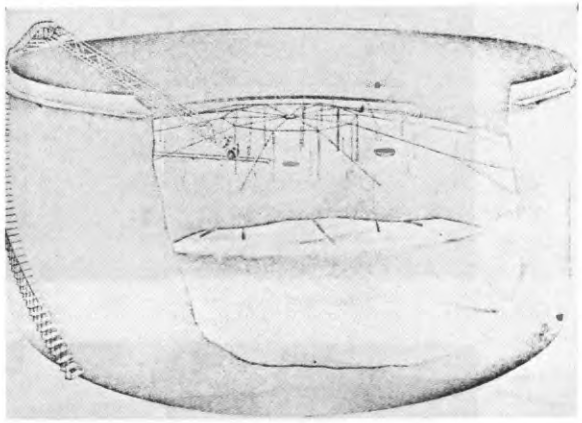


Figure 2(1): Vertical, cylindrical, fixed-roof storage tank.







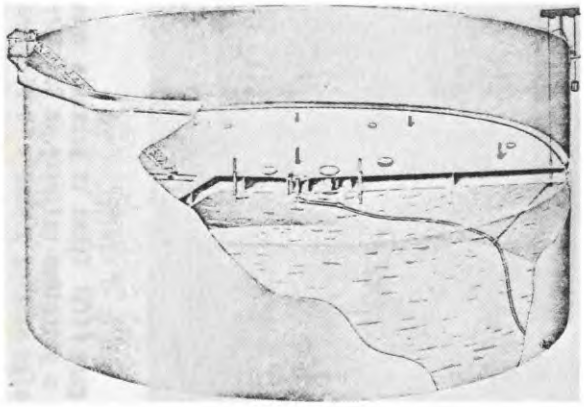


Figure 4(1): Types of floating-roof tanks: (upper left) Sectional view of single-deck, center-weighted (pan-type) floating roof; (upper right) sectional view of pontoon deck floating roof; (lower left) cutaway view of double-deck floating roof; (lower right) cutaway view of trussed-pan floating roof (Graver Tank and Manufacturing Company, East Chicago, Ind.).

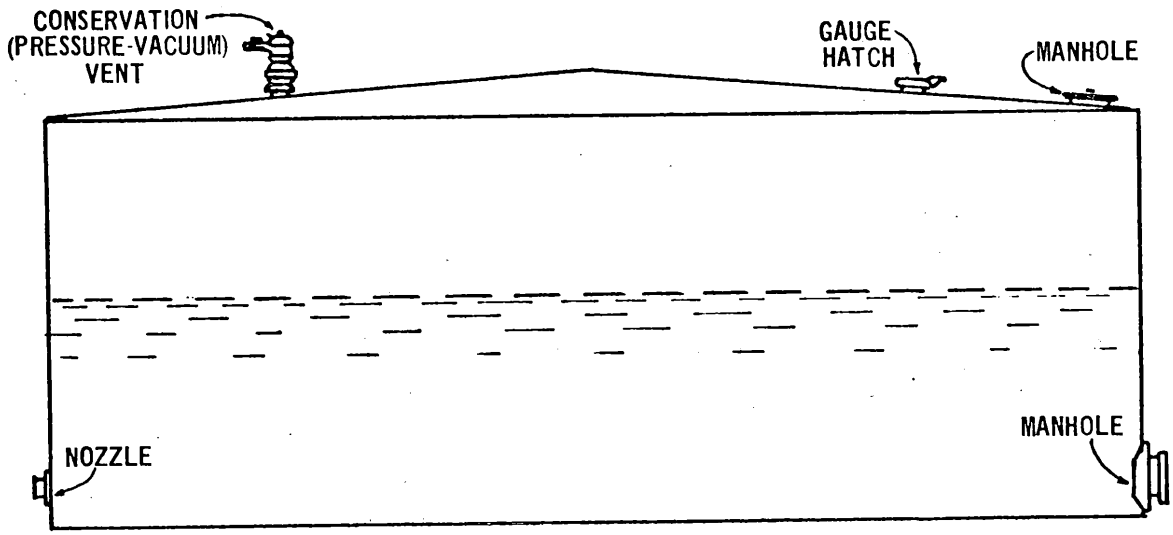


Figure 3(5): Fixed-roof storage vessel

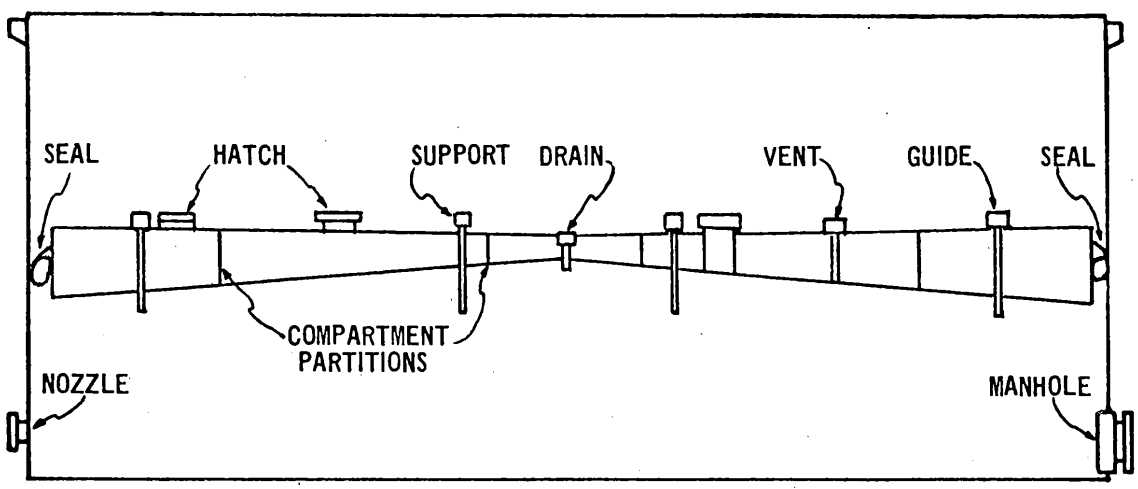


Figure 5(5): Double-deck floating-roof storage vessel.

Pan-type floating-roof tanks are seldom used on new tanks because their use results in high vaporization losses. Solar radiation causing the heating of the metal pan-type roof which is in contact with the liquid surface, results in greater than average liquid surface temperatures. Hydrocarbons vaporize more rapidly at the higher temperatures and escape from the opening around the roof's periphery. Center-weighted pontoons, double pontoons, and high- and low-deck pontoon floating-roof tanks with some type of vapor trap or dam, tends to retard hydrocarbon vapor loss due to boiling.

The double-deck floating-roof (Figure 5) was eventually developed to reduce the effect of solar boiling while gaining roof rigidity. The top deck is sloped toward the center of the tank with a compartmental dead air space of more than twelve inches thick over the entire liquid surface (Reference 1). Roof traps are also installed to capture any vapors entrained with incoming liquid or any vapors that might form in storage.

3. Conservation Tanks

Lifter-roof tanks (Figure 6) are considered to be one type of conservation tank. The lifter roof is used for low-pressure gaseous products and low-volatility liquids. One type of lifter-roof tank has a dry seal consisting of a gastight, flexible fabric; another type employs a liquid seal. The sealing liquid can be fuel oil, kerosene, or water. The physical weight of the roof, itself floating on vapor, maintains a slight positive pressure in the lifter-roof tank. When the roof has reached its maximum height, the vapor is vented to prevent over-pressure and damage to the tank.

Fixed-roof tanks with an internal, flexible diaphragm or internal, plastic, floating blanket are also classified as conservation tanks. (Figure 7 and 8). The diaphragm is flexible and rises or falls to balance changes in vapor volume. Two basic types of diaphragm

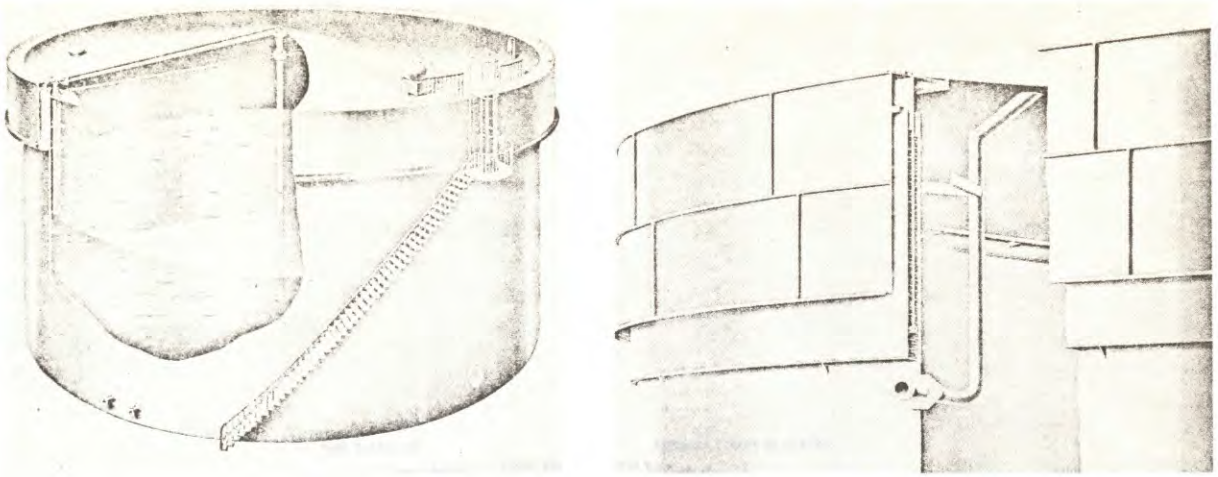


Figure 6(IV): Types of lifter-roof tanks: (left) Sectional view of expansion roof tank with a liquid seal, (right) closeup view of liquid seal and vapor piping (Graver Tank and Manufacturing Co., Division of Union Tank Car Co., East Chicago, Indiana).

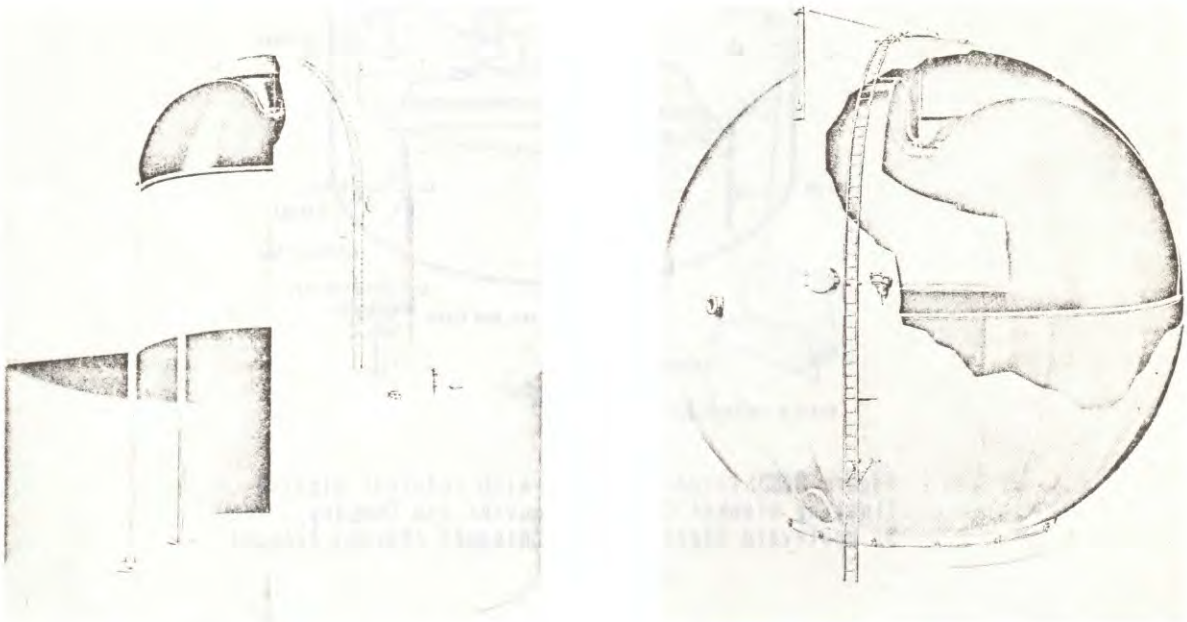


Figure 7(I): Conservation tanks; (left) Sectional view of integrated conservation tank with internal, flexible diaphragm; (right) cutaway view of a vapor conservation tank showing flexible membrane (Chicago Bridge and Iron Co., Chicago, Ill.).

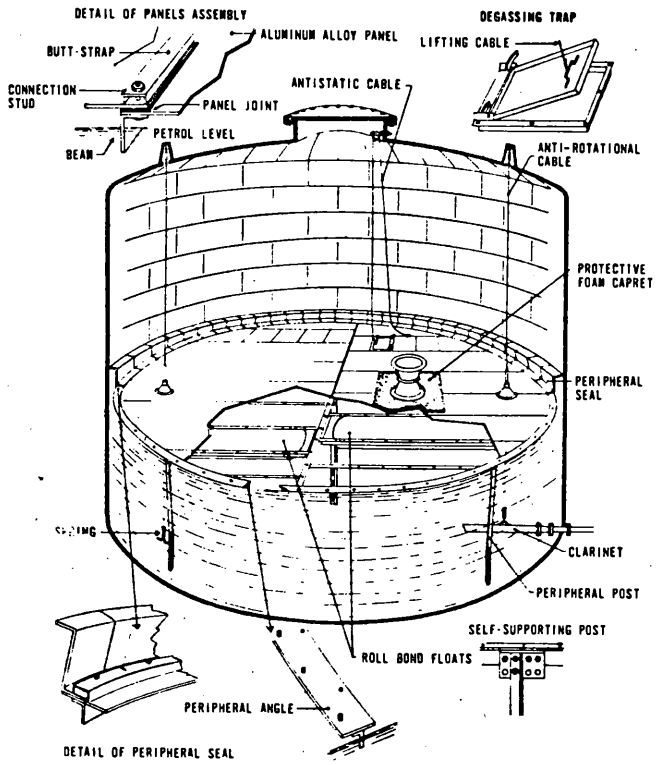


Figure 8(5): Fixed-roof tank with internal plastic floating blanket (Laroche Bouvier and Company, 5. Boulevard Edgar-Quinet, Colombes (Seine), France).

tanks are the integrated tank, which stores both liquid and vapor, and the separate tank, which stores only vapor.

4. Open-Top Tanks, Reservoirs, Pits, and Ponds

Safety, conservation, controlled crude production, and house keeping are factors that have virtually effected an elimination of open-storage facilities. Open tanks that require full access are usually equipped with removable covers. Reservoirs devised to store large quantities of residual oils, fuel oils, and crude oil are in minimal use today. Open pits used to hold waste products, refinery effluent water, or inexpensive oil products have diminished, and the remaining ponds are usually reserved for emergency use. Ponds used for crude oil storage have, for the most part, disappeared because of the nuisance problems they create.

B. Emission Source

The types of air pollution that are emitted from storage vessels are aerosols, odors, and vapors. By far, the most significant of these pollutants in quantity and concentration are hydrocarbon vapors (Reference 1).

Several sources of hydrocarbon losses for petroleum storage have been established and are described below.

1. Breathing Loss

Vapor expelled from the tank because of thermal expansion of existing vapors, expansion caused by barometric pressure changes, and/or increase in the amount of vapor from added vaporization in the absence of a liquid level change can be regarded as breathing loss.

2. Standing Storage Loss

Vapor emissions resulting from other causes than breathing or changes in liquid level are defined as standing storage loss.

Wind is a factor to this source of loss. Other sources from which vapor may escape are gauging hatches, vents, fittings, seals, or other openings.

3. Filling Loss

Vapor expelled from a tank as the result of filling, irrespective of the exact mechanism by which the vapors are produced is known as filling loss.

4. Emptying Loss

Vapor emitted from a storage tank after the contained liquid is removed is called emptying loss.

5. Wetting Loss

Vaporization of liquid from a wetted tank wall, exposed when a floating-roof is lowered by drainage of liquid, is defined as wetted loss.

6. Boiling Loss

Vapor expelled from a storage tank as a result of boiling of the liquid is boiling loss.

Aerosol emissions from storage vessels can also cause an air pollution problem. For example, the storage of heated asphalt produces an aerosol-type emission. Whenever steam or air is added to a vessel for mixing, heating, oxidizing, or brightening, aerosols or mists may result. The discharges involve product loss and possible odors.

Odor detection is closely related to evaporation and filling operations associated with petroleum storage tanks. The highly malodorous compounds usually contain sulfur or nitrogen. Agitation, especially by air or steam, will increase the release of odors to the atmosphere.

This analysis considers water pollution caused by petroleum storage vessels to be minimal but noteworthy. If a tank farm site is above a groundwater stream, potential adverse impact on the soil and groundwater exists. Leakage from storage tanks could allow water to percolate into and through the soil to the water table. The oil could flow along the water table and naturally discharge into the surrounding wetlands.

C. Emission Factors

The rate of hydrocarbon emission from a petroleum storage tank is dependent on the volatility of the stored material and the physical actions upon it. Changes in heat or pressure of the storage material changes its rate of evaporation. Physical factors that affect the rate of hydrocarbon evaporation include: tank shell temperature and outage, vapor space temperature, liquid body and surface temperatures, ambient weather conditions, tank condition and diameter, filling operations, and vapor tightness of the vessel.

The vapor emissions from stored materials are minimized by the selection of a storage tank on the basis of the volatility and temperature of the liquid hydrocarbon. Fixed-roof tanks are generally used for the storage of materials having a vapor pressure of 1.5 psia or less at 80°F i.e., less volatile distillate fuel oils, kerosenes, heavy catalytic cracked haphthas, and heavy crude and residual oils (References 1, 5). Hydrocarbon emissions from fixed-roof tanks containing low volatility hydrocarbons are minimal. However, when fixed-roof tanks contain high volatility materials, they are the minimum accepted standard due to breathing, filling, and emptying losses.

Materials with the intermediate vapor pressures of 1.5 to 11 psia at 80°F i.e., jet fuels, volatile crude oils, gasoline components and finished gasoline should be kept in floating-roof storage tanks (Reference 1, 5). The roof of this tank floats on the stored liquid which virtually eliminates vapor space. Some venting may occur around the flexible gaskets that seal the roof to the tank wall, but overall emissions from this type tank are low.

Conservative tanks reduce hydrocarbon emissions from tank breathing and are widely acceptable when tank throughput is low. Substances that have a vapor pressure greater than 11 psia at 80°F i.e., certain winter-grade northern gasolines and volatile gasoline-blending components are stored as saturated liquids in floating-roof tanks (Reference 1, 5). Pressure tanks withstand relatively large pressure variations without emitting hydrocarbons and experience little or no hydrocarbon emissions.

D. Air Pollution Control Equipment

Control of emissions resulting from storage vessels produce many benefits. Among these are elimination or reduction of air contaminants, elimination or reduction of fire hazards, and economic savings through product recovery. Methods of control include floating-roofs, floating plastic blankets or plastic microsphere which are similar in principle to floating-roofs, variable vapor recovery systems, and altered pumping and storage operations.

Vapor recovery systems collect vapor from storage tanks and send it to a gas recovery plant. For example, gasoline components and finished gasoline have vapor pressures in the range of 1.5 to 11 psia. These substances normally would be stored in a floating-roof tank. However, since these materials are a potential source of reactive hydrocarbon, they may be stored in a fixed-roof tank equipped with a vapor recovery system. This system, when connected to a gas plant, will prevent hydrocarbon emissions (Reference 1).

Calculation procedures can be used to estimate emissions from petroleum storage tanks. Extensive correlation of formulas and factors are published and provide estimates of storage emissions. Extensive knowledge is required about the stored material and the storage vessel design. For rough estimation purposes, table 1 (Reference 3) gives rough emission factors for fixed- and floating-roof storage tanks.

Table 1. Hydrocarbon Emission Factors for the Storage of Petroleum Products in Fixed- and Floating-Roof Storage Tanks

Type of Tank[a/]	Units	Type of Material Stored	
		Gasoline or finished petroleum product	Crude oil
Fixed roof			
Breathing loss	lb/day-1000 gal storage capacity	0.4	0.3
Working loss[b/]	lb/1000 gal throughput	11	8
Floating roof			
Breathing loss	lb/day-tank	140(40 to 210)[c/]	100(30 to 160)[d/]
Working loss	lb/1000 gal throughput	Neg.	Neg.

a/ For tanks equipped with vapor-recovery systems, emissions are negligible.

b/ An annual average turnover rate for petroleum storage is approximately 6. Thus, the throughput is equal to 6 times the capacity.

c/ 140 based on average conditions and tank diameter of 100 ft; use 40 for smaller tanks, 50 ft diameter; use 210 for larger tanks, 150 ft diameter.

d/ Use 30 for smaller tanks, 50 ft diameter; use 160 for larger tanks, 150 ft diameter.

E. Environmental Impact

The air and water environmental impacts from a tank storage farm are described in Section IV - Environmental Impact.

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3. Final Report: A Program to Investigate Various Factors in Refinery Siting, Radian Corporation Contract Number 100-029, Submitted to the Council on Environmental Quality and Environmental Protection Agency, 15 February 1974.

4. Shell Oil Company Proposed Refinery Environmental Impact Statement for Logan Township, New Jersey, submitted to the State of New Jersey, Department of Environmental Protection, 1973.

5. Background Information for Proposed New Source Performance Standards: Petroleum Refineries, Volume 1, Main Text, Environmental Protection Agency, APTD-1352a, June 1973.

SECTION III

NATURAL GAS PROCESSING

Crude oil production is usually associated with the production of substantial quantities of natural gas. Production wells are categorized as gas or oil wells depending on the ratio of gas to oil produced by the well. For example, Texas law states a gas well to be a well that produces less than one barrel of crude oil to each 100,000 cubic feet of natural gas (Reference 1).

Natural gas may be classified as dry, wet, sweet or sour gas. Dry gas is defined as gas that contains no hydrocarbons heavier than methane or ethane. Wet gas contains hydrocarbons from methane through pentanes. Sweet gas is defined as gas which contains little or no hydrogen sulfide. Sour gas implies that the natural gas is contaminated with sulfur in excess of pipeline specifications mainly in the form of hydrogen sulfide and carbon dioxide. Approximately five percent of the U.S. natural gas production is sour (Reference 2). Refinery and manufactured gas streams may contain mercaptains (RSM), carbon disulfide (CS_2) and/or carbonyl sulfide (COS). These three compounds usually only appear in trace amounts in natural gas streams.

A. Processes Employed

The natural gas industry comprises several discrete activities including the drilling and completion of wells, separating and dehydrating the well-head gas, sweetening the gas, sulfur recovery, processing the gas into its constituent parts, and transmission of the refined gas in pipelines.

The natural gas well-head may be land or water-based. If the well-head is water-based, it is possible to pass the natural gas through separators before piping it to the shore. However, a platform support will need to be constructed for the processing equipment.

Figure 1 is a simplified diagram showing a typical natural gas processing facility. Gas from the well-head first goes through a separation and dehydration process. The sour gas is processed into sweet gas with sulfur as a by-product. The sweet gas is processed into several constituents including natural gas liquidified petroleum gas, and gas containing C_5 hydrocarbons or higher, which is usually further processed at a petroleum refinery.

Distinctions between small and large facilities are not very useful because the unit processes used in a particular facility depend more on natural gas composition than on plant size. For example, if the well-head natural gas is sour or wet, even the smallest facility will have to use a gas sweetening process or liquid recovery unit. Just the same, if the well-head natural gas if sweet or dry, even large facilities processing large quantities of gas do not need to use sweetening or liquid recovery units.

The primary processes for preparing natural gas for consumption are described below:

1. Gas Separation

Natural gas from gas wells pass through separators at the well-head to remove hydrocarbon condensates and water. Removal of liquid water and liquid hydrocarbons like condensate, gasoline, and oil, soon after the gas leaves the well head is essential in reducing restriction to flow through the piping system, and avoiding ice and hydrate formation within the system. Choice of operating conditions and management of separation units,

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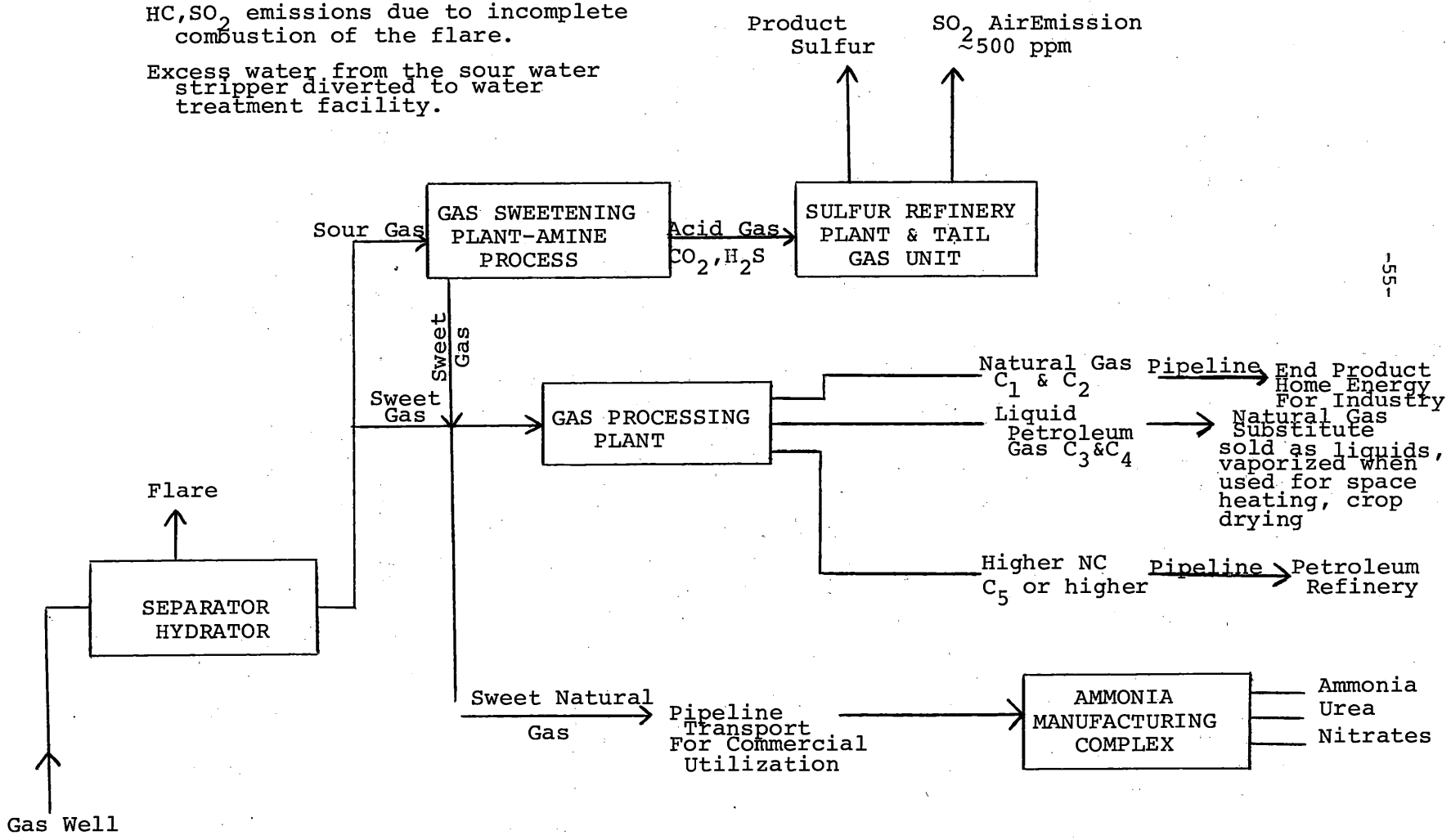
Figure 1: Flow Diagram of A Natural Gas Refinery

EMISSIONS:

Flare during well testing and completion: H_2O vapor, H_2S, CO_2 Mercaptans, carbon sulfide, carbonyl sulfide.

HC, SO_2 emissions due to incomplete combustion of the flare.

Excess water from the sour water stripper diverted to water treatment facility.



including consideration of the phase behavior in the fluid mixture and other secondary phenomenon is made on the basis of the gas-flow rate, well-head gas pressure and temperature, and changes or modifications in pre-separator stream-flow conditions. Secondary phenomenon to be considered include foaming, emulsification, solid corrosion products in the wellstream, drilling mud, and extreme parafin conditions.

2. Gas Dehydration

Principle reasons for dehydration of natural gas for long distance transmission include the prevention of:

a. freeze-ups due to ice and hydrate formation,
b. corosion, with subsequent dirt troubles,
c. condensation, and
d. reduced line capacity due to water or dust accumulations.

Dehydration is the best method of hydrate prevention in a natural gas pipeline. To be effective, water must be removed to the point where the dew point will not be reached at the lowest opeating temperature or maximum pressure of the system. Dehydration methods classified in order of preference are:

1) absorption by a triethylene glycol-water solution,
2) absorption by solid granular desiccants in a regressive process,
3) simple expansion-refrigeration method, and
4) expansion-refrigeration method combined with use of liquid disiccant (a triethylene glycol solution).

3. Sweetening Process

Factors to be considered when selecting a sweetening process include:

a. the types of impurities to be removed from the gas stream,

b. the concentration level of these impurities and the degree at removal desired,

c. the acid gas selectivity required,

d. the volume and temperature-pressure conditions of the process gas, and

e. the feasibility and desirability of sulfur recovery including economic factors.

Gas sweetening processes may be divided into the following major categories:

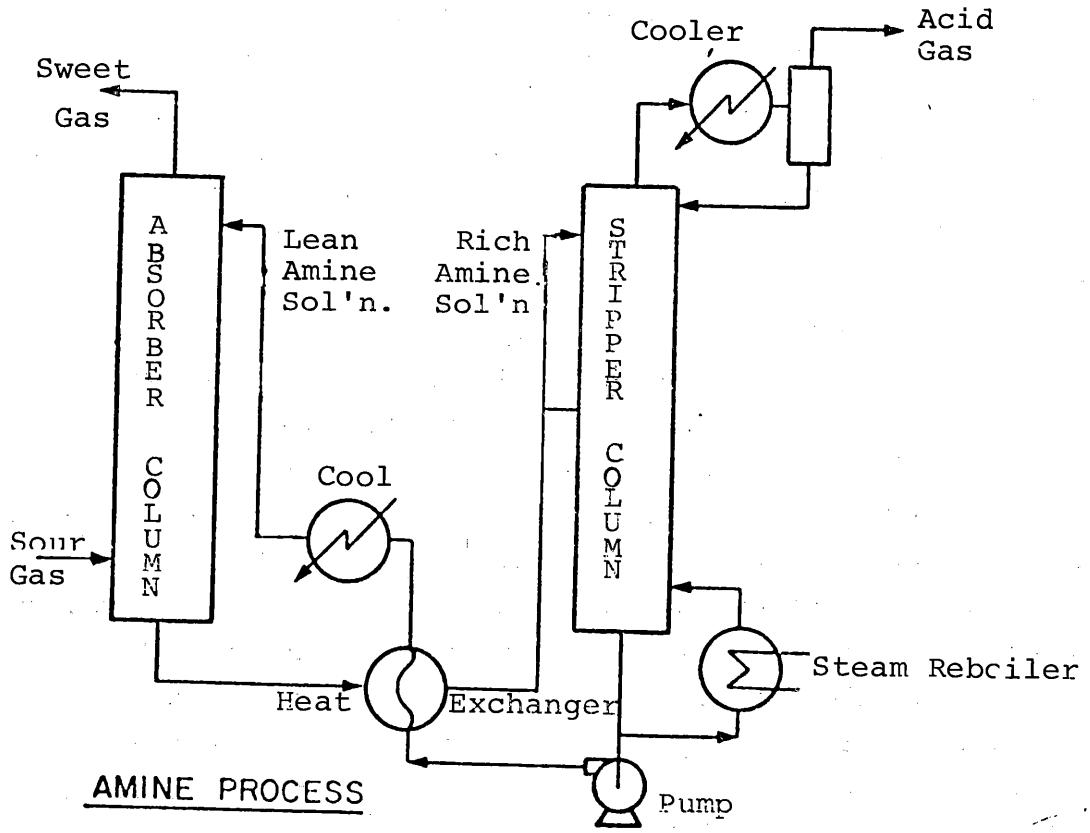
1) amine and amine-type processes,
2) carbonate and other chemical processes,
3) physical absorption techniques, and
4) solid bed sweetening processes.

However, the process most frequently used is the amine process to which this discussion will be limited (Reference 3).

The amine processes were developed to remove high concentrations of hydrogen sulfide (H_2S) in large volumes of gas at high pressures. The alkanolamines are the most generally accepted and widely used at the many available solvents for removal of H_2S and CO_2 from natural gas streams. The three alkanolamines generally used in amine washing are monoethanolamine, diethanolamine and triethanolamine. Essentially, the principle used is the chemical reaction of H_2S and CO_2 with amine.

Diagram 1 shows the general process flow diagram of an amine sweetening plant. The sour gas enters the plant through a scrubber to remove any free liquids and/or entrained solids. The sour gas enters the bottom of the absorber in counter-current contact with the aqueous amine solution. Sweetened gas leaves the top of the absorber and flows to a dehydration unit before being a commercial product. Lean amine solution from the bottom of the stipper column is pumped through a heat exchanger and water or air cooler before entering the top tray of the absorber column.

Diagram 1. Flow Sheet of Basic Amine Process (3)



Rich amine solution leave the bottom of the stripper column.

Amine treating processes tend to be troubled with the same operating difficulties regardless of the type amine used. These are: corrosion, solution degradation, and foaming.

4. Sulfur Recovery Plant

There are many processes available for production of sulfur from hydrogen sulfide. Some of these processes were designed to produce sulfur and others developed to remove H_2S from a gas stream with the production of sulfur as a by-product. The available procedures can be classified as (1) liquid absorption-oxidation processes, and (2) direct oxidation processes. The Claus process considered primarily in this discussion is of the latter type.

The Claus process it the most widely used sulfur production process in both the natural gas and petroleum industry. It used an acid gas rich stream from another sweetening process as input. A typical Claus plant consists of a thermal stage followed by two or three catalytic stages. Depending on the hydrogen sulfide concentration in the acid gas fed to the unit, the number of catalytic stages, and the quality of catalyst used, conversion efficiencies of up to 98 percent can be attained.

5. Tail Gas System

Tail gas scrubbing removes trace quantities of sulfur compounds from the Claus gas stream. There are a large number of processes available for additional sulfur removal from Claus tail gases. Tail gas processes are primarily installed to meet applicable suflur emission standards. The available tail gas processes can be broken up into these four approximate categories:

a. processes that are designed to complete the Claus reactions i.e, the Sulfreen Process, the Institut Frangais di Petrole (IFP) Process

b. processes that are designed to remove SO_2 rich gas stream for processing i.e. the Wellman-Lord Process

c. processes that convert all sulfur compounds to H_2S before conversion to elemental sulfur i.e. the Beavon Process, the Shell Claus Off-gas Treating (SCOT) Process.

d. processes which remove SO_2 by production of a solid (sulfate) i.e. the NiHetu Process.

The addition of a tail gas conditioning unit can increase the overall efficiency of a sulfur recovery system upwards toward 99.9%.

6. Gas Processing Plant

Natural gas is processed to recover components heavier than methane. Depending upon the constituents and the percentage recovery desired, the following three techniques are used:

a. Absorption in liquids.

This is the most common process used for gasoline removal. The absorber is usually a lean oil which removes the desired hydrocarbons from the natural gas stream. The efficiency of this process increases when absorption is combined with refrigeration.

b. Adsorption on a solid

The natural gas is sent through an adsorption tower of silica gel or activated charcoal where water and and heavy hydrocarbons are retained. This process is economic for lean gases on small volumes.

c. Refrigeration

After dehydration, the natural gas stream is directed into a eryogenic processing unit, where its temperature is progressively

lowered. The subsequent effect is all desired hydrocarbons heavier than methane may be condensed out and recovered.

Products produced from a natural gas processing plant include:

1) natural gas-methane and ethane
2) liquified petroleum gas (LPG) propane and butane
3) higher hydrocarbons - five or more carbon atoms which are usually piped to a petroleum refinery for further processing.

B. Emission Sources

Separators and dehydrators have approximately no emissions to the atmosphere as their operation is only concerned with the physical composition of the gas stream from the well, and all operations are in a closed system. In cases of emergencies, venting or flaring of the gas may occur.

Gas processing itself has approximately no emissions to the atmosphere because the processes involved occur in a closed system. The processes involv. changing the physical properties of natural gas and any emissions to the atmosphere are essentially a loss of product. Emergencies can cause venting of the gas to the atmosphere but this is unusual.

Emissions from a gas sweetening process are minimal. However, processing of the acid gas from the sweetening unit does result in the emission of sulfur dioxide. The emission rate of sulfur dioxide from the sulfur recovery units is dependent upon the specific control method used and the incoming hydrogen sulfur concentration in the acid gas stream. Table 1 (Reference 4) lists emissions from a two and three stage Claus Sulfur Plant The efficiency of the Sulfur Plant can be increased to a removal efficiency of 99.9 per cent when a tail gas unit is added to the Claus plant as depicted in the table. Overall, the concentration of sulfur dioxide in the gaseious emissions from the sulfur plant will be reduced from a potential of approximately 10,000 ppm to approximately 500 ppm or less (Reference 5).

Table 1. EMISSION FACTORS FOR CLAUS SULFUR PLANTS

Number of catalytic stages	Recovery of sulfur, %	SO_2 emissions[a] lb/ton 100% sulfur
Twc	92 to 95	211 to 348
Three	95 to 96	167 to 211
3 Stage & Tail-gas process	99.9	4.0

[a]The range in emission factors corresponds to the range in the percentage recovery of sulfur.

When incomplete combustion occurs in gas flares, minor emissions of hydrocarbons and particulates may result. Compressor engines used in the gas distribution system as also emission sources. The engines either burn natural gas or refinery gas. Emissions from heavy-duty, gaseous-fueled internal combustion engines are reported in Table 2 (Reference 4). Sulfur oxide emissions are dependent on fuel sulfur content whereas nitrogen oxide emissions are dependent on engine work output.

The emission of pollutants that may have a deterious effect on a receiving stream are not significant in a natural gas treatment facility. The one concern may be with the sour water stripper. The steam from this unit is treated to remove 99 percent of the contained hydrogen sulfide and more than 90 percent of the ammonia from the feed. The stripped water is then recycled to the process units and any excess if diverted to the waste water treatment facility.

C. Environmental Impact

The environmental air and water impact from a natural gas processing plant is minimal. The major air emissions would result from the sulfur recovery plant. Other emissions from flares and compressor engines can be considered not significant. Assuming that the sulfur recovery plant will have a start gas treatment unit along with a 2 or 3 stage Clause unit, the SO_2 emissions from the sulfur recovery unit should be less than 500 ppm. This emission would have a negligible overall effect on the ambient air quality unless the ambient SO_2 levels in the proposed area approximate the AAQS. It is assumed that the water effluent from the natural gas processing plant will be either treated or recycled resulting in a non-definable environmental impact on the receiving stream.

Table 2. EMISSION FACTORS FOR HEAVY-DUTY, GENERAL-UTILITY STATIONARY ENGINES USING GASEOUS FUELS

Pollutant	Emissions[a]			
	$lb/10^6 ft^3$	$kg/10^6 m^3$	lb/hr	kg/hr
Sulfur oxides[b]	0.6	9.6	-	-
Nitrogen oxides	-	-	-	-
Hydrocarbons[c]	1.2	19	4.2	1.9

[a]Values for $lb/10^6 ft^3$ ($kg/10^6 m^3$) based on 3.37 $10^6 ft^3/hr$ heat input.

[b]Based on an average natural gas sulfur content of 2000 $gr/10^6 ft^3$ (4600 $g/10^6 m^3$).

[c]24-hour operation was assumed.

References

1) Screening report crude oil and National Gas Production Processes Final Report, Task Order No. 13, Contract No. 68-02-0242, December 27, 1962.

2) Characterization of Sulfur Recovery in Oil and Natural Gas Production, Keshava S. Murthy, Contract No. 68-02-0611, Task 6.

3) Gas and Liquid Sweetening, Dr. R.N. Maddox, Cambell Petroleum Series, 1974, 2nd Edition, Norman, Oklahoma.

4) Compilation of Air Pollutant Emission Factors - 2nd Edition, U.S. EPA, AP-42, April 1973.

5) Shell Oil Company Proposed Refinery Environmental Impact Statement, for Logan Township, New Jersey, submitted to the New Jersey-Department of Environmental Protection, summary pp 145, 1973.

SECTION IV

PROPOSED REFINERY EFFLUENT

In the following analysis, air and water are the only environmental factors considered. Other environmental factors such as land, noise, ecology, economics, esthetics, transportation, and socio-cultural are excluded from this discussion.

A. Definition of Refinery

1. Design

The refinery is assumed to be of the following type:

- 250000 barrel per day capacity
- product mix is approximately 50% gasoline, 30% distillate and 20% residual
- sulfur content in the residual and distillate fuel products is 0.3 weight percent
- refinery fuel is off gas augmented by residual oil
- refinery processes will include a crude distillation unit, hydrotreating unit, catalytic cracking unit, catalytic reforming unit, isomerization unit, desalting unit, gas treating unit, sulfur recovery plant, a tail gas treating plant, a gasoline blending unit, a water treatment plant, CO boiler, vapor recovery system, storage tank farm, and hydrogen plant
- crude oil composition similar to light Arabian crude (1.8 weight percent sulfur)

2. Environmental Control

The refinery is assumed to be of the following type:

- based on best available demonstrated environmental control technology for refinery processes and storage facilities

- lead-free gasoline production will be provided
- low sulfur and low ash content fuel is utilized
- a carbon monoxide boiler followed by an electrostatic precipitation is installed on the catalytic cracker regeneration
- maximum practical water recycle and reuse
- primary and secondary treatment for waste water
- hydrocarbon emissions are controlled through the use of mechanical seals, rupture discs, and vapor recovery systems
- high level of maintenance for pollutant leakage elimination

a. Air Pollutants

This section only consideres particulates, sulfur dioxide, nitrogen dioxide, photochemical oxidant, hydrocarbon, and carbon monoxide which are regulated by Federal and State Ambient Air Quality Standards.

Two models were used to perform the air quality calculations reported in this section - a short-term and a long-term average model. Both models are based on the Gaussian Dispersion Approximation using the source emission inventory shown in Table 1(2). It was assumed in Table 1 that the miscellaneous hydrocarbon emissions from the refinery were 0.1 % of the refinery capacity. The composition of these hydrocarbons can be expected to be a composite of all volatile immediate and refined products. The tank farm was assumed to have storage capacity for one month of feed and products. Residual and distillate fuel storage created negligible emissions, whereas, crude oil and gasoline storage had significant emissions. Capacity of the crude oil storage tanks were assumed to be 200,000 barrels each. The tanks themselves were assumed to be floating roof tanks. The remaining products were assumed to be stored under pressure in completely sealed facilities due to their high volatility. As a result, emissions from these facilities were negligible.

Table 2(1) states the approximate maximum emissions from the proposed refinery under normal operation. It can be seen that with the exception of hydrocarbons, all primary and secondary air quality standards are met assuming pollutant emission control achievable in terms of current technology. It was assumed that 10 percent of the total hydrocarbon emission from the petroleum refinery is non-methane hydrocarbons. This assumption is questionable as there is reasonable contraversy as to what species can be characterized as a reactive or non-methane hydrocarbon (3). However, some studies have shown that only ten percent of such emissions can be considered reactive (EN-043).

b. Water Pollutants

The proposed refinery of 250,000 barrels per day capacity will have a single out fall from which aqueous effluents will be released. It is assumed that the refinery will have at its disposal a waste treatment plant. This waste treatment plant will have as a minimum primary waste treatment, and a high efficiency secondary treatment such as activated sludge. Proposed effluent characteristics are present in Table 3 (2,4). These values were approximated from existing refinery performance data (2).

c. Thermal Impact and PH

A study conducted by the Mobil Oil Company states that the water used by a 250,000 BPD refinery will experience a maximum potential induced temperature rise of 20°F (4). For example, if the maximum intake temperature is 81°F, then the discharge temperature will be 101°F. It is assumed that the PH of the discharge effluent from the proposed refinery will range between 6 and 8 (5). However, this can easily be reduced with the installation of cooling towers.

d. Flow Rate

A flow rate of 3.75 million gallons per day is assumed for the proposed 250,000 BPD refinery. This flow rate was based on performance data for existing petroleum refineries (6,7), and the assumption that water reuse and recycling will be maximumized at the proposed refinery.

Table 1: Source Inventory of Proposed Petroleum Refinery

Source	Emissions (kg/day)[c]				
	Particulate	SO_2	HC[a]	NO_x[b]	CO
1) Distillation	1,734	3,550	227	3,014	309
2) Hydrotreating	799	1,643	135	1,397	135
3) Isomerization	109	218	18	182	18
4) Reformer	890	1,816	118	1,544	154
5) Hydrogen Plant	345	826	54	1,380	73
6) Cat Cracker	808	1,643	109	1,398	136
7) CO Boiler and SO_2 from Tail Gas	427	3,859	218	5,357	136
8) Incineration	36	0	0	0	36
9) Tank Farm	0	0	4,523	0	0
10) Miscellaneous	0	0	33,750	0	0
Total	5,148	13,555	39,116	14,272	997

a Hydrocarbons including methane
b NO and NO_2
c 1 Short Tons = 907.185 Kg

Table 2: Predicted Maximum Concentrations[d] from the Proposed Refinery - Background Not Included

Averaging Time	(ug/m^3) Particulate	ppm SO_2	ppmC HC[a]	ppmC NMNC[b]	ppm NO_x[c]	ppm CO
Annual	2.3	0.002	0.82	0.08	0.003	0.44
24-Hour	8.2	0.007	2.91	0.29	0.010	1.48
8-Hour	10.8	0.009	3.00	0.38	0.013	1.91
3-Hour	13.7	0.012	4.84	0.48	0.017	2.44
1-Hour	17.9	0.016	6.34	0.63	0.022	3.22

a Hydrocarbons including methane

b Non-methane hydrocarbons

c NO and NO_2

d ppm (Vol) pollutant = 40.9 x MW (ug/m^3)

Table 3: Aqueous Effluents from the proposed 250000 BPD Petroleum Refinery - Flow rate = 3.75 MGD

Pollutant	Concentration (mg/l)
BOD	15
COD	80
Ammonia - Nitrogen	2[a]
Sulfide	0.1
Total Phosphorus	2
Phenol	0.1
Oil and Grease	2
Suspended Solids	10
Dissolved Solids	370
Total Chromium	0.26[b]
Zinc	0.16[b]

a/ ammonia strippers are assumed to be incorporated in the sour water strippers

b/ Reference 5

79-065 O - 76 - 41

References (Proposed Refinery Effluent)

1) Shell Oil Company Proposed Refinery Environmental Impact Statement for Logan Township, New Jersey, submitted to the State of New Jersey, Department of Environmental Protection, 1973.

2) Final Report: A Program to Investigate Various Factors in Refinery Siting, Radian Corporation Contract Number 100-029, submitted to the Council on Environmental Quality and Environmental Protection Agency, 15 February 1974.

3) Communication with Clemmans LaZenka at the Air Management Services, Philadelphia Department of Public Health, Philadelphia, Penna., 19 February 1976.

4) Environmental Report on the Proposed Modernization of the Paulsboro Refinery - Volume 2, submitted by Mobil Oil Corporation to the State of New Jersey, Department of Environmental Protection, April 1974.

5) Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining-Point Source Category, U.S. Environmental Protection Agency, EPA 440/1-73/014, December 1973.

6) Diehl, Douglas S., et al., Effluent Quality Control at a Large Oil Refinery, J. WPCF 43, 2254-70,1971.

7) American Petroleum Institute, Division of Refining, Recommended Rules for Design and Construction of Large, Welded, Low-Pressure Storage Tanks, API Standard 620, Washington, D.C., 1970.

SECTION V

PROPOSED AREA-AMBIENT AIR AND WATER QUALITY

The sites evaluated in this study were Glouchester, Middlesex, and Salem Counties in New Jersey diagrammed in figure 1A and New Castle County, Delaware shown in figure 1B. However, it should be noted that the Delaware legislature has passed a bill forbidding refinery construction in its coastal or wetland areas. The air quality, water quality, and available water resources in the proposed areas will be discussed in this chapter.

A. Air Quality

The purpose of this section is to approximate the ambient air quality in Glouchester, Middlesex, and Salem Counties in New Jersey and New Castle County, Delaware. Pollutants considered as applicable air quality standards are sulfur dioxide, total suspended particulates, nitrogen dioxide, carbon monoxide, non-methane hydrocarbons, and photochemical oxidants.

1. New Jersey

The State of New Jersey monitors SO_2 and CO concentrations in Paulsboro, Glouchester County, Penns Grove, Salem County, and Perth Amboy, Middlesex County. Table 1 shows these concentrations and the applicable Federal and State Ambient Air Quality Standards (AAQS). The ambient air SO_2 concentration in the proposed area was not higher than the AAQS, except in Middlesex County where the primary and secondary maximum 24-hour SO_2 standard was exceeded five times in 1973, and the secondary maximum 24-hour standard was exceeded once in 1974. The maximum 8-hour CO concentration, as shown in table 1, was exceeded 233 times in 1973 and 214 times in 1974 in the proposed area. All other SO_2 and CO AAQS's were not violated during 1973 and 1974 in the proposed area.

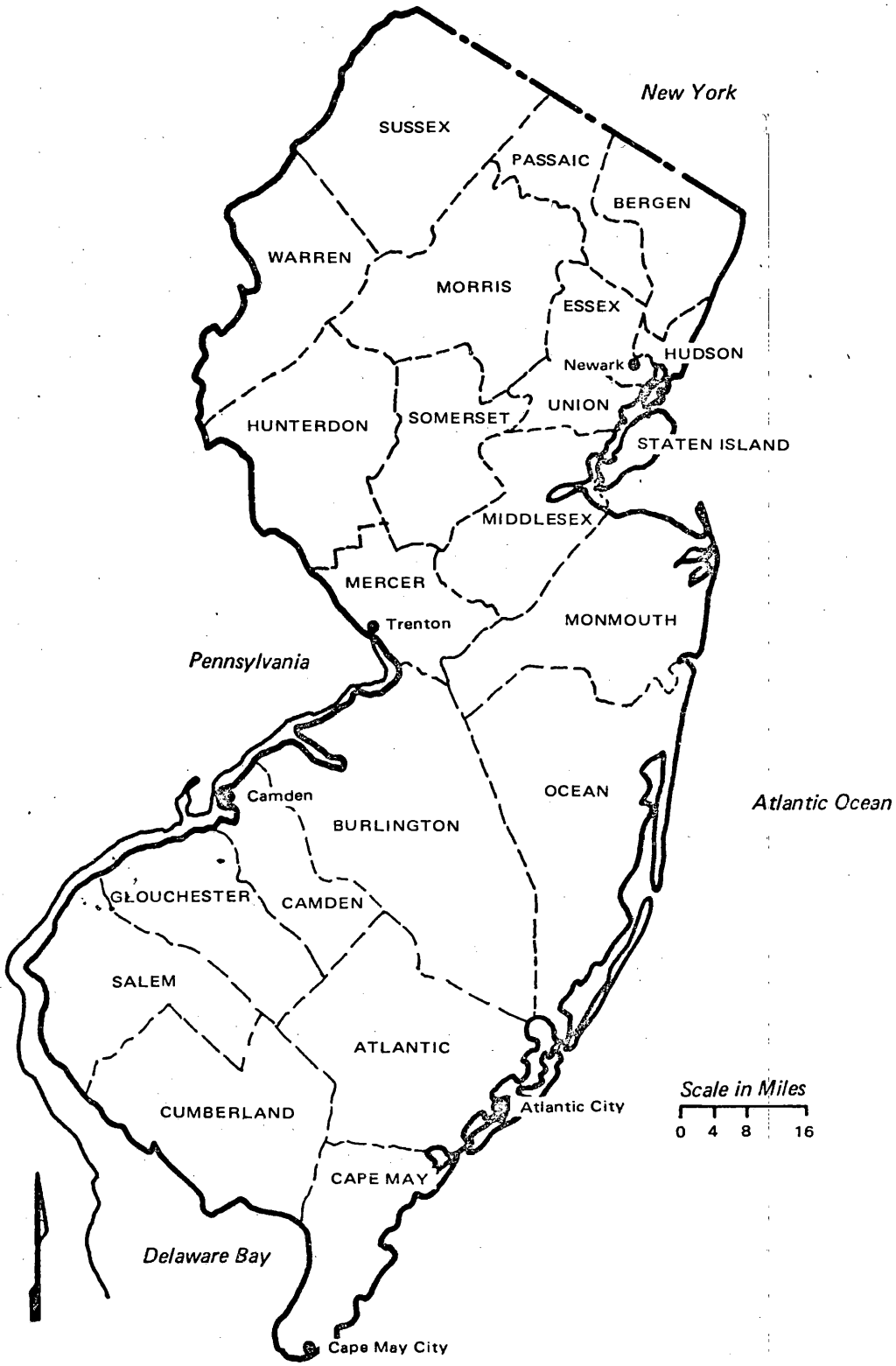


Figure 1A: County Outline Map of New Jersey (6)

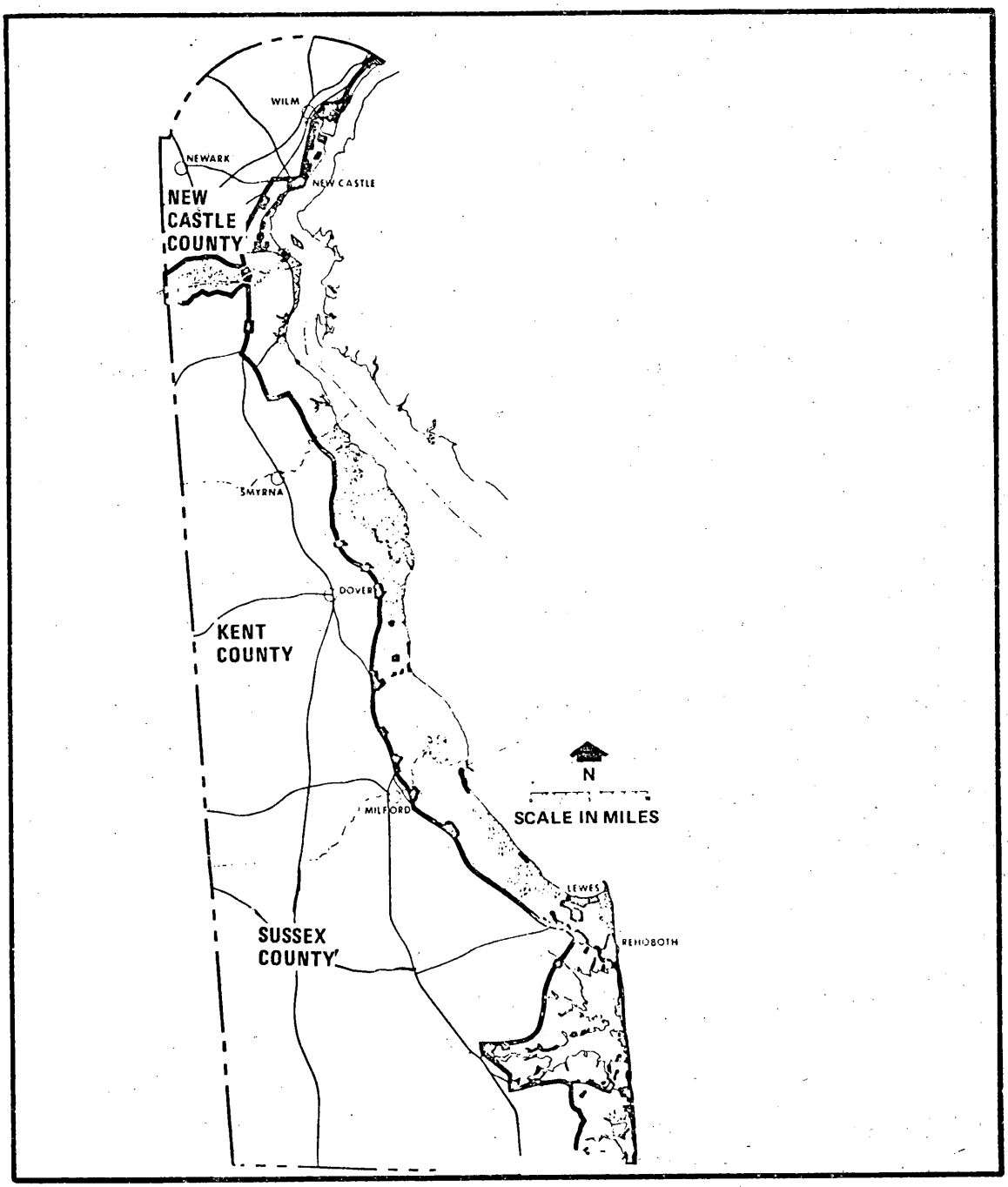


Figure 2B: Existing Land Use in the Delaware Coastal Zone, 1972 County Outline of Delaware

Source: Preliminary Delaware Coastal Zone Plan. Delaware State Planning Office, Dover, Delaware, April 1973, p. 36.

The ozone concentration in Glouchester, Salem, and Middlesex Counties were viewed using the Metropolitan Philadelphia and New Jersey-New York-Connecticut Air Quality Control Regions (AQCR). Within the Metropolitan Philadelphia AQCR, which includes Glouchester and Salem Counties, the AAQS for photochemical oxidant measured as ozone was exceeded in 1974 and 1973, anywhere from 27 to 60 times and 13 to 47 times, respectively, depending on the sampling site location. The average maximum 1-hour ozone concentration in the Metropolitan AQCR was 0.196 ppm in 1974 and 0.172 in 1973, which is above the AAQS of 0.08 ppm. The findings are similar in the New Jersey-New York-Connecticut AQCR which includes Middlesex County as can be seen in table 2. Table 2 also states the non-methane hydrocarbon and NO_2 ambient air quality levels in the Metropolitan Philadelphia and New York-New Jersey-Connecticut AQCR. The NMHC level exceeds the AAQS for all days which data was taken, while the NO_2 ambient level bordered on the AAQS. The NMHC AAQS is for use as a guide in devising implementation plans to achieve the oxidant standard as denoted by Appendix J, Code of Federal Regulations (40 CFR 2.100), and in itself, is not enforced. For example, the hydrocarbon level can exceed the hydrocarbon AAQS in an area, as long as the oxidant level is below the maximum 1-hour level of 0.08 ppm.

Table 3 lists the particulate levels and their relation to the AAQS in Glouchester, Salem, and Middlesex Counties. The proposed area was in compliance with the particulate AAQS in 1973 and 1974, except in Middlesex County where 14 samples in 1974 and 13 samples in 1973 were in violation of the secondary maximum 24-hour concentration AAQS.

It is assumed that the air quality data for 1973 and 1974 are representative of the ambient air quality levels at present. However, as the pollutant concentrations indicate in tables 1, 2, and 3, ambient pollutant concentrations appear to be decreasing,

except for oxidant and particulate levels in the proposed area. This may be a result of better control of the emission sources county-wide and in the surrounding air quality control regions i.e., the City of Philadelphia. Table 4 lists the total emissions of particulates, SO_2, NO_x, CO, and hydrocarbons for the proposed area of interest. As can be seen, pollutant emissions are greater in Philadelphia and Middlesex County than in Salem or Glouchester County.

Both New Jersey and Delaware have State Implementation Plans (SIP) designed to reduce pollutant emissions from sources within the State and control ambient pollutant concentrations as dictated by Federal and State AAQS. The SIP which includes the Transportation Control Plan for each State[a/] is drafted by the State and approved by the Federal government. Even though a State may have a comprehensive SIP, its air quality may not improve if the surrounding regional area possesses dominating pollutant sources. For example, emissions from the City of Philadelphia have a significant effect on the air quality of surrounding areas i.e., Glouchester County. Even if the emissions in Glouchester County are reduced according to the New Jersey SIP, the air quality of the area may not be reduced to the designed level due to the overriding effect of Philadelphia's air emissions.

2. Delaware

The primary area of interest in Delaware is New Castle County. Table 5 lists the Delaware Primary and Secondary Ambient Air Quality standards. The State of Delaware does not monitor hydrocarbons or nitrogen dioxide but does provide particulate, SO_2, oxidant and CO concentrations in the state. Table 6 is a summary of the SO_2 and particulate ambient air quality data for New Castle County.

a/ New Jersey, Delaware, Pennsylvania

Table 1: SO_2 and CO Concentration Levels for Glouchester, Salem, and Middlesex Counties in New Jersey (Reference 1)

Pollutant	Site	AQ Parameter	1° AQ[c/] Standard	2° AQ[c/] Standard	Times 1° Std. Exceeded 1974	Times 1° Std. Exceeded 1973	Times 2° Std. Exceeded 1974	Times 2° Std. Exceeded 1973
SO_2		Maximum 24-Hr. Avg. 1974 (ppm) 1973	0.14 ppm[a/] d/	0.10 ppm[a/] d/				
	Glouchester	0.079 0.087						
	Salem	0.067 0.073						
	Middlesex	0.119 0.164				1	1	9
		Annual Arith. Mean 1974 (ppm) 1973	0.03 ppm[a/]	0.02 ppm[b/]				
	Glouchester	0.017 0.018						
	Salem	0.015 0.012						
	Middlesex	0.023 0.024						
		Maximum 3-Hr. Avg. 1974 (ppm) 1973		0.5ppm[a/] d/				
	Glouchester	0.183 0.203						
	Salem	0.139 0.161						
	Middlesex	0.214 0.306						
CO		Maximum 8-Hr. Avg. 1974 (ppm) 1973	9 ppm[a/] d/	9 ppm[a/] d/				
	Glouchester	14.6 23.4			68	130		
	Salem	9.4 21.3			3	164		
	Middlesex	18.8 20.1			143	939		
		Maximum 1-Hr. Avg. 1974 (ppm) 1973	35 ppm[a/] d/	35 ppm[a/] d/				
	Glouchester	33.9 26.8						
	Salem	21.2 33.7						
	Middlesex	33.0 30.8						

a/ National and New Jersey Ambient Air Quality Standard
b/ New Jersey Ambient Air Quality Standard
c/ A primary AQS protects human health; a secondary AQS protects all other effects.
d/ Not to be exceeded more than once per year.

Table 2: Ozone, NMHC and NO_2 Levels for Glouchester, Salem, and Middlesex Counties in New Jersey (Reference 1)

Pollutant	Site	AQ Parameter		Primary AQ Std.	2° AQ Standard	Times 1° Std. Exceeded 1974	1973
Ozone		Maximum 1-Hr. Avg. 1974 (ppm)	1973	0.08 ppm a/ 1/	0.08 ppm a/ 1/		
	Metro. Philadelphia AQCR including Glouchester and Salem Counties c/	0.196 i/	0.172			(27-60) f/	(13-47)
	N.J-N.Y.-Conn. AQCR including Middlesex County d/	0.165	0.185			(5-47)	(13-29)
NMHC k/		Maximum 6-9AM Avg. 1974 j/ (ppm)	1973 j/	0.24 ppmC a/ m/	0.24 ppmC a/ m/		
	Metro. Philadelphia g/ AQCR including Glouchester and Salem Counties	4.13	4.93			(21-24) f/	(24-26)
	N.J.-N.Y.-Conn. h/ AQCR including Middlesex County	3.3	4.2			273	303
NO_2 n/		Annual Arith. Mean 1974 (ppm)	1973	0.05 ppm a/	0.05 ppm a/		
	Metro. Philadelphia g/ AQCR including Glouchester and Salem Counties	0.045	0.057				
	N.J.-N.Y.-Conn. h/ AQCR including Middlesex County	0.042	0.044				

a/ National and New Jersey Ambient Air Quality Standard.

b/ New Jersey Ambient Air Quality Standard.

c/ For the New Jersey portion of the Metropolitan Philadelphia Air Qualicy Control Region (AQCR), the State of New Jersey monitored ozone levels in Camdem, Burlington, and Mercer Counties.

d/ For the New Jersey portion of the N.J.-N.Y.-Conn. AQCR, the State of New Jersey monitored ozone levels in Eseex, Hudson, Mammouth, Morris, Somerset, and Union Counties.

Table 2: Ozone, NMHC and NO_2 Levels for Glouchester, Salem, and Middlesex Counties in New Jersey (Reference 1) Footnotes Continued.

f/ Range of times per month standard exceeded at the AQCR sampling stations.
g/ For the New Jersey portion of the Metropolitan Philadelphia AQCR, the State of New Jersey monitored NMHC and NO_2 levels in Camdem County.
h/ For the New Jersey portion of the N.J.-N.Y.-Conn. AQCR, the State of New Jersey monitored NMHC and NO_2 levels in Hudson, Union, and Essex Counties.
i/ Average values of those reported.
j/ Standard exceeded on all days for which data is reported (ppm C = ppm as Carbon).
k/ Total hydrocarbons measures; non-methane portion assumed to be 35 percent of the total.
l/ Not to be exceeded more than once per year.
m/ To be achieved in meeting the oxidant standard.
n/ Sampling method was Colorimetric Modified Salzman

Table 3: Particulate Levels for Glouchester, Salem, and Middlesex Counties in New Jersey (Reference 1)

Pollutant	Site	Parameter ($\mu g/m^3$)		Samples Over 260 $\mu g/m^3$		Samples Over 150 $\mu g/m^3$		Number of Samples		1° AQ Standard	2° AQ Standard
		Max. 24-Hr Avg 1974	1973	1974	1973	1974	1973	1974	1973	a/&b/ 260 $\mu g/m^3$	a/&b/ 150 $\mu g/m^3$
Particulate	Glouchester	130	108	0	0	0	0	177	85		
	Salem	115	108	0	0	0	0	60	14		
	Middlesex	167	158	0	0	14	13	562	561		
		Ann.Arith.Mean 1974	1973							a/ 75 $\mu g/m^3$	a/ 60 $\mu g/m^3$
	Glouchester	37.5	42.5					177	58		
	Salem	34.5	-					60	-		
	Middlesex	59.5	55.7					562	542		

a/ National and New Jersey Ambient Air Quality Standard.
b/ Not to be exceeded more than once per year.

Table 4: Area and Point Sources in Glouchester, Salem, and Middlesex Counties in New Jersey (Reference 1)

County	Point and Area Sources - 1975 (T/yr)				
	Particulates	SO_2	CO	HC	NO_x
Glouchester	3441.47	6532.54	72973.6	15939.9	26130.58
Salem	2614.88	12711.18	29868.6	10371.43	19396.14
Middlesex	12924.56	30792.4	355882.2	67503.76	85051.64
City of Philadelphia a/	39400	88740 b/	446530	160550	120110

a/ 1973 emission summary (Reference 9)
b/ SO_x

The SO_2 long-term averages (99th percentile, annual geometric mean, and arithmetic mean) in New Castle County are well within the Federal and State AAQS for the time period of December 1974 to December 1975. The SO_2 24-hour average AAQS was violated four times during the same time period with values in the concentration range of 0.11 ppm to 0.16 ppm. These violations occurred at the Claymont and Delaware City sampling site. The SO_2 3-hour average AAQS was not exceeded during the prescribed time period.

The particulate annual geometric mean primary AAQS was exceeded once at the Wilmington sampling site whereas, the secondary AAQS was exceeded at the Urban Wilmington and Newark sampling sites. The average annual geometric mean listed in table 5 for New Castle County was below all AAQS between December 1974 and December 1975. The twenty-four hour average particulate Federal and State AAQS were violated twelve times at the Wilmington sampling site between December 1974 and December 1975. The range of 24-hour average concentration values varied from 153 $\mu g/m^3$ to 314 $\mu g/m^3$.

The CO ambient air concentrations are below all Federal and State AAQS in New Castle County (Reference 2). However, oxidant concentrations have been on the increase. The higher concentrations are believed by the State of Delaware-Division of Environmental Control to be due largely to the increasing number of automobiles on the State's highways and surrounding region. Automobiles emit both nitrogen oxides and hydrocarbons which are both directly involved in the formation of oxidants. Violations of the 0.08 ppm oxidant standard at four sampling sites in New Castle County ranged from 0.88 ppm to 0.40 ppm and numbered 117 in November, 1975. The highest twenty-four hour NO_2 concentrations at the Newark and Wilmington sampling sites in New Castle County was 0.037 ppm and 0.057 ppm, respectively, in 1973. The value of the twenty-four hour NO_2 concentration at the Wilmington site is greater than the annual NO_2 arithmetic mean AAQS of 0.05 ppm.

Table 5. Delaware Primary Ambient Air Quality Standards

PRIMARY STANDARD		SECONDARY STANDARD		PRIMARY AND SECONDARY STANDARDS			
Particulates	Sulfur Dioxides	Particulates	Sulfur Dioxides	Nitrogen Oxides c/	Photochemical Oxidants c/	Carbon Monoxide c/	(Non-methane) Hydrocarbons c/
1. 70 $\mu g/m^3$ annual geometric mean	1. (0.025 ppm) annual geometric mean	1. 60 $\mu g/m^3$ annual geometric mean	1. (0.02 ppm) annual arithmetic mean	1. (0.05 ppm) annual arithmetic mean	1. (0.08 ppm) maximum 1-hour concentration b/	1. (8 ppm) maximum 8-hour concentration not to be exceeded more than 0.1% of the time	1. (0.2 ppmC) maximum 3-hour concentration b/
2. 200 $\mu g/m^3$ maximum 24-hour concentration b/	2. (0.03 ppm) annual arithmetic mean	2. 150 $\mu g/m^3$ maximum 24-hour concentration b/	2. (0.1 ppm) maximum 24-hour concentration b/		2. (0.1 ppm) maximum 1-hour concentration a/	2. (12 ppm) maximum 8-hour concentration a/	2. (0.3 ppmC) maximum 3-hour concentration a/
3. 500 $\mu g/m^3$ maximum 1-hour concentration a/	3. (0.1 ppm) 99th percentile 24-hour average		3. (0.5 ppm) maximum 3-hour concentration b/			3. (35 ppm) maximum 1-hour concentration a/	
	4. (0.13 ppm) maximum 24-hour concentration						

a/ Not to be exceeded.
b/ Not to be exceeded more than once per year.
c/ Primary and secondary standards are the same.

Table 6: SO_2 and Particulate Concentration Levels for New Castle County, Delaware from 12/74 to 12/75

Pollutant	Air Quality Parameter	Value	Number of Stations
SO_2	99th Percentile	0.06 ppm	12
	Annual Geometric Mean	0.008 ppm	12
	Arithmetic Mean	0.014 ppm	12
Particulate	Annual Geometric Mean	54 $\mu g/m^3$	12

However, one value from one samplier does not necessarily reflect the air quality in an area. At present, the reference method for the determination of nitrogen dioxide in the atmosphere is questionable. This should be considered along with the sampling method used when reviewing NO_x data. The sampling method used to acquire this data was the NASN Sodium Arsenile - Frit (Reference 8). Hydrocarbon concentrations are not monitored in Delaware.

3. Summary

This section considered the ambient suspended particulate matter, SO_2, NO_x, CO, photochemical oxidant, and hydrocarbon levels in the proposed area of Glouchester, Salem and Middlesex Counties in New Jersey, and New Castle County in Delaware. In New Jersey, the SO_2, CO, particulate and NO_2 ambient concentration are approaching or exceeding the AAQS. The ozone and NMHC levels for the proposed areas in New Jersey exceed the AAQS. In New Castle County, SO_2 and particulate concentrations appear to be of the same magnitude as the AAQS and exceed the AAWS at some sampling sites. The CO ambient air concentrations are below all Federal and State AAQS in New Castle County. However, oxidant and NO_x are above the AAWS. Hydrocarbon concentrations are not monitored in Delaware.

It should be noted that there are new source performance standards issued by both the Federal Environmental Protection Agency and respective State governments. However, they were considered not significant to this analysis because of their nature and are not reported.

B. Water Quality

It is assumed that the water borne effluents from a refinery located in Glouchester, Salem, or New Castle Counties will be discharged into the Delaware River and Basin, and refinery located in Middlesex County will discharge its effluent into the Arthur Kill which flows into the Raritan Bay. This section will present a brief description of the water quality in these receiving streams and the local and Federal requirements.

1. Arthur Kill and Raritan Bay

The Arthur Kill and Raritan Bay collectively have a surface area of 93 square miles and a water volume of 38 billion cubic feet, both at low water (Reference 3). Average water temperatures in the region follow a general seasonal pattern ranging from 32°F to 79°F. Chloride concentration in the estuary range from 13,000 to 15,000 mg/l, compared to a normal value for ocean water of 20,000 mg/l. Hence, the estuary is roughly two-thirds ocean water, with the balance representing freshwater in-flow to the estuary. Tides throughout the estuary are semi-diurnal and have a mean range varying from 4.3 feet at Fort Wadsworth at the Narrows to 5.3 feet at Toltenville, Staten Island, New York. The spring range throughout these locations is 5.2 and 6.4 feet. The large flow caused by tidal movement throughout the Arthur Kill qualifies it as a likely location for a petroleum refinery. Figure 1C is a map of Raritan Bay and adjoining waters.

a. Water Quality Standards in the Arthur Kill

The Arthur Kill has been classified as to best usage by the New Jersey State Department of Environmental Protection (NJDEP), the Interstate Sanitation Commission (ISC), and the New York State Department of Environconservation (NYDEC). Table 7 lists the applicable water quality standards promulgated by these groups with an explanation of their classifications in tables 8, 9, and 10.

b. Existing Water Quality

Several agencies have conducted water quality surveys on the Arthur Kill. Table 11 presents the results of the ISC surveys which were conducted in the time period of January 1969 to July 1971. Parameters surveyed include oil, suspended solids, ammonia as nitrogen, and total chromium. Figures 2 through 5 show the Arthur Kill phenol, chemical oxygen demand (COD), biological oxygen demand (BOD) and dissolved oxygen (DO) distributions. The phenol data and the chemical oxygen demand data was collected by the Federal Water Pollution Control Administration (FWPCA) Northeast Region for the Raritan Bay project studies. The BOD and dissolved oxygen data was presented by the New York City (NYC) Department of Water Resources.

Values of pH range from 6.8 to 7.5 along the Arthur Kill BOD concentrations in the kill are quite uniform. BOD's values throughout the stream range from 4 to 5 mg/l and the COD ranges from 110 to 135 mg/l. The reason for the much lower BOD in comparison with the COD is due to the presence of large amounts of non-biodegradable materials and perhaps some toxic effect of some materials upon the exertion of BOD in the stream. Sulfide concentrations in the stream have not been reported investigated.

2. Delaware River and Basin

The Delaware Bay is a tidal estuary created at the outfall of the Delaware River into the Atlantic Ocean. The municipality of New Castle is approximately 66 miles upstream. Wilmington is approximately 75 miles upstream, and Philadelphia is approximately 110 miles upstream from the Delaware Basin. Figure 6 is a regional map of the Delaware River and Basin showing the New Jersey and Delaware River borders.

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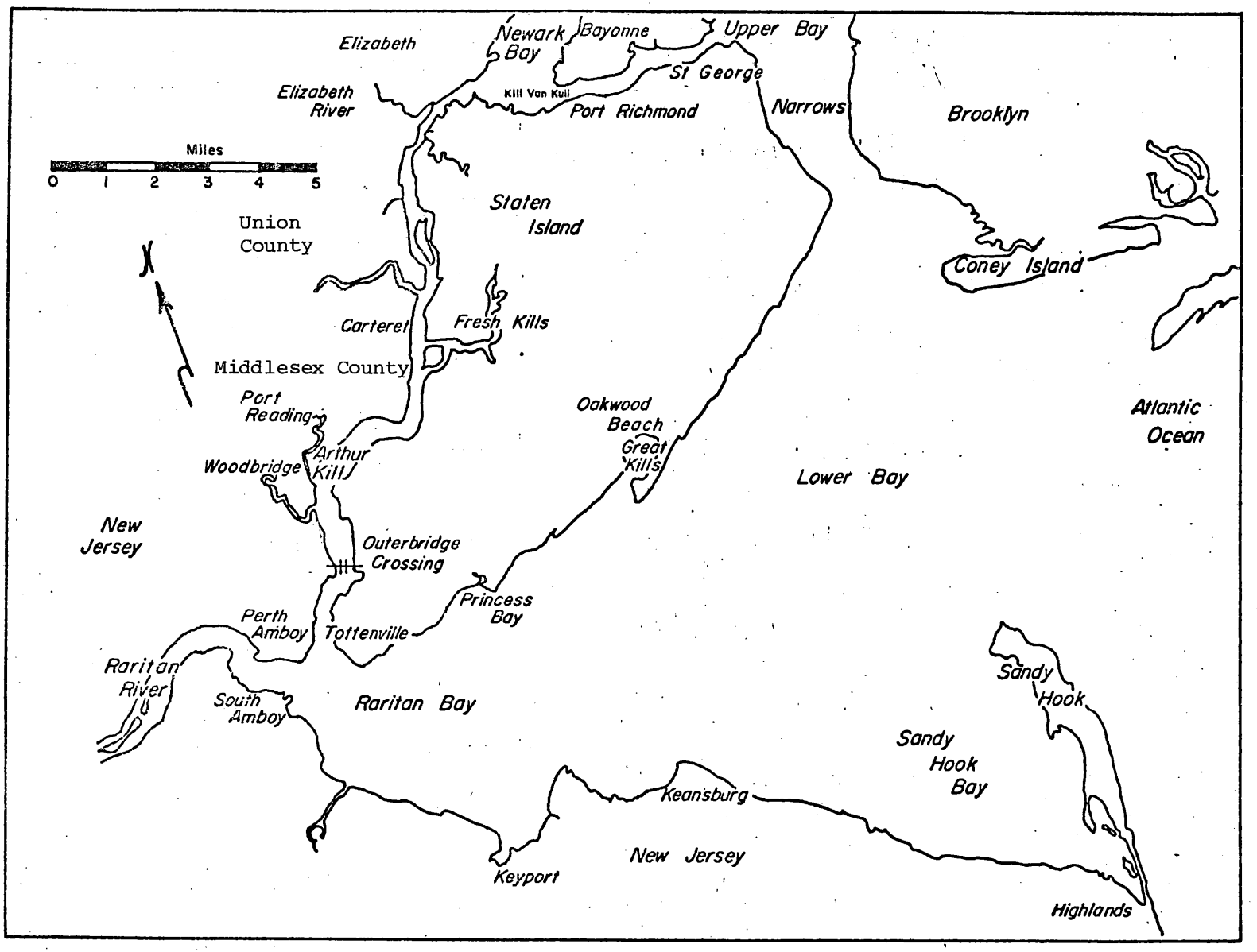

Figure 1C. Map of Raritan Bay and Adjoining Waters (11)

Table 7. Existing Classifications of Arthur Kill
(see table 8 for explanation)

Water Area	Agency & Classification		
	New York State Dept. of Environmental Conservation	New Jersey State Dept. of Environmental Protection	Interstate Sanitation Commission
Arthur Kill-Outerbridge Crossing to Newark Bay	II	TW-3	B-2
Arthur Kill-Outerbridge Crossing to Tottenville	I	TW-3	B-1

Table 8. New York State Water Quality Standards

ITEMS	SPECIFICATIONS	
	CLASS I	CLASS II
Best usage of waters	Fishing and any other usages except bathing or shellfishing for market purposes.	All waters not primarily for recreational purposes, shellfish culture or the development of fish life.
Floating solids; settleable solids; sludge deposits	None which are readily visible and attributable to sewage, industrial wastes, or other wastes or which deleteriously increase the amounts of these constituents in receiving waters after opportunity for reasonable dilution and mixture with the wastes discharged thereto.	
Garbage, cinders, ashes, oils, sludge or other refuse	None in any waters of the marine district as defined by State Conservation Law.	
Sewage or waste effluents	Effective disinfection if required by Interstate Sanitation Commission.	- - -
Dissolved Oxygen	An average of not less than 50 per cent saturation during any week of the year, but not less than 3.0 parts per million at any time.	An average of not less than 30 per cent saturation during any week of the year, provided such saturation levels insure adequate oxygen to support fish and shellfish life at all times.
Toxic wastes, oil, deleterious substances, colored or other wastes, or heated liquids	None alone or in combination with other substances or wastes in sufficient amounts to be injurious to edible fish and shellfish, or which shall in any manner affect the flavor, color, odor, or sanitary condition of such fish or shellfish so as to injuriously affect the sale thereof, or which shall cause any injury to the public and private shellfisheries of this State; and otherwise none in sufficient amounts to impair the waters for any other best usage as determined for the specific waters which are assigned to this class.	- - -
Toxic wastes, oil, deleterious substances, colored or other wastes	- - -	None alone or in combination with other substances or wastes in sufficient amounts to be injurious to edible fish and shellfish, or the culture or propagation thereof or which sall in any manner affect the flavor, color, odor, or sanitary condition of such fish or shell fish so as to injuriously affect the sale thereof, or which shall cause any injury to the public and private shellfisheries of this State.

Table 9. New Jersey State Surface Water Quality Criteria For TW-3 Waters

CLASS TW-3

Tidal waters used primarily for navigation, not recreation. These waters shall be suitable for fish survival and the passage of anadromous fish and for any other reasonable uses.

FLOATING SOLIDS, SETTLEABLE SOLIDS, OIL, GREASE, COLOR AND TURBIDITY

None noticeable in the water or contributing to the formation of sludge deposits.

TOXIC OR DELETERIOUS SUBSTANCES INCLUDING BUT NOT LIMITED TO MINERAL ACIDS, CAUSTIC ALKALI, CYANIDES, HEAVY METALS, CARBON DIOXIDE, AMMONIA OR AMMONIUM COMPOUNDS, CHLORINE, PHENOLS, PESTICIDES, ETC.

None, either alone or in combination with other substances, in such concentrations as to cause fish mortality or inhibit their natural migration or which would render the waters unsuitable for the designated uses.

TASTE AND ODOR PRODUCING SUBSTANCES

None offensive to humans or which would produce offensive tastes and/or odors in fauna used for human consumption. None which would render the waters unsuitable for the designated uses.

pH

Between 6.5 and 8.5

DISSOLVED OXYGEN

Not less than 3.0 mg/l at any time.

TEMPERATURE

No heat may be added, except in designated mixing zones, which would cause temperatures to exceed 85°F or which would cause the temperature at any given site to exceed the monthly mean of the maximum daily temperature prior to the addition of any heat by more than 4°F during September through May; or more than 1.5°F during June through August. The rate of temperature change in designated mixing zones shall not cause mortality of the biota.

Table 9. New Jersey State Surface Water Quality Criteria For TW-3 Waters (Contd.)

RADIOACTIVITY

Current U.S. Public Health Service Drinking Water Standards shall apply.

BACTERIAL QUALITY

Fecal coliform levels shall not exceed a geometric mean of 1500/100 ml. Samples shall be obtained at sufficient frequencies and at locations and during periods which will permit valid interpretations of laboratory analyses.

Appropriate sanitary surveys shall also be carried out as a supplement to such sampling and laboratory analyses.

Table 10. Interstate Sanitation Commission Water Quality Regulations For B-1 and B-2 Waters

1. All waters of the Interstate Sanitation District shall be of such quality and condition that they will be free from floating solids, settleable solids, oil, grease, sludge deposits, color or turbidity to the extent that none of the foregoing shall be noticeable in the water or deposited along the shore or on aquatic substrata in quantities detrimental to the natural biota; nor shall any of the foregoing be present in quantities that would render the waters in question unsuitable for use in accordance with their respective classifications.

2. No toxic or deleterious substances shall be present, either alone or in combination with other substances, in such concentrations as to be detrimental to fish or inhibit their natural migration or that will be offensive to humans or which would produce offensive tastes or odors or be unhealthful in biota used for human consumption.

3. Streams and other water bodies shall have a minimum dissolved oxygen content in accordance with their respective classifications as follows:

B-1: 4 parts per million
B-2: 3 parts per million

4. In addition to meeting the dissolved oxygen requirements, waters shall in all respects be suitable for their best intended uses, as follows:

B-1: Suitable for fishing and secondary contact recreation
B-2: Suitable for fish survival, passage of anadramous fish and for any other reasonable purposes compatible with their use for navigation

5. Effluents discharged or flowing into waters of any class shall meet the following requirements:

(a) pH within the range from 6.5 to 8.5 may be required if the receiving waters are outside this range.
(b) Fecal Coliform levels shall not exceed 200 per 100 ml at any time when disinfection is required to protect the best intended uses of the waters in question.
(c) Biochemical Oxygen Demand removal shall not be less than 80 per cent. In addition, a discharge from an industrial source shall meet any requirements for effluent quality imposed by permit or otherwise pursuant to state law.
(d) Settleable Solids removal shall be at least 90 per cent.

Table 11. Existing Arthur Kill Water Quality Data[a/] (3)

Parameter	Number of Values	Lower Detection Limit	Number of Values Below Lower Detection Limit	Low Value	High Value	Average Value[b]
Oil	9	0	0	2	140	11
Suspended Solids	11	0	0	7	220	66
pH	12	--	--	6.8	7.5	7.2
Ammonia-nitrogen	9	0.01	1	0.01	9.20	4.63
Total chromium	12	0.05	7	<0.05	0.10	<0.05

[a/] Interstate Sanitation Commission Data, January 1, 1969 - July 15, 1971. All units are milligrams per liter except pH.

[b/] All averages are arithmetic means except pH which is a logarithmic mean.

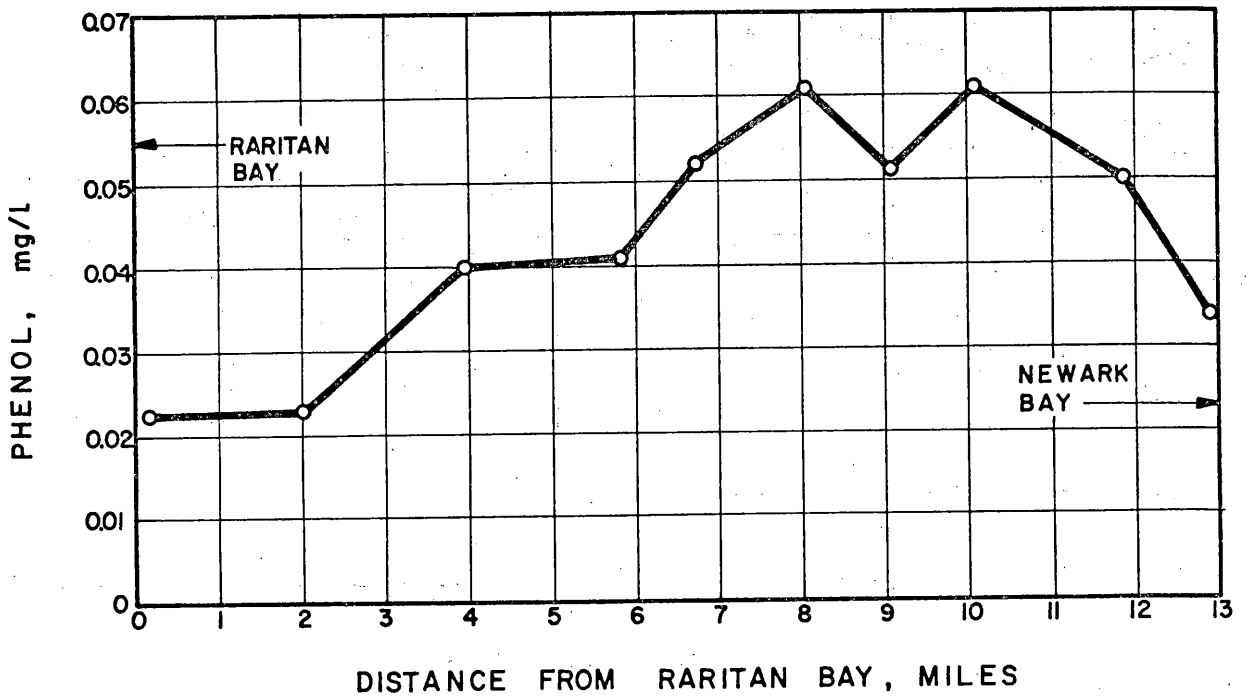

Figure 2. Existing Arthur Kill Phenol Distributions, FWPCA Northeast Region - Raritan Bay Project Studies, 1963-1964 (3)

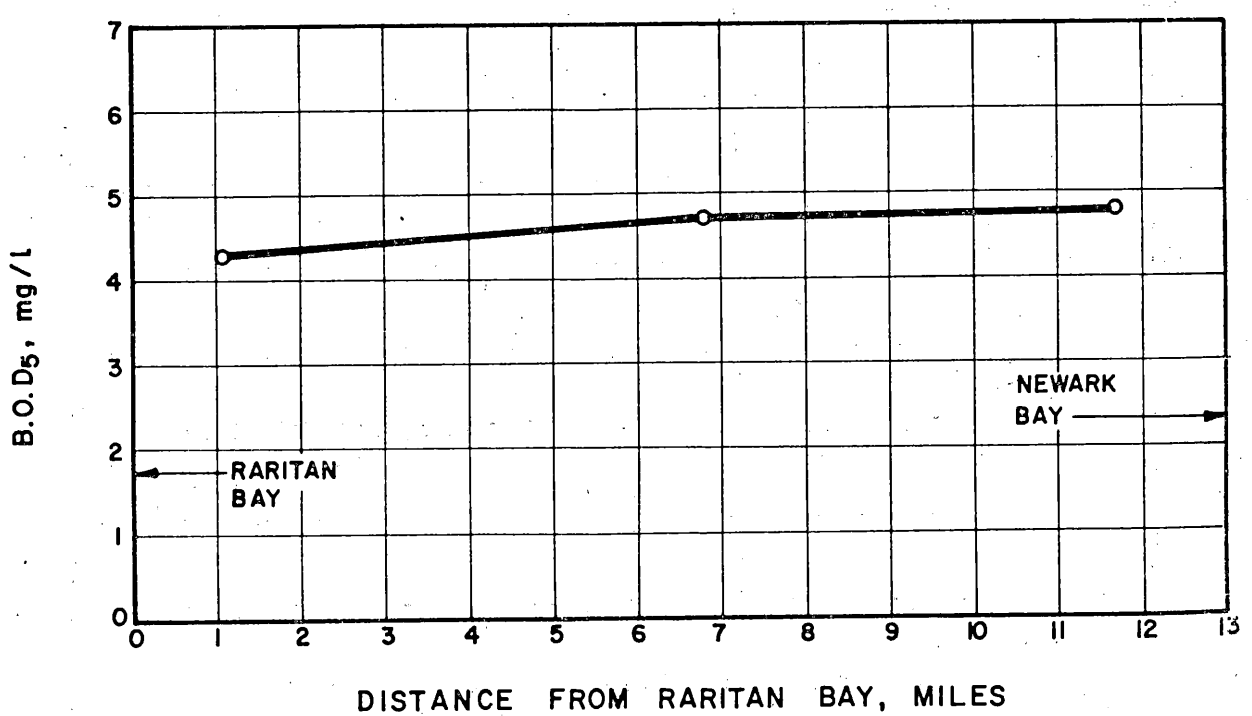

Figure 3. Existing Arthur Kill BOD_5 Distributions, NYC Department of Water Resources Surveys, June 8 - September 24, 1970 (3)

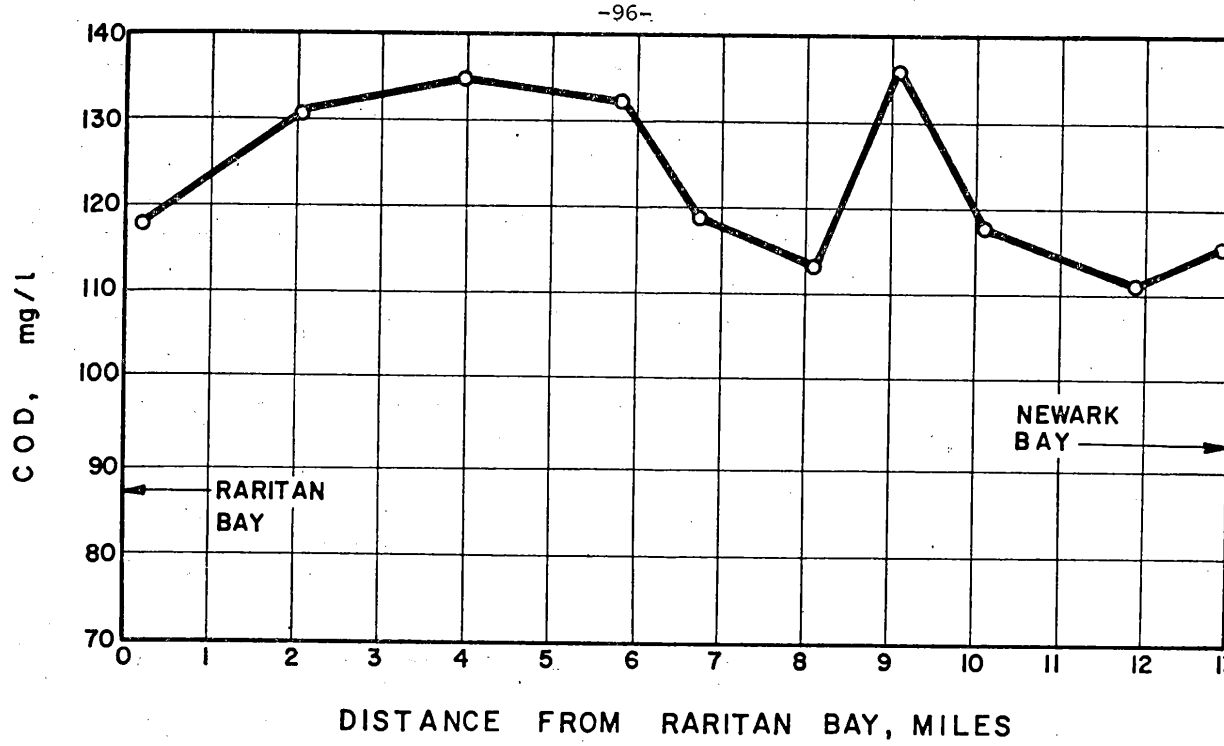

Figure 4. Existing Arthur Kill COD Distributions, FWPCA Northeast Region-Raritan Bay Project Studies, August, 1962 - September, 1964 (3)

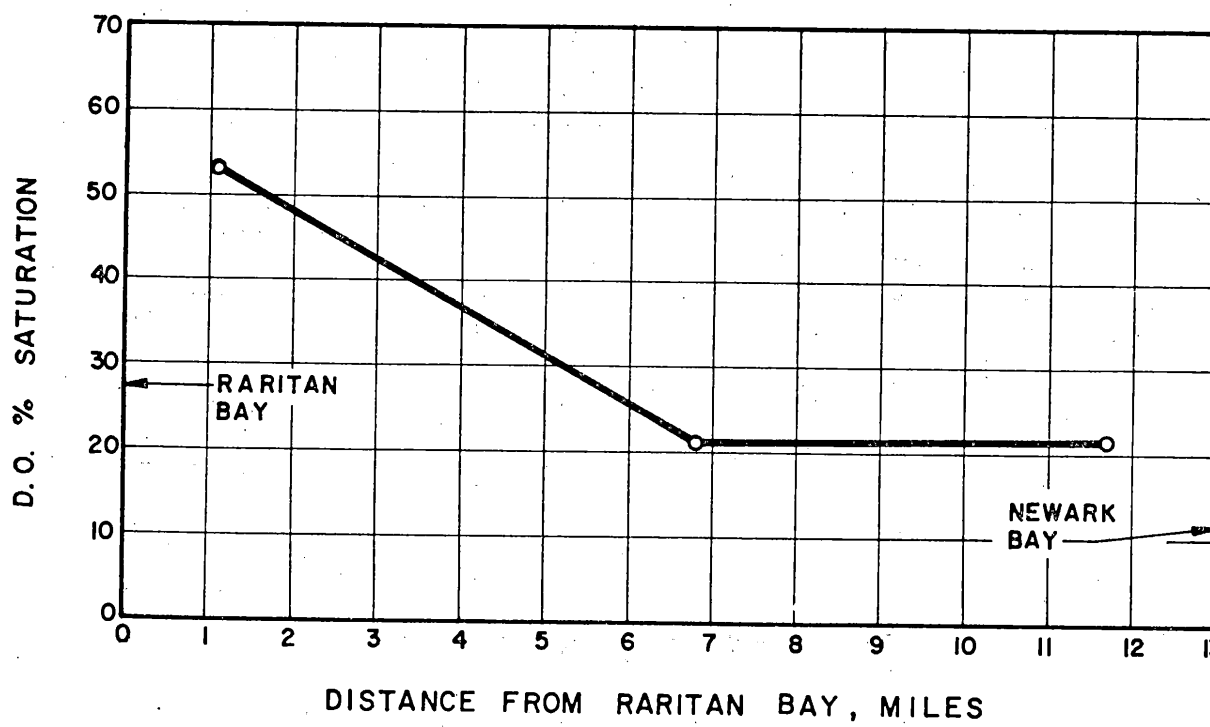

Figure 5. Existing Arthur Kill D.O. Distributions, NYC Department of Water Resources Surveys, June 8 - September 24, 1970 (3)

a. Existing Water Quality

Representative water quality data is plotted in figures 7 through 10. The sources for this plotted data (Reference 5) was: 1) the U.S. Geological Survey and Delaware River Basin Commission (1967), and (2) the Delaware River Basin Commission (1973). Figure 7 shows the average total chloride concentration along the Delaware River and Basin. Since the bay is a tidal estuary, the salinity of the water decreases as you travel upstream. The total chloride concentration in a receiving stream is indicative of the dissolved solids content. The chloride content of the water drops off rapidly at approximately 100 miles upstream.

Figure 8 shows the fecal coliform content of the Delaware River and Basin. Note that the coliform content of the receiving water increases significantly in the Philadelphia area. Fecal coliform concentration is generally an indicator of polluted waters. The fecal content decreases as you travel downstream due, in part, to the dillution and toxic effects of tidal water on the fecal coliform. Figure 9 shows that the pH of the Delaware River and Basin is fairly constant and centers around a pH 7. However, values of less than 6.5 have been recorded at several sampling sites between New Castle and Philadelphia (river mile 80).

Figure 10 illustrates the biological oxygen demand, the dissolved oxygen, and summer temperature distribution of the Delaware River and Basin. The BOD concentrations varied from approximately 3 mg/l to 5.4 mg/l, while the temperature stayed fairly constant at approximately 25-26°C. Note that BOD increases denoting poorer water quality after flowing through Philadelphia.

The Delaware River and Basin are under the strong influence of a strong tidal flow. The tides cause a significant alteration in bay flow and results in increased mixing and dispersion of waterborne pollutants.

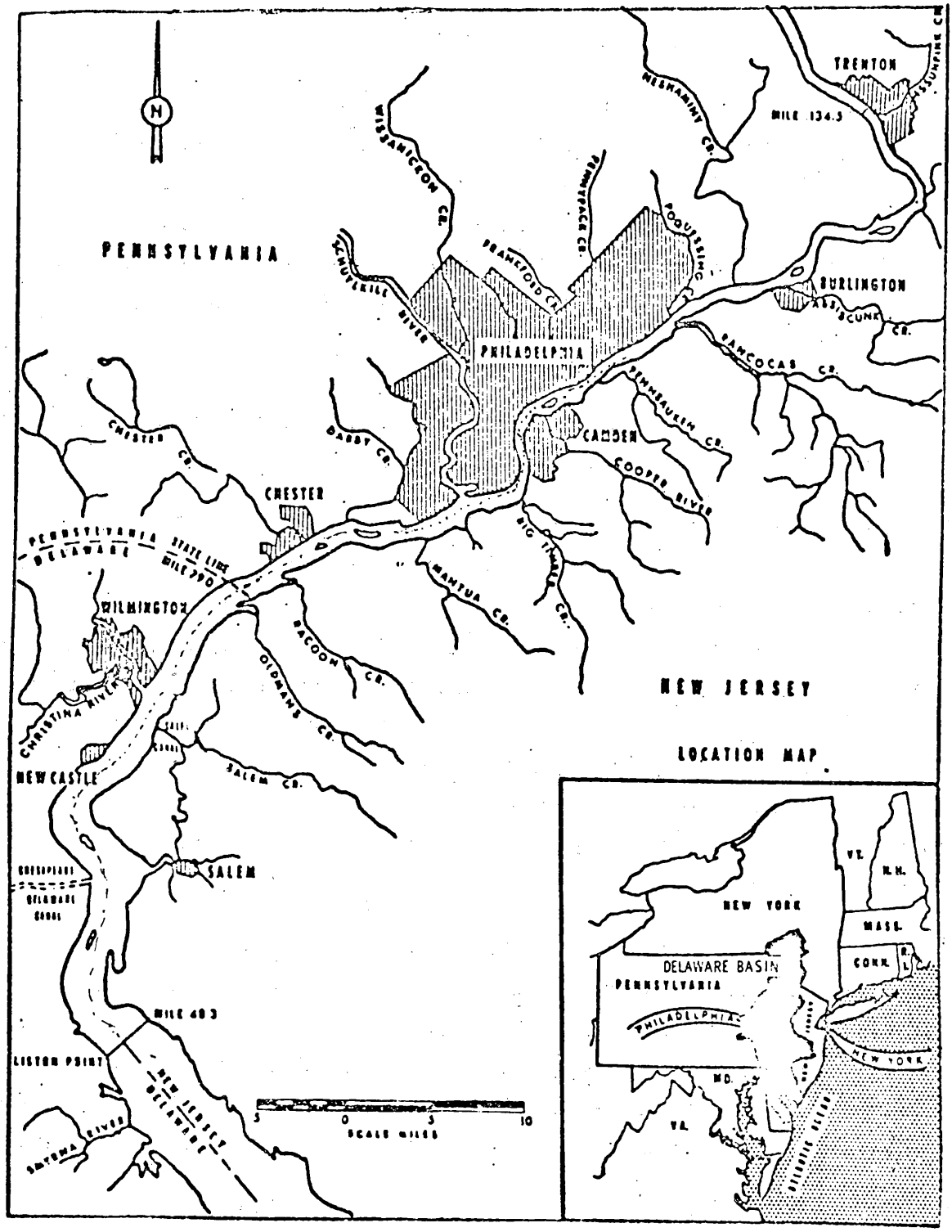

Figure 6. The Delaware Estuary (Reference: Edgemoor EIS)

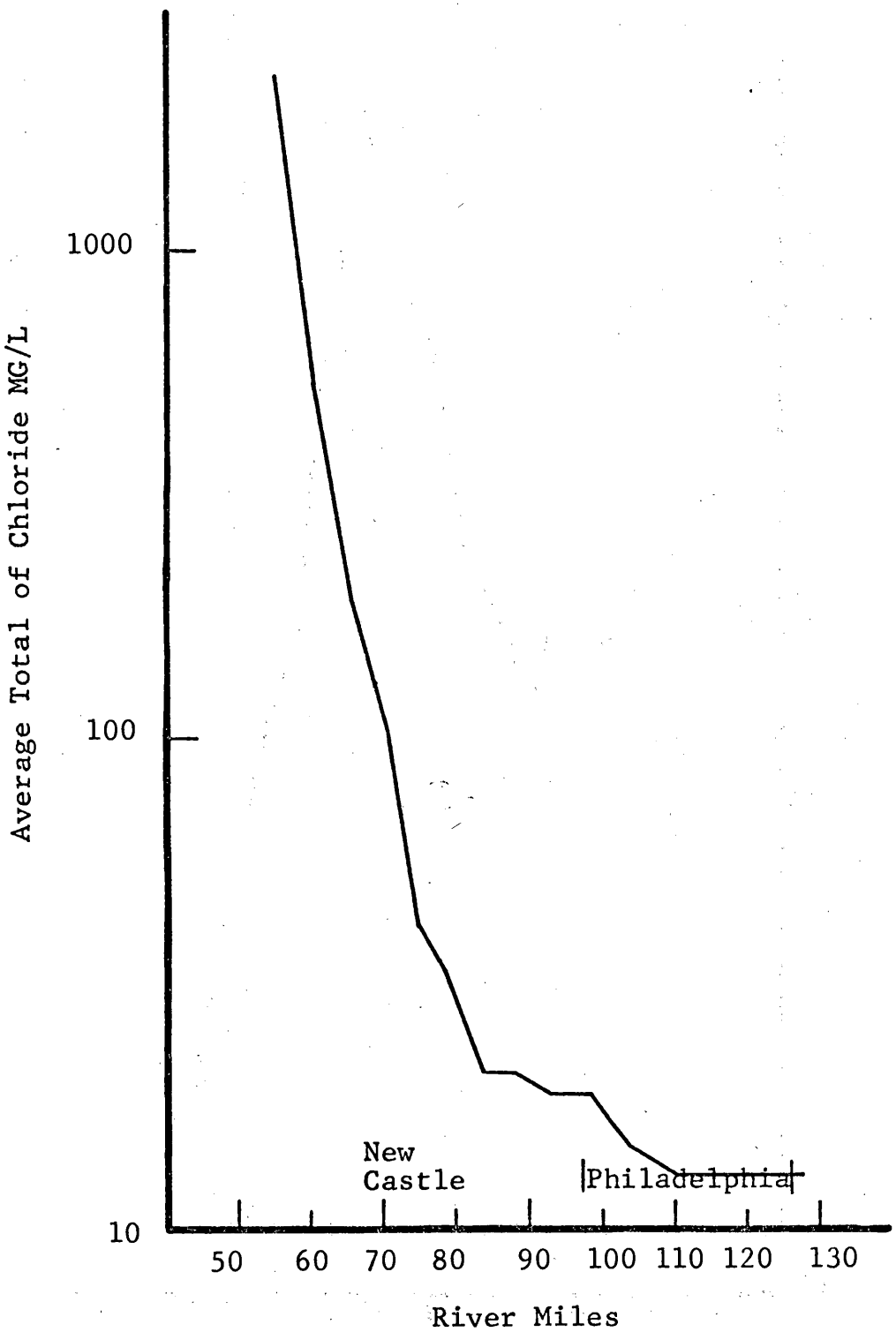

Figure 7. Average Total Chloride Versus Miles Upstream from Outfall (Indicator of Dissolved Solids Content) (10)

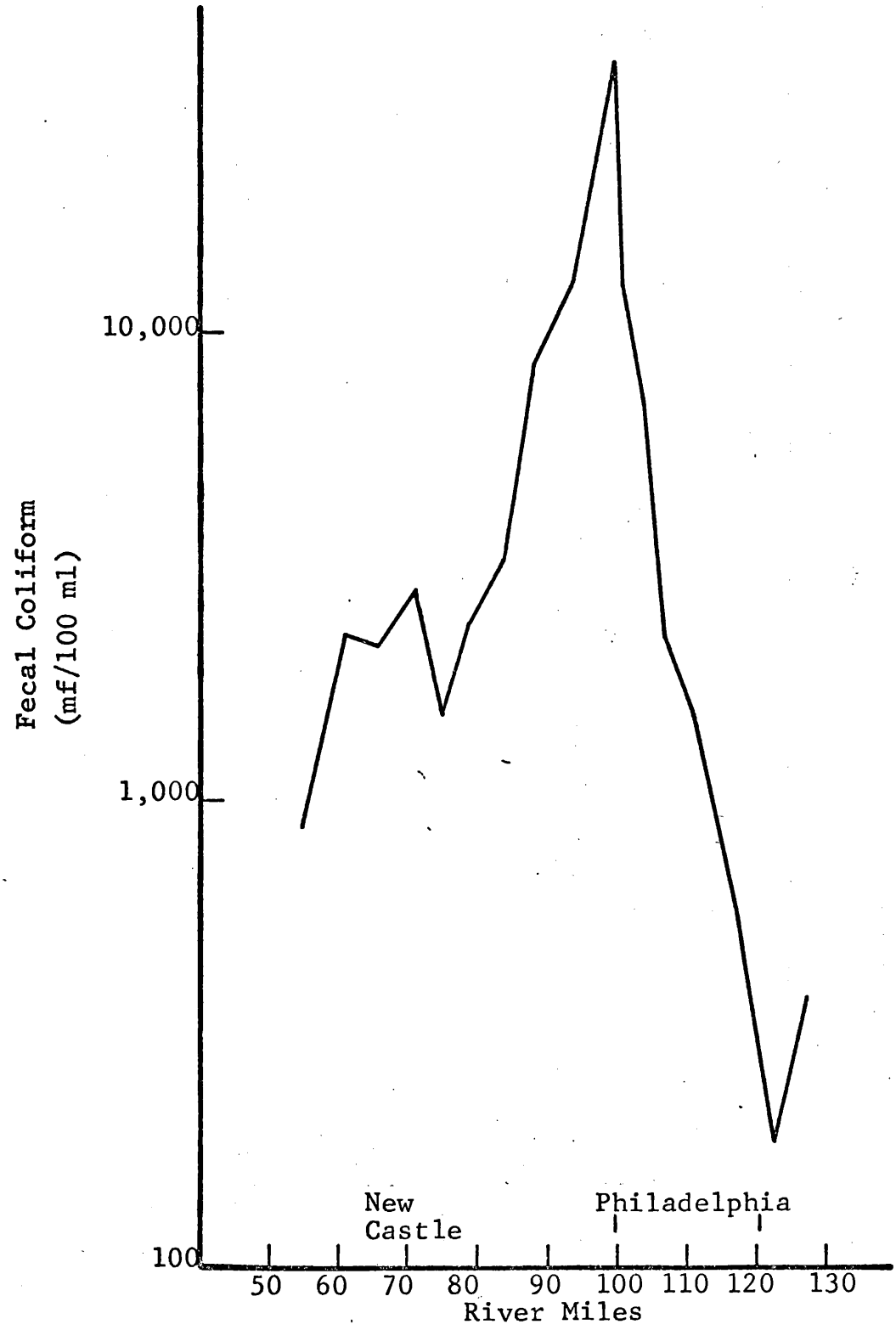

Figure 8. Fecal Coliform Content Versus Miles Upstream
(Membrane Filter Count Per 100 ml During Summer Season)(10)

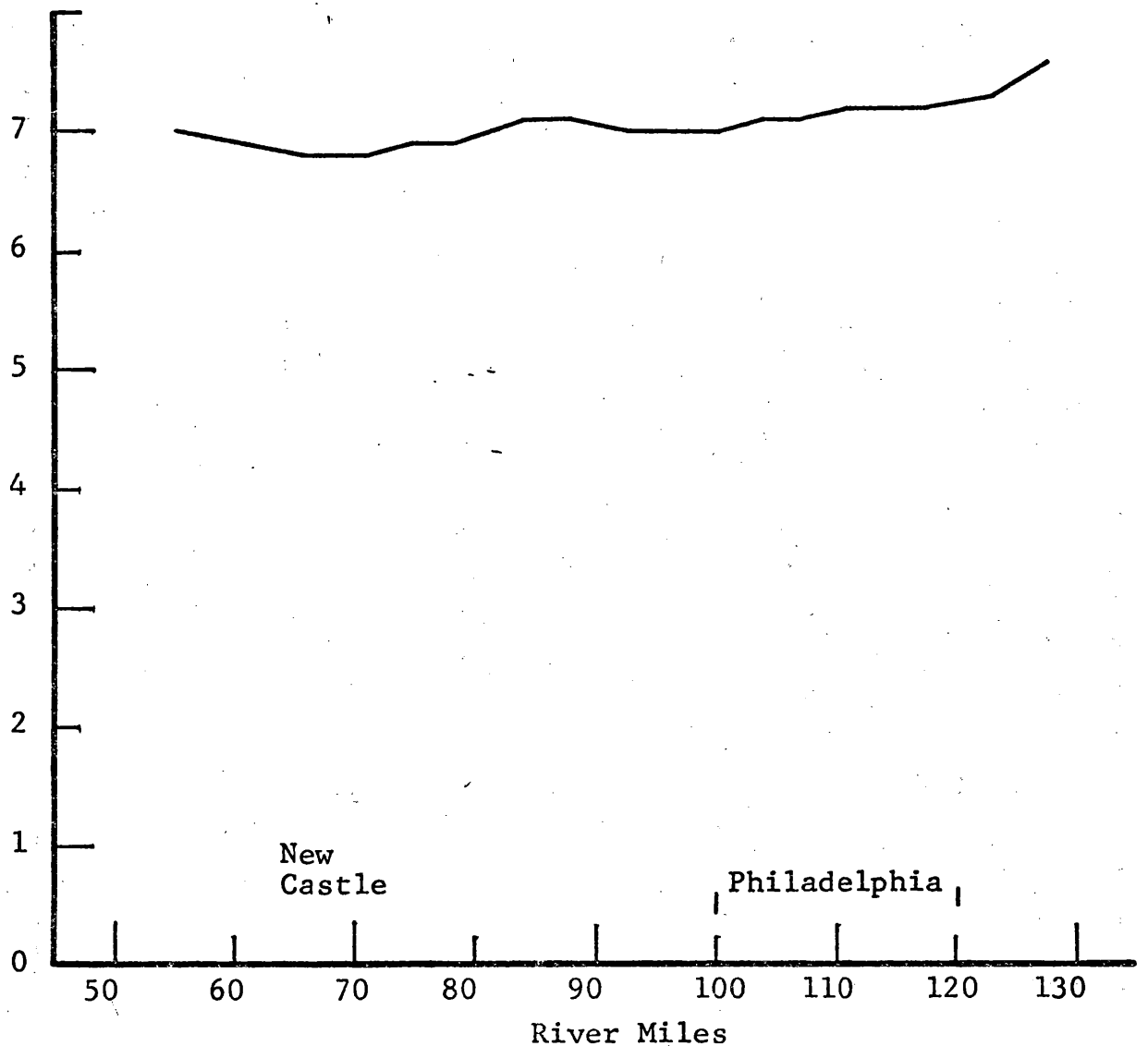

Figure 9. pH Versus Miles Upstream (10)

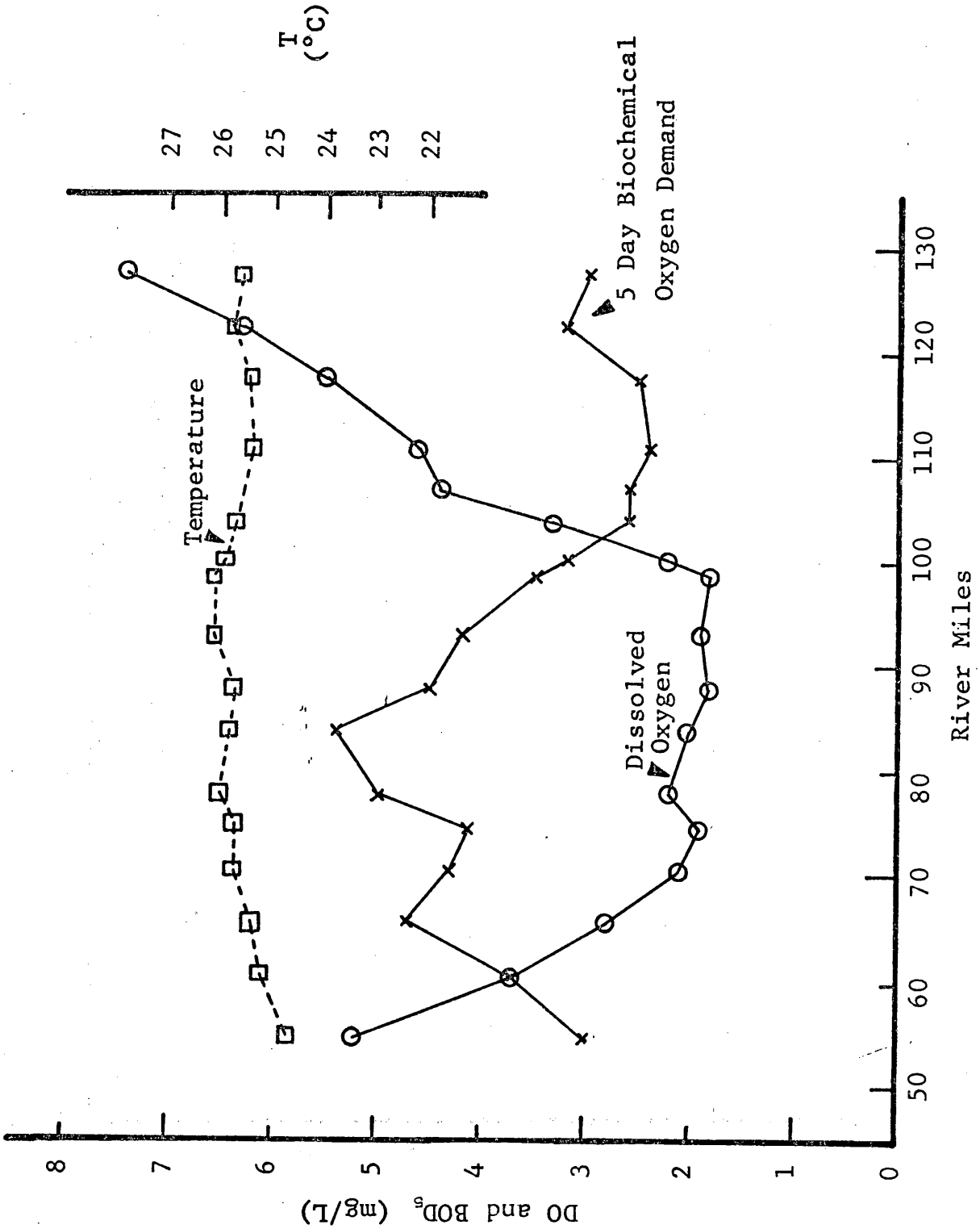

Figure 10. Dissolved Oxygen (DO), Biochemical Oxygen Demand (BOD), and Temperature Versus Miles Upstream (10)

b. Water Quality Standards in the Delaware Estuary

The Delaware Estuary has been classified as to best usage by both the Delaware Basin Committee (DRBC) and the New Jersey State Department of Environmental Protection (NJDEP). The Delaware Estuary Proper has been divided into zones for classification of water quality standards. These zone classifications are:

Zone 2 - River Mile 133.4 (head of tidewater) to 108.4
Zone 3 - River Mile 108.4 to 95.0
Zone 4 - River Mile 95.0 to 78.8
Zone 5 - River Mile 78.8 to 48.2 (Liston Point)
Zone 6 - River Mile 48.2 to 0.0 (Atlantic Ocean)
Appendix A contains a copy of Articles 2-1, 2-2, and 2-3 of Basin Regulations - Water Quality, DRBC.

3. Summary

This section reviewed the water quality of the Arthur Kill and Raritan Bay, and the Delaware River and Bay. It is assumed that the outfall from the petroleum refinery's wastewater treatment plant would be into either one of the these receiving streams.

Overall, the water quality in these two water bodies is of lower or intermediate classification. In the Delaware River, pollutant levels increase as the river flows by Philadelphia and New Castle; whereas, water quality in the Arthur Kill is generally more constant. Most major water pollutants approach or exceed the majority of applicable water quality standards in these two water bodies.

It should be noted that emission rate regulations are used to protect the environment from detrimental water impacts. The

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emission rates are regulated for discharge into surface waters by the National Pollutant Discharge Elimination System (NPDES). The NPDES is the mechanism which assures designated beneficial use of the receiving water will be achieved. These regulations were considered significant to this analysis because of their nature, and were not reported.

C. Water Supply

Refineries require large amounts of water for cooling, process requirements and miscellaneous uses. The water used for cooling need not be of drinking water quality; however, process water must be of that quality. Although not all of the water requirements need to be met on a continuous basis due to the practice of revising and recycling water, the continuous water requirements are quire large.

In the area of water availability within the study area, potential problems could exist. BDM (Reference 6) projected that is the water demand increases to 2,500 mgd in Northeastern New Jersey, a supply deficit could result. This projection assumed Northeastern New Jersey to be an isolated area, one that lacked a regional water supply plan. Even though there appears to be, at the present time, a lack of resources, lack of authority to effectively enforce existing regulations, vague restrictions, and a general lack of water resource management, a regional water supply plan should be adopted by the respective State governments in the near future. Alternative regional water supply plans that have been proposed include:

1) The Delaware River Basin Project (Reference 7) which would produce an estimated yield of 350 mgd.

2) The Raritan River Basin Project (Reference 7) which would increase the yield of the Raritan River by 70 mgd.

3) The South Jersey Groundwater Project (Reference 7) which would produce an estimated yield of 400 mgd.

4) The Hudson River Basin Project (Reference 7) which would produce an estimated 500 to 1,300 mgd.

Therefore, when the total region including the Hudson, Raritan, and Delaware Rivers are considered, the overall supply of water is more than adequate to meet any foreseeable demand. The primary problems in obtaining this water are economical and socio-institutional. However, with the construction of new water control facilities, i.e., pipelines, dams, water for new sources such as petroleum refineries, would be available.

References (Proposed Area - Ambient Air and Water Quality)

1) 1974 and 1973 Annual Air Quality Report, New Jersey Department of Environmental Protection, Bureau of Air Pollution Control, Trenton, New Jersey.

2) Communication with Robert R. French, P.E. at the State of Delaware, Department of Environmental Control, Air Resources Section, Dover, Delaware, February 26, 1976 and April 6, 1976.

3) Environmental Report on the Proposed Modernization of the Perth Amboy Refinery - Volume I, submitted by the Chevron Oil Company to the State of New Jersey - Department of Environmental Protection, pp. 4-47, August 1973.

4) U.S. Department of the Interior, Federal Water Pollution Control Administration, Northeast Region - Raritan Bay Project, Report for the Conference on Pollution of Raritan Bay and Adjacent Interstate Waters, Third Session, Volume 1 - Project Studies and Results, Metuchen, New Jersey, May 1967.

5) U.S. Geological Survey and Delaware River Basin Commission, Water Quality of the Delaware River Estuary, 1967, 1970.

6) Final Report - A Study of New Use Demands on the Coastal Zone and Offshore Areas of New Jersey and Delaware - Apprndix 5, The BDM Corporation, Office of Technology Assessment, Contract OTA-C-8, December 1975.

7) Northeastern United States Water Supply Study - Engineering Feasibility Report on Alternative Regional Water Supply Plans: Northern New Jersey - New York City - Western Connecticut Metropolitan Area, pp. 4-17 to 4-24, November 1971.

8) Monitoring and Air Quality Trends Report, 1973, U.S. EPA - Office of Air and Waste Management, EPA-450/1-74-007, October 1974.

9) Emission Inventory and Air Quality Data Report to the Air Pollution Control Board, City of Philadelphia Department of Public Health - Air Management Services, October, 1974 (Revised).

10) Final Report: A Program to Investigate Various Factors in Refinery Siting, Radian Corporation Contract Number 100-024, Submitted to the Council on Environmental Quality and Environmental Protection Agency, 15 February 1974.

11) Reference 3.

SECTION VI

ENVIRONMENTAL IMPACT

This section examines the general environmental impact on the ambient air and water quality from the location of new or expanded petroleum refinery capacity equal to 250,000 barrels per day in Glouchester, Salem, and Middlesex Counties in New Jersey and New Castle County in Delaware. The analysis is viewed in general terms because of the nonspecificity of the refinery site, and intents to give general predictable trends that might result from location of refining capacity in the proposed area. A normally operating refinery is assumed.

A. Air Impact

The purpose of this section is to provide an approximate estimate of the impact of ambient air quality which might result from the location of new or expanded oil refinery capacity in the proposed area. Although there are many species of air emissions associated with oil refineries, this report considers only suspended particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, hydrocarbons and photochemical oxidants for which EPA and the respective State governments have set ambient air quality standards (AAQS). This analysis assumes pollution control at the refinery to be achievable in terms of current technology.

Particulates, SO_2 and CO emissions from a petroleum refinery can be viewed on a local scale, i.e., county-wide, as far as its effect on air quality is concerned. However, the non-methane hydrocarbon and NO_x emissions from a petroleum refinery must be viewed on a greater spatial area, i.e., surrounding counties or Air Quality Control Region (AQCR). This theory is supported by laboratory data (Reference 1) that has shown the maximum concentration of photochemical oxidant depends significantly on the

initial hydrocarbon:NO_x ratio in a geographical area. Photochemical oxidant is a secondary pollutant which forms photochemically in the presence of sunlight in a matter of hours after hydrocarbons and NO_x are released into the ambient air. As a result, the non-methane hydrocarbon and NO_x ambient air level must be viewed using an area approach because of the secondary photochemical reactions inherent to these pollutants. There is not a modelling program, at present, that relates hydrocarbon emissions from point sources, i.e., a petroleum refinery to ambient oxidant concentrations. This analysis will assume hydrocarbons (and NO_x) are precursors to oxidant formation and base its analysis upon that assumption.

Sulfur Dioxide, Carbon Monoxide, Suspended Particulate Matter

In Chapter IV - Proposed Refinery Effluent, table 2, the predicted maximum concentrations from the proposed refinery are tabulated. As shown, the refinery, in itself, would not cause the SO_2 Federal and State AAQS to be exceeded in the proposed area. In fact, the largest percentage infraction upon the SO_2 AAQS from the projected maximum SO_2 concentration emitted from the refinery was ten percent in the case of the secondary annual authmetic mean of 0.02 ppm. However, if the ambient air in the refinery siting area approximates or exceeds the AAQS, at present, or is predicted to do so in the next ten or fifteen years, a potential SO_2 problem could exist. This is the case in Middlesex County where the present SO_2 air quality approximates the maximum 24-hour and Annual Arithmetic Mean AAQS. Since the SO_2 ambient air quality appears to be improving (Chapter V - Proposed Area: Ambient Air and Water Quality, table 1), future ambient sulfur dioxide concentrations may be significantly less.

The same type of situation exists for CO emissions in the proposed area. The refinery CO emissions total 21.2 percent of the maximum 8-hour CO AAQS and 9.2 of the maximum 1-hour

CO AAQS in the proposed area.[1/] The 8-hour CO AAQS could possibly be exceeded in Gloucester, Salem, and Middlesex Counties with the addition of new refinery capacity. The present ambient CO concentration can be associated principally with automobiles. This is illustrated by the New Jersey Transportation Control Plan (1970) where 86, 91, and 74 percent of CO emission in Gloucester, Salem, and Middlesex Counties were transportation sources (Reference 4).

Once again, particulate emissions from the proposed refinery would not, in themselves, exceed the Federal and State AAQS. The largest percentage infraction upon the particulate AAQS from the projected maximum particulate concentration emitted from the refinery was 5.5 percent in the case of the secondary maximum 24-hour AAQS of 150 ug/m^3. However, Middlesex County could have ambient particulate levels exceeding the maximum 24-hour and the Annual Geometric Mean AAQS if additional petroleum refinery capacity is located in the area.

Hydrocarbons, Nitrogen Dioxide, Oxidants

The NO_x (NO and NO_2) levels in the site area appear to be quite close to the Federal and State Annual Arithmetic Mean AAQS of 0.05 ppm. The refinery emissions of NO_x are basically limited to NO generated by combustion. Nitrogen dioxide is formed in the atmosphere by the oxidation of NO. The annual concentration of NO_x due to the refinery is small(projected as 0.003ppm in Chapter IV-table 2) and should not be a factor in the ultimate compliance with annual AAQS when automobile sources are brought into compliance with Federal emission standards. However, if the NO_x concentrations in the area remain at approximately the AAQS level, the additional contribution of NO_x from increased refinery capacity could be significant.

1/ In Delaware, the refinery CO emissions total 15.9 percent of the maximum eight-hour CO AAQS.

Hydrocarbons AAQS are enforced as a means to achieve the Federal and State maximum 1-hour photochemical oxidant standard of 0.08 ppm. In spite of the elaborate hydrocarbon control designed into the proposed 250,000 BPD petroleum refinery, the 3-hour maximum NMHC[1/] concentration of 0.48 ppmC exceeds the applicable Federal and State NMHC AAQS. In 1974, the non-methane hydrocarbon ambient concentration in the New Jersey portion of the Metropolitan Philadelphia AQCR which includes Glouchester and Salem Counties, was 17 times the 3-hour guideline value of 0.24 ppmC[2/] and the ambient photochemical oxidant (ozone) concentration was 0.196 ppm. The New Jersey portion of the N.J.-N.Y.-Conn. AQCR which includes Middlesex County registered a 3-hour NMHC level of 3.3 ppmC which was 13.8 times the Federal and State AAQS. The ozone level in the same area was 0.165 ppm. The most likely source of hydrocarbon emissions is automobile traffic and industrial emissions. According to Appendix J (Reference 4), total hydrocarbon emissions in the Metropolitan Philadelphia AQCR and N.Y.-N.J.-Conn. AQCR's need to be reduced approximately 65 and 55 percent ot meet the photochemical oxidant AAQS of 0.08 ppm. The State of Delaware Division of Environmental Control does not monitor ambient hydrocarbon concentrations within the State. However, violations of the 0.08 ppm oxidant standard at four sampling sites in New Castle County ranged from 0.88 ppm to 0.40 ppm, and numbered 117 in November, 1975. This data suggests there is also an oxidant problem in New Castle County, Delaware.

The regional area of study is for the most part, exceeding the oxidant and non-methane hydrocarbon AAQS. Overall, approximately 43 tons/day of hydrocarbons are emitted from the proposed refinery. Miscellaneous hydrocarbon losses account for approximately 85 percent of this loss or approximately 37 tons/day. The

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1/ Assume 10 percent of the total hydrocarbon emitted from the refinery are non-methane. This is a conservative estimate.

2/ ppmC - parts per million carbon.

tank farm emits approximately 12 percent of the overall hydrocarbon loss or approximately 5 tons/day even with the use of floating roof tanks. Assuming 365 operational days per year, a 250,000 B/D refinery with its tank farm included will emit 15,700 tons of hydrocarbons. This would amount to 99, 151, 23, 54, and 10 percent of the total hydrocarbon emissions from sources in Glouchester, Salem, Middlesex, and New Castle Counties, and the City of Philadelphia, respectively as can be seen in Table 1. The hydrocarbons that would be emitted by additional refinery capacity are probable precursors to photochemical oxidants and would most likely worsen the ambient air quality in the proposed area. Therefore, if there is an air quality constraint on possible new or expanded refineries in the proposed area, it probably would be the result of hydrocarbon emissions from the refinery and its tank farm.

In this analysis, it was assumed that the refinery tank farm is part of the refinery proper. It should be noted that a tank farm may be located outside the refinery parameter which would reduce its overall hydrocarbon emission (in this case, by approximately 12 percent). The refinery tank farm would have to be located outside the regional area to have an effect on the resulting ambient oxidant concentrations.

Table 1: Total Hydrocarbon Emissions and Percent of Present HC Emissions With Addition of a 250,000 BPD Refinery in Glouchester, Salem, Middlesex, and New Castle Counties, and the City of Philadelphia.

	Total Hydrocarbon Emissions	Percent of Present HC Emission With addition of 250,000 BPD Petroleum Refinery[a/]
Glouchester County, N.J.	15939.9 [c/]	98.5
Salem County, N.J.	10371.43[c/]	151.4
Middlesex County, N.J.	67503.76[c/]	23.3
New Castle County, D.C.	28856 [b/]	54.4
City of Philadelphia	160550 [d/]	9.8

a/ Assume a 250,000 BPD petroleum refinery will emit 15,700 tons of hydrocarbons in one year (365 days).

b/ A total of 28,856 tons of hydrocarbons were emitted in New Castel County during 1974 (Reference 5).

c/ 1975 emission data (Reference 11).

d/ 1973 emission data (Reference 13).

1. Analysis of Situation

There appears to be two basis options open to the environmental assessment of a new or expanded petroleum refinery in the proposed areas. These options are described below.

Option 1: There is approximately 1,500,000[1/] barrels/day of refining crude capacity in the New Jersey, Delaware, and Metropolitan Philadelphia regional areas. At present, these refineries process imported crude oil. It can be postulated that in eight to ten years, 600,000 barrels/day of crude may be extracted from the Baltimore Canyon to replace the foreign oil being refined now. A Senate-proposed amendment to the Clean Air Act specifies that if more than a one-to-one trade-off in emissions can be demonstrated, a new refinery may be constructed or an existing one expanded. In other words, even if the ambient air quality standard is being violated, as long as the new plus old facility shows progress toward attaining the air quality standard and produced less emissions than the old facility would have, had it met all regulations, new construction could be allowed. However, if there is a need for a new or expanded facility, and even with the newest technology the refinery cannot produce a one-to-one trade-off, the Administrator of EPA under a currently developing EPA policy has the flexibility to review the case and approve construction. Therefore, if a petroleum refinery is needed in an area that is environmentally constrained, EPA feels that it may be able to weigh the economic, cosial and environmental issues of a new or expanded refinery and approve construction on a case-by-case basis.

1/ "Petroleum Refineries in the U.S. and Puerto Rico," Mineral Industry Surveys, U.S. Bureau of Mines.

This is a viable option in the proposed area for future refinery development. With the addition of stringent air pollution control equipment, a petroleum refinery can show a less than 1:1 trade-off in emissions and expand its capacity. Two cases in point are as follows:

1. Chevron Oil Company is presently completing expansion of their 88,000 BPD petroleum refinery at Perth Amboy, Middlesex County, New Jersey to a 150,000 BPD capacity. With additional, more up-to-date air control technology, Chevron was able to reduce their SO_2, particulate, CO, NO_x and hydrocarbon emissions by 62.1, 39.6, 93.8, 26.0 and 43.7 percent, respectively. (Reference 12)
2. Mobil Oil Company submitted an environmental impact statement to the New Jersey Department of Environmental Protection for expansion of their 98,000 BPD petroleum refinery at Paulsboro, Clouchester County, New Jersey to 165,000 BPD. The projected net reductions in SO_2, particulates, CO, NO_x and hydrocarbon emissions after expansion was completed were 16.7, 83.7, 100, 12.8 and 66.4 percent, respectively. (Reference 2)

It appears, therefore, that this policy of a 1:1 trade-off would be applicable and amenable to the petroleum refineries in the proposed area.

Option 2: If the present Federal and State AAQS are enforced as written, it can be postulated that new or expanded refinery capacity in the proposed area would not be probable. At present, the ambient air quality in the proposed area approximates or exceeds present Federal and State AAQS. The air pollutants emitted from a 250,000 BPD petroleum refinery appear to be within Federal and State AAQS except for possibly non-methane hydrocarbon emissions and the resultant ambient photochemical oxidant

concentration. However, when a refinery of this type is located in an area where ambient air pollutant concentrations are approaching or exceeding the AAQS such as in the proposed area, the AAQS in that area are likely to be exceeded. As a result, if the AAQS are to be exceeded in an area as a result of additional development of refinery capacity, under current regulations, the new or expanded refinery can not be built. This type of analysis is, of course, very site-specific. However, the situation described above does appear to be applicable to the project area, in that, until the air quality in the area satisfies all AAQS, a new or expanded refinery, under current legislation, should not be constructed. This discussion assumes that the proposed refinery meets all new source performance standards.

Three cases where current legislation has hindered the development of new or expanded refinery capacity are discussed below.

1) When Union Oil of California wanted to expand their storage tank farm, it took 3 years to get approval from State and local governments to build 3 additional tanks on their own property (Reference 6).

2) Mobil Oil applied for expansion of its Paulsboro petroleum refinery in Glouchester County from 98,000 to 240,000 barrels per day capacity in April 1974. Due to the delay caused by zoning, planning and land use commissions, and environmental action groups, Mobil was caught up in the rapid cost increase of petroleum equipment and forced to discontinue their expansion plans. This example illustrates that fact that economic along with enviromental consequences confront petroleum refinery construction and expansion (Reference 6).

3) The Shell Oil Company sought permission from the State of Delaware to build a refinery in the New Castle County. Shell Oil was discouraged from going ahead with their plan when the Delaware legislature instituted a moratorium on refinery construction in the lower Delaware Bay from Marcus Hook south along the coast. Shell Oil has since submitted an environmental impact statement for construction of a new 150,000 BPD petroleum refinery to the New Jersey Department of Environmental Protection. Shell Oil has purchased 10,000 acres of land for the new grass-roots refinery in Glouchester County. Shell Oil is presently in the initial permit stage of application to the NJDEP and, at present, is not initiating future action (References 6 and 7).

B. Conclusion

Hydrocarbon and NO_x emissions from a petroleum refinery even with emission control in terms of current technology, could possibly cause major air pollution problems by acting as a precursor to photochemical oxidants in the proposed area. Other refinery air pollutants such as SO_2, CO, and suspended particulate matter, may produce more localized, less major air pollution problems. The air emission from the proposed refinery could be a determining factor in its construction depending on the current air legislation at that time.

C. Water Impact

This section presents the estimated water quality impact of locating a 250,000 BPD petroleum refinery in the proposed area of Glouchester, Salem, and Middlesex Counties in New Jersey, and New Castle County in Delaware. The expected waterborne pollutants resulting from the operation of a new or expanded refinery include BOD, COD, ammonia as nitrogen, sulfide, oil and grease, phenol, phorphorus, suspended solids, dissolved solids, chromium, and heat.

It is assumed that the refinery will have a waste treatment facility with a single outfall with effluent control facilities based upon current best available and proven technology. Proposed effluent characteristics are presented in Chapter IV - Proposed Refinery Effluent, table 3. Normal operation i.e., no oil spills is assumed.

The refinery's maximum influence on the receiving stream is a function of ambient flow conditions, and flow rate which varies with the time of year. Due to the lack of specific site for the proposed refinery, the water impact will be viewed in general terms. The two assumed receiving streams in this impact analysis are the Arthur Kill and Raritan Bay, and the Delaware River and Basin.

Table 1 contains the estimated water impact of a 250,000 BPD petroleum refinery in the Delaware River and Basin. This analysis using the water quality display model (Reference 8) assumed a negligible background concentration and a discharge point downstream of New Castle, New Castle County, Delaware. It is assumed that the refinery effluent once discharged into the receiving stream, will be diluted by means of turbulent dispersion and advection. Using the water quality-hydrodynamic model (Reference 9), the contribution of a 250,000 BPD petroleum refinery to the Delaware River and Basin of total chromium was investigated. The outlet point was Paulsboro, Glouchester County, New Jersey. The resultant maximum and average concentration was 0.07 and 0.026 μg/l, respectively.

The results from this analysis suggests that the pollutant concentrations from a 250,000 BPD petroleum refinery sited on the Delaware River and Basin are small and probably will not detrimentally affect the overall water quality except possibly in extreme conditions of slack tide inside the localized mixing zone.

Table 1: Water Quality Impact of a 250,000 B/D Refinery on the Delaware River and Basin[a/] (Reference 8)

Pollutant	Effluent Concentration (mg/l)	Pollutant Concentration (mg/l) in Receiving Stream[c/]		
		Ebb Flow	Slack Water	Flood Flow
BOD_5[b/]	15	0.021	5.7	0.024
COD	80	0.11	30	0.13
Ammonia as Nitrogen	2.0	0.0028	0.75	0.0023
Oil and Grease	2.0	0.0028	0.75	0.0033
Phenol	0.1	0.000014	0.038	0.00016
Dissolved Solids	370	0.52	140	0.69
Suspended Solids	10	0.014	3.8	0.016
Sulfides	0.1	0.00014	0.038	0.00016
Phorphorous	2.0	0.0028	0.75	0.0033

a/ Outlet point is downstream of New Castle, New Castle County, Delaware.
b/ 5-day BOD.
c/ Assume negligible pollutant concentration in receiving stream.

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Similar results can be deduced from modelling studies (Reference 10) conducted for the Chevron Oil Company in the Arthur Kill and Raritan Bay. This study assessed the probable water quality impact of a 150,000 BPD oil refinery on the receiving waters of the Arthur Kill and Raritan Bay. As can be seen in Table 2 which summarizes these results, ambient water quality is not detrimentally affected by the refinery effluent. In some cases, the range of pollutant concentration in the refinery effluent was lower than the pollutant concentration in the receiving stream, i.e., COD or bridged the pollutant concentration in the receiving stream, i.e. ammonia as nitrogen, oil and grease, suspended solids.

1. Thermal Effects

Mobil Oil (Reference 9) performed an analysis to determine the impact of the proposed 250,000 BPD refinery's thermal discharge upon the Delaware Estuary. In order to determine the maximum potential induced temperature increase caused by the summer maximum refinery thermal discharge of 2×10^9 Btu/day, a freshwater flow of 1,000 cfs was chosen. Assuming complete mixing, this flow resulted in a maximum induced temperature increase of $0.37^{\circ}F$. Mobil preducts the actual induced temperature increase caused by their refinery will be less than $0.37^{\circ}F$ and will vary inversely with the net flow in the estuary. Based upon the average annual flow, the induced temperature increase would be $0.03^{\circ}F$. This increase temperature will produce minimal effects on the Delaware River and Basin assuming a viable ambient temperature exists in the receiving stream.

Since both Delaware and Raritan Bay are close to their maximum allowed thermal load and a potential problem may exist with thermal pollution, it is assumed that the proposed refinery will use control devices (i.e., cooling towers) to alleviate this potential problem.

Table 2: Violation of Ambient Water Quality Standards in the Arthur Kill and Raritan Bay (Reference 10)

Pollutant	Existing Ambient Conditions and Range of Pollutant in Receiving Water (mg/l)	Background Plus Projected Refinery Discharge	Projected Discharge Concentration Ranges (mg/l)	Proposed Refinery Effluent Concentrations (mg/l)
BOD_5	1 (4.3 - 4.8)	1	18-25	15
COD	3 (112 to 135)	3	95-99	80
Ammonia as Nitrogen	3 (0.1 to 9.2)	3	4-25	2.0
Oil and Grease	2 (2 to 140)	2	1-20	2.0
Phenol	2 (0.023 to 0.061)	2	0.1-0.5	0.1
Suspended Solids	2 (7 to 220)	2	20-50	10
Sulfides	3 a/	3	0.1-0.5	0.1
pH	5 (6.5 to 8.5)	5	6.5-8.5	≈ 7
Total Chromium	3 ($<$ 0.05 to 0.1)	3	0.1-0.5	0.26

a/ Unknown

Notation:
(1) Violates a quantitative standard
(2) Probably violates a quantitative or qualitative standard
(3) May or may not violate a quantitative or qualitative standard
(4) Probably does not violate a quantitative or qualitative standard
(5) Does not violate a quantitative standard

D. Conclusion

It appears from this analysis that considering the non-pristine quality of the receiving waters in the Delaware River and Basin, and the Arthur Kill and Raritan Bay, any incremental water pollution from the proposed oil refinery above ambient conditions would be insignificant. Water quality modelling studies indicate that the effluent discharges due to the proposed petroleum refinery along result in ambient concentrations that are well within the standards, and represent only a small fraction of background ambient conditions. The proposed new refinery construction or expansion would produce very little impact on regional water quality and would probably not be constrained on the basis of its water quality impact.

References (Environmental Impact)

1) Steinfeld, John H., Air Pollution - Physical and Chemical Fundamentals, McGraw-Hill, Inc., 1975.

2) Environmental Report on the Proposed Modernization of the Paulsboro Refinery - Volume 2, submitted by Mobil Oil Corporation to the State of New Jersey, Department of Environmental Protection, pp. 4.1-48, April 1974.

3) New Jersey Transportation Control Plan, US EPA, Washington, D.C.

4) Code of Federal Regulations, 40 CFR 2.100, Washington, D.C., 1973.

5) Communication with Robert E. French, P.E., State of Delaware, Division of Environmental Control, Dover, Delaware, February 26, 1976.

6) Communication with Ray Wright, Director Division of Refining, American Petroleum Institute, Washington, D.C., February 25, 1976.

7) Communication with Lawrence Schmidt, State of New Jersey, Department of Environmental Protection, Office of Environmental Review, Trenton, New Jersey, March 9, 1976.

8) Final Report: A Program to Investigate Various Factors in Refinery Siting, Radian Corporation Contract Number 100-024, submitted to the Council on Environmental Quality and Environmental Protection Agency, 15 February 1974.

9) Reference 2, pp. 4.2-62.

10) Environmental Report on the Proposed Modernization of the Perth Amboy Refinery - Volume 1, submitted by the Chevron Oil Company to the State of New Jersey, Department of Environmental Protection, pp. 4-67, August 1973.

11) 1974 Annual Air Quality Report, State of New Jersey, Department of Environmental Protection, Trenton, New Jersey.

12) Reference 10, pp. 4-27.

13) Emissions Inventory and Air Quality Data Report to the Air Pollution Control Board, City of Philadelphia, Department of Public Health, Air Management Services, October 1974 (revised).

APPENDIX A

ARTICLES 2-1, 2-2, AND 2-3 OF BASIN REGULATIONS - WATER QUALITY, DELAWARE RIVER BASIN COMMISSION

WATER QUALITY STANDARDS FOR THE DELAWARE RIVER BASIN

Article 2-I

Basinwide

Section 2-I.1 Water Uses

(1) Uses paramount. Water uses shall be paramount in determining stream quality objectives which, in turn, shall be the basis for determining effluent quality requirements.

(2) Uses to be protected. The quality of Basin waters shall be maintained in a safe and satisfactory condition for the following uses: (a) agricultural, industrial, and public water supplies after reasonable treatment, except where natural salinity precludes such uses; (b) wildlife, fish and other aquatic life; (c) recreation; (d) navigation; (e) controlled and regulated waste assimilation to the extent that such use is compatible with other uses; and (f) such other uses as may be provided by the Comprehensive Plan.

Section 2-I.2 Stream Quality Objectives

(1) Limits. The waters of the Basin shall not contain substances attributable to municipal, industrial, or other discharges in concentrations or amounts sufficient to preclude the specified water uses to be protected. Within this requirement, the waters shall be substantially free from unsightly or malodorous nuisances due to floating solids, sludge deposits, debris, oil, scum, substances in concentrations or combinations which are toxic or harmful to human, animal, plant, or aquatic life, or that produce color, taste, odor of the water, or taint fish or shellfish flesh. In no case shall concentrations of substances exceed those values given for rejection of water supplies in the United States Public Health Service Drinking Water Standards.

(2) Nondegradation of Interstate Waters. It is the policy of the Commission to maintain the quality of interstate waters, where existing quality is better than the established stream quality objectives, unless it can be affirmatively demonstrated to the Commission that such change is justifiable as a result of necessary economic or social development or to improve significantly another body of water. In implementing this policy, the Commission will require the highest degree of waste treatment determined to be practicable. No change will be considered which would be injurious to any designated present or future use. In the implementation of this policy, the Secretary of the Interior will be kept advised and will be provided with such information as he will need to discharge his responsibilities under the Federal Water Pollution Control Act.

Section 2-I.3 Effluent Quality Requirements

(1) Minimum treatment. All wastes shall receive a minimum of secondary treatment, regardless of the stated stream quality objective.

(2) Disinfection. Wastes (exclusive of stormwater bypass) containing human excreta or disease producing organisms shall be effectively disinfected before being discharged into surface bodies of water.

(3) Public safety. Effluents shall not create a menace to public health or safety at the point of discharge.

(4) Limits. Discharges shall not contain more than negligible amounts of debris, oil, scum or other floating materials, suspended matter which will settle to form sludge, toxic substances, or substances or organisms that produce color, taste, odor of the water, or taint fish or shellfish flesh.

(5) Allocation of capacity. Where necessary to meet the stream quality objectives, the waste assimilative capacity of the receiving waters shall be allocated in accordance with the doctrine of equitable apportionment.

Section 2-1.4 Other Considerations

(1) Combined sewers. Any new facility or project combining sanitary or industrial waste with stormwater drainage which would have a substantial effect on the quality of waters of the Basin shall not be permitted, whether or not any such project or facility discharges into an existing combined system.

(2) Access and reports. The Commission, or its duly authorized representatives, shall have access, at reasonable hours, to observe and inspect waste treatment facilities and to collect samples for analyses. Upon written request, waste treatment facility operation reports shall be submitted to the Commission.

(3) Zones. The Delaware River and Bay and their tributaries may be divided into zones which will facilitate the management of surface and underground water quality.

(4) Streamflow. Numerical stream quality objectives are based on a minimum consecutive 7-day flow with a 10-year recurrence interval.

Section 2-1.5 Definitions

(1) Biochemical oxygen demand. Biochemical oxygen demand as determined under standard laboratory procedures for 5 days at 20° C.

(2) Carbonaceous oxygen demand. That part of the ultimate oxygen demand associated with biochemical oxidation of carbonaceous, as distinct from nitrogenous, material.

(3) Effective disinfection. The destruction of pathogenic organisms in such manner and under such controls as shall be prescribed by Commission regulations.

(4) Secondary treatment. The removal of practically all suspended solids at all times and the reduction of the biochemical oxygen demand by at least 85 percent, and may include the in-plant control of industrial wastes as prescribed by the Commission.

(5) River mile. The distance, in statute miles, of a location or item measured from "mile zero."

a. Delaware Bay and River. Mile zero is located at the intersection of the centerline of the navigation channel and a line between the Cape May Light and the tip of Cape Henlopen. Distances from mile zero are measured essentially along the centerline of the navigation channel up to the Trenton-Morrisville Toll Bridge (R. M. 133.4) and above that point along the State boundary line as shown on published quadrangle maps of the United States Geological Survey.

b. Tributaries. Mile zero is located at the intersection of the centerline of the tributary and a line joining the opposite banks at its mouth. Distances from mile zero are measured along the centerline of the tributary.

Section 2-1.6 Application. This Article shall apply to all surface waters of the Delaware River Basin.

Article 2- 2

Interstate Streams--Nontidal

Section 2- 2.1 Application. This Article shall apply to the interstate nontidal streams of the Delaware River Basin.

Section 2- 2.2 Description. The interstate nontidal streams of the Delaware River Basin are those rivers, lakes, and other waters that flow across or form a part of state boundaries. The interstate waters are further classified as follows:

(1) Zone 1A is that part of the Delaware River extending from the confluence of the East and West Branches of the Delaware River at Hancock, New York, R.M. (River Mile) 330.7, to the U. S. Route 106 bridge at Narrowsburg, New York, R.M. 289.9.

(2) Zone 1B is that part of the Delaware River extending from the U. S. Route 106 bridge at Narrowsburg, New York, R.M. 289.9, to the U. S. Routes 6 and 209 bridge at Port Jervis, New York, R.M. 254.75.

(3) Zone 1C is that part of the Delaware River extending from the U. S. Routes 6 and 209 bridge at Port Jervis, New York, R.M. 254.75, to Tocks Island Dam, R.M. 217.0 (proposed axis of dam).

(4) Zone 1D is that part of the Delaware River extending from Tocks Island Dam, R.M. 217.0 (proposed axis of dam), to R.M. 185.0, above Easton, Pennsylvania.

(5) Zone 1E is that part of the Delaware River extending from R.M. 185.0, above Easton, Pennsylvania, to the head of tidewater at Trenton, New Jersey, R.M. 133.4 (Trenton-Morrisville Toll Bridge).

(6) Zone E is East Branch Delaware River extending from its source in the town of Roxbury, Delaware County, New York, to its mouth at Hancock, New York, at R.M. 330.7 on the Delaware River.

(7) Zone W1 is West Branch Delaware River extending from its source in the town of Jefferson, Schoharie County, New York, to its mouth at Hancock, New York, at R.M. 330.71 on the Delaware River.

(8) Zone W2 is Sand Pond Creek extending from R.M. 1.8 at the confluence of Sherman Creek and Starboard Creek in Pennsylvania to its mouth in New York at R.M. 10.1 on the West Branch Delaware River; Cat Hollow Brook extending from its source in New York to its mouth in Pennsylvania at R.M. 1.05 on Sand Pond Creek; Sherman Creek in Pennsylvania extending from its source to its mouth at R.M. 1.8 on Sand Pond Creek; an unnamed tributary of Sherman Creek extending from its source in New York to its mouth in Pennsylvania at R.M. 1.6 on Sherman Creek; and Starboard Creek extending from its source in Lake Oquaga in New York to its mouth in Pennsylvania at R.M. 1.81 on Sand Pond Creek.

(9) Zone N1 is that part of the Neversink River extending from R.M. 0.5 at its confluence with Clove Brook to its mouth on the Delaware River at R.M. 253.64.

(10) Zone N2 is Clove Brook extending from its source in Steeny Kill Lake in New Jersey to its mouth in New York at R.M. 0.5 on the Neversink River; an unnamed tributary of Clove Brook extending from its source in New York to its mouth in New Jersey at R.M. 1.0 on Clove Brook; and an unnamed tributary to the above unnamed tributary of Clove Brook extending from its source in New York to its mouth in New Jersey at R.M. 0.7 on the unnamed tributary of Clove Brook.

(11) Zone C1 is that part of the Christina River extending from its source in Pennsylvania to the head of tidewater at R.M. 16.3 at the outlet of Smalley's Pond in Delaware.

(12) Zone C2 is West Branch Christina River extending from its source in Maryland to its mouth on the Christina River in Delaware at R.M. 25.7; Persimmon Run extending from its source in Maryland to its mouth on the West Branch Christina River in Delaware at R.M. 0.8; and East Branch Christina River extending from its source in Pennsylvania to its mouth on the Christina River in Delaware at R.M. 30.2.

(13) Zone C3 is White Clay Creek extending from its source in Pennsylvania to R.M. 14.7 at the Pennsylvania-Delaware State line.

(14) Zone C4 is that part of White Clay Creek extending from R.M. 14.7 at the Pennsylvania-Delaware State line to its mouth on the Christina River in Delaware at R.M. 10.0.

(15) Zone C5 is that part of Red Clay Creek extending from the confluence of the East and West Branches of Red Clay Creek in Pennsylvania at R.M. 13.4 to R.M. 12.6, at the Pennsylvania-Delaware State line; and West Branch Red Clay Creek extending from its source to its mouth on Red Clay Creek at R.M. 13.4.

(16) Zone C6 is that part of Red Clay Creek extending from R.M. 12.6 at the Pennsylvania-Delaware State line to its mouth on White Clay Creek in Delaware at R.M. 2.6.

(17) Zone C7 is that part of Brandywine Creek extending from the confluence of the East and West Branches of Brandywine Creek in Pennsylvania at R.M. 20.0 to the head of tidewater at R.M. 2.0 at the Market Street Bridge in Wilmington, Delaware; and West Branch Brandywine Creek extending from its source to its mouth on Brandywine Creek at R.M. 20.0.

(18) Zone C8 is Naaman Creek extending from its source in Pennsylvania to the head of tidewater in Delaware.

Section 2- 2.3 Water Uses to be Protected. The quality of interstate nontidal waters shall be maintained in a safe and satisfactory condition for the uses specified in Column 2 of Table II-1 (page II-7). The following designations apply to that column:

A. Agricultural, industrial, and public water supplies after reasonable treatment.
B. Wildlife, maintenance and propagation of resident game fish and other aquatic life.
C. Maintenance and propagation of trout.
D. Spawning and nursery habitat for anadromous fish.
E. Passage of anadromous fish.
F. Recreation.

Section 2- 2.4 Stream Quality Objectives. The stream quality objectives of the interstate nontidal waters shall be those specified in Column 3 of Table II-1 (page II-7). The following designations apply to that column:

A. Dissolved oxygen.
   1. Not less than 5.0 mg/l at any time; with a minimum daily average of 6.0 mg/l; and not less than 7.0 mg/l in spawning areas whenever water temperatures are suitable for trout spawning.
   2. Not less than 4.0 mg/l at any time.

B. Temperature.
   1. Not to exceed 2°F rise above natural temperature until stream temperature reaches 68°F; natural temperature will prevail above 68°F; wastewater effluents which would create more than a 1°F rise above background may not be dishcarged to natural trout propagation waters.
   2. Not to exceed 5°F rise above natural temperature until stream temperature reaches 87°F, except in heat dissipation areas which may be designated by the Commission; natural temperature will prevail above 87°F, except in designated heat dissipation areas.

C. pH
   1. Between 6.0 and 8.5.
   2. Between 6.5 and 8.5.

D. Phenols - not to exceed 0.005 mg/l.

E. Threshold odor number - not to exceed 24 at 60°C.

F. Synthetic detergents (M.B.A.S.) - not to exceed 0.5 mg/l.

G. Fluorides - not to exceed 1.0 mg/l.

H. Alkalinity - not less than 20 mg/l.

I. Radioactivity--
   alpha emitters - not to exceed 3 pc/l (picocuries per liter);
   beta emitters - not to exceed 1,000 pc/l.

J. Turbidity - not to exceed the natural background by 10 units or a maximum of 25 units, whichever is less, except following precipitation; increases not to be attributable to industrial waste discharges.

K. Fecal coliform - not to exceed 200 per 100 milliliters as a geometric mean; samples shall be taken at such frequency and location as to permit valid interpretation.

Section 2- 2.5 Effluent Quality Requirements. The effluent quality requirements of interstate nontidal waters shall be those specified in Column 4 of Table II-1 (page II-7). The following designations shall apply to that column:

A. All discharges shall meet the effluent quality requirements of Article 2- 1. The carbonaceous oxygen demand from an outfall (exclusive of stormwater bypass) shall not exceed that assigned by the Commission to maintain stream quality objectives.

TABLE II-1

Water Quality Standards for Interstate, Nontidal Streams in Terms of Minimum Water Uses, Stream Quality Objectives and Effluent Quality Requirements

Zone	Water uses	Stream quality objectives	Effluent qu. requirem.
(1)	(2)	(3)	(4)
1A. Delaware River, Hancock to Narrowsburg	ABCDF	A1,B1,C1,D,E,F,I,K	A
1B. Delaware River, Narrowsburg to Port Jervis	ABDEF	A2,B2,C1,D,E,F,I,K	A
1C. Delaware River, Port Jervis to Tocks Island	ABDEF	A2,B2,C1,D,E,F,I,K	A
1D. Delaware River, Tocks Island to Easton	ABDEF	A2,B2,C1,D,E,F,I,K	A
1E. Delaware River, Easton to Trenton	ABDEF	A2,B2,C1,D,E,F,H,I,K	A
E. East Branch Delaware River	ABCF	A1,B1,C1,D,E,F,I,K	A
W1. West Branch Delaware River	ABCF	A1,B1,C1,D,E,F,I,K	A
W2. Sand Pond Creek, Cat Hollow Brook, Sherman Creek, Starboard Creek	ABCF	A1,B1,C1,D,E,F,I,K	A
N1. Neversink River, R.M. 0.0 to 0.5	ABF	A2,B2,C2,D,E,F,I,K	A
N2. Clove Brook and its interstate tributaries	ABCF	A1,B1,C2,D,E,F,I,K	A
C1. Christina River above Smalley's Pond	ABF	A2,B2,C1,D,E,F,I,J,K	A
C2. East and West Branches Christina River, Persimmon Run	ABF	A2,B2,C1,D,E,F,I,J,K	A
C3. White Clay Creek in Pennsylvania	ABCF	A1,B1,C1,D,E,F,I,J,K	A
C4. White Clay Creek in Delaware	ABF	A2,B2,C1,D,E,F,I,J,K	A
C5. Red Clay Creek in Pennsylvania and West Branch Red Clay Creek	ABCF	A1,B1,C1,D,E,F,I,J,K	A
C6. Red Clay Creek in Delaware	ABF	A2,B2,C1,D,E,F,I,J,K	A
C7. Brandywine Creek and West Branch Brandywine Creek	ABDEF	A2,B2,C2,D,E,F,G,I,J,K	A
C8. Naaman Creek	ABF	A2,B2,C1,D,E,F,I,K	A

Article 2- 3

Interstate Streams--Tidal

Section 2- 3.1 Application. This Article shall apply to the Delaware River Estuary and Bay, including the tidal portions of the tributaries thereof.

Section 2- 3.2 Zone 2

(1) Description. Zone 2 is that part of the Delaware River extending from the head of tidewater at Trenton, New Jersey, R.M. (River Mile) 133.4 (Trenton-Morrisville Toll Bridge) to R.M. 108.4 below the mouth of Pennypack Creek, including the tidal portions of the tributaries thereof.

(2) Water uses to be protected. The quality of Zone 2 waters shall be maintained in a safe and satisfactory condition for the following uses: (a) agricultural, industrial, and public water supplies after reasonable treatment; (b) wildlife, maintenance and propagation of resident fish and other aquatic life, passage of anadromous fish; (c) recreation; and (d) navigation.

(3) Stream quality objectives.

a. Dissolved oxygen. Daily average concentration shall not be less than 5.0 mg/l, except during the periods from April 1 to June 15 and September 16 to December 31 when the dissolved oxygen shall not average less than 6.5 mg/l.

b. pH. Between 6.5 and 8.5.

c. Total alkalinity. Between 20 and 100 mg/l.

d. Temperature. Shall not exceed 5°F above the average daily temperature gradient displayed during the 1961-66 period, or a maximum of 86°F, whichever is less.

e. Phenols. Maximum 0.005 mg/l.

f. Threshold odor number. Not to exceed 24 at 60° C.

g. Syndets. (synthetic detergents) measured as M.B.A.S. (methylene blue active substances). Maximum monthly mean 0.5 mg/l.

h. Turbidity. Maximum monthly mean 40 units, maximum 150 units.

i. Radioactivity.
alpha emitters, maximum 3 pc/l (picocuries per liter);
beta emitters, maximum 1,000 pc/l

j. Chlorides. Maximum 15-day mean 50 mg/l.

k. Hardness. Maximum monthly mean 95 mg/l.

l. Fecal coliform. Maximum geometric mean of 200 per 100 milliliters above R.M. 117.81 and 770 per 100 milliliters below R.M. 117.81; samples shall be taken at such frequency and location as to permit valid interpretation.

(4) Effluent quality requirements. All discharges shall meet the effluent quality requirements of Article 2- 1. The carbonaceous oxygen demand from all outfalls in the zone (exclusive of stormwater bypass) shall not exceed that assigned by Commission regulations.

Section 2- 3.3 Zone 3

(1) Description. Zone 3 is that part of the Delaware River extending from R.M. 108.4 to R.M. 95.0 below the mouth of Big Timber Creek, including the tidal portions of the tributaries thereof.

(2) Water uses to be protected. The quality of Zone 3 waters shall be maintained in a safe and satisfactory condition for the following uses: (a) agricultural, industrial, and public water supplies after reasonable treatment; (b) wildlife, maintenance of resident fish and other aquatic life, passage of anadromous fish; (c) recreation; and (d) navigation.

(3) Stream quality objectives.

a. Dissolved oxygen. Daily average concentration shall not be less than 3.5 mg/l, except during the periods from April 1 to June 15 and September 16 to December 31 when the dissolved oxygen shall not average less than 6.5 mg/l.

b. pH. Between 6.5 and 8.5.

c. Total alkalinity. Between 20 and 120 mg/l.

d. Temperature. Shall not exceed 5°F above the average daily temperature gradient displayed during the 1961-66 period, or a maximum of 86°F, whichever is less.

e. Phenols. Maximum 0.005 mg/l.

f. Threshold odor number. Not to exceed 24 at 60°C.

g. Syndets. (M.B.A.S.) Maximum monthly mean 1.0 mg/l.

h. Turbidity. Maximum monthly mean 40 units, maximum 150 units.

i. Radioactivity.
alpha emitters, maximum 3 pc/l (picocuries per liter);
beta emitters, maximum 1,000 pc/l.

j. Chlorides. Maximum 200 mg/l.

k. Hardness. Maximum monthly mean 150 mg/l.

l. Fecal coliform. Maximum geometric mean of 770 per 100 milliliters; samples shall be taken at such frequency and location as to permit valid interpretation.

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(4) Effluent quality requirements. All discharges shall meet the effluent quality requirements of Article 2- 1. The carbonaceous oxygen demand from all outfalls in the zone (exclusive of stormwater bypass) shall not exceed that assigned by Commission regulations.

Section 2- 3.4 Zone 4

(1) Description. Zone 4 is that part of the Delaware River extending from R.M. 95.0 to R.M. 78.8, the Pennsylvania-Delaware boundary line, including the tidal portions of the tributaries thereof.

(2) Water uses to be protected. The quality of Zone 4 waters shall be maintained in a safe and satisfactory condition for the following uses: (a) industrial water supply after reasonable treatment; (b) wildlife, maintenance of resident fish and other aquatic life, passage of anadromous fish; (c) recreation; and (d) navigation.

(3) Stream quality objectives.

a. Dissolved oxygen. Daily average concentration shall not be less than 3.5 mg/l, except during the periods from April 1 to June 15 and September 16 to December 31 when the dissolved oxygen shall not average less than 6.5 mg/l.

b. pH. Between 6.5 and 8.5.

c. Total alkalinity. Between 20 and 120 mg/l.

d. Temperature. Shall not exceed 5°F above the average daily temperature gradient displayed during the 1961-66 period, or a maximum of 86°F, whichever is less.

e. Phenols. Maximum 0.02 mg/l.

f. Threshold odor number. Not to exceed 24 at 60°C.

g. Syndets. (M.B.A.S.) Maximum monthly mean 1.0 mg/l.

h. Turbidity. Maximum monthly mean 40 units, maximum 150 units.

i. Radioactivity.
alpha emitters, maximum 3 pc/l
beta emitters, maximum 1,000 pc/l.

j. Chlorides. Maximum 250 mg/l at R.M. 92.47.

k. Fecal coliform. Maximum geometric mean of 770 per 100 milliliters; samples shall be taken at such frequency and location as to permit valid interpretation.

(4) Effluent quality requirements. All discharges shall meet the effluent quality requirements of Article 2- 1 The carbonaceous oxygen demand from all outfalls in the zone (exclusive of stormwater bypass) shall not exceed that assigned by Commission regulations.

Section 2- 3.5 Zone 5

(1) Description. Zone 5 is that part of the Delaware River extending from R.M. 78.8 to R.M. 48.2, Liston Point, including the tidal portions of the tributaries thereof.

(2) Water uses to be protected. The quality of Zone 5 waters shall be maintained in a safe and satisfactory condition for the following uses: (a) industrial water supply after reasonable treatment; (b) wildlife, maintenance of resident fish and other aquatic life, propagation of resident fish from R.M. 70.0 to R.M. 48.2, passage of anadromous fish; (c) recreation; and (d) navigation.

(3) Stream quality objectives.

a. Dissolved oxygen. Daily average concentration shall not be less than 3.5 mg/l at R.M. 78.8, 4.5 mg/l at R.M. 70.0 and 6.0 mg/l at R.M. 59.5, except during the periods from April 1 to June 15 and September 16 to December 31 when the dissolved oxygen shall not average less than 6.5 mg/l in the entire zone.

b. pH. Between 6.5 and 8.5.

c. Total alkalinity. Between 20 and 120 mg/l.

d. Temperature. Shall not exceed 5°F above the average daily temperature gradient displayed during the 1961-66 period, or a maximum of 86°F, whichever is less.

e. Phenols. Maximum 0.02 mg/l.

f. Threshold odor number. Not to exceed 24 at 60°C.

g. Syndets. (M.B.A.S.) Maximum monthly mean 1.0 mg/l.

h. Turbidity. Maximum monthly mean 40 units, maximum 150 units.

i. Radioactivity.
alpha emitters, maximum 3 pc/l (picocuries per liter);
beta emitters, maximum 1,000 pc/l.

j. Fecal coliform. Maximum geometric mean of 770 per 100 milliliters; samples shall be taken at such frequency and location as to permit valid interpretation.

(4) Effluent quality requirements. All discharges shall meet the effluent quality requirements of Article 2-1. The carbonaceous oxygen demand from all outfalls in the zone (exclusive of stormwater bypass) shall not exceed that assigned by Commission regulations.

Section 2- 3.6 Zone 6

(1) Description. Zone 6 is that part of Delaware Bay extending from R.M. 48.2 to R.M. 0.0, the Atlantic Ocean, including the tidal portions of the tributaries thereof.

(2) Water uses to be protected. The quality of Zone 6 waters shall be maintained in a safe and satisfactory condition for the following uses: (a) industrial water supply after reasonable treatment; (b) wildlife, maintenance and propagation of resident fish, shellfish, and other aquatic life, and passage of anadromous fish; (c) recreation; and (d) navigation.

(3) Stream quality objectives.

a. Dissolved oxygen. Daily average concentration shall not be less than 6.0 mg/l.

b. pH. Between 6.5 and 8.5.

c. Total alkalinity. Between 20 and 120 mg/l.

d. Temperature. Shall not exceed 5°F above the average daily temperature gradient displayed during the 1961-66 period, or a maximum of 86°F, whichever is less.

e. Phenols. Maximum 0.02 mg/l.

f. Threshold odor number. Not to exceed 24 at 60°C.

g. Syndets. (M.B.A.S.) Maximum monthly mean 1.0 mg/l.

h. Turbidity. Maximum monthly mean 40 units, maximum 150 units.

i. Radioactivity.
alpha emitters, maximum 3 pc/l (picocuries per liter);
beta emitters, maximum 1,000 pc/l.

j. Coliform. MPN (most probable number) not to exceed U. S. Public Health Service's shellfish standards in designated shellfish areas.

k. Fecal coliform. Maximum geometric mean of 200 per 100 milliliters; samples shall be taken at such frequency and location as to permit valid interpretation.

(4) Effluent quality requirements. All discharges shall meet the effluent quality requirements of Article 2-1. The carbonaceous oxygen demand from an outfall (exclusive of stormwater bypass) shall not exceed that assigned by the Commission to maintain stream quality objectives.

Working Paper #5

Regional Energy Supply and Demand Considerations

Prepared for OTA
by Energy and Environmental Analysis, Inc.
Arlington, Va.

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SUMMARY

The Northeast is a region which is heavily dependent on external sources for its oil and gas. Imports and movements of products from refineries in other regions of the U. S. supply a large share of the Northeast's demand for petroleum products. Of the crude oil actually refined in the Northeast, a high percentage comes from foreign sources. While the region consumes about 26 percent of the nation's petroleum products, they have only about nine percent of total refinery capacity. The region is very highly dependent on gas from the states in the West South Central, with only about five percent of the quantity consumed actually produced in the region.

The economics of petroleum transport and refinery siting suggests that, theoretically, there is considerable flexibility for companies making oil transportation and refinery siting decisions. While theoretically OCS oil could be transported by one of a number of different modes and refined in several different areas, it is most likely that it will be refined in Northeastern refineries. A simple substitution can be expected for the foreign crude oil which is the source of much of the oil now refined by the refineries in the two major refinery areas. Expected production of OCS oil is only a small share of both present refinery capacity and projected demand. It is expected that OCS natural gas will substitute for the gas now being transported from the West South Central.

Any refinery expansion in the Northeast would be expected to occur as a result of companies attempting to meet the growing demand for petroleum products projected for the region. Projections suggest increased consumption of petroleum products, although long-range forecasting depends on highly uncertain

assumptions concerning conservation potential, economic activity, and inter-fuel substitution. Once the basic substitution of OCS oil for foreign oil has occurred, decisions concerning how to meet expanded demand are essentially independent of OCS development, and will depend on how each company reacts to their own projections of future demand.

Any analysis of petroleum transportation and refinery location must deal with industry average cost relationships. The actual decision of how to react to OCS oil will be made at a company level, and individual companies may face cost curves which differ from industry averages. For this reason, it may be that OCS oil could affect the refinery location decision of a company, although isolating the extent to which OCS oil influenced what is essentially a decision dependent on demand would be difficult.

SECTION I

INTRODUCTION

The effects that development of Baltimore Canyon oil and gas will have on such factors as refinery sitings and supply and demand patterns must be evaluated by examining the economics of energy transport and processing in general terms, as well as the energy patterns specific to the Northeast.[1/]

In Sections II and III, present supply and demand in the Northeast is characterized, and the transportation system for oil and gas are discussed. Special emphasis is placed on the economics of oil transport. Current oil refining operations in the region are described, and the general considerations relevant to siting of refineries are discussed. In Section IV, energy projection techniques are evaluated, and three alternative projections for demand in the Northeast are presented. The assumptions necessary for any such projections are made explicit, and the uncertainty of the key variables is noted.

The final section applies the previously developed general framework for examining oil transport and refinery location decisions to the particular circumstances associated with development of the Baltimore Canyon. Flexibility theoretically exists for pursuing any one of a number of transportation and refining options, and several options are briefly examined.

1/ Northeast will be used as a term for the New England and Middle Atlantic Census regions.

SECTION II

ENERGY SUPPLY, DEMAND, AND TRANSPORTATION

A. Current Energy Consumption Patterns

Table II-1 presents estimates of energy consumption by type of fuel and sector in the Northeast. Table II-2 puts this pattern into perspective by comparing fuel type shares with the national average and with other regions. The heavy dependence of the Northeast on petroleum products is apparent. New England, in particular, consumes petroleum products for over 80 percent of its total energy. At the opposite extreme, coal provides only 1.7 percent of New England's energy, compared to 18.2 percent for the nation as a whole and 21.3 percent for the Middle Atlantic states. On a percentage share basis, the Northeast utilizes natural gas only about half as much as the nation as a whole.

As would be expected, the transportation and household-commercial sectors are the major users of petroleum products. The heavy dependence of New England's electric utilities on petroleum products should be noted.

The estimates made of 1974 consumption suggest several trends emerging from 1972 to 1974 in the region. Coal and nuclear power both increased their shares of total consumption from 1972. Over the same time period, natural gas and petroleum products declined in importance as sources of energy. These shifts were usually of about 1-2 percentage points, and must be viewed as somewhat tentative until final regional data is published. Natural gas curtailments and the rapid post-embargo rise in petroleum prices prompted declines in the shares of these energy sources. The ability to substitute fuel types obviously varies between sectors, with the residential and transportation sectors being particularly constrained to conservation rather than switching of fuel types.

TABLE II-1

1974 Energy Consumption Patterns in the Northeast[1]

(10^{12} BTU)

	Coal	Petroleum Products	Natural Gas	Hydro-power & Nuclear[2]	Total Gross Energy Inputs
New England					
Household-commercial	1	925	201	0	1127
Industrial	5	181	55	0	241
Transportation	0	753	1	0	754
Electric Power	41	505	12	230	788
Miscellaneous	2	5	0	0	7
Total	49	2369	269	230	2917
(Percent)	(1.7%)	(81.2%)	(9.2%)	(7.9%)	(100%)
Middle Atlantic					
Household-commercial	13	1855	1051	0	2919
Industrial	969	353	528	0	1850
Transportation	0	2438	25	0	2463
Electric Power	1004	1019	63	530	2616
Miscellaneous	149	17	0	0	166
Total	2135	5682	1667	530	10014
(Percent)	(21.3%)	(56.7%)	(16.6%)	(5.3%)	(100%)
Northeast[3]					
Household-commercial	14	2780	1252	0	4046
Industrial	974	534	583	0	2091
Transportation	0	3191	26	0	3217
Electric Power	1045	1524	75	760	3404
Miscellaneous	151	22	0	0	173
Total	2184	8051	1936	760	12,931
(Percent)	(16.9%)	(62.3%)	(15.0%)	(5.9%)	(100%)

1) Estimated, based on Bureau of Mines data. 1972 regional BTU totals (in "Fuel and Energy Data, U. S. by States and Regions") for each fuel type were adjusted to reflect 1972-1974 changes shown in Mineral Industry Surveys. Sectoral breakdowns of these totals are estimated for each fuel type based on the region's 1972 distribution. 1974 sectoral breakdowns are available for utility coal and for natural gas, and were used.

2) 10,500 BTU/KWH

3) New England and Middle Atlantic

TABLE II-2

Regional and National Energy Usage Patterns, 1974

(% Distribution)

	Coal	Petroleum Products	Natural Gas	Hydropower, Nuclear	Total Gross Inputs
U.S. Total	18.2	45.8	29.8	6.2	100.0
New England	1.7	81.2	9.2	7.9	100.0
Middle Atlantic	21.3	56.7	16.6	5.3	100.0
1972 range, all regions[1/]	0.7-37.0 WSC-ESC	20.6-84.6 ESC-NE	9.1-67.6 NE-WSC	0.4-20.0 WSC-PAC	

1/ WSC: West South Central; ESC: East South Central; NE: New England; PAC: Pacific

Source: Fuel and Energy Data, United States by States and Regions, 1972, U.S. Bureau of Mines for 1972 ranges, and Table II-1 for 1974 breakdown. 1974 National from Bureau of Mines News Release, April 5, 1976.

B. Pattern of Energy Supply

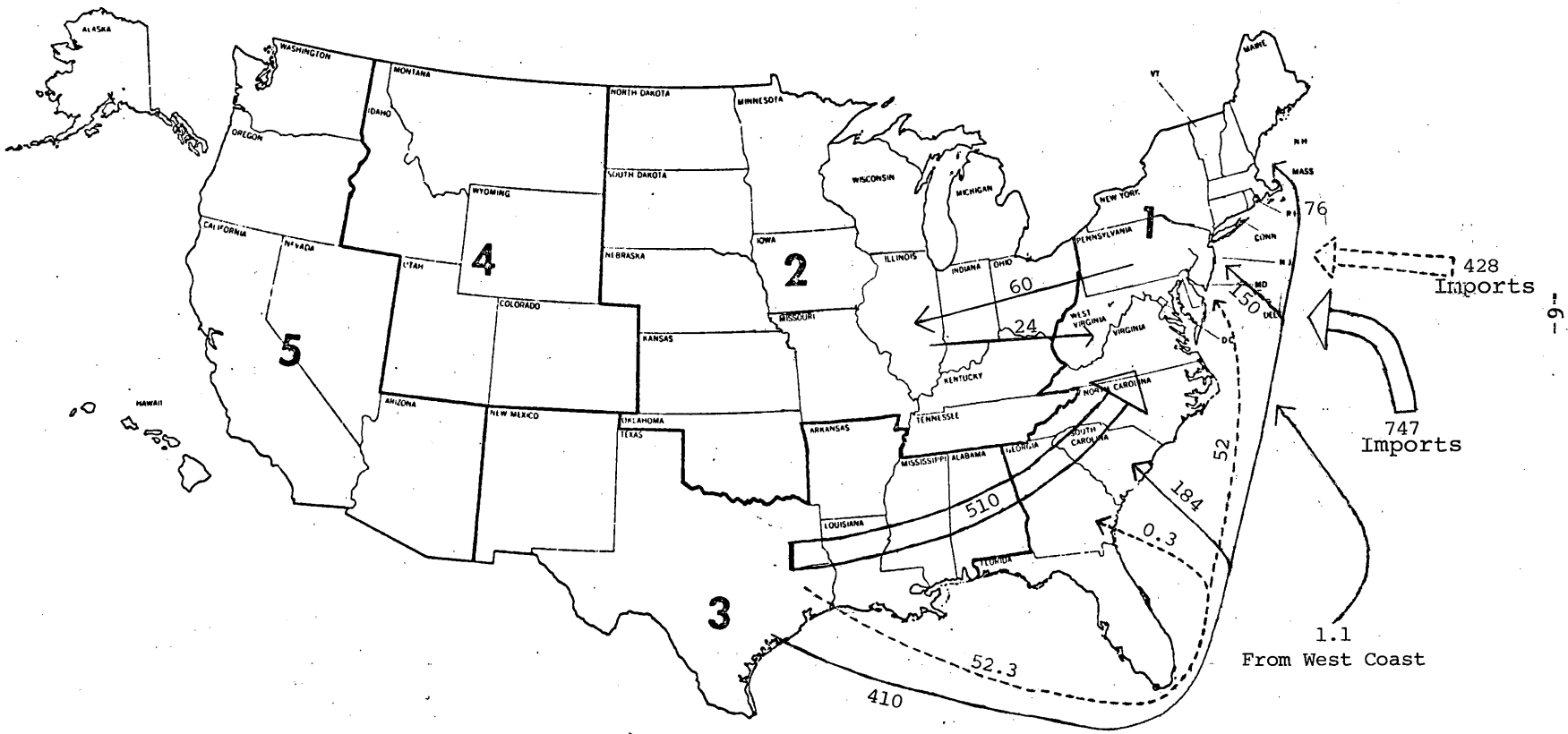
As shown by the map in Figure 2-1 the East Coast (PAD 1) is supplied by two major sources. PAD 3 is a major source of refined petroleum products. Movements of petroleum products to PAD 1 are by pipeline, tanker, and barge. Pipeline movements of product are 65 percent gasoline and jet fuel and 30 percent distillate. The products moved by water to both New England and the Central Atlantic are about one-third gasoline. Only about 10-15 percent of these water movements are residual fuel oil, and since residual is very difficult to pipe, no pipeline movements of residual are made from PAD 3 to PAD 1. Foreign sources supply nearly 40 percent of all the petroleum products which are refined outside of PAD 1 and shipped there for consumption. These imports are predominantly residual fuel oil, (71 percent of refined imports) much of which is burned by electric utilities.

The 31 refineries of PAD 1 are supplied with primarily imported crude oil. Relative to the imports of crude (428 million barrels in 1974), production of crude within PAD 1 is limited (44 million barrels). Over eighty percent of this production is in Florida. Central Atlantic refineries are also supplied by crude oil brought by tanker and barge[1/] from PAD 3 (52 million barrels), although this quantity combined with crude oil production in PAD 1 is less than one-fourth the quantity of crude imported to PAD 1. Imports in 1974 originated in a large number of countries with Nigeria, Iran, Venezuela, Saudi Arabia, and Canada being the primary sources.

New England and the Middle Atlantic states rely almost entirely on the states in the West South Central region for natural gas.

1/ There are no major crude pipelines which can bring crude into area from PAD 3.

Figure 2-1
Supply of Crude Oil
and Petroleum Products to
the East Coast, 1974
(millions of barrels)



Movement of Petroleum Products ⟶

Movement of Crude Oil - - - - ⟶

Source: Based on Bureau of Mines data: Mineral Industry Surveys, "Petroleum Statement", December, 1974.

Over 80 percent of the natural gas produced in the U. S. originates in Texas, Louisiana, and Oklahoma. There is no production in New England, and only limited production in New York and Pennsylvania. Production in these two states (87.6 billion cubic feet in 1974) represents less than 0.5 percent of national production, and this quantity is less than 5 percent of the natural gas consumed in New England and the Middle Atlantic states.

C. Oil and Gas Transportation

1. Petroleum

a. Trends in the Petroleum Transportation System

Table II-3 shows the trend in the last ten years in the mode of transport of crude oil and petroleum products. The dependence of petroleum transport on pipelines is apparent. About 70 percent of all crude oil transported to refineries is carried in pipelines. The major Northeastern refineries are, of course, not typical in both receiving their crude by tanker and barge, and receiving 80 percent of their oil from foreign sources (versus 20 percent for the nation as a whole).

The mix of transport modes for oil (both crude and refined products) has remained relatively stable over the past ten years. The major shift has been one whereby pipelines have slowly increased their share of total movements at the expense of water carriers. Both modes have increased their volumes moved, in absolute terms. Motor carriers, the second most important mode, have the same share in 1973 as they had in 1965.

Figures 2-2 and 2-3 show the basic outlines of the crude oil and petroleum product, pipeline systems serving the Northeast. The complexity of the systems is not shown in the maps, which give only the principal corridors for the major pipelines.

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Table II-3

REFINERY RECEIPTS OF CRUDE OIL BY METHOD OF TRANSPORTATION

(Daily Averages in Thousands of 42 Gallon Barrels)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Domestic crude oil:										
Intrastate:										
Pipe lines	3,855	4,016	4,332	4,571	4,699	4,741	4,664	5,006	4,923	4,637
Tankers and barges	403	417	354	374	378	406	441	425	408	357
Tank cars and trucks	95	104	109	112	115	102	101	130	125	142
Total	4,353	4,537	4,795	5,057	5,192	5,249	5,206	5,561	5,456	5,136
Interstate:										
Pipe lines	2,618	2,729	2,728	2,797	2,890	3,039	3,102	3,092	3,036	2,908
Tankers and barges	813	953	1,174	1,171	1,120	1,265	1,178	816	684	580
Tank cars and trucks	10	12	16	19	16	15	15	15	34	60
Total	3,441	3,694	3,918	3,987	4,026	4,319	4,295	3,923	3,754	3,548
Foreign crude oil:										
Pipe lines[1]	294	345	401	462	546	649	713	868	1,120	1,015
Tankers and barges	944	879	727	828	862	669	966	1,340	2,124	2,455
Total	1,238	1,224	1,128	1,290	1,408	1,318	1,679	2,208	3,244	3,470
Total Receipts[1]	9,032	9,455	9,841	10,334	10,626	10,886	11,180	11,692	12,454	12,154

[1] Excludes crude oil imported for direct fuel use by pipelines.

Source: Bureau of Mines, *Petroleum Statement*, January and Annual issues.

TOTAL CRUDE PETROLEUM AND PETROLEUM PRODUCTS CARRIED IN DOMESTIC TRANSPORTATION AND PER CENT OF TOTAL CARRIED BY EACH MODE OF TRANSPORTATION

(Daily Averages in Thousands of Short Tons)

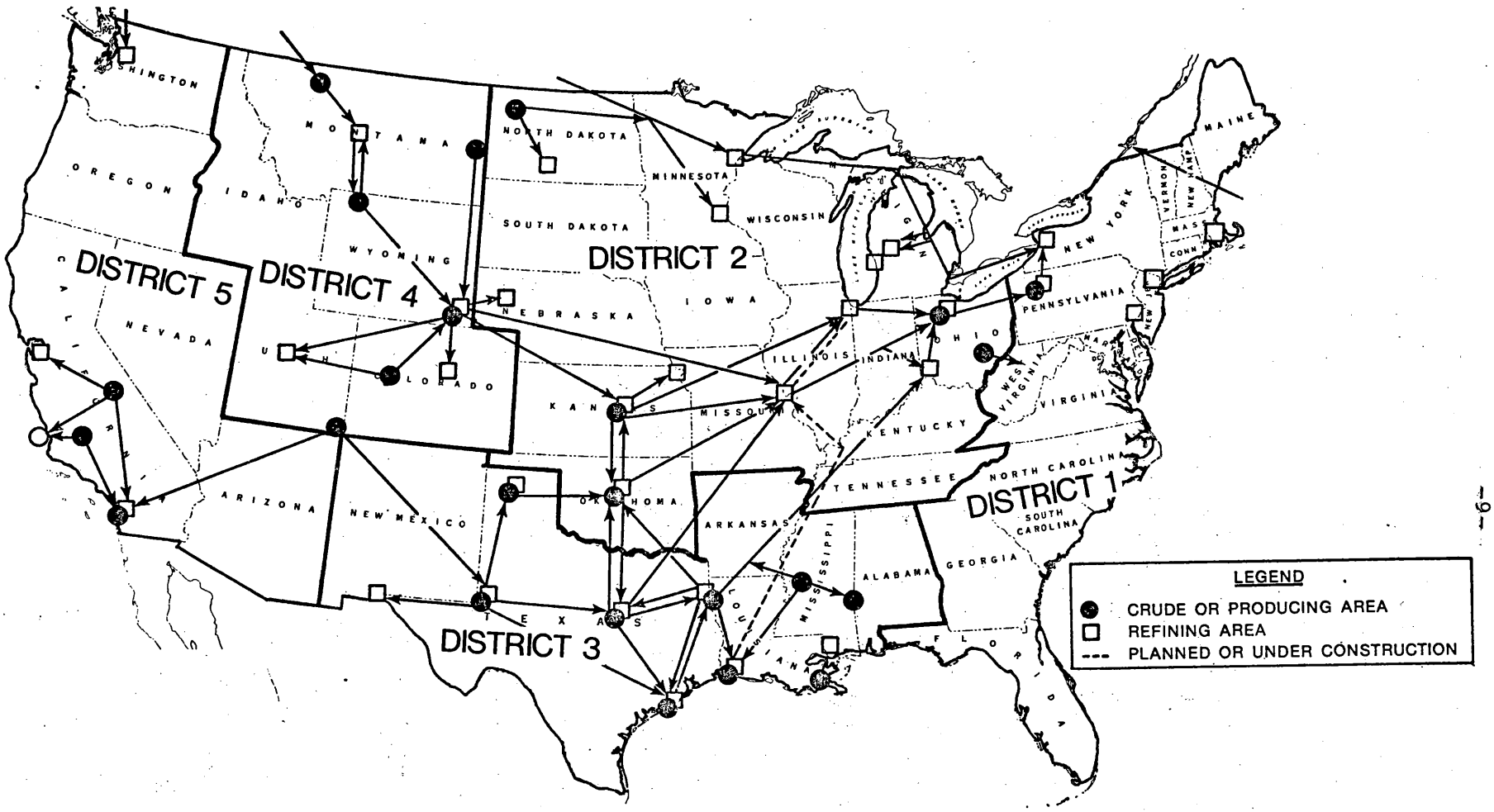
	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974[a]
Pipe lines										
Tons carried	1,610	1,725	1,861	1,985	2,081	2,165	2,210	2,394	2,499	
Per cent of total	44.4	44.8	45.6	46.4	46.8	46.9	46.9	47.5	47.5	
Water carriers										
Tons carried	887	912	958	986	1,038	1,103	1,142	1,166	1,154	
Per cent of total	24.5	23.7	23.5	23.1	23.4	23.9	24.2	23.1	21.9	
Motor carriers[1]										
Tons carried	1,056	1,142	1,188	1,229	1,255	1,277	1,290	1,403	1,534	
Per cent of total	29.1	29.7	29.1	28.8	28.2	27.6	27.4	27.9	29.1	
Railroads										
Tons carried	71	71	71	72	72	73	70	74	81	
Per cent of total	2.0	1.8	1.8	1.7	1.6	1.6	1.5	1.5	1.5	
Total tons carried	3,624	3,850	4,078	4,272	4,446	4,618	4,712	5,037	5,268	

[a] Not available.
[1] Estimated.

Source: Association of Oil Pipe Lines, *"Shifts in Petroleum Transportation."*

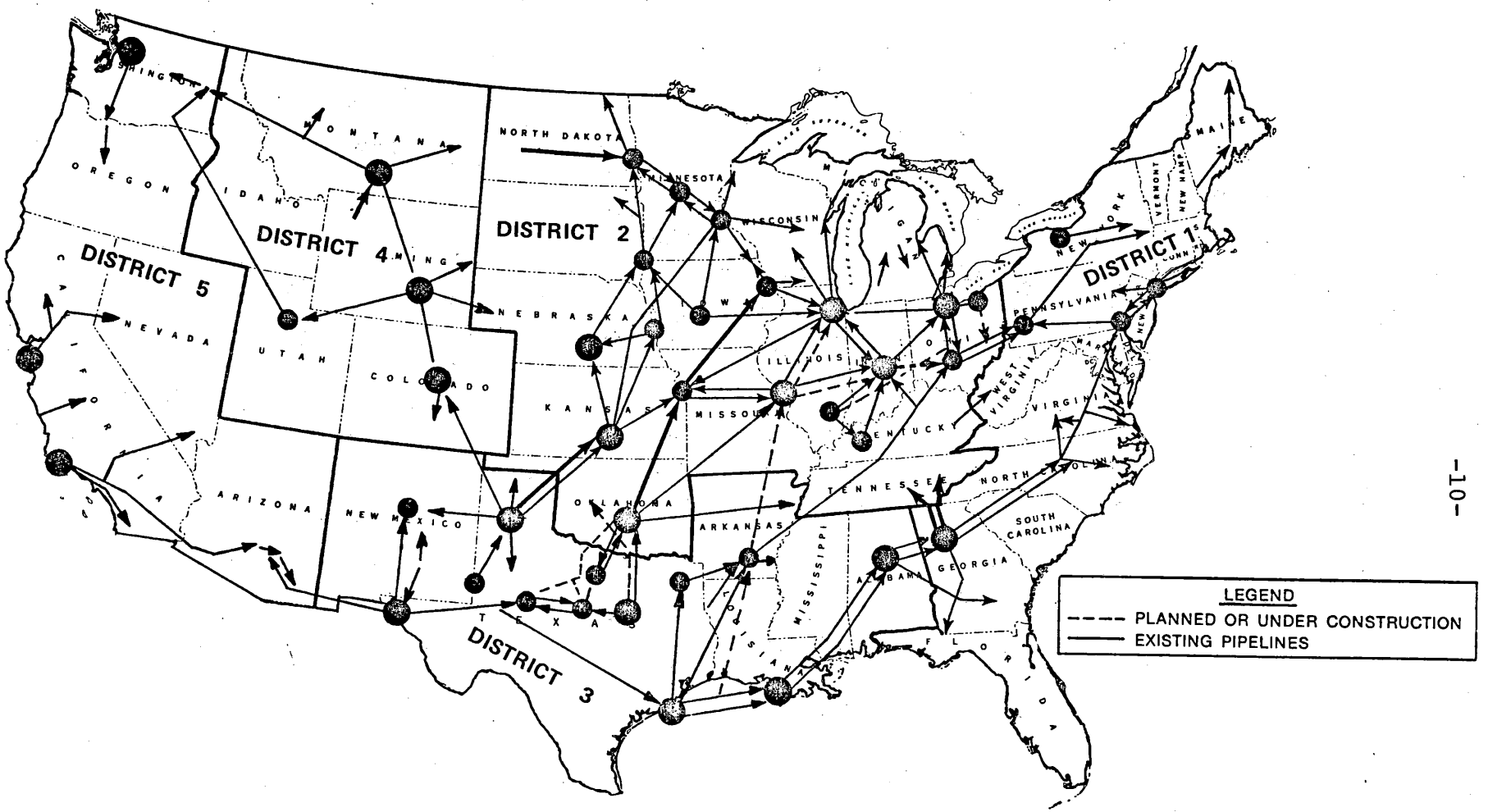
Source: Annual Statistical Review, API, 1965-1974.

Figure 2-2
Major Crude Oil Pipelines



Source: National Petroleum Council in Project Independence Report, Federal Energy Administration, November, 1974.

Figure 2-3
Major Product Pipelines



Source: National Petroleum Council in Project Independence Report, Federal Energy Administration, November, 1974

It is apparent from Figure 2-2 that the major Northeastern refinery areas depend on water, and not pipeline for their crude oil.

Two points should be noted concerning these networks. First, the pipelines do not contain mixtures of products, and hence certain lines are distillate lines, others carry gasoline, LPG, or other pipeable products. Second, certain products are not generally pipeable, and hence are not carried on this network. Examples include residual fuel oil, asphalt, lubricants, and wax.

b. The Economics of Petroleum Transport

Any brief discussion will, of course, not be able to completely capture the complexity of the economics of transporting all of the various petroleum products (from gasoline to lubricating grease) by all of the possible modes (from huge tanker to small truck). This discussion will, therefore, focus on the major products and major modes of transport. Specialty products such as wax or lubricating oil, with their high value per unit of weight, are obviously special cases. They cannot be piped, and the truck or rail transportation which would be uneconomical for crude oil or other lower value products may be the appropriate transportation mode for these products.

c. Petroleum Transport Costs

As an input to the previously cited DOT model, cost curves for various modes of transport were developed. The curves represent costs as of 1972, and while there may have been some cost increases since then, these are felt to be minor and the shapes of the curves will not have changed dramatically.

Cost curves are presented for barges, intercoastal tankers, and pipelines. Data for truck costs are not presented, but the DOT model's estimates ranged from 6.18 cents per ton-mile in the Middle Atlantic states to 3.34 cents in Texas, Oklahoma and New Mexico. New England's cost, at 5.11 cents, was near the high end of the range. These costs are, of course, much higher than the other modes at the distance ranges discussed below.

d. Barge Costs

A typical cost curve for petroleum transport on inland waterways is shown in Figure 2-4 . Barge cost per ton-mile is shown as an exponential function of distance. This shape is to be expected because of the fixed costs associated with the loading and unloading operations. At very short distances, costs per ton-mile are high because these fixed costs are spread over fewer ton-miles. The calculation of the curve involved assumptions concerning, among other things: size of towboat, size of barge, upbound and downbound speeds, loading and unloading times, size of original investment, operating costs, and so forth. The assumptions made for each of these elements were best estimates of typical barges used to transport petroleum products on inland waterways.

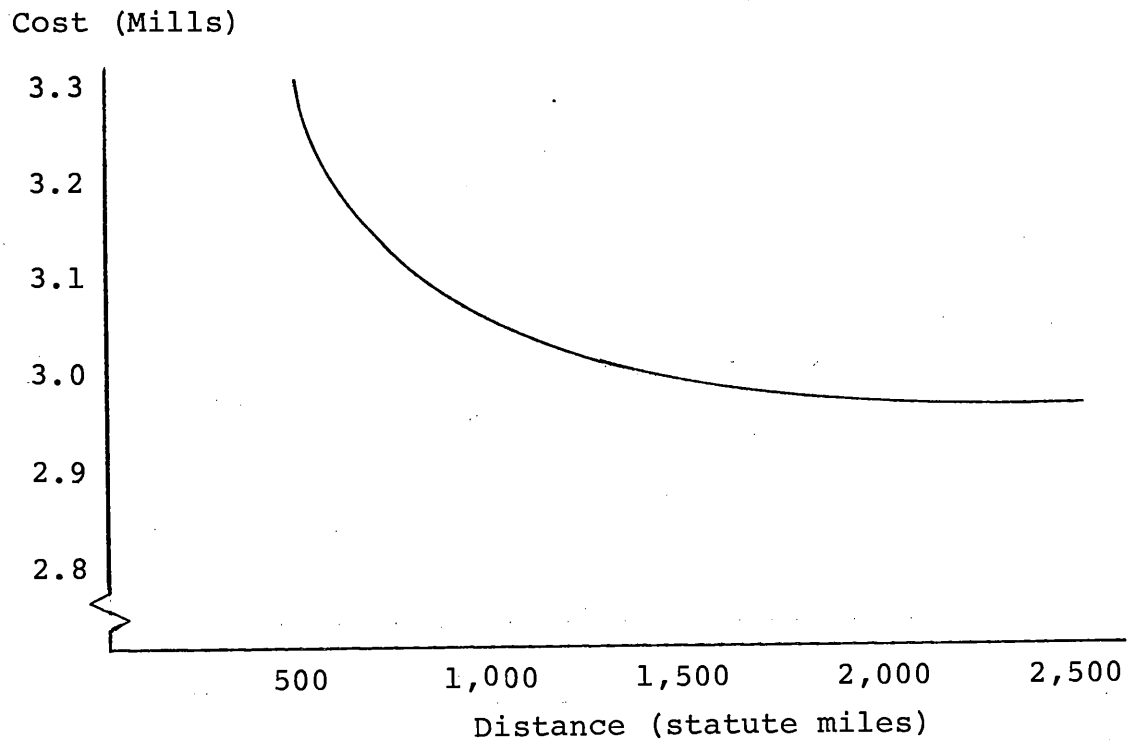
e. Inter-coastal Petroleum Tanker

Figure 2-5 presents cost curves for three sizes of U. S. Flagship tankers. The shapes, like that of the barge cost curve, reflect the fact that loading and unloading costs result in cost per ton-mile being an exponential function of distance. The cost curves were derived by making assumptions concerning hours required for various lengths of trips, unloading times and costs, and operating costs. The lowering of cost per ton-mile

Figure 2-4

Cost Curve per Ton-Mile on Inland Waterways

(Barge Transport)[1/]

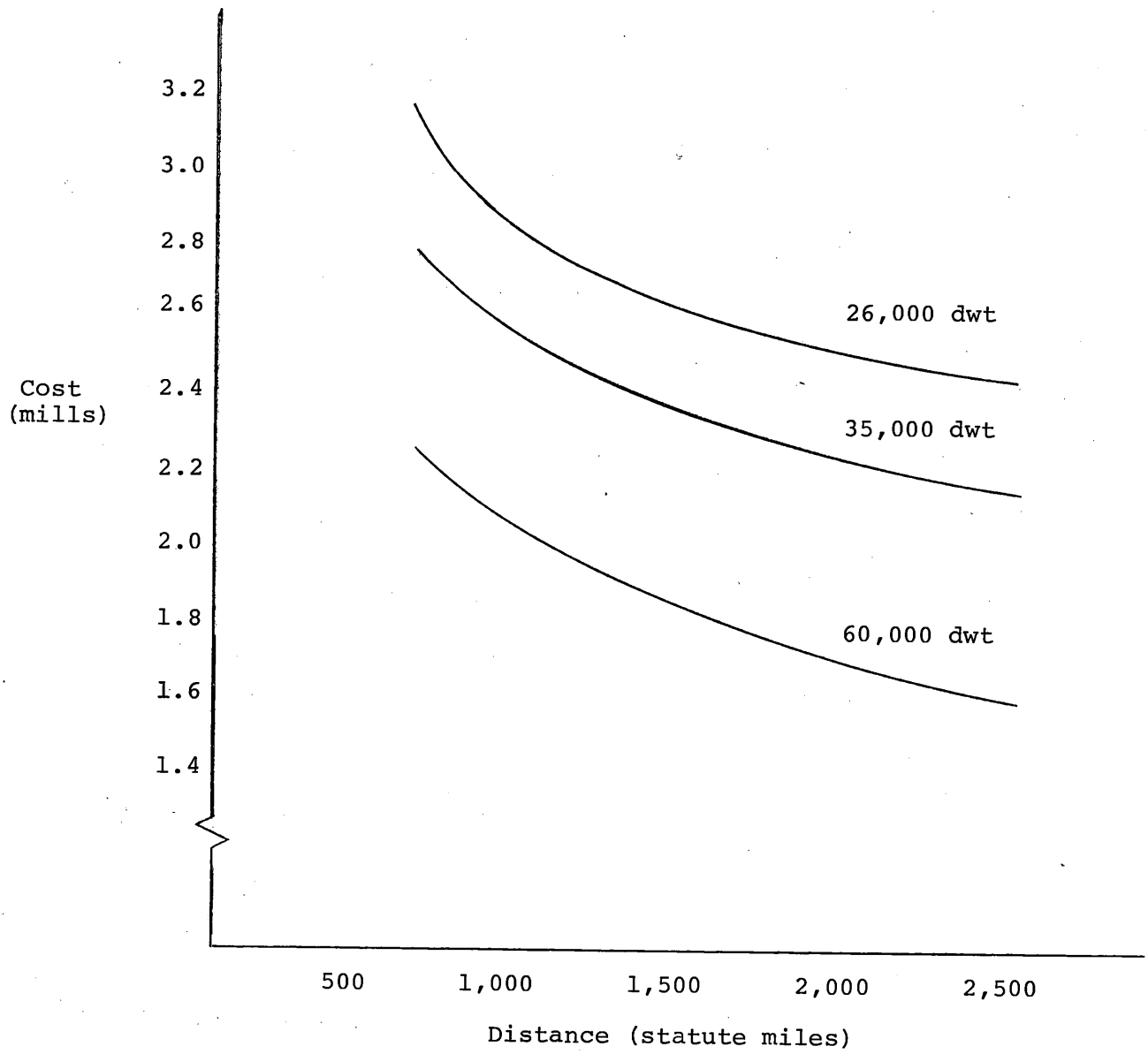


1/ For 3,200 horsepower towboat and 4 petroleum barges 290' x 50' x 12' (i.e., 11,600 tons of petroleum).

Source: Economic Aspects of Refinery and Deep-Water Port Location in the United States, U.S. Department of Transportation, May, 1974.

Figure 2-5

Cost Curves per Ton-Mile for
Intercoastal U.S. Flag Petroleum Tankers



Source: Economic Aspects of Delivery and Deep-Water Port Location in the United States, U.S. Dept. of Transportation, May, 1974.

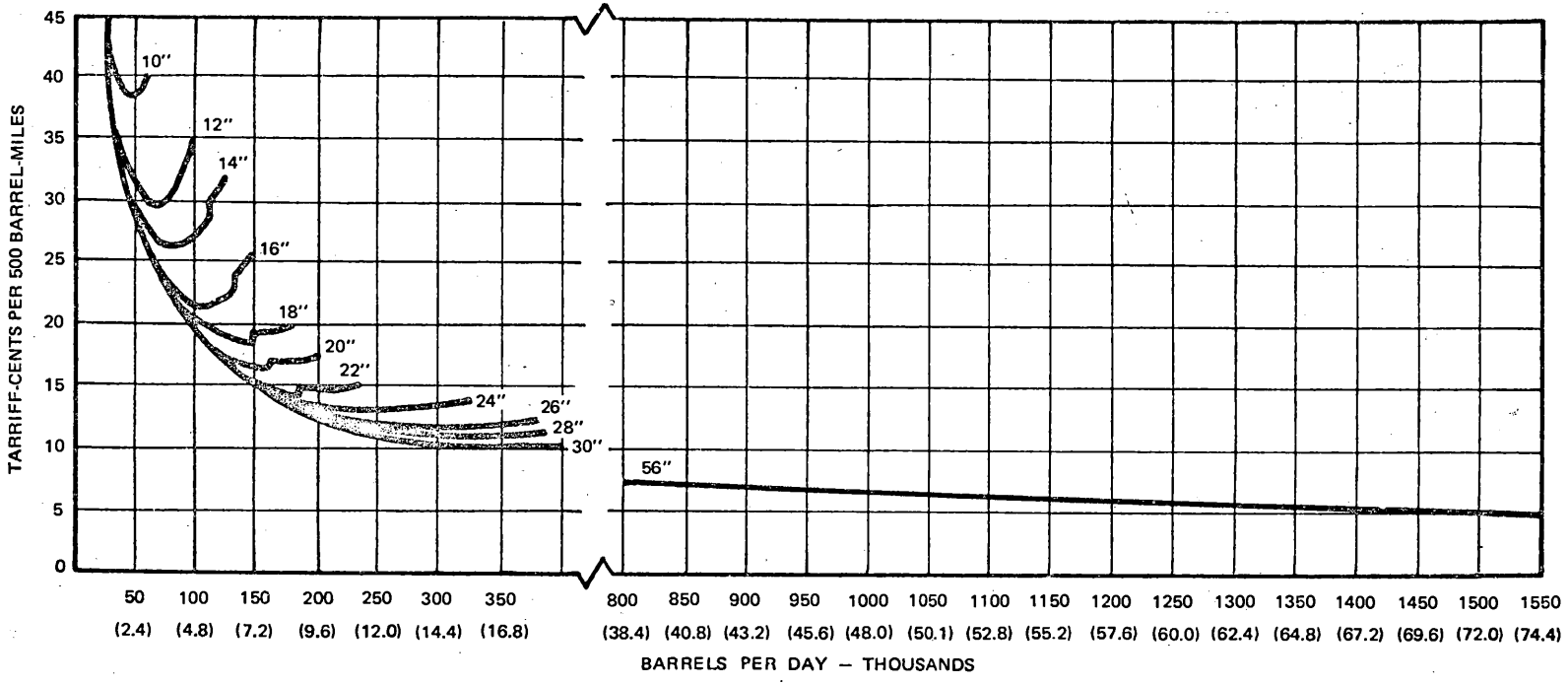
is apparent when a larger tanker is utilized over the range of distances presented. As with barges, cost per unit rises rapidly at shorter distances. The flattening of the curves at longer distances implies that once the tanker has gone a long distance, (2,000 miles, for example) there is no large cost-per-unit penalty associated with slight additions to the length of the trip. With VLCC's (very large crude carriers) this flattening of the curve is significant at very long distances with the implication that Persian Gulf Oil bay be taken 500 extra miles to another region in the U. S. with only minimal cost penalties.

f. Pipeline Costs

Pipeline costs per barrel-mile are a function of volume. Larger volumes require a larger diameter pipe and greater power requirements, thereby affecting barrel-mile costs. Figure 2-6 presents cost curves for a number of pipe sizes and a total envelope curve of total costs. The total cost curve is a combination of the decreasing cost segments of a number of curves for different sizes of pipes. The reason for this is that for a given diameter of pipe the cost per barrel-mile decreases with greater volumes as the fixed costs (such as right-of-way and investment capital) are spread over a larger number of barrels. The cost curves eventually turn upward as inappropriately high volumes for a given diameter pipe cause decreasing economies of scale. The total cost curve is, therefore, an envelope of the individual curves for different sizes of pipes. Decreasing average costs occur at higher daily volumes. The curves in Figure 2-6 are drawn for crude oil at a distance of 500 miles. Product pipeline costs are about 25 percent higher than crude.

Figure 2-6

Pipeline Tariff Including 7 Percent Return on Investment



Notes: (1) The numbers in parentheses along the abscissa inidcate annual throughput in million long tons assuming 7.5 barrels per ton.

(2) The 56" curve is a linear approximation of the exponential curve. For all practical purposes a linear approximation beyond 30 m.t.a. significantly represents the theoretical exponential.

(3) The series of cost curves are drawn for crude oil for a distance of 500 miles. Product pipeline costs are approximately 25% higher (based on national barrel/mile averages of tariff revenues on crude trunk and product trunk lines).

(4) The true behavior of the 56" line's cost at throughput levels lower than 30 m.t.a. is unknown and accurate knowledge of same is irrelevant. The high capital cost required for this size is not justified at low levels of throughput. The little data available strongly indicates that at throughput levels less than 30 m.t.a. the cost per barrel is significantly higher than the envelope establishing the minimum cost range.

(5) Pipeline tariffs are true indicators of costs.

Source: Cost curves for 0–350 throughput range from a paper presented by W. H. McCollough on "Pipeline Economics" at the Association of Oil Pipelines Educators' Tour, July 26, 1972.

Source: Economic Aspects of Delivery and Deep-Water Port Location in the United States, U.S. Dept. of Transportation, May, 1974.

The right-of-way, labor, and construction costs which are an element of the cost curves in Figure 2-6 will differ from region to region. The DOT model, in incorporating these curves, developed regional multipliers. Lack of data, as well as a desire for simplicity of modelling, led to development of only two multipliers: 1.30 for the North Atlantic states [1/] and .94 for the other states in the Mid-Atlantic area[2/]. In the actual application of the curve shown in Figure 2-6, equations were derived and costs were calculated based on these approximations for the curve. These are shown in Appendix 1, and will be used later in lieu of taking cost estimates directly from the curve in Figure 2-6 itself.

g. Comparison of Costs of Petroleum Transport Modes

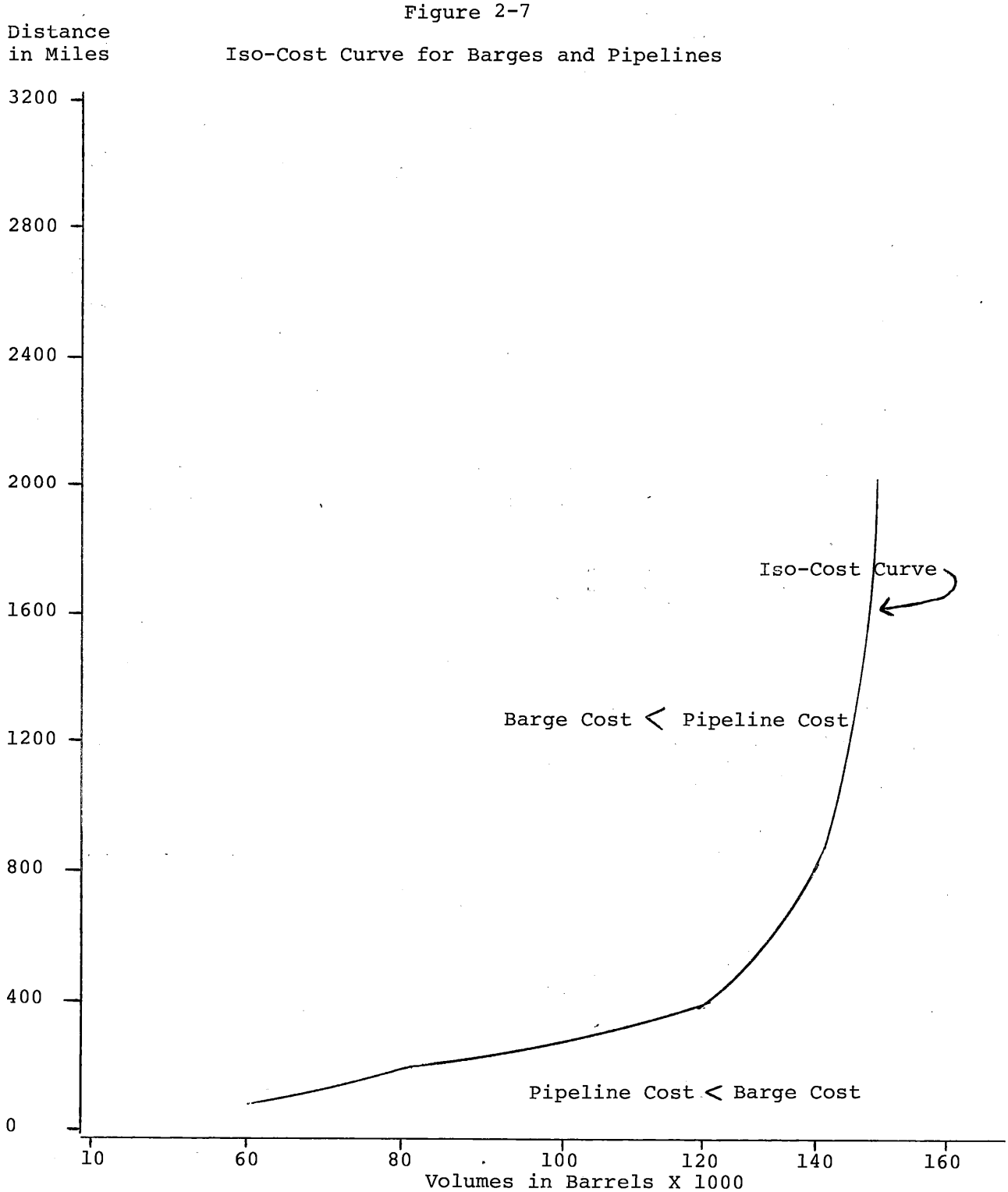
The extent to which different modes of transport are or are not competitive with each other at various distances and volumes can be shown by combining the various curves previously shown. For a comparison of barge costs (which are a function of distance) with pipeline costs, (which are a function of volume) costs can be compared at a series of distance-volume combinations. This is done in the iso-cost curve shown in Figure 2-7. The points on the curve itself represent equal costs between the two modes, with the low volume-long distance combinations to the left of the curve giving a cost advantage per barrel-mile to barges. Pipelines have a cost advantage at high volumes. At a volume greater than about 160,000 barrels/day, barges cannot compete with pipelines at any distance. At low volumes and short distances, pipelines costs are also lower than barge costs.

1/ Connecticut, New York, Pennsylvania, Rhode Island, Vermont, New Hampshire, Massachusetts, and Maine.

2/ In this case, including New Jersey, Maryland, and Delaware.

Figure 2-7

Iso-Cost Curve for Barges and Pipelines



Source: Economic Aspects of Delivery and Deep-Water Port Location in the United States, U.S. Dept. of Transportation, May, 1974.

An iso-cost curve is also derived for pipelines and tankers in Figure 2-8. The pipeline costs are expected to be less than tanker costs at high volumes, with increasing volumes giving an advantage to pipelines over a larger range of distances. At long distances and low volumes, tanker costs are lower per barrel-mile. The particular curve derived is for a 26,000 dwt tanker, and the lower cost per ton-mile of a 60,000 dwt tanker would result in a shift of the iso-cost curve to the left.

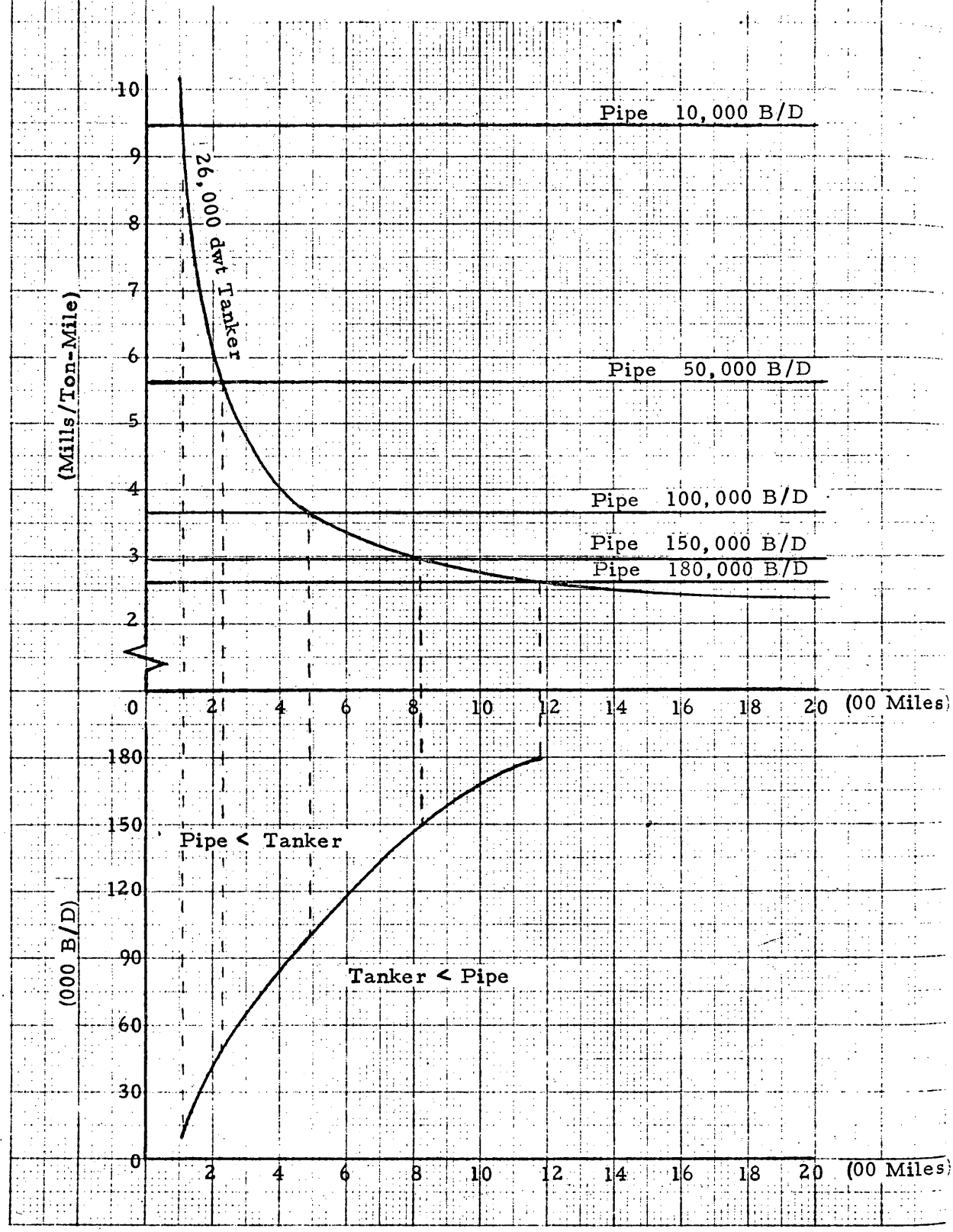
h. Conclusions -- Petroleum Transport

These cost curves show that, in theory, there is considerable flexibility to move petroleum by a number of different modes. Two limitations to this analysis should be noted at this point. First, the costs from which these curves are derived are industry-wide averages. A full understanding of the transportation options open to a particular company would require detailed analysis of the costs being faced by that company. These may diverge significantly from the industry average, but data is not available to analyze transportation costs at the company level.

A second limitation to any analysis using present cost curves is that these are a static view of current cost relationships, and decisions will in fact be based on projected costs. A decision to utilize a certain mode of transport will be based on what the expected costs of the mode will be over time. The advantage which a long-distance pipeline might currently have over a tanker in a particular application can clearly change over time. For example, rising right-of-way costs and pipeline construction costs could be expected to drive total pipeline transportation costs up more quickly than tanker costs, thereby changing the cost relationship between the alternative modes.

Figure 2-8

Iso-Cost Curve for Tankers and Pipelines



Source: Economic Aspects of Delivery and Deep-Water Port Location in the United States, U.S. Dept. of Transportation, May, 1974.

2. Natural Gas

The lack of alternative transportation modes for natural gas[1/] simplifies a discussion of its transportation. Figure 2-9 shows the major pipelines serving the Northeast. Gas is usually moved to end-users in a two step process involving transmission companies and local distributors. Large users (electric utilities and major industrial users) often buy directly from the transmission companies which operate the major pipelines.

High pressures are a key to the long distance gas transmission process. Some lines operate at pressures of more than 1000 psi, with many in the range of 700 to 1000 psi. Pipeline systems are designed to operate within specific pressure ranges. The design of long distance pipelines requires an intricate economic-engineering cost calculation involving pipe size, compression horsepower, distance between compressor stations, and the size and timing of probable future expansions in capacity. Capacity can be expanded by adding compression horsepower, installing new pipe, or by a combination of the two.[2/] Continuous capacity expansion has taken place on nearly all of the pipeline systems.

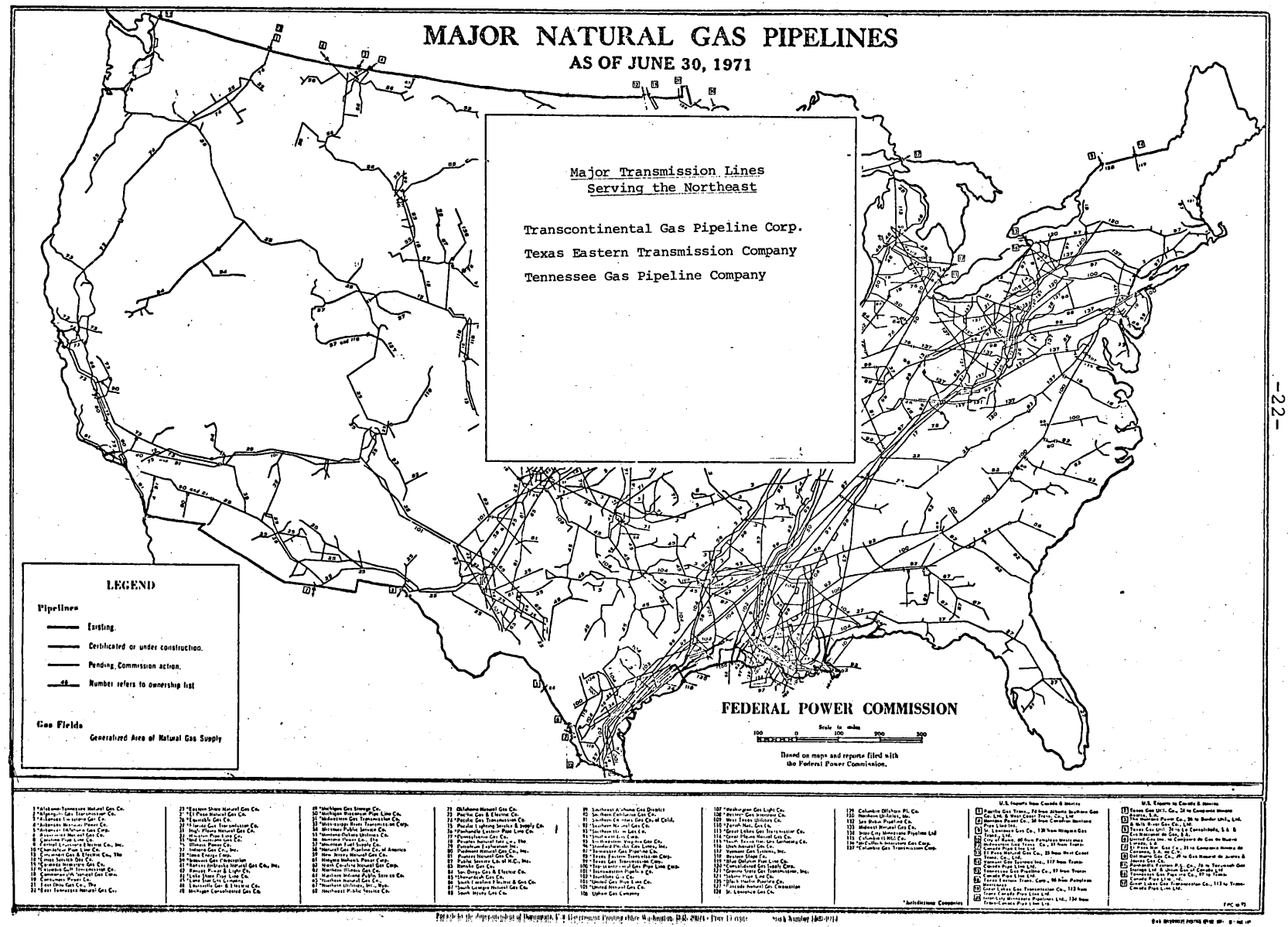
For a typical 30-inch diameter, 1,000 mile pipeline operating during 1973 at an average pressure of 800 psi and at 95 percent load factor, total cost of transporting gas is about two cents per thousand cubic feet per 100 miles, of which over 90 percent represents fixed charges (return on plant investment, depreciation, and taxes)[3/].

1/ Natural gas can be liquified, moved by tanker, and re-gasified for use. This alternative is a method for moving African gas to the U. S., for example. It is one alternative being considered for Alaskan gas.

2/ National Gas Survey, U.S. Federal Power Commission, 1975.

3/ Ibid.

Figure 2-9


MAJOR NATURAL GAS PIPELINES
AS OF JUNE 30, 1971
Major Transmission Lines
Serving the Northeast
Transcontinental Gas Pipeline Corp.
Texas Eastern Transmission Company
Tennessee Gas Pipeline Company
LEGEND
Pipelines
Existing.
Certificated or under construction.
Pending Commission action.
Number refers to ownership list
Gas Fields
Generalized Area of Natural Gas Supply
FEDERAL POWER COMMISSION
Based on maps and reports filed with the Federal Power Commission.

This high element of fixed costs implies that the cost of gas rises rapidly at lower load factors, as high fixed costs are spread over a small quantity of gas.

3. Trends in Regional Pipeline Construction and Costs

Figure 2-10 shows the rapid increase in pipeline construction costs. These costs increased about 26 percent between 1972 and 1974. The cost of line pipe and construction costs accounted for about 70 percent of the 1974 cost of these pipelines.

The extremely low level of pipeline construction activity in the Northeast makes regional average cost data meaningless. A 9.2 mile 20-inch onshore transmission line in Massachusetts had an average cost per mile of $156,000, and a 4.8 mile, 30-inch line in New Jersey cost $415,000 per mile.[1/] Costs per mile vary greatly between similar size and lengths of lines due to factors such as terrain, land costs, or special construction problems.

Bureau of Mines data for petroleum pipelining activity between 1971 and 1974 shows only 163 miles of new petroleum pipe laid in the Northeast, with an additional 452 miles of second-hand pipe. With 694 miles of pipe taken up in the region over the same period, a net loss of 79 miles of petroleum line actually occurred.[2/]

1/ Oil and Gas Journal, Ibid.

2/ Crude-Oil and Refined-Products Pipeline Mileage in the United States, January 1, 1974.

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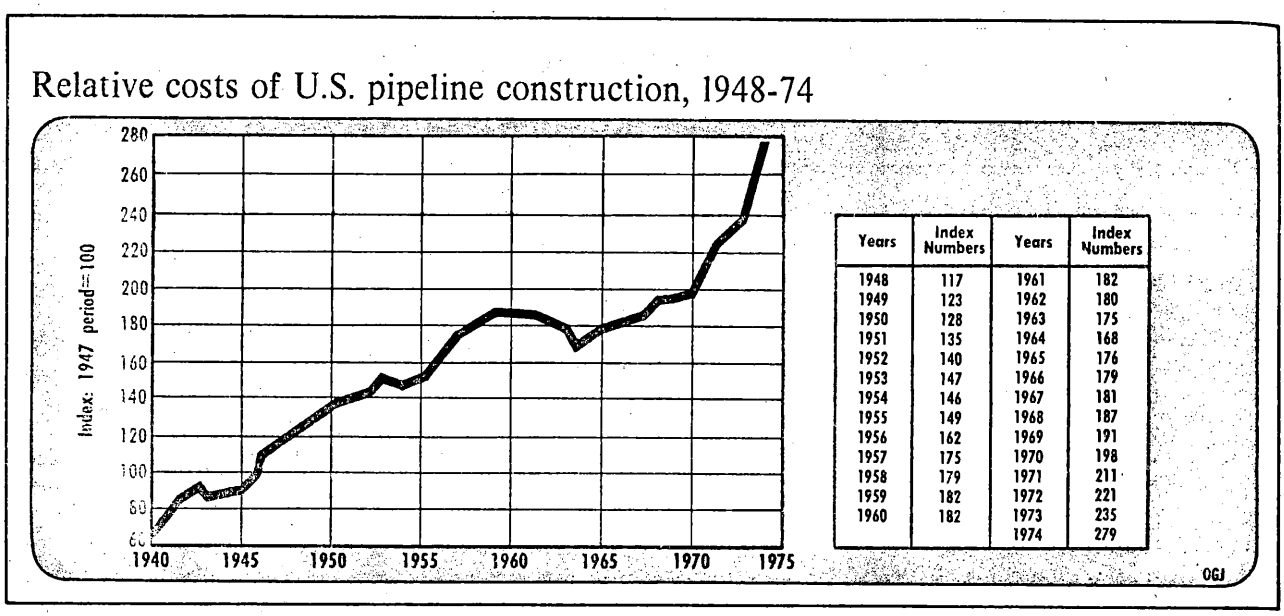
Figure 2-10

National Pipeline Construction Trends



Years	Index Numbers	Years	Index Numbers
1948	117	1961	182
1949	123	1962	180
1950	128	1963	175
1951	135	1964	168
1952	140	1965	176
1953	147	1966	179
1954	146	1967	181
1955	149	1968	187
1956	162	1969	191
1957	175	1970	198
1958	179	1971	211
1959	182	1972	221
1960	182	1973	235
		1974	279

Source: "Oil and Gas Journal," August 18, 1975

SECTION III

REGIONAL REFINERY OPERATIONS

A. Profile of Present Operations

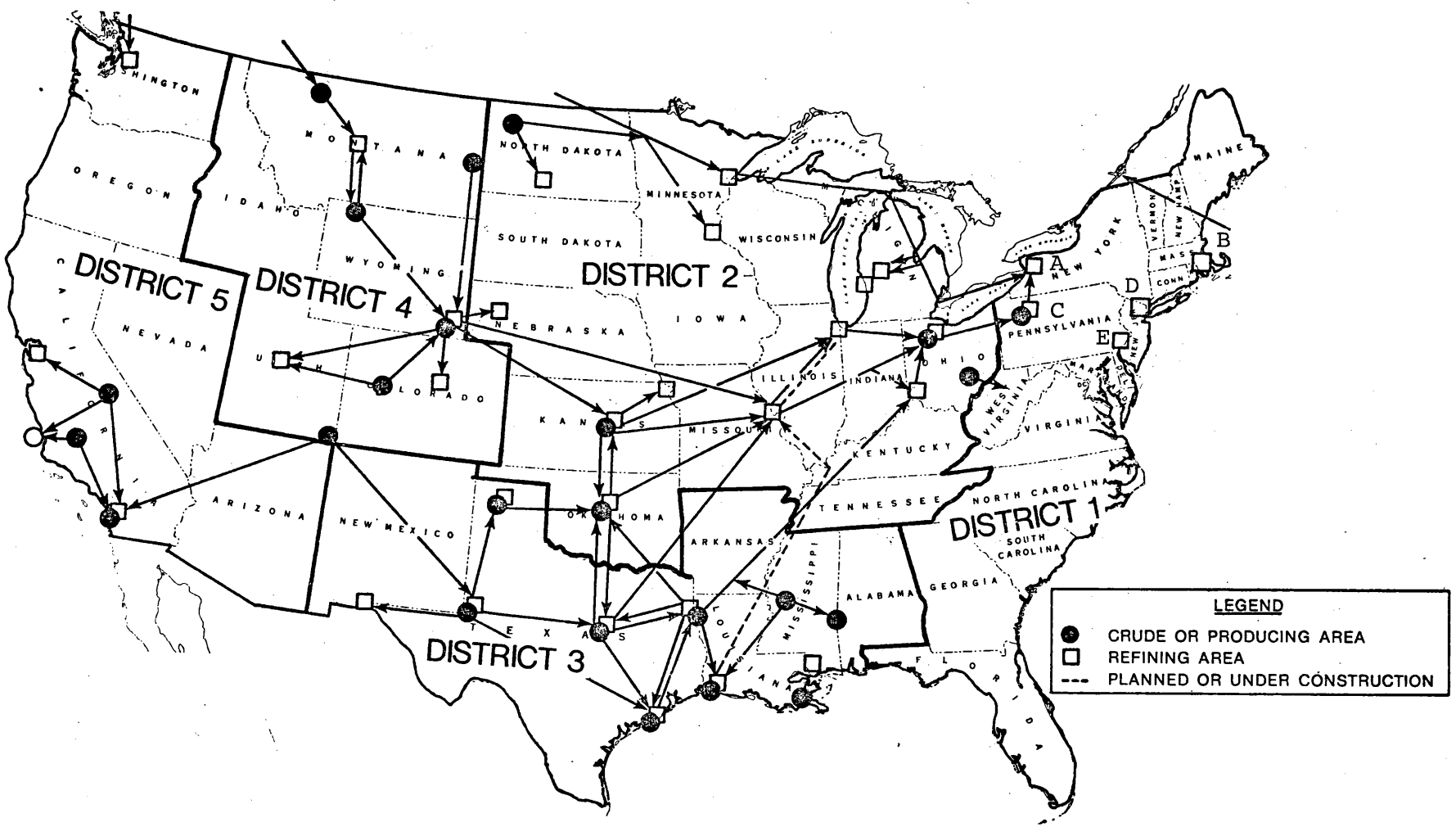
The 21 refineries in New England and the Middle Atlantic States are grouped into 5 major refining areas as shown in Figure 3-1, and are presented with their capacities in Table III-1, Total operable capacity of the refineries is about 1.5 million[1/] barrels per day, with close to 97 percent of this capacity concentrated in the 12 refineries with over 40,000 barrels per day capacity. Most of the small refineries produce primarily special products, such as asphalt or lubricants. The bulk of the region's refining capacity is concentrated in two areas: Northern New Jersey and southern New Jersey and Eastern Pennsylvania. All of the region's large refineries (88,000 to 265,000 barrels per day) and 86 percent of its total capacity are in these two areas. Ownership of the region's refineries is by a combination of both the major oil companies and smaller independents. Most of the large refineries are owned by the major oil companies, but only Mobil (with 2) owns more than one of the twelve major refineries.

The regional refining capacity represents about 10 percent of the total operable national capacity of about 15 million barrels per day. This figure is put somewhat into perspective by comparing the share of refinery throughout capacity to share of petroleum product consumption. As can be seen in Table III-2 , New England (8 percent) and the Middle Atlantic States (18 percent) consume about 26 percent of the nation's pretroleum products and have about 9 percent of refinery capacity.

1/ In addition to existing capacity, published data from the Bureau of Mines indicates 80,000 BPD under construction in Perth Amboy (Chevron) and 25,000 BPD under construction at Linden (Exxon).

Figure 3-1

CRUDE OIL PIPELINES AND REFINING AREAS



Source: Project Independence Report, FEA, November, 1974.
National Petroleum Council cited as source.

Table III-1

Refineries in the Northeast
(as of January 1, 1975)

Area[1/]	Company	Location	Capacity[2/] (barrels/day)
A. New York	Ashland Oil, Inc.	N. Tonowanda	64,000
	Mobil Oil Corp.	Buffalo	43,000
B. Rhode Island	Mobil Oil Corp.	E. Providence	7,500
C. Pennsylvania (West)	Pennzoil Co.	Oil City	10,000
	Pennzoil-Wolf's Head	Reno	2,100
	Quaker State Corp.	Emlenton	3,320
	Quaker State Corp.	Southport	6,500
	United Refining Co.	Warren	52,000
	Valvoline Oil Co.	Freedom	6,800
	Witco Chem. Corp.	Bradford	9,000
D. New Jersey (North)	Amerada Hess Corp.	Port Reading	67,900[3/]
	Chevron Oil Co.	Perth Amboy	88,000
	Exxon Co.	Linden	265,000
	National Oil Recovery Corp.	Bayonne	3,000
	Texaco, Inc.	Westville	88,000
E. Pennsylvania (East) and New Jersey	Atlantic Richfield Co.	Philadelphia	185,000[4/]
	BP Oil Corp.	Marcus Hook	143,000
	Gulf Oil Corp.	Philadelphia	174,300
	Sun Oil Co.	Marcus Hook	165,000
	Mobil Oil Corp.	Paulsboro (N.J.)	98,000
Total Regional Capacity (Operable)			1,481,420[5/]

1/ Corresponds to areas marked on map, Figure 3-1.

2/ Crude oil distillation capacity.

3/ Shutdown, but operable.

4/ 60,000 shutdown, but operable.

5/ Although not in the "Northeast" as defined by the Census and used in this study, a Getty Oil Company refinery of 140,000 BPD capacity is located in Delaware City and could be included in Area "E".

Source: "Petroleum Refineries in the U.S. and Puerto Rico", Surveys, U. S. Bureau of Mines.

Table III-2

Relationship of Refining Capacity to Energy Consumption

Region/State	Share of Refinery Throughput Capacity[1/] (%)	Share of Petroleum Product Consumption[2/] (%)	Share of Total Gross Energy Consumption[2/] (%)
New England	0.0	7.9	4.0
Middle Atlantic	9.2	17.7	14.1
New Jersey	3.7	4.4	2.5
New York	0.7	8.7	5.9
Pennsylvania	4.7	4.7	5.7
West South Central	42.6	10.6	15.5
Oklahoma	3.4	1.0	1.4
Texas	26.9	6.7	9.5
Louisiana	11.9	2.0	3.7
Arkansas	0.4	0.8	0.9
East North Central	16.9	14.5	19.6
All Other Regions	31.3	49.3	53.2
U.S. Total	100.0	100.0	100.0

1/ Includes only operating capacity in the U.S.. Excludes Puerto Rico.

2/ Capacities are as of January 1, 1975.

Source: Bureau of Mines, "Petroleum Refineries, Annual" and "Fuel and Energy Data, United States by States and Regions".

Table III-2 establishes several points regarding refinery location which will be dealt with at greater length below. Both the Middle Atlantic States and New England are dependent on other areas (foreign or domestic) for refinement of the petroleum products they consume. The location of refinery capacity is so skewed geographically that, on average, this dependency is also shown by the five regions not displayed separately in Table III-2. The West South Central (as well as California,) for example, with about 13 percent of refining capacity and eight percent of petroleum product consumption) are example of areas where refineries have located near the source of crude in numbers which are out of proportion to the area's consumption of petroleum products. The East North Central region, however, is an example of a case where refineries have located near markets for products. They have done so to an extent that the region, by the measure shown in Table III-2, is actually refining more products than it consumes.

Product transportation costs are higher than the cost of transporting crude oil. Economic location theory would suggest that, since product transport costs are greater than raw material transport costs, petroleum refining should display the characteristics of a weight gaining industry and therefore it would be expected that refineries would tend to locate near markets as opposed to near sources of crude. Table III-2 shows that historically the pattern of refinery location has evolved in such a way that it is not easily explained by such a model. There are examples of refineries locating near both the source of crude and near a major market for the refined products. Refineries have, of course, always located where they had access to crude oil. As the map in Figure 3-1 shows, most major refining areas in the U. S. are close to either a producing area or a large crude oil pipeline.

The lack of both of these is clear for the two largest refining areas in the Northeast, and access to water-borne crude has clearly been important in determining the siting of these refineries. The current supplies of crude for these refineries consists principally of imported crude, with some tanker and large movements of crude from the Gulf Coast.

B. Trends and Economic Considerations

New crude oil refinery construction has not occurred on the East Coast in more than 15 years. Table III-2 compares the growth in refining capacity in the Northeast to that of the U.S. as a whole. As can be seen from the table, while U.S. refinery capacity has increased by about 75 percent in the last 20 years, capacity in the Northeast has lagged behind and increased only about 16 percent over the 20-year period. The Northeast's share of total refining capacity has therefore fallen fairly steadily from almost 14 percent in 1955 to just over nine percent in 1975. The capacity increase that has occurred has been through additions to existing refineries rather than through construction of new refineries.[1/]

Recent attempts to locate refineries in the region have been unsuccessful. In New England, for example, which is without a major refinery, the Pittston Company's recent attempts to locate a 250,000-barrel-a-day refinery in Eastport, Maine has been blocked after debate by those opposing the refinery on environmental grounds. Opposition by citizens and environmentalists have also blocked refineries in Durham, New Hampshire and in Maryland.

In addition to these problems of siting new refineries, Amerada Hess recently (1974) closed its Port Reading, New Jersey refinery with its 65,000 barrel-a-day capacity. Built in 1958

1/ The last new crude oil facility on the East Coast was built in 1958.

Table III-2

Crude Oil Capacity of Operating Refineries - Historical Trends

Year	U.S. Total Capacity[1/] (barrels/day)	Index (1955=100)	Northeast[2/] Capacity (barrels/day)	Index (1955=100)	Northeast as % of U.S. Total
1975	14,696,750	175.3	1,353,520	116.1	9.2
1970	11,882,393	141.8	1,241,920	106.5	10.5
1965	10,161,311	121.2	1,232,040	105.7	12.1
1960	9,543,329	113.9	1,307,440	112.1	13.7
1955	8,380,801	100.0	1,165,968	100.0	13.9

1/ Excluding Puerto Rico. All capacity data excludes shutdown operable capacity.

2/ Includes New England and Middle Atlantic States. Includes Massachusetts refinery in 1965 and earlier.

Source: Bureau of Mines, "Petroleum Refineries in the U.S."

it was among the last two refineries built in the Northeast. It cited "unusually high" operating costs and "red tape" stemming from environmental lawsuits blocking its refinery expansion plans. The jump in the cost of planned expansion from $20 million to $50 million was also cited as a major reason. Amerada Hess assured FEA at the time of the closing that it could make up the lost production by taking up the slack at its huge refinery in the Virgin Islands. Mobil Oil Corp. also cancelled plans to expand the capacity of its Paulsboro, New Jersey refinery to 250,000 barrels per day. Among its major reasons were the rapidly rising construction costs associated with the expansion. These were estimated to be close to 400 million dollars at the time of the company's decision.

The reason for the Northeast's diminishing share of U.S. refining capacity is both a lack of new refinery construction and limited additions to capacity of existing refineries. In recent years, as the major reasons which can be cited are a combination of economic considerations and local opposition on environmental grounds. Neither reason is unique to the Northeast although environmental considerations may be a greater constraint than in other regions. Economic considerations are complex, and will be discussed in greater detail later. In general, however, all regions can be expected to be facing rising construction and operating costs, and the economic issue therefore is largely a question of whether these costs are higher and/or rising more rapidly in the Northeast than in other regions.[1/]

The strength of demand in local markets, and the cost and availability of crude oil are also potential economic issues surrounding refinery siting and expansion decisions.

1/ Government import regulations have probably also contributed to the slow growth of refining capacity. By both increasing the price of the imports upon which East Coast refineries are so dependent and, especially by favoring imported products from refineries built in the Caribbean, government regulations have affected the economics of refinery location.

C. Refinery Siting Decisions

The decision to add refining capacity to an area, either through construction of a grass-roots refinery or additions to existing capacity, is a complex decision which is dependent on a number of factors. A list of the major factors which might be included when considering a particular site includes:

- cost of moving products to market from the refinery
- cost of moving crude oil to refinery
- local construction costs, land
- operating costs (fuel, labor, non-petroleum materials, taxes)
- local support or opposition (environmental/local employment tradeoff)
- expectations concerning future growth in regional demand

Such a list could certainly be expanded to include a number of other lesser economic and non-economic considerations. It should also be noted that the factors above are considered (except for construction costs and local sentiment) over the probable life of the refinery. While a source of cheap natural gas may provide low fuel costs at a particular site in 1976, for example, what are the prospects for this advantage to continue over the life of the refinery? As another example of the uncertainty of future developments, a refinery siting choice could focus on whether a local market for fuel oil in electric utilities could be adversely affected by coal conversion, either due to government regulation or a choice by the utility.

A brief discussion of each of the major factors is provided below. The relative importance given to the various considerations can obviously vary greatly between companies and between individual

siting decisions. Any such discussion of the multitude of considerations which go into location decisions clearly points to the fact that there is no single "optimal" location. This is particularly true when one considers the uncertainties surrounding estimation of the variables in the future. The non-quantifiable nature of a variable such as "delays likely due to local opposition by environmental groups" makes a single optimal decision model unlikely.

For the purpose of the discussion in this section, it is assumed that the refineries does, in fact, have control over the factors listed above. In the case of crude oil transportation costs, for example, a refinery making a particular siting decision may depend on crude oil which is produced and transported by another company. In such a case, the cost of delivered crude oil would be taken as a "given", and the siting decision would then be based on other factors. The implications of this possibility will be discussed further in Section V and the discussion in this section carries the implicit assumption that the oil company making the refinery location decision is vertically integrated through (at least) the crude oil transport, refining, and product distribution phases.

1. Transportation Costs

In one sense, transportation costs are relatively "unimportant" when considering some petroleum products. The four major sectors of the petroleum industry (and hence four components of delivered cost) are: exploration and production, refining, transportation, and distribution. The variety of products derived from oil complicates the analysis of the cost components of final prices.

However, based on 1971 data available for Boston and New York City [1/] production costs account for a high percentage of the delivered price for number 2 fuel oil, amounting to close to 80 percent for large commercial and industrial users, and about 50 percent for small commercial users. The remainder is equally split between distribution and transportation for large users, with distribution accounting for about three times the transportation costs for small users. For number 6 fuel oil, production is between 70 and 80 percent of delivered prices, while for gasoline there is about an even percentage split between production, distribution, and taxes.

While transportation costs are a relatively small share of the delivered price for some products, they are of great importance in siting refineries. Final product distribution costs and the large non-refining element of production costs are, in effect, a "given" regardless of where a refinery is placed. For this reason, the competitive advantage or disadvantage which results from a particular siting decision will show up largely as a result of the effect on transportation costs.

A basic tradeoff in siting a refinery is between minimizing the transportation costs of crude oil and the transportation costs of petroleum products. If one were to ignore the transportation costs of petroleum products and focus only on crude oil transportation costs, this would imply that all crude oil received at a refinery is consumed there. At the other extreme,

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1/ Energy Prices, 1960-1973, Foster Associates, Inc.

an attempt to optimize only product transportation costs would suggest that each market should have a refinery. These two competing factors are not, however, equally weighted. The locational economics of refineries indicates that, theoretically, the refinery industry shows the general characteristics of a weight-gaining industry. This type of industry tends to locate processing plants near markets because product transportation costs per unit-mile are higher than crude material transportation costs.[2/]

As noted previously in the discussion of the current and historical location pattern of refining capacity, there are numerous examples of refining capacity built nearer to the source of crude than to the market. While the Northeast's relative shortage of capacity (See Table III-2) seems to contradict this weight-gaining hypothesis, it is important to note that transportation costs are not the only consideration in refinery sitings.[3/]

The previous discussion of petroleum transportation costs showed the large differences in transportation costs associated with different modes of transport, combinations of distance and volume, and types of oil or product. Crude oil transportation at a given volume and distance by pipeline, for example, is about

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2/ Economic Aspects of Refinery and Deep-Water Port Location in the United States, U.S. Dept. of Transportation, May, 1974.

3/ It may also be that historically the relatively cheap cost of acquiring crude gave companies more latitude to sacrifice optimality on the transportation costs component. This would be only one of many possible explanations for the historical trend in refinery sitings. The various cost components change over time, thereby changing location patterns.

25 percent less expensive per unit than product transportation costs. Crude oil can be piped, but many of the major (residual fuel oil) and minor (asphalt,wax, lubricants) products of a refinery cannot be moved economically by pipeline. These products (see Table III-3 for the breakdown of products from a barrel of oil) must be moved by rail, water, or truck. As the cost curves presented earlier show, the cost per unit of moving these products is higher than pipeline costs per unit over a broad range of distances and volumes. The costs of moving these non-pipeable products is considerably higher per barrel-mile than crude oil transportation costs.

Other things equal, a decision-maker examining alternative sites for additional refining capacity would be expected to favor a location which reduced the cost of transporting products from refinery to market. The important point, of course, is the other things are not, in fact, equal between alternative sites.

2. Construction and Operating Costs

As an input to a refinery location model designed by the Department of Transportation 1/ to examine deep-water port locations, operating costs were studies and inter-regional differences were noted. These differences, summarized in Table III-4 for new and existing refineries, reflect differences in the following cost factors which vary from region to region:

- labor costs
- fuel costs
- chemical costs
- processing costs

1/ Economic Aspects of Refinery & Deep-Water Port Location in the United States, U.S. Dept. of Transportation, May, 1974.

Table III-3

Percent Yield of Products from Crude Oil

	June 1974		December 1974	
	PAD I (East Coast)	National Average	PAD I (East Coast)	National Average
Total gasoline	47.4	46.7	43.6	44.3
Special napthas	--	.7	--	.6
Kerosine	.5	1.0	.4	1.5
Distillate oil	24.9	21.8	26.0	23.0
Residual oil	9.5	8.0	13.0	10.5
Total jet fuel	2.5	6.4	2.0	6.8
All other products	15.2	15.4	15.0	13.3
Total	100.0	100.0	100.0	100.0

Source: Bureau of Mines, Mineral Industry Surveys, "Monthly Petroleum Statement."

Table III-4

Summary Refinery Operating Costs in the DOT Model

Refining District	Operating Costs ($/bbl) for Existing Refineries	Operating Costs ($/bbl) for Grass-Roots Refineries
1. Mid-Atlantic	1.48	1.98
2. Appalachian #1	1.33	1.93
3. Appalachian #2	1.22	1.89
4. South Atlantic	1.33	1.64
5. Ind., Ill., Ky.	1.38	1.97
6. La. Gulf Coast	1.30	1.81
7. La., Ark. Inland	1.13	1.77
8. Tx. Gulf Coast	1.41	1.69
9. Tx. Inland	1.37	1.67
10. New Mexico	1.03	1.81
11. Ok., Kan., Mo.	1.36	1.85
12. Minn., Wisc., N.D., S.D.	1.15	1.88
13. New England	1.48	1.92
14. Ark., Miss. Gulf	1.30	1.81
15. Ore., Wash.	1.38	1.93
16. N. Calif., Nev.	1.38	1.98
17. S. Calif., Ariz.	1.38	1.98
18. Rocky Mountain	1.26	1.88

Source: Economic Aspects of Refinery and Deep-Water Port Location in the United States, U.S. Dept. of Transportation, May, 1974.

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A distinction is made between existing refineries and grass-roots refineries. Refining costs for existing refineries are generally considered to be a function of the "complexity" of the refinery. The complexity varies dependent on the characteristics of the oil being processed. A refinery supplying a market emphasizing gasoline and distillate will generally have a higher complexity than a fuel oil refinery emphasizing residual.

Construction labor costs can vary between districts by about 2.9 cents per barrel, and operating labor can vary by about 1.9 cents per barrel. Both of these figures account for the percent variation in the wage rate 2/ and the importance of labor costs, which account for about 19 percent of total operating cost, can vary by about 30 percent. Operating costs are not greatly affected by variations in chemical costs in different regions. Processing costs do vary significantly due to dissimilar processing modes. As previously mentioned, this factor is particularly relevant for existing refineries.

The DOT calculations for the operating costs of grass-roots refineries focus on site-specific factors such as the previously mentioned labor and direct operating costs as well as land costs, refinery construction costs, and taxes. The asumption is made that the complexity of grass roots refineries will be the same due to the use of similar crudes and production of a similar mix of output. Dropping this assumption by assuming different markets, for example, would tend to increase the regional variation shown in Table III-4 for grass-roots refineries.

2/ Refinery operating labor costs on the Gulf Coast, for example, are 4 percent lower than on the East Coast.

Table III-4 shows that for grass-roots refineries there is about a 30 cent per barrel difference in total operating costs between the Middle Atlantic States and Texas.[3/] The difference between the two areas for existing refineries is not as great. Presumably additions to existing refineries would display a variation more closely resembling that shown for grass-roots refineries, since the existing refinery column in Table III-4 does not account for variations in construction, labor, and costs.

3. Other Factors

A company making a siting decision will certainly consider the transportation, construction, and operating cost implications of the various alternatives it is considering. However, the analysis of these factors alone does not encompass all of the considerations necessary to make a final decision.

Although it is not always precisely quantifiable, delays caused by local opposition, environmental lawsuits and permit processes can be ultimately translated into a cents-per-barrel penalty. Refinery construction costs, for example, are rapidly rising. As noted earlier in the discussion of recent refinery delays, rising construction costs between the time of planning and the time when construction could begin has been the cause of abandonment of expansion or construction plans. Whenever delays due to a certain area's opposition to a refinery cause construction costs to rise

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3/ While the costs have undoubtedly risen since the estimates were made, it is not clear that the differences between the regions would have changed significantly.

more rapidly than the ability of the company to pass through the cost increase to consumers, the company can be expected to attribute an added "cost" to that area relative to others. An added complication to this issue of construction delays is the fact that the financial situation of the company may cause an increase in construction cost or a change in the timing of the outlays to adversely affect expansion plans.

The way in which all of the various costs discussed above are projected to change over time can clearly affect a company's refinery siting decision. If, for example, it is expected that a certain cost advantage which one region presently has (e.g. fuel or labor costs) will not continue over the life of the refinery, this can change the calculation of the costs and benefits associated with a particular location. The same consideration applies to projections of the relative strength of demand for petroleum products in a given market area over time. A strong market at the time of planning may be projected to weaken, and the necessarily inexact nature of energy forecasting means that a potentially important uncertainty is introduced into the siting decision process. Energy forecasts, an important consideration in siting decisions, will be discussed in greater detail in Section IV.

SECTION IV

ENERGY DEMAND PROJECTIONS

A. Published Projections and General Considerations

1. Comparison of Projections

When the various scenarios within each projection are included, the number of energy projections done in the last few years number in the dozens. Appendix II provides a survey of the results of a number of major projections. Both in terms of the estimates of total energy consumption and the fuel type mix, these projections vary widely. Table IV-1 shows two major additions to the list in Appendix II, and shows the changes that have occurred as a result of recent revisions to the original projections. The Bureau of Mines (BOM) and Federal Energy Administration projections are the ones which will be utilized in this section. The changes shown in Table IV-1 point to the fact that it is extremely difficult to project energy consumption with today's rapidly changing circumstances. The large changes which occurred with the revision of the BOM and FEA projections (after 3 and 1 years, respectively) are in terms of both a lower total demand for energy and a different mix of energy types.

2. Assumptions Required for Energy Projections

Projections of energy are made by making a number of assumptions concerning the future progression of a number of key variables. One of the most important assumptions necessary to project energy consumption is the future price of energy. Like any other good, energy is subject to the law of supply and demand, and users can be expected to economize in their use of more expensive energy. The various FEA scenarios are developed at 3 prices, with the world price per barrel of crude oil being the key variable. The most

Table IV-1

PROJECTED UNITED STATES TOTAL GROSS ENERGY CONSUMPTION: A COMPARISON

(Trillion BTU)

Forecast	Coal	Petroleum 1/	Natural Gas	Nuclear and Hydropower	Total Gross Energy Inputs
PIES 1985 2/	22,863	37,976	24,775	17,306	102,920
PIES Revised 1985	20,575	41,532	24,154	12,605	98,866
% Δ	- 9.08%	+ 9.36%	- 2.51%	- 2.72%	- 3.94%
BOM 1985 3/	21,470	50,700	28,390	16,070	116,630
BOM Revised 1985	21,250	46,500	20,100	15,690	103,540
% Δ	- .10%	- 8.28%	- 2.92	- 2.36%	- 1.12%
BOM 2000	31,360	71,380	33,980	55,180	191,900
BOM Revised 2000	34,750	56,930	19,600	52,150	163,430
% Δ	+ 10.81	- 2.02%	- 4.23%	- .55%	- 1.48%

1/ In the revised cases for BOM this number includes oil shale.

2/ $13 reference cased for revised, and the approximately equivalent $11 reference case for the original PIES projections. Original made in November 1974 and revised in February, 1976.

3/ Original projections made in December, 1972 and revised projections made in December, 1975.

recent version of PIES[1/] projects energy at $8, $13, and $16 per barrel, with $13 per barrel being approximately the current price. Total consumption of energy is sensitive to these prices, with 1985 total gross energy consumption (reference scenario) being 103.3 quads at $8, 98.9 quads at $13, and 97.3 quads at $16.

Energy is a derived demand. For example, energy is demanded in greater quantities when industrial production increases or more households are formed. Two key assumptions are the growth in population and the growth in either GNP or some other measure of economic activity.

In order to forecast actual consumption, as opposed to demand, assumptions must be made concerning future energy supplies. Deregulation of oil and gas prices, with the expected added incentive to producers, is assumed in most projections. Both the PIES and BOM projections used have assumed de-regulation, although PIES has scenarios for continued price regulation. Assumptions must also be made concerning the amount of coal supply, the growth in nuclear power, and the quantity of energy available from advanced technologies.

The three projections utilized here have different assumptions concerning the potential for energy conservation. The current ratios between population and energy or GNP and energy can obviously change over time, and with energy conservation, a 50 percent increase in industrial production, for example, need not require 50 percent more energy.[2/] Projections can be done on the basis of an expected continuation of present trends, or decreasing energy-output ratios.

1/ Project Independence Evaluation System, FEA's Forecasting model of the technologies, leadtimes, costs, and geographical locations which affect energy commodities from the point of discovery, through production, transportation, conversion to more useful forms, and ultimately consumption by all sectors of the economy.

2/ The increasing complexity of an industrial process (such as has occurred in the chemical industry) can partially or fully offset energy conservation efforts.

The future progression of such key variables is highly uncertain. The uncertainty increases even further as attempts are made to project the future growth of a particular energy source, as opposed to total energy. Because one form of energy can, subject to certain limitations, substitute for another form, the growth in petroleum products is dependent on the growth in coal, natural gas, and nuclear power. Diminishing supplies of natural gas, for example, can prompt substitution of coal or oil in a particular application.

Finally, the timeframe being considered is of great importance. With energy projections intended to help analyze the disposition of OCS oil and gas from the Baltimore Canyon, the relevant timeframe is probably the late 1990's. No attempt is made here to accurately project the PIES projections beyond 1985. BOM projections are to the year 2000, and are presented as published. However, the potential for energy conservation is greatest in the period beyond 1985, and therefore, straight-line extrapolations are not appropriate for anything except illustrative purposes. Projections to 1985 are for energy consumption by a system which is essentially fixed. Some changes can be made to the capital stock in the industrial sector, for example, but these are minor compared to the possibilities for the period beyond 1985. New equipment, houses, automobiles, and offices designed with energy conservation in mind provide potential for greater energy conservation beyond 1985.[1/]

B. Projections of Energy in the Northeast

1. Published Projections and Assumptions

Figures 4-1 and 4-2 show three published projections of energy consumption in the Northeast. The values for New England, the

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1/ Assuming that high energy prices continue to provide an incentive for such conservation.

Figure 4-1

PUBLISHED PROJECTIONS OF DEMAND
FOR TOTAL ENERGY IN THE NORTHEAST

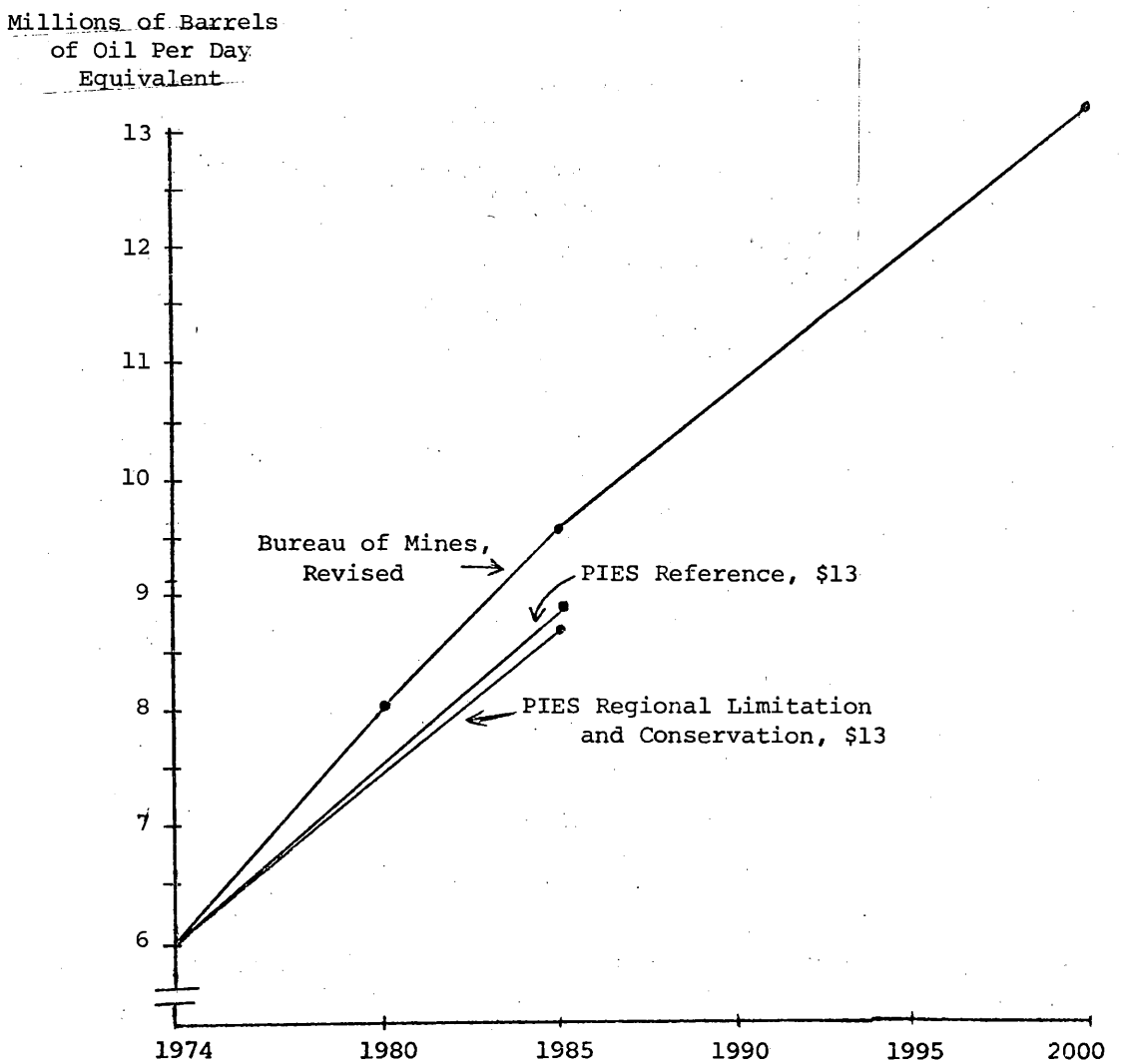
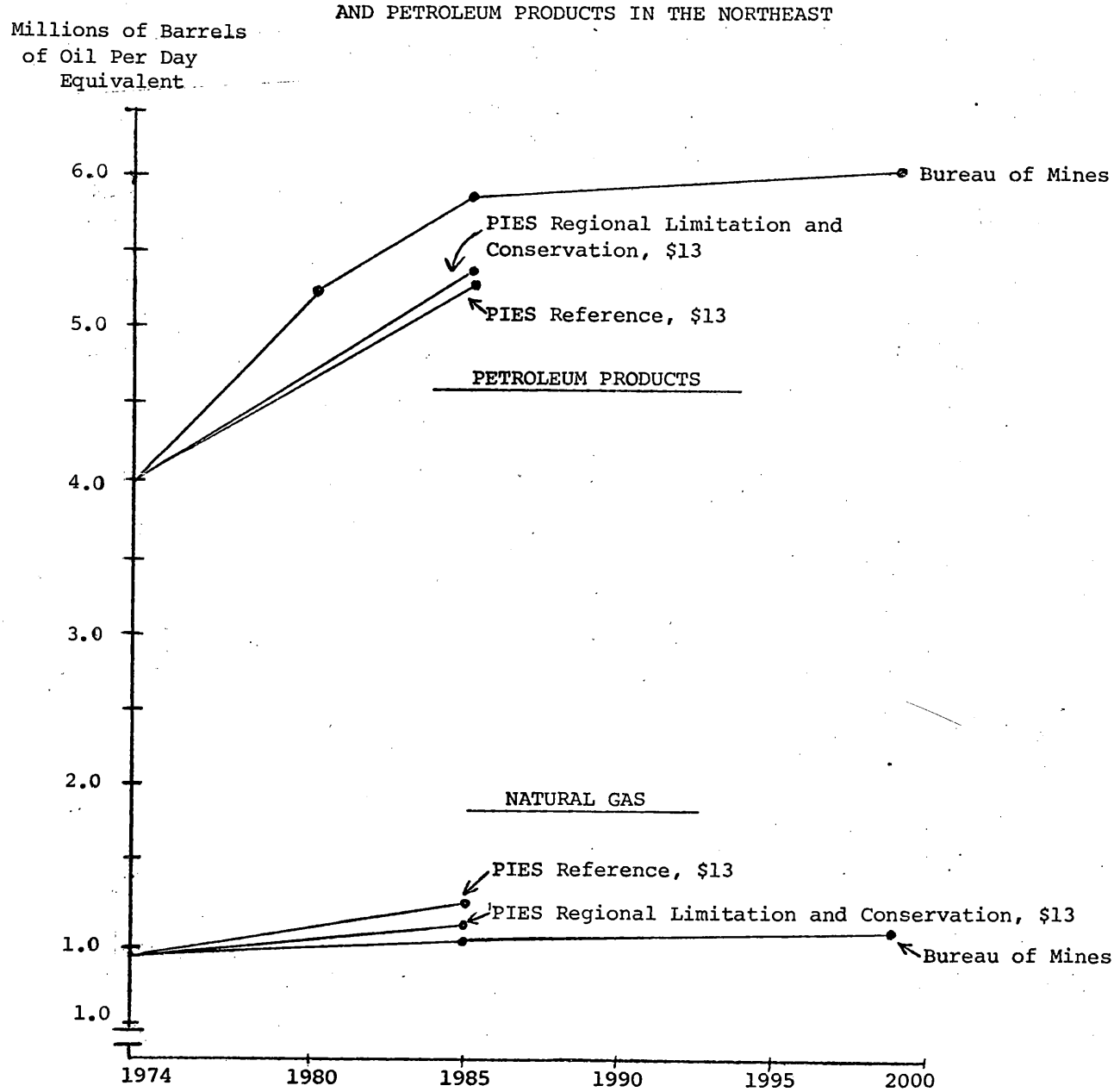


Figure 4-2

PUBLISHED PROJECTIONS OF DEMAND FOR NATURAL GAS AND PETROLEUM PRODUCTS IN THE NORTHEAST



Middle Atlantic, and for each fuel type are shown in Table IV-2 for PIES and Table IV-3 for the Bureau of Mines. The PIES projections are derived for each region, but the Bureau of Mines provides only a national projection, and hence, the Northeasts' share of the total projection was estimated on the basis of historical shares of national consumption.

The Bureau of Mines projection is essentially an extrapolation of present trends in energy consumption, with judgement imposed to reflect expectations about limitations to supply. Deregulation of oil and gas are assumed. The potential for conservation was not considered in their forecast, although a projection of a declining trend in energy/value added ratios does inject some measure of increased efficiency.

The PIES reference case assumed "Business as Usual" supply and demand. The BAU demand case is based on FEA's econometric demand model. This model is based on current relationships between energy use and the variables which influence energy use. The BAU demand case does not assume conservation measures of the type likely to be prompted by governmental intervention, although it does reflect some conservation resulting from higher energy prices. The BAU supply case assumes de-regulation of old oil prices and new natural gas prices and various "medium" assumptions concerning Alaskan oil and gas, LNG imports, and military reservation production. Assumptions are also made concerning nuclear growth and the growth in electricity demand.

The PIES regional limitation case assumes an energy conservation scenario on the demand side. Improved auto efficiency, van pooling programs, increased airline load factors, better residential and commercial insulation, increased industrial conservation, and peak load management by utilities are all assumed. On the supply side, major assumptions include restrictions on nuclear power plant construction (with no projects beyond

Table IV-2

PROJECT INDEPENDENCE EVALUATION SYSTEM (PIES) PROJECTIONS
(Thousands of Barrels of Oil Per Day Equivalent)

PIES 1985 Reference, $13 Imports	Coal	Petrol. Products	Natural Gas	Nuclear & Hydropower	Total Gross Energy Inputs
New England	171	1,447	174	284	2,077
Middle Atlantic	1,643	3,645	961	872	7,121
Northeast	1,814	5,092	1,135	1,156	9,198
PIES 1985 Regional Limitation and Conservation Demand, $13 Imports					
New England	256	1,355	153	160	1,924
Middle Atlantic	1,214	3,789	877	779	6,663
Northeast	1,470	5,144	1,030	939	8,587

Source: Federal Energy Administration, National Energy Outlook, 1976 for 1985 reference case. Other case from preliminary model results.

Table IV-3

Bureau of Mines Projections, Northeast Area[1/]

(Thousands of Barrels of Oil Per Day Equivalent)

	Coal	Petroleum Products	Natural Gas	Nuclear & Hydro-power	Total Gross Energy Inputs
B.O.M. 1980					
New England	25	1557	131	174	1887
Middle Atlantic	1219	3486	893	472	6070
Northeast	1244	5043	1024	646	7957
B.O.M. 1985					
New England	31	1735	136	327	2229
Middle Atlantic	1429	3885	908	888	7110
Northeast	1460	5620	1044	1215	9339
B.O.M. 2000					
New England	41	1765	139	1076	3020
Middle Atlantic	1815	4071	923	2922	9730
Northeast	1856	5836	1062	3998	12750

Note: Detail may not add to total due to independent rounding.

1/ Source: Energy Through the Year 2000, Revised, "Bureau of Mines, Dec., 1975. The BOM projections are compiled only on a national basis. These regional estimates are based on each region's 1972 share of national consumption of each fuel type in each sector.

currently granted construction permits) and environmental restrictions on mining and burning coal.

The compound annual growth rates from 1974 to 1985 are shown in Table IV-4 for the various fuels and for total energy. In combination with Figure 4-2, it can be seen that the different projections make different assumptions concerning the mix of energy sources within the projection of total energy. For example, although the PIES Regional Limitation and Conservation scenario projects total energy consumption in 1985 to be lower than under the reference scenario, petroleum products are actually higher in the Northeast under the reference scenario. If nuclear energy does not develop as expected, (especially in the long run beyond 1985) other fuels (probably mainly coal) will have to step in to fill some or all of the gap. The projection of growth in specific types of energy is, therefore, dependent on the complexity of inter-fuel substitution, and such fuel-specific projections are particualrly uncertain as a result. This uncertainty increases with more long-range projections as the possibility for fuel substitution is no longer as tightly constrained by the existing capital stock.

The seemingly rapid growth in energy consumption shown by BOM, whereby total energy roughly doubles between 1974 and 1995, should be put in perspective by historical trends. While energy is projected to grow more rapidly than population, it should be noted that energy use per capita rose from 229 million BTU in 1947 to 355 million BTU in 1973. This represents an average annual growth rate of 1.7 percent. The increase between 1960 and 1973 was a very rapid 2.8 percent per year.[1/]

Partly due to the depressed economy, but also due to changed energy patterns prompted by higher prices, this trend has been reversed in 1974 and 1975, with gross energy use per capita declining from 355 million Btu in 1973 to 338 million in 1975. This section has pointed to the difficulty of projecting energy use, and the number of variables

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1/ Bureau of Mines, Energy through the Year 2000.

Table IV-4

GROWTH IN ENERGY AND RELATED VARIABLES

A. Compound Annual Growth Rate in Energy (%/yr, 1974-1985)

CASE	COAL	PETROLEUM PRODUCTS	NATURAL GAS	NUCLEAR AND HYDRO POWER	TOTAL GROSS ENERGY INPUTS
PIES Reference 1/					
New England	19.94	2.37	2.92	9.14	3.80
Mid-Atlantic	4.54	2.82	1.83	12.02	3.79
PIES Conservation 2/					
New England	24.42	1.76	1.71	3.56	3.08
Mid-Atlantic	1.70	3.19	1.03	10.87	3.17
BOM Revised 3/					
New England	2.73	4.07	.59	10.54	4.47
Mid-Atlantic	3.22	3.42	1.31	12.20	3.78

B. Compound Annual Growth Rates in Related Variables

	1971 - 1980	1971 - 1990
POPULATION 4/		
New England	.84	.86
Mid-Atlantic	.77	.81
TOTAL EMPLOYMENT 4/5/		
New England	1.89	1.41
Mid-Atlantic	1.85	1.41
EARNINGS IN MANUFACTURING 4/		
New England	3.57	2.89
Mid-Atlantic	3.68	2.98

1/ PIES 1985 Reference, $13 imports case. SOURCE: Federal Energy Administration's National Energy Outlook, 1976.

2/ PIES 1985 Regional Limitation and Conservation Demand, $13 imports case. FEA, National Energy Outlook, 1976.

3/ BOM Revised 1985 case.

4/ SOURCE: U.S. Department of Commerce, BEA, Area Economics Projections 1990, Table 4, based on series "E" projections.

5/ Commerce, BEA 1970 used as base year.

which can affect the growth in energy use. While a Bureau of Mines projection as used here, with its essentially business-as-usual assumptions, probably represents an upper limit to energy growth, it is highly uncertain to what extent energy use patterns will change and how these changes will affect growth in each of the fuel types.

The discussion below will show, however, that an analysis of the disposition of OCS oil and gas is not highly dependent on precise projections of consumption. When economic recovery begins, energy use will almost certainly resume its upward trend, although probably at well under recent historical rates. Almost whatever the exact shape of the energy growth curves, the expected oil and gas production from the Baltimore Canyon will be a relatively small share of gas and (especially) oil.

SECTION V

OCS OIL AND GAS

A. Introduction

The discussion to this point has focused on the present supply and demand pattern in the Northeast, regional refinery operations, the economics of transportation and refinery siting, and projected energy consumption in the region. A consideration of all of these factors is necessary to understand the probable disposition of OCS oil and gas from the Baltimore Canyon. Among questions to be answered concerning a given OCS oil and gas find are the following:

- Where will the OCS crude oil be refined?
- How will the oil and gas be transported and what flexibility exists in transportation choices?
- Will additions to refining capacity be necessary, and if so, what form will additions to refining capacity take?
- How will choices concerning the disposition of the oil and gas be affected by expectations of growth in energy demand and/or expected shifts in the mix of energy sources?
- How would the various sizes of gas and oil discoveries affect energy supply and demand in the region?

B. OCS Oil and Gas and the Regional Energy Pattern

The size of the OCS oil and gas discovery can be placed somewhat in perspective by Figure 5-1 which shows the size of the expected find under two scenarios, and by Table V-1 which compares expected production to the Bureau of Mines energy projection discussed

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Figure 5-1

Potential Energy Supply Provided by
Baltimore Canyon Oil and Gas Development

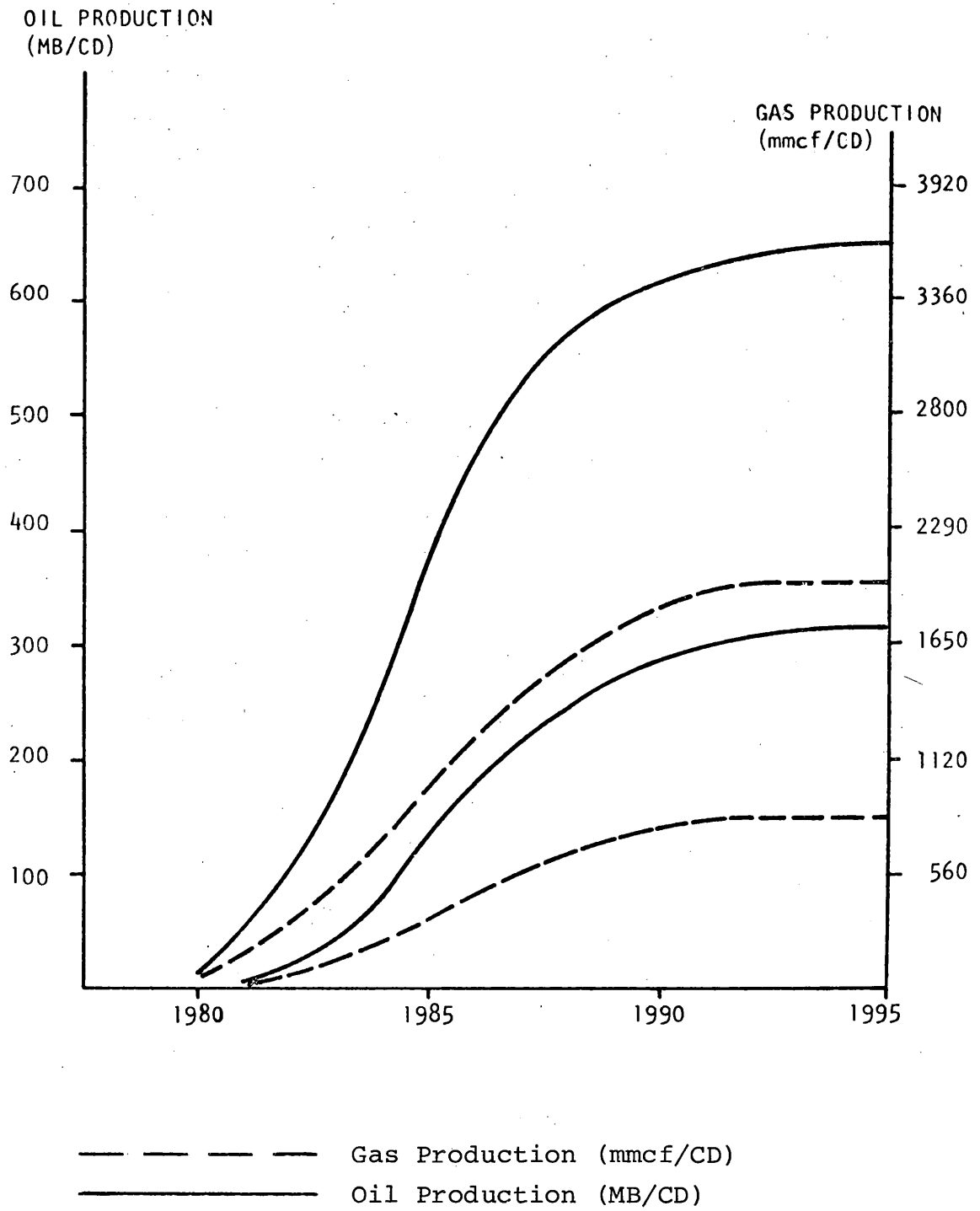

Table V-1

Comparison of Expected Peak Production
With Projected Demand
(10^{15} BTU)

	1995 Production	1995 Demand 1/	Production as % of Demand
High Recovery Scenario 2/			
Natural Gas	2.04	2.4	85%
Oil	4.03	12.2	33%
Medium Recovery Scenario 3/			
Natural Gas	.87	2.4	36%
Oil	1.98	12.2	16%

1/ Based on Bureau of Mines projections. This is a Business as Usual Projection which does not account for conservation potential.

2/ On basis of preliminary U.S.G.S. estimates, about one chance in 20 of this level of production.

3/ The median estimate of production.

in the last section. As can be seen from the table, the OCS oil and gas, even under the more likely medium recovery scenario, will only supply about 16 percent of the region's demand for petroleum products and about 36 percent of demand for natural gas. Area refineries will still be dependent upon external sources for their crude oil inputs, and the region as a whole will also be dependent upon external sources for natural gas.

Relative to present refining capacity in the region (1.5 million BPD with about 1.3 million BPD in the two major areas), the expected peak daily production under the most likely peak production level of 300,000 BPD would only be 20 to 23 percent of current daily crude throughout. While this production is based on the median reserve estimate, the high reserve estimate and corresponding daily production of 600,000 BPD would provide 40 to 45 percent of the current daily crude throughput in the regional refineries.

In the case of completely stagnant demand for petroleum products, the analysis of the disposition of OCS oil and gas would be relatively simply: OCS oil would be substituted for the more expensive foreign crude[1/] which is now the source of most of the crude for area refineries. In such a case, no construction of refining capacity would be prompted by OCS oil, and other than reduced shipments of foreign crude, no major changes in the transportation system would result. However, as was shown in the projections developed in the previous section, demand for petroleum products is not expected to stagnate at present levels. This growth in demand means that refinery expansion is likely in the absence of OCS oil. The complexity of the refining alternatives is obvious, but it is somewhat independent of the OCS oil itself.

1/ It will be assumed, for simplicity, that the OPEC cartel remains relatively stable. Instability of some type in the cartel is, of course, a very real possibility. In the extreme case where the cartel broke and imported oil prices fell dramatically without protection of domestic prices, cheap foreign crude could replace domestic crude (including OCS).

OCS natural gas will presumably be fed into the existing transportation network[1/] and will serve to replace natural gas currently being transported from the Gulf Coast. The gas "freed up" by such a substitution can presumably be transported to other areas of the country. While gas brought into the region may somewhat change demand patterns in the region, this is not expected to be a major factor. Widespread conversion to natural gas as a fuel for utilities and industry would not be expected, for example. Deregulation of natural gas has been assumed in the previously developed projections. Such deregulation would means that, unlike the current situation, the gas would enter a market where its price would rise to a market-clearing level which reflected its true value. Presumably, users and potential users would bid for its use, and OCS gas would enter a market which is considerably more national in scope than the present dual market which includes a large unregulated segment in the Gulf Coast states.

C. The Effect of Energy Demand Projections on Transportation and Refining Strategies

The general discussion of national and regional energy projections established the number of variables which must be considered when projecting energy consumption. Those who will decide where OCS oil will be transported, refined, and marketed must consider both demand in the Northeast as well as demand in other regions. While possible transportation and refining options will be discussed more fully below, it is important at this point to note that, while OCS oil and gas will be divided among a number of companies, there are certain indivisibilities associated with refinery construction. The most likely peak production is 300,000 BPD and this will be divided

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1/ Additions to capacity will undoubtedly be necessary through additional pipelines and/or compressors on existing pipelines. Lower deliveries and lower load factors on pipelines from the West South Central region due to lower demand could increase the cost of delivering gas in the existing network. Pipeline consolidation would be one way of averting this.

among a yet-to-be-determined number of companies. It seems unlikely that a grass roots refinery would be built today which has a capacity of less than 150-200 thousand BPD. This somewhat reduces the number of refining options in that it is unlikely the OCS oil, by itself, will prompt construction of grass roots refineries. However, it is at this point that assumptions concerning regional demand projections become important. A company which considers future regional demand to be strong may seriously consider the construction of a refinery designed to serve the region in the absence of OCS oil. OCS oil, in reducing the transportation costs associated with serving the Northeast markets, could provide an incentive for placement of the refinery in (or near) the Northeast. A company without a refinery in the area may view OCS oil as the necessary incentive to locate a refinery in the region.

The previous discussion of refinery siting decisions established the fact that such decisions involve uncertainty due to the inherently uncertain projections of future costs and benefits which must be made. The projections presented in the previous section are based on a series of assumptions with which a particular refinery planner may not agree. The growth in the population and economic variables which drive the demand for energy may be seen to be either optimistic or pessimistic. The potential for conservation and the future prices of energy sources are areas of uncertainty. Because inter-fuel substitution is important in making fuel-specific projections, such variables as the future of the nuclear industry or environmental regulations concerning coal burning can clearly have an effect on projections of the Northeast's demand for petroleum products.

Projections of demand in other regions will be important. With the previously discussed trade-offs in crude and product transportation costs, the Northeast could theoretically be served by OCS oil refined in a number of locations. If future demand is felt to be

stronger in the South, for example, OCS oil may be refined in a location which allows easier transportation to those markets. In one sense, OCS oil from the Baltimore Canyon must be viewed with an almost national perspective.

D. Transporting and Refining OCS Oil

As previously stated, it is not expected that OCS oil in the quantities expected will, in and of itself, prompt construction of new grass roots refineries. OCS oil can be expected to simply replace the imported oil which is currently the source of most of the region's crude input, and for that reason it does not appear that OCS oil can even be expected to result in additions to capacity. In this sense, oil companies will be making refinery location decisions almost independent of whether or not OCS oil is found. Based primarily on how they view the strength of demand for petroleum products in the region, a decision will be made as to whether or not to add capacity for future regional demand and, if added, where to locate it.

Given that an oil company with both a share of OCS oil and a regional refinery projects increased regional demand and decides to meet it with increased capacity, there are several options for where to add the capacity. Although the mid-Atlantic refineries refineries are generally quite flexible as to the type of oil (in terms of physical characteristics) they can process, it may be that OCS oil is not compatible with a particular company's existing refinery. This introduces a number of options, one of which is to modify the existing regional refinery, and another being the possibility of shipping it to another refinery with different capabilities. The following three options should cover most of the possibilities for disposition of OCS oil:

- refine the oil in Gulf Coast refineries;

- refine it in the two major New Jersey-Pennsylvania refinery areas;
- refine the oil elsewhere on the East Coast.

Although the second option is felt to be the most likely, examination of all three options should cover the range of actions which could be pormpted by OCS oil.

1. Texas Refining of OCS Oil

While it might seem obvious that the "large" expense of shipping crude to Texas and shipping product back to the Northeast would eliminate this option, the recent expansion of Exxon's Baytown, Texas refinery (by 250,000 BPD) suggests that the alternative should be examined. The expansion will be used to serve Northeastern markets, and was done in lieu of expanding Exxon's New Jersey refinery or building in the Northeast.

Unlike the case of Baltimore Canyon OCS oil, the Baytown expansion will refine imported crude. In the discussion of transportation costs, it was noted that the flatness of tanker cost curves at long distances implies that there would be little cost difference between transporting crude to Texas as opposed to New Jersey. Texas also had the advantage of experience in handling the type of crude which is to be refined in the expanded capacity, and perhaps most importantly, Exxon did not expect to face the degree of local opposition in an expansion at Baytown as opposed to the Northeast.

Table V-2 provides several sample calculations of the cost of transporting Baltimore Canyon crude to Texas and products from Texas to New Jersey. The range of costs shown by these calculations is between 32.7¢ and 53.7¢ per barrel.[1/] Because these costs are based on the previously discussed cost curves, they are necessarily dependent

1/ One-way cost. Various combinations would be possible for two-way shipment.

Table V-2

SAMPLE TRANSPORTATION COST CALCULATIONS[1/]

Transport Mode[1/]	Volume	Cost per Unit	Distance	Cost per Barrel
Crude pipeline	300,000 BPD	10.90¢/500 bbl/mile	1,500 miles	32.7¢
Product pipeline	300,000 BPD	13.63¢/500 bll/mile	1,500 miles	40.8¢
Tanker (U.S.)[2/]	60,000 dwt	1.8 mills/ton-mile	1,750 miles	42.0¢
Tanker (U.S.)[2/]	35,000 dwt	2.3 mills/ton-mile	1,750 miles	53.7¢

1/ Based on cost/volume relationships shown in previously discussed DOT cost curves.

2/ Intercoastal U.S. flag carrier. Separate costs not developed for crude and product.

upon size of tanker, size of pipeline, and volume. For example, considerably higher costs would be faced by attempting to ship low daily volumes to and from Texas by pipeline.

The cost penalty for the additional transportation required by Texas refining operations is 1-2¢ per gallon. Part of this cost penalty may be made up by the lower operating costs in Texas than in the mid-Atlantic. As Table V- showed, this is about a 30¢ per barrel difference for grass roots refineries given certain assumptions concerning regional differentials in construction and operating costs. Based on transportation and refinery operating costs alone, it seems unlikely that most companies would be willing to incur such a cost penalty (and potential competitive disadvantage) if it could be avoided by locating nearer both the source of crude and the market. Opposition to refinery construction based on environmental grounds could be a factor which, due to delays, would be translated by the company into a cents-per-barrel penalty associated with the mid-Atlantic location. Economies stemming from the location of numerous ancillary support industries in Texas as well as the location of a large petrochemical industry could also be seen as a benefit associated with a Texas location.

2. New Jersey-Pennsylvania Refining

In terms of minimizing product[1/] transportation costs, and assuming that the producing companies have refineries in the area, there is an incentive to refine OCS crude in the existing refinery areas in the Northeast. Over 85 percent of the present refining capacity is in the Northeast and is located in the two major areas in the north and southwestern areas of New Jersey. These refineries are currently heavily dependent on imported oil, and the PIES model

---

1/ Assuming that the product is marketed in the mid-Atlantic. A New England location would result in somewhat lower product transportation costs for New England markets.

projects a continuarion of this dependence on foreign crude.[1/] OCS crude oil can, in such a case, substitute directly for foreign oil and the projected increase in demand for petroleum products in the region can be met through either increased capacity in the Northeast and/or greater inter-regional (or international) transfer of refined products.

3. Other East Coast Locations

OCS oil could be refined in other locations on the East Coast. Possible areas for expansion are not numerous, however,[2/] and in all likelihood this option would involve a grass roots refinery. The considerations involved are similar to those for the Texas and New Jersey cases. OCS oil would not be expected to prompt construction of a new refinery by itself, although it may provide an element of supply at a cost reduction relative to the previous cost of crude.

Dependent on the exact location chosen, and whether or not the company is its own supplier of crude, it may be possible to reduce total transportation costs by utilizing an East Coast refinery location and OCS oil. Whether transportation costs are the factor which is most heavily weighed, and whether OCS could provide a significant share of crude input will, of course, depend on the particular company and site chosen.

1/ 1985 Reference Case, $13

2/ A 53,000 BPD refinery is the only "large" refinery elsewhere in PAD 1 assuming that the Getty Delaware refinery should be grouped with New Jersey refineries.

Appendix A
Pipeline Costs Used in DOT Model

Computed Pipeline Costs*

Volume (000 bbl/day)	Cost per 500 barrel-miles(¢)	Volume (000 bbl/day)	Cost per 500 barrel-miles(¢)
10.000	50.000	260.000	11.697
20.000	48.847	270.000	11.493
30.000	41.500	280.000	11.293
40.000	35.258	290.000	11.096
50.000	30.000	300.000	10.902
60.000	27.555	310.000	10.712
70.000	25.310	320.000	10.525
80.000	23.247	330.000	10.341
90.000	21.353	340.000	10.161
100.000	19.600	350.000	9.984
110.000	18.794	360.000	9.809
120.000	18.021	370.000	8.371
130.000	17.280	380.000	8.343
140.000	16.569	390.000	8.314
150.000	15.887	400.000	8.286
160.000	15.234	410.000	8.257
170.000	14.607	420.000	8.229
180.000	14.007	430.000	8.200
190.000	13.431	440.000	8.171
200.000	13.000	450.000	8.143
210.000	12.773	460.000	8.114
220.000	12.550	470.000	8.086
230.000	12.331	480.000	8.057
240.000	12.116	490.000	8.029
250.000	11.905	500.000	8.000

Continued --

* Costs are computed by the use of the appropriate cost equation (constant, linear, or exponential) at a given volume.

Source: Economic Aspects of Refinery and Deep-Water Port Location in the United States, U. S. Department of Transportation, May, 1974.

Appendix A, continued

Volume (000 bbl/day)	Cost per 500 barrel-miles(¢)	Volume (000 bbl/day)	Cost per 500 barrel-miles(¢)
510.000	7.971	760.000	7.257
520.000	7.943	770.000	7.229
530.000	7.914	780.000	7.200
540.000	7.886	790.000	7.172
550.000	7.857	800.000	7.143
560.000	7.829	810.000	7.114
570.000	7.800	820.000	7.086
580.000	7.772	830.000	7.057
590.000	7.743	840.000	7.029
600.000	7.714	850.000	7.000
610.000	7.686	860.000	6.972
620.000	7.657	870.000	6.943
630.000	7.629	880.000	6.914
640.000	7.600	890.000	6.886
650.000	7.572	900.000	6.857
660.000	7.543	910.000	6.829
670.000	7.514	920.000	6.800
680.000	7.486	930.000	6.772
690.000	7.457	940.000	6.743
700.000	7.429	950.000	6.714
710.000	7.400	960.000	6.686
720.000	7.372	970.000	6.657
730.000	7.343	980.000	6.629
740.000	7.314	990.000	6.600
750.000	7.286	1000.000	6.572

Continued --

Appendix A, concluded

Volume (000 bbl/day)	Cost per 500 barrel-miles(¢)	Volume (000 bbl/day)	Cost per 500 barrel-miles(¢)
1010.000	6.543	1260.000	5.829
1020.000	6.514	1270.000	5.800
1030.000	6.486	1280.000	5.772
1040.000	6.457	1290.000	5.743
1050.000	6.429	1300.000	5.714
1060.000	6.400	1310.000	5.686
1070.000	6.372	1320.000	5.657
1080.000	6.343	1330.000	5.629
1090.000	6.314	1340.000	5.600
1100.000	6.286	1350.000	5.572
1110.000	6.257	1360.000	5.543
1120.000	6.229	1370.000	5.514
1130.000	6.220	1380.000	5.486
1140.000	6.172	1390.000	5.457
1150.000	6.143	1400.000	5.429
1160.000	6.114	1410.000	5.400
1170.000	6.086	1420.000	5.372
1180.000	6.057	1430.000	5.343
1190.000	6.029	1440.000	5.314
1200.000	6.000	1450.000	5.286
1210.000	5.972	1460.000	5.257
1220.000	5.943	1470.000	5.229
1230.000	5.914	1480.000	5.200
1240.000	5.886	1490.000	5.172
1250.000	5.857	1500.000	5.143

Appendix B

All Energy Resources
Non-FEA Forecasts of Energy Consumption
(In Quadrillion Btu's/Year)

	1972	1977 3/	1980	1985
TOTAL:				
1. Actual (DOI/BOM) 1/	72.11			
2. Dupree-West 2/		86.567	96.020	116.630
3. NPC Case I 4/			108.402	144.935
4. NPC Case II			105.101	133.911
5. NPC Case III			103.483	128.744
6. NPC Case IV			102.571	124.927
6. Ford Foundation Historical Growth 5/				
A. High Imports			95.0	115.0
B. High Fossil			95.0	115.0
C. High Nuclear			95.0	115.0
8. Ford Foundation Technical Fix				
A. Base			90.0	95.0
B. Low Nuclear			-	95.0
C. High Nuclear			-	95.0
9. Ford Foundation Zero Energy Growth			87.0	93.0
10. National Academy of Engineering 6/			-	104.16
11. MIT Econometric Model @ $11 Oil 7/			97.38	-
12. MIT Judgmental Model @ $11 Oil			83.41	-
13. NPC Medium Case 8/			92.77	108.8

1/ DOI/BOM News Release, March 13, 1974.
2/ U.S. Energy Through the Year 2000, Dupree-West, December 1972, Table 4, page 21
3/ In all cases these interpolations are from 1975 to 1980
4/ Guide to NPC Report on U.S. Energy Outlook, December 1972 (consumption includes imports)
5/ Exploring Energy Choices; Energy Policy Project, Ford Foundation, 1974
6/ U.S. Energy Prospects: An Engineering Viewpoint, National Academy of Engineering, 1974
7/ "Energy Self-Sufficiency: An Economic Evaluation," Technology Review, May 1974
8/ Emergency Preparedness for Interruption of Petroleum Imports into the U.S., November 1974 (advance draft)

Source: Project Independence Report, Federal Energy Administration, November, 1974.

Appendix B, continued

Comparisons of Energy Consumption Estimates
(In Quadrillion Btu's/Year)

	1972	1977	1980	1985
Petroleum:				
1. Actual	32.97			
2. Dupree-West 1/		37.930	42.190	50.700
3. NPC Case I		37.800	40.487	42.203
4. NPC Case II		38.724	42.476	47.860
5. NPC Case III		41.245	46.478	53.835
6. NPC Case IV		45.130	52.841	62.371
7. Ford Foundation Historical Growth				
A. High Imports		38.400	42.000	45.000
B. High Fossil Fuels		36.600	39.000	38.000
C. High Nuclear		36.200	38.000	39.000
8. Ford Foundation Technical Fix				
A. Base		--	36.000	28.000
B. Low Nuclear		--	--	34.000
C. High Nuclear		--	--	31.000
9. Ford Foundation Zero Energy Growth		--	--	--
10. National Academy of Engineering		--	--	28.79
11. MIT Econometric Model @ $11 Oil		--	31.33	--
12. MIT Judgmental Model @ $11 Oil		--	28.79	--
13. NPC Medium Case			41.1	44.5

1/ Petroleum products refined and processed crude oil including still gas, liquified refinery gas and natural gas liquids.

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Appendix B, continued

Comparisons of Energy Consumption Estimates
(In Quadrillion Btu's/Year)

	1972	1977 1/	1980	1985
Natural Gas:				
1. Actual	23.13			
2. Dupree-West 2/		25.924	26.980	28.390
3. NPC Case I 2/			31.364	41.114
4. NPC Case II			29.375	35.457
5. NPC Case III			25.373	29.482
6. NPC Case IV			21.971	22.568
7. Ford Foundation Historical Growth 2/				
A. High Imports			26.000	29.000
B. High Fossil Fuels			29.000	35.000
C. High Nuclear			26.000	29.000
8. Ford Foundation Technical Fix				
A. Base			28.000	32.000
B. Low Nuclear			--	32.000
C. High Nuclear			--	29.000
9. Ford Foundation Zero Energy Growth			--	--
10. National Academy of Engineering			--	33.025
11. MIT Econometric Model @ $11 Oil			35.78	--
12. MIT Judgmental Model @ $11 Oil			24.34	--
13. NPC Medium Case			24.4	26.4

1/ Interpolated between 1975 and 1980
2/ At 1.032 quads/TCF

Appendix B , continued

Comparisons of Energy Consumption Estimates
(In Quadrillion Btu's/Year)

	1972	1977 1/	1980	1985
Coal:				
1. Actual	12.50			
2. Dupree-West 2/		14.751	16.140	21.470
3. NPC Case I 3/			21.200	27.100
4. NPC Case II			18.284	21.388
5. NPC Case III			18.284	21.388
6. NPC Case IV			17.550	20.300
7. Ford Foundation Historical Growth 4/				
A. High Imports			15.000	20.000
B. High Fossil Fuels			15.000	19.000
C. High Nuclear			18.000	23.000
8. Ford Foundation Technical Fix				
A. Base			15.000	18.000
B. Low Nuclear			--	19.000
C. High Nuclear			--	14.000
9. Ford Foundation Zero Energy Growth			--	--
10. National Academy of Engineering			--	21.17
11. MIT Econometric Model @ $11 Oil			16.94	--
12. MIT Judgmental Model @ $11 Oil			16.94	--
13. NPC Medium Case			17.3	19.7

1/ Interpolated between 1975 and 1980
2/ 24.50 quads/Billion Tons
3/ 24.00 quads/Billion Tons
4/ 25.00 quads/Billion Tons

Appendix B , continued

Comparisons of Energy Consumption Estimates
(In Quadrillion Btu's/Year)

	1972	1977 2/	1980	1985
Nuclear:				
1. Actual	0.58			
2. Dupree-West 1/		4.224	6.720	11.750
3. NPC Case I 1/			11.349	29.810
4. NPC Case II			11.349	25.249
5. NPC Case III			9.787	20.220
6. NPC Case IV			6.778	16.126
7. Ford Foundation Historical Growth 1/				
A. High Imports			8.000	16.000
B. High Fossil Fuels			8.000	18.000
C. High Nuclear			9.000	19.000
8. Ford Foundation Technical Fix				
A. Base			7.000	12.000
B. Low Nuclear			--	5.000
C. High Nuclear			--	16.000
9. Ford Foundation Zero Energy Growth			--	--
10. National Academy of Engineering			--	17.57
11. MIT Econometric Model @ $11 Oil			9.60	--
12. MIT Judgmental Model @ $11 Oil			9.60	--
13. NPC Medium Case			6.5	14.2

1/ Converted at average heat rate based on AEC data for projected plant mixes (for energy input)
2/ Interpolated between 1975 and 1980

Appendix B., concluded

Comparisons of Energy Consumption Estimates
(In Quadrillion Btu's/Year)

	1972	1977 2/	1980	1985
Hydro and Other:				
1. Actual	2.95			
2. Dupree-West 1/		3.738	3.990	4.320
3. NPC Case I 1/			4.022	4.715
4. NPC Case II			3.641	3.981
5. NPC Case III			3.583	3.834
6. NPC Case IV			3.431	3.577
7. Ford Foundation Historical Growth 1/				
A. High Imports			4.000	5.000
B. High Fossil Fuels			4.000	5.000
C. High Nuclear			4.000	5.000
8. Ford Foundation Technical Fix				
A. Base			4.000	5.000
B. Low Nuclear			--	5.000
C. High Nuclear			--	5.000
9. Ford Foundation Zero Energy Growth			--	--
10. National Academy of Engineering			--	3.60
11. MIT Econometric Model @ $11 Oil			3.50	--
12. MIT Judgmental Model @ $11 Oil			3.50	--
13. NPC Medium Case			3.47	4.0

1/ Converted to theoretical energy inputs on the basis of national August heat rates for fossil fuel steam plants

2/ Interpolated between 1975 and 1980

Working Paper #6

Fiscal Effects of OCS Oil & Gas Development and Deepwater Port Development

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March 1976

PREFACE

This report has been prepared in a very short time utilizing easily available data on State and local fiscal structures and the investment and employment data for offshore oil-gas and deepwater port scenarios developed by the Office of Technology Assessment. Data from OTA are utilized to permit estimates of fiscal impacts on State and local governments from offshore developments in all coastal States. The methodology underlying the estimates is described in sufficient detail so that an analyst with intimate knowledge of any unusual tax treatment of the oil and gas industry within a particular state can fine tune the estimates for that State. It does appear however, that the results of the analysis are so strong that the general conclusions are likely to remain even with refinement of particular estimates.

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FISCAL EFFECTS ON STATE AND LOCAL GOVERNMENT FROM OFFSHORE OIL/GAS AND PORT DEVELOPMENT

INTRODUCTION

All states tax businesses and individuals to finance the provision of public services for their citizens. Development of offshore oil and gas production and deepwater port facilities has raised the question of whether state and local governments are adversely affected by offshore developments because much of the business portion of the tax base is outside state and local government jurisdiction while the employees and their dependents reside onshore where they must be provided with the same public services as are provided to citizens who both work and live within the state taxing jurisdiction. Two earlier studies of this issue concluded that offshore developments created a net fiscal burden for their state and local governments.[1]

The purpose of this analysis is to estimate the fiscal contribution to state and local governments resulting from representative offshore developments. Like all studies where perfect data is not available certain assumptions are necessary. In spite of data problems, however, we are confident that the analysis indicates both the general impact of offshore developments on coastal states, and equally important, identifies why equivalent offshore developments result in different fiscal effects in different states.

GENERAL APPROACH

State and Local Governments receive revenues from three basic sources: the federal government, taxes and charges on businesses and taxes and charges on individuals. Because our objective is to measure the net fiscal impact on state and local governments from offshore development we will omit revenues from the federal government from the analysis and concentrate on revenues raised within the state and expenditures made from those revenues. Furthermore, state and local governments tend to spend all of the revenues they receive so that per capita revenue raised from their own sources is close to per capita expenditure made from their own sources.[2] Thus, we will focus on whether or not offshore developments result in greater or lesser revenue per person directly associated with that development than the average per capita revenue raised from other economic activities within the state. This comparison will indicate whether or not businesses and employees and their dependents engaged in offshore development pay more or less into state and local treasuries than businesses and employees in other sectors of the state economy. If our analysis reveals that businesses and persons associated with offshore developments pay a lower per capita amount in taxes than is paid in other sectors of the economy we can conclude that persons associated with offshore activities are probably not paying their fair share of the public services they receive. Conversely, if our analysis reveals that businesses and persons associated with offshore developments pay a higher per capita amount in taxes than is paid in other sectors of the economy we can conclude that

the net fiscal effects of offshore developments may be of net benefit to other citizens who can then enjoy higher public services financed from offshore development revenues. This conclusion, however, is dependent on the assumption that businesses and people involved in offshore development do not require above average expenditures on special services -- which could reduce or eliminate any net fiscal benefits that would otherwise accrue.

Within this framework the empirical problem can be simplified still further by focusing only on revenues generated from the taxation of businesses and individuals, or direct spending by those individuals, engaged in offshore activity. This simplification is based on the assumption that there is no reason to expect that the businesses and individuals benefited from spending by offshore businesses or the spending by employees engaged in offshore activities are taxed above or below the state wide average. While focusing on direct fiscal effects instead of effects from second, third and subsequent rounds of induced economic activity is justified for net fiscal impact analysis, it should be remembered that induced effects may aggravate a boom-bust impact on a small local economy. This boom-bust effect will be examined more closely in the conclusions of the analysis after fiscal effects have been identified.

Within this general framework the empirical analysis of fiscal impact is designed to answer the following questions.

1. What state and local tax revenues are generated by the onshore components of businesses engaged in offshore activities.

2. What state and local revenues are generated by employees of businesses engaged in offshore activity.

3. What is the total population of employees and their dependents directly associated with offshore activities. We need to know the size of the population associated with offshore developments to make per capita estimates of business tax revenues generated.

4. What are the per capita tax revenues from other sectors of the state's economy. We need to compare this amount with the per capita revenues associated with offshore development to determine if the net fiscal effects of offshore development are positive or negative.

Furthermore, because different states use different tax rates and different taxes, separate estimates for questions 1, 2 and 4 must be made for each coastal state to estimate the net fiscal impact for that state. Finally, by comparing the answers to question 1 and 2 for different states we can tell what difference the use of different taxes makes for capturing revenues from offshore developments.

Because different states do utilize different tax structures, however, an additional qualification must be introduced into the analysis. When estimates of net fiscal impact are made for each state it is assumed that all onshore components of an offshore development occur within a <u>single</u> state. If different onshore components of the same offshore development take place in different states, conclusions of net fiscal impact may be drastically altered. Implications of this problem will be explored further in the concluding section of the analysis.

METHODOLOGY

Estimates of fiscal impact from the offshore developments associated with oil and gas were derived by estimating the revenue that would result from a detailed scenario for the development of the Baltimore Trough off the coast of New Jersey and Delaware. A similar process was followed for estimating the impact of a representative deep water port consisting of two berths. Because of the uncertainties surrounding the amount and location of oil and gas in the Baltimore Trough one must view the scenario more as a systematic listing of all the investment and labor necessary to undertake development than as a precise forecast of future development of any particular field. The existence of a detailed scenario, however, does provide the information necessary for estimating the population associated with the offshore development and the investment expenditure patterns from which tax revenue estimates can be made for any state where a similar development was undertaken offshore. Furthermore, because estimates are broken down into per capita amounts based on the population directly associated with the development the size of the scenario is not important because undertakings at smaller or larger scale would generate similar per capita results.[3] Thus the use of a "representative development"--which was developed from the analysis of existing and proposed offshore developments--makes it possible to examine fiscal impacts on any of the coastal states--even those where no offshore oil/gas development is anticipated. Undertaking the analysis for all coastal states, however, lets one examine the

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effects of various tax structures to see if the net fiscal impacts are highly sensitive to the pecularities of any particular state's tax system.

While details of the development scenario are presented in a series of reports by the BDM Corporation,[4] the most important information for the purpose of this analysis is:

1. Employment levels for the duration of the development, from which the directly affected population can be estimated by applying employment/population ratios developed by the Department of Commerce.

2. Onshore land purchases for tank farms and pipelines to deliver oil to refinery locations. Knowledge of these purchases permits estimation of real estate transfer taxes at the time of purchase and real property taxes for the life of the project.

3. Investments in onshore facilities such as tank farms, gas plants and pipelines. Knowledge of the time and amount of these investments permits estimation of sales or use tax revenues on construction inputs and cumulative investment value provides a proxy for real property values for property taxation.

4. Finally, Census and Advisory Commission on Intergovernmental Relations data provide sources from which to estimate the per capita revenue expected to be generated by the directly employed population and their dependents from major state and local taxes, including: the individual income tax, the residential property tax, general sales taxes, selective excises such as tobacco, gasoline and liquor taxes, and user charges. All tax data is for 1973-74, although estimates to divide the property tax into residential and non-residential components and to divide the general sales tax between taxes on consumers and taxes on business inputs were based on empirical studies from earlier years.

The results of these analyses are a set of per capita estimates (with per capita meaning division of the revenues by the population of employees employed on offshore development and their dependents) for taxes paid by

businesses: real estate transfer, real property and sales taxes, and for taxes paid by employees and their families: residential property, individual income tax, general sales and selective excise taxes and user charges. Each estimate was made for each coastal state for each year of an 18 year development scenario.

One deficiency of this analysis is that no reasonable estimate could be made of business gross receipts, business personal property[5] (which includes oil and gas inventories in tanks and pipelines) or state corporate income taxes.[6] The problems are insurmountable as profits and gross receipts are part of a multi-national firm's income and revenue and business personal property is subject to considerable variation; hence problems outweighed the potential benefits of attempting to make estimates in these areas. It is also likely that to the extent that gross receipts or corporate income taxes are captured it will be from the sale of refinery products rather than from offshore development itself. In any case, to exclude gross receipts, business personal property and state corporate profits taxes biases the estimates downward. Two other assumptions also need to be made clear. Real property tax estimates for onshore business property are based on the cost of the property. A depreciated base would result in lower tax revenues, but a "cost of replacement" base would result in higher revenues: using cost provides a reasonable middle ground. Business sales or use tax estimates were based on the entire cost of the onshore investment (excluding land) because most inputs do not become ingredients

in the final output and it was not possible to separate out some equipment in the few states that exempt machinery under a direct use rule. To the extent exemptions in the sales or use tax for pipelines or gas plant machinery exist, business sales or use tax revenues are overestimated.[7] Finally, tax rate and dollar estimates are based on 1973-74 data, applied to investment and land cost data for the mid 1970's. No price or tax rate adjustments were made for the future because our interest is in estimating the difference between per capita revenues associated with offshore developments and average per capita state and local tax revenues. Inflating both at the same rate would not affect the net difference, and to the extent that average state and local revenues rise because of tax rate increases additional taxes will also be paid by offshore developers and their employees. Sufficient data is provided in the analysis for analysts who wish to make adjustments for future price and tax rate changes.

The general approach and specific methodologies were similar for estimating the impact of both offshore oil/gas and offshore port development. A description of the scenario upon which estimates were based is presented along with the results of each analysis.

RESULTS

Oil and Gas

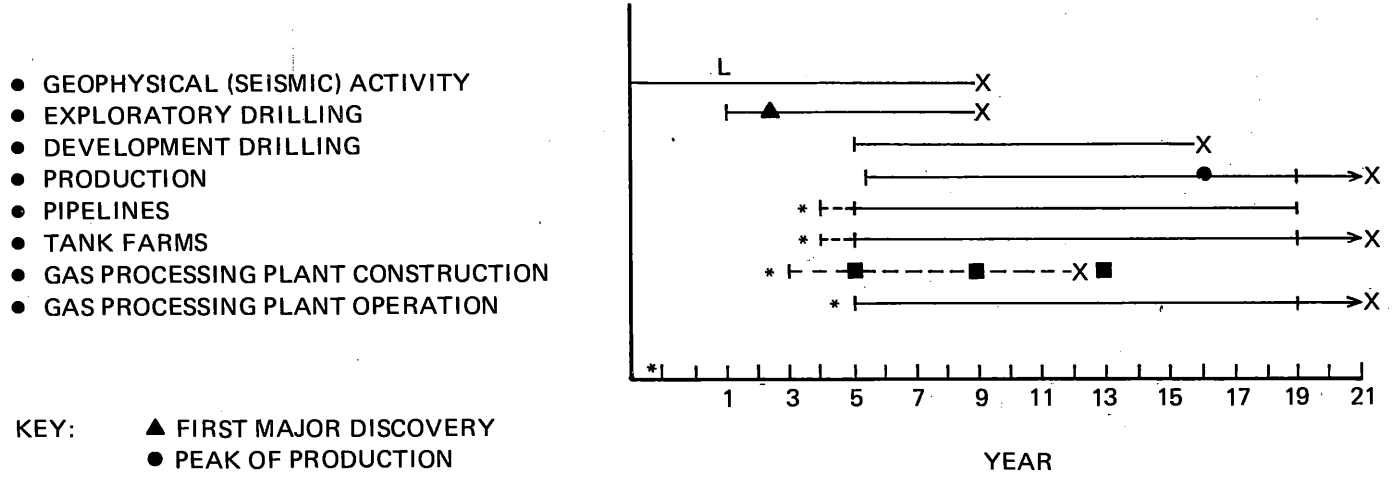
The time sequence for the oil and gas development scenario is presented in Figure 1. Year one is the year during which exploratary drilling is begun. The first major discovery is assumed to occur early

in year two, followed by onshore gas plant construction in year three. Tank farm and onshore pipeline construction is concentrated in year four, while additional gas plants are under construction from years five through eleven. The particular elements of the onshore activity subject to state and local taxation are listed in Table 1. One should note that the concentration of tank farm and onshore pipeline construction in year four provides an extremely large sales or use tax revenue base for that year.

While onshore components can be identified in Figure 1 and Table 1, the magnitude of total activity is better indicated by Figure 2. Figure 2 shows the direct employment--both on the offshore--for the entire period of development. One can observe that offshore oil and gas development is an activity with rapid increases in employment through year eight and rapid declines following this peak. This boom-bust impact is a large one, especially when we remember that for each employee there are approximately 1.3 related dependents.

The results of the analysis are presented in two formats: tables and graphs. Table 2 provides a year-by-year summary of state and local tax revenues from the oil and gas development scenario for each coastal state. The figures are in terms of the revenues generated per employee and their dependents (called the "direct population") from business taxes on the onshore components of the development and the individual taxes paid by employees and their families. The individual taxes only are given in column 2, with columns labeled years 1 through 18 presenting the total revenues per member of the direct population for each year. Those figures

Figure 1
Sequence of Offshore Oil and Gas Development



KEY:
- ▲ FIRST MAJOR DISCOVERY
- ● PEAK OF PRODUCTION
- L LEASE SALE
- --- CONSTRUCTION
- —— OPERATION
- X TERMINATION OF ACTIVITY
- ■ GAS PROCESSING PLANT ON LINE

*activity taxable by state

Source: OTA estimates.

TABLE 1

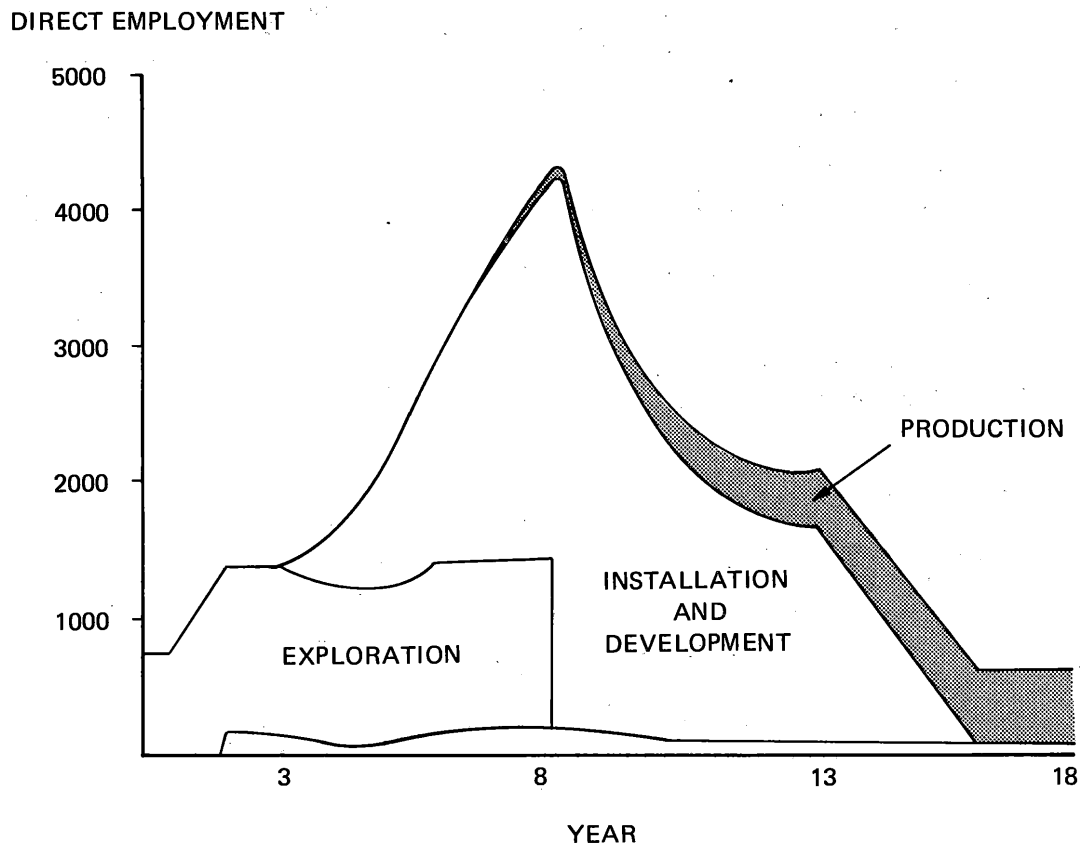
ONSHORE COMPONENTS OF OIL AND GAS DEVELOPMENT

Year	Activity	Land Purchase[1]	Construction Costs[2]
		(millions $)	
1	Exploratory Drilling Only		
2	1st Major Discovery Onshore Land Acquisition	9.24	
3	Onshore Land Acquisition 1st Gas Plant Construction	9.24	19.25
4	1st Gas Plant Construction Tank Farm and Onshore Pipeline Construction		19.25 434.00
5-8	2nd Gas Plant Construction		9.625 per yr.
9-11	3rd Gas Plant Construction		12.8 per yr.

[1]Subject to real estate transfer tax and enters into real property tax base.
[2]Subject to sales or use tax and enters into real property tax base.

Source: BDM Scenario

Figure 2
Direct Employment in Offshore Oil and Gas Development



Source: OTA estimates.

TABLE 2

STATE-LOCAL TAX REVENUE FROM OFFSHORE OIL AND GAS DEVELOPMENT

State	Per Capita St.-Loc. Tax Revenue [1]	Per Capita St.-Loc. Tax Revenue from Indiv's. [2]	Tax Revenues from Business and Individuals per Direct Population [3] -- by Year of Development [4]																	
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
Alabama	546	286	286	320	475	3036	1233	987	843	785	802	990	1149	1238	1256	1378	1670	2700	3099	3196
Alaska	1284	684	684	745	964	9160	2521	1745	1771	1651	1643	2056	2366	2487	2521	2753	3305	5256	6069	6196
Calif.	949	516	516	608	1156	11435	3311	2583	2171	1988	2044	2598	3070	3294	3346	3703	4554	7559	8811	9006
Conn.	811	466	466	554	1123	11879	3163	2461	2062	1886	1941	2478	2934	3132	3182	3525	4341	7225	8427	8615
Delaware	894	459	459	575	659	2175	1816	1463	1263	1175	1193	1461	1689	1870	1896	2078	2510	4037	4673	4772
Florida	692	369	369	430	774	7318	1969	1553	1316	1211	1245	1563	1834	1948	1978	1281	2665	4373	5085	5196
Georgia	651	371	371	426	773	7361	1984	1579	1337	1230	1265	1589	1865	1984	2014	2221	2715	4460	5187	5301
Hawaii	989	643	643	677	983	6925	1716	1436	1277	1207	1234	1447	1629	1673	1692	1825	2141	3255	3720	3792
Louisiana	687	289	289	308	705	8593	1016	825	719	669	698	844	968	916	928	1008	1200	1879	2162	2206
Maine	704	427	427	517	1003	10022	3147	2439	2008	1860	1911	2451	2910	3149	3200	3550	4384	7328	8555	8746
Maryland	854	504	504	605	1012	8583	2998	2350	1981	1818	1864	2358	2780	3013	3060	3383	4151	6865	7997	8173
Mass.	889	565	565	685	1108	8599	3998	3106	2599	2376	2429	3109	3688	4071	4137	4588	5662	9454	11035	11281
N. H.	604	347	347	463	712	4623	3729	2851	2352	2132	2176	2844	3414	3864	3930	4383	5460	9264	10850	11097
N. J.	848	512	512	623	1155	10897	3857	2987	2493	2275	2334	2998	3562	3884	3947	4380	5413	9060	10580	10817
N. Y.	1171	638	638	738	1363	13143	3711	2909	2455	2254	2318	2929	3449	3685	3742	4134	5067	8362	9736	9950
N. Carolina	583	327	327	387	745	7507	2110	1647	1383	1266	1302	1656	1958	2097	2130	2357	2899	4814	5612	5736
Oregon	776	351	351	433	618	3524	2860	2209	1839	1676	1708	2204	2627	2961	3010	3345	4145	6968	8145	8328
Pa.	746	336	336	472	983	10819	2786	2148	1786	1626	1677	2164	2578	2755	2801	3112	3853	6470	7561	7731
R. I.	729	451	451	533	1002	9747	2934	2288	1921	1759	1807	2300	2720	2926	2973	3291	4049	6727	7843	8017
S. Carolina	560	318	318	362	669	6627	1413	1127	965	893	920	1138	1324	1371	1390	1526	1848	2987	3462	3536
Texas	617	261	261	329	774	9148	2421	1859	1540	1399	1442	1872	2236	2400	2440	2716	3371	6585	6650	6800
Virginia	652	373	373	429	765	7199	1876	1485	1263	1164	1197	1496	1750	1851	1879	2069	2522	4121	4788	4892
Washington	840	467	467	528	950	8959	2315	1833	1560	1440	1470	1847	2159	2281	2315	2549	3105	5067	5886	6013
Direct Population			1786	2595	3279	3605	4651	6395	8140	9302	9302	6977	5814	5070	4977	4419	3488	2000	1698	1659

NOTES FOR TABLE 2

[1]U.S. Bureau of the Census, Governmental Finances in 1973-74, p. 47

[2]For derivation see Table 4

[3]Direct Population is defined as the employees and their families associated with offshore oil and gas production. It is calculated by relating employment by year from the BDM scenario to 1972 OBERS Projections, Series E Population.

[4]Entries are the sum of tax estimates derived in Tables 4-7.

can be compared with the state-wide per capita revenues collected by state and local governments and listed in column 1. Where column 1 figures are higher--as in years 1 and 2 for all states--revenues per direct population are less than state-wide per capita revenues from other sectors of the economy and one can conclude that offshore developments are not paying their fair share of state-local tax revenues. Where column 1 figures are lower--as in years four through eighteen for all except Louisiana in year eight--the converse is the case. For example Alabama is the first state listed. Its state-local revenues per capita were $546. Per capita taxes paid by individuals are estimated to be $286. Total revenues per direct population are $286 in year 1, indicating that no business tax revenues from offshore activities are received that year. In year 2 there are some business taxes, bringing the total to $320. Year 3 shows $475; still less than the state per capita average. In year 4, however, tax revenues from offshore development jump (due to the sales or use taxes on onshore construction) to $3036 per direct population--an amount considerably greater than the state per capita average of $546. Revenues in remaining years -- due to real property taxes on onshore facilities--are also higher than the state per capita average.

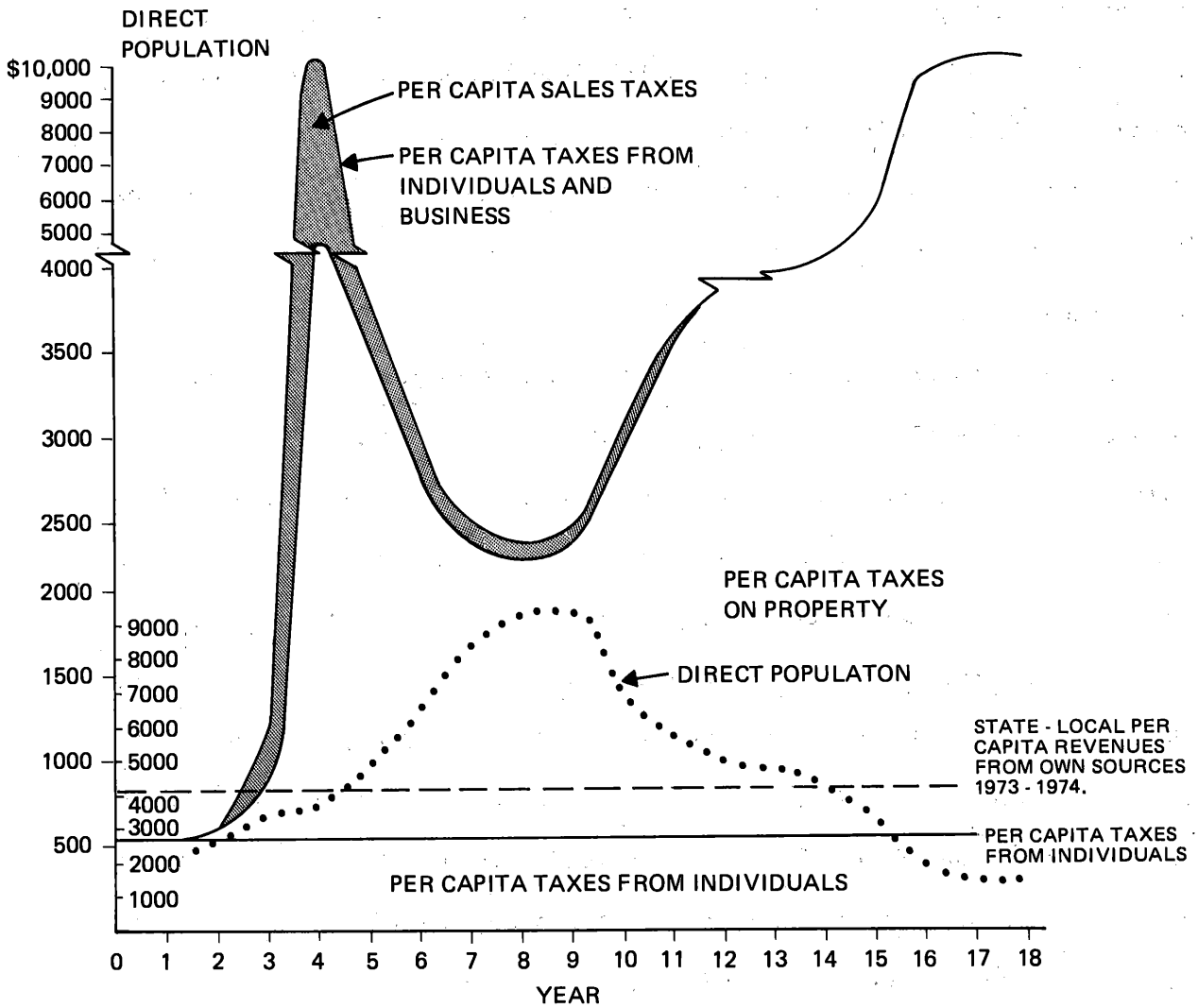
The calculations used to estimate the data in Table 2, as well as the separate components making up the total tax figures are explained and displayed in Tables 5 through 8 of the appendix. By examining those tables one can trace through the events causing the changes--which are primarily

changes in sales or use taxes, real property taxes and the direct population associated with the development.

While data for each state for each year is given in Table 2 and the appendix tables, it is easier to follow the patterns of revenue change in the graphical summaries prepared for 8 states. The graphs show two horizontal lines for comparative purposes. The lowest solid line shows the per capita individual taxes paid by employees and their dependents. The second line (dashed) shows the per capita state and local revenues from other sectors of the economy. It provides the benchmark with which to compare the total per direct population revenues generated by offshore oil and gas development. A dotted line indicates the direct population base upon which per capita calculations are based. In addition, the major components of revenues generated from offshore activities--individual taxes, sales or use taxes and real property taxes--are identified and labeled.

Figure 3 illustrates New Jersey. One can see the early low revenues, followed by a peak of sales tax revenues in year four, then a decline in the per capita amount of property taxes as they are divided among the larger and larger direct population engaged in offshore construction. Finally in year nine per capita property tax revenues begin to rise as completion of offshore construction lowers direct the population. One can observe that except for year 1 through 3, tax revenues associated with offshore development are much higher than average per capita revenues from taxes on the rest of the population and businesses in the state.

Figure 3
NEW JERSEY
Oil and Gas



State-Local Revenue Per Employee and their Families from OCS Oil-Gas Development.

Similar patterns exist for Alabama, California, Delaware, Louisiana, Maine, Texas and Washington (Figures 8-14 in the Appendix). The only deviations are Delaware's lack of a sales or use tax peak and observable impact of its high real estate transfer taxes, and Louisiana's exceptionally high sales or use tax peak followed by very low real property tax revenues. Louisiana's real property tax rate is actually so low that at the peak of construction revenues per direct population from oil and gas development fall below the state wide per capita revenues from other economic activities in the state.

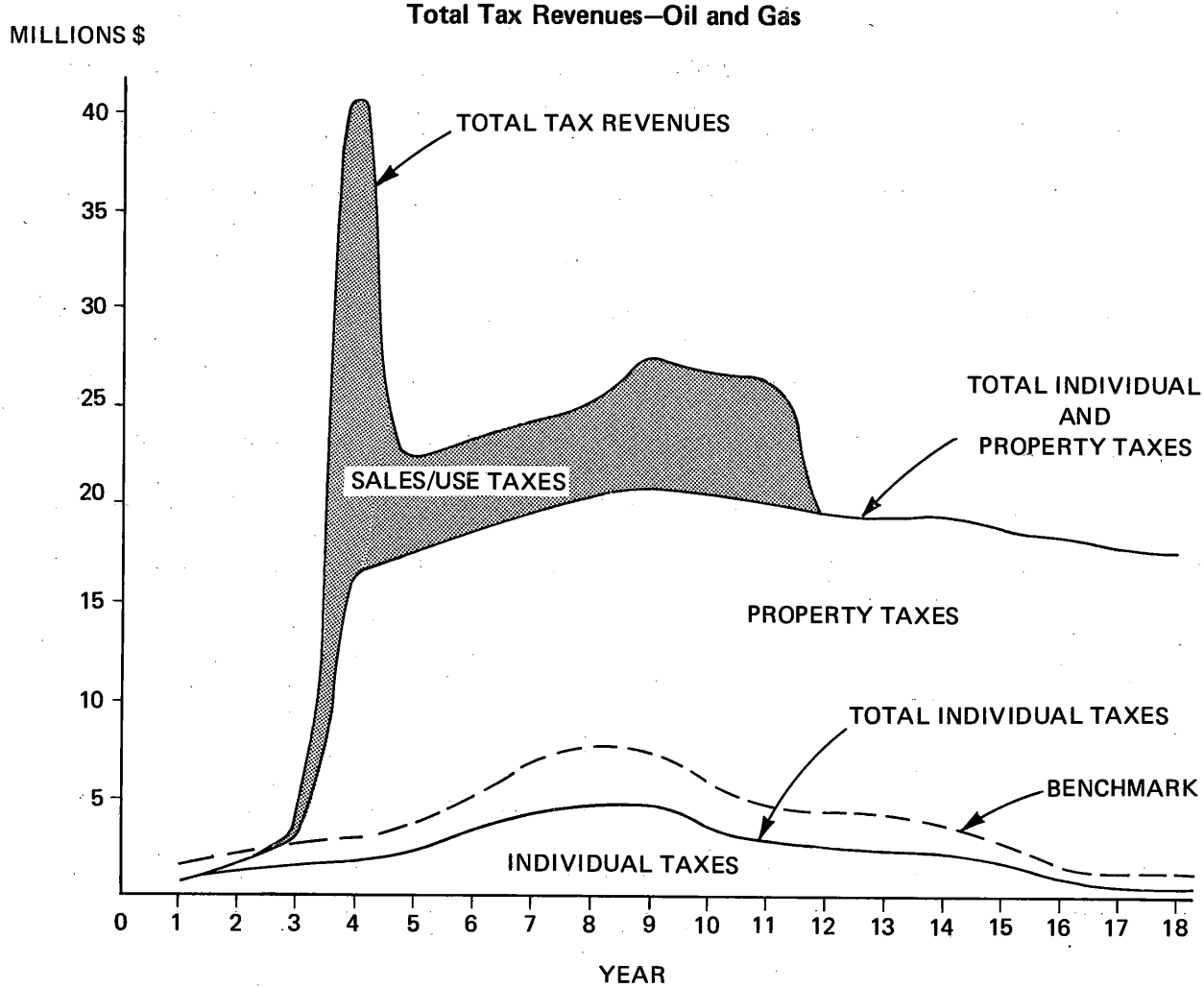
If business gross receipts, business personal property or corporate income taxes on oil and gas production were added to the graph their effect would be to raise the height and steepness of the total tax curve following year eight as production is undertaken and the additional tax revenues are spread over a decreasing direct population base. Our other uncertainty--that some components of onshore construction may be exempt from sales or use taxation--would reduce the shaded area of the graphs, but would not alter the conclusion that beginning with year four states, except for Louisiana, should receive net fiscal benefits from offshore oil and gas development. Only total removal of the sales or use tax base in Louisiana pulls years seven and nine, in addition to eight, to a deficit position. Finally, one must keep in mind that the estimates are based on a scenario developed for a particular field and that employment-investment relationships may vary--perhaps by as much as 25 percent for a development in another location.

Even with this potential variance, however, most states should receive net fiscal benefits from offshore oil and gas development after the first 3 years of development.

While per capita estimates and comparisons are superior when utilizing a representative development scenario, total tax revenues from the Baltimore Trough scenario for New Jersey are illustrated in Figure 4. Individual, real property, sales or use and total tax revenues are plotted over the 18 year scenario. For comparative purposes a dashed line labeled "benchmark" indicates the total revenues that would need to be collected from the businesses and individuals directly engaged in offshore oil and gas development for them to be paying their "fair share" of taxes. This amount is simply state per capita tax revenues from its own sources times the direct population associated with offshore development.

Figure 4 reveals the same revenue pattern as Figure 3. Beginning in year 3 total tax revenues exceed benchmark costs. Sales and use taxes provide a large amount during tank farm and onshore pipeline construction in year 4, and additional revenues during construction of the second and third gas plants. Real property tax revenues become significant in year 4 and continue for the life of the project. The greatest net fiscal benefits occur at two points: first, during onshore construction prior to the expansion of population associated with offshore development, and second, after offshore development activity decreases but production continues. The years of net negative fiscal impacts are the first two, prior to significant onshore activity.

Figure 4
NEW JERSEY
Total Tax Revenues—Oil and Gas



Finally, we must emphasize again that these estimates are based on the assumption that all onshore components of offshore oil and gas development occur within a single state. If, for example, the staging for offshore development were to take place in one state--say Delaware--while the oil and gas was landed in another state--say New Jersey--Delaware would bear most of the costs of serving the population engaged in oil and gas development while New Jersey would obtain virtually all state and local government revenues. This problem is potentially a serious one because the staging areas for exploration and eventual development are set up in relation to where oil is expected to be discovered, but the location of tank farms, gas plants and onshore pipelines is determined only after major discoveries are made. Thus, the potential for ending up with net fiscal deficits in one state while huge fiscal surpluses accrue to another state is a very real one, even though after the first three years total state and local tax revenues generated from onshore components of oil and gas development should exceed the costs of serving the related populations.

PORT DEVELOPMENT

The process for estimating the fiscal impacts from an offshore port was identical to the processes for estimating the impacts of oil and gas development, except that real estate transfer taxes were omitted because onshore land purchases are very low. There are some differences between the oil and gas and port development scenarios and fiscal impacts. First, the port development process is much shorter, with all investment occurring

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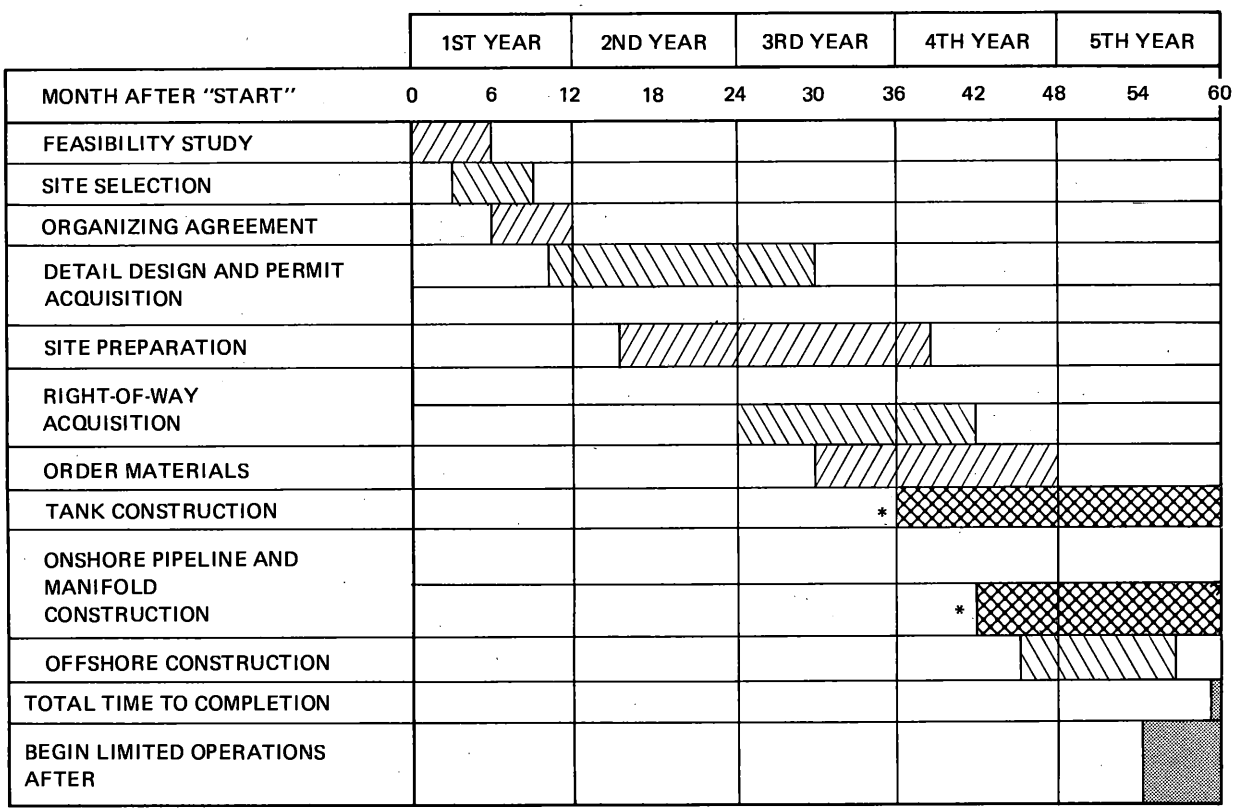
within 5 years and all onshore investment (tank farm and pipeline construction) concentrated in years 4 and 5. In each of these years onshore construction costs are estimated to be $46.5 million. This scenario is indicated in Figure 5. Investment activity in offshore components is also concentrated, with the peak of direct employment occurring in year 3, prior to the beginning of onshore construction. (The total direct employment pattern is indicated in Figure 6.) Thus, while of smaller magnitude than oil and gas development, a boom-bust cycle will occur with significant business tax revenues resulting only after the peak of the boom. When businesses tax revenues do begin to accrue, however, they greatly exceed per capita revenues derived from other sectors of the state's economy--as can be seen from the data in Table 3. This table provides figures for the revenue impacts of the port scenario by year and Tables 9 and 10 in the appendix explain calculations and components of the totals. Figure 7 illustrates graphically the revenue effects on New Jersey and Figures 16-22 in the appendix illustrate the revenue effects on seven other states. Figure 15 in the appendix also illustrates total revenues for the scenario in New Jersey. In all cases there is a net adverse fiscal impact the first three years and a strong positive impact from the 4th year forward. As with oil and gas, inclusion of gross receipts, business personal property or corporates profits taxes on port operation would create even greater net benefits. Elimination of sales tax revenues would eliminate the revenue bulge in years 4 and 5 without changing basic conclusions of the analysis.

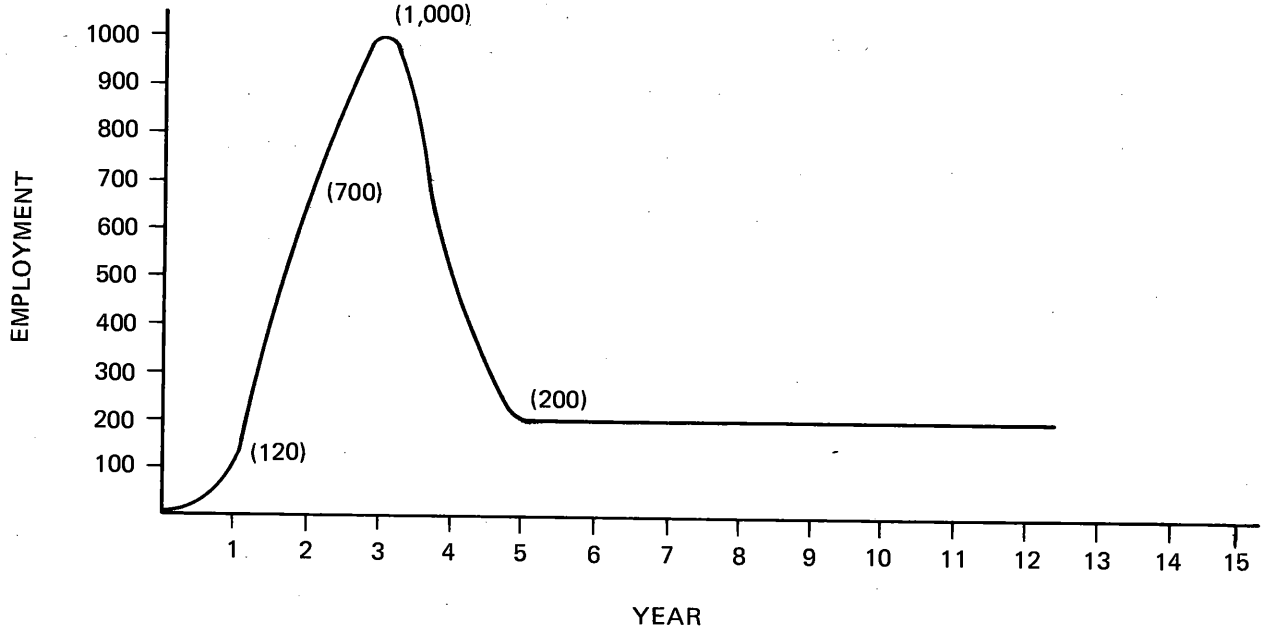
Figure 5
Sequence of Deepwater Port Development



*subject to state and local government taxation

Source: OTA estimates.

Figure 6
Direct Employment—
Deepwater Port Development



Source: OTA estimates.

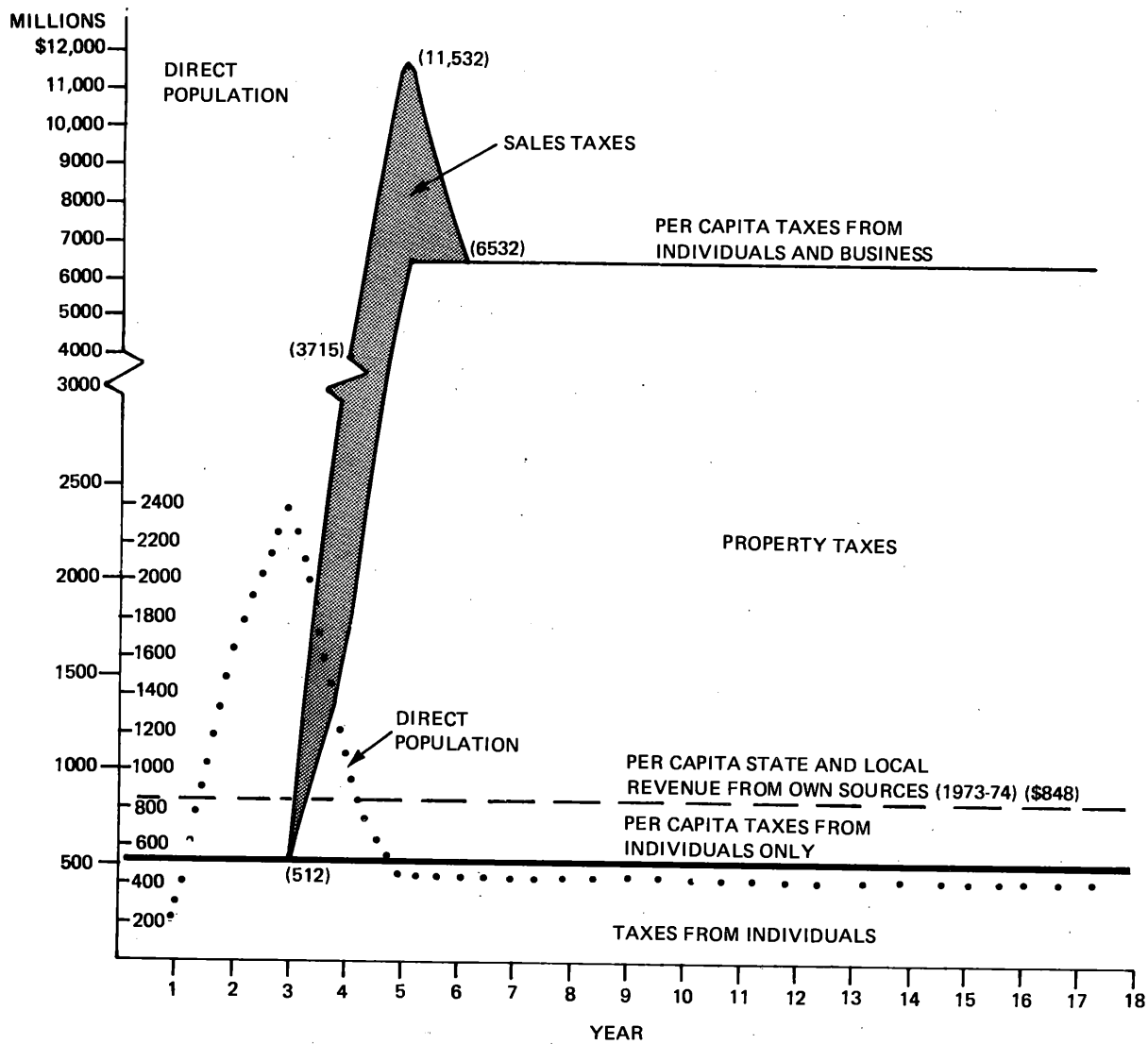
TABLE 3

STATE-LOCAL TAX REVENUE FROM
OFFSHORE PORT DEVELOPMENT

STATE	Per capita State-Local Tax Revenue[1]	Per capita State-Local Tax Revenue from Individuals[2]	Tax revenues from business and individuals by direct population[3] - by year of development[4]			
			1,2,3 (annual amt)	4	5	6-18 (annual amt)
Alabama	546	286	286	1226	3486	1986
Alaska	1284	684	684	3328	8904	3904
California	949	516	516	3906	11,476	5476
Conn.	811	466	466	3986	11,726	5226
Delaware	894	459	459	999	2979	2979
Florida	692	369	369	2529	7189	3189
Georgia	651	371	371	2546	7251	3251
Hawaii	989	643	643	2611	6483	2483
Louisiana	687	289	289	2913	7409	1409
Maine	704	427	427	3399	10,287	5287
Maryland	854	504	504	2999	8984	4984
Mass.	889	565	565	3016	9825	6825
N.H.	604	347	347	1602	6627	6627
N.J.	848	512	512	3715	11,532	6532
N.Y.	1171	638	638	4525	13,078	6078
N. Carolina	583	327	327	2558	7487	3487
Oregon	776	351	351	1283	5011	5011
Pa.	746	336	336	3600	10,656	4656
R.I.	729	451	451	3336	9871	4871
S. Carolina	560	318	318	2294	6190	2198
Texas	617	261	261	3025	9081	4081
Virginia	652	373	373	2501	7013	3013
Washington	840	467	467	3115	8707	3707
Direct Population			1-286 2-1667 3-2381	1163	465	465 (Annually)

[1]U.S. Bureau of the Census, Governmental Finances in 1973-74, p. 47
[2]For derivation see Table 4
[3]Direct Population is defined as employees and their families associated with offshore port development. It is calculated by relating employment by year from the BDM Scenario to 1972 OBERS Projections, Series E, Population.
[4]Entries are the sum of tax estimates derived in Table 4, 8 and 9.

Figure 7
NEW JERSEY
Deepwater Port



State and Local Revenue Per Employee and their Family from Deepwater Port Development.

CONCLUSIONS

In spite of the qualifications inherent in the estimation process three general conclusions are warranted. First, during the first two or three years of offshore oil/gas or port development state and local revenues from onshore components of the activities cannot be expected to cover the costs of serving the population involved in the offshore activities. Second, if all onshore components of an offshore development take place within a single state, beginning in either the third or fourth year revenues from onshore components will contribute larger per capita revenues from the population associated with the offshore development than is generated in other sectors of a state's economy (with the exception of Louisiana in year eight). Furthermore, unless large extra expenditures are necessitated by offshore development, the favorable net fiscal impact will be very large in most states. For example, in New Jersey the total cumulative fiscal deficit from the representative oil and gas scenario in years one through three would be $1,070,639. Sales tax revenues alone in year 4 would be $6,799,030, or $4,830,700 greater than servicing the direct population and more than adequate to cover the fiscal deficit from the first three years, and real property tax revenues would continue to provide a net revenue surplus. Finally, if different onshore components are undertaken in different states, general conclusions on revenue surpluses are not valie as it would be possible for one state to bear most of the costs of servicing the

direct population while another state obtained the revenues from the onshore components of the development.

The major fiscal problems resulting from offshore development are related to the timing of revenue flows relative to expenditure requirements, and to the potential that different onshore components of development take place in different taxing jurisdictions. The timing problem is common to all large developments in a small local economy. First, service requirements precede revenues, and second, the service requirements are of a boom-bust nature as workforce and population expand rapidly during development and then decline as development is completed and only the labor required for ongoing operation is retained. This problem is aggrevated if service requirements fall on one jurisdiction while the tax revenues accrue to another jurisdiction because the feasibility of tax anticipation debt finance by the government providing the services is eliminated. Both the timing and location of development problem require serious analysis by larger governments. For example, where all components of offshore activity occur within a single state the state government could make loans to local governments impacted by population associated with the offshore development against which state sales tax revenues could be credited for repayment. Where components of offshore development occur in different states it may be necessary for some kind of federal adjustments to offset the potentially negative impact on an area with large

service requirements but little or no tax revenues. It must also be recognized, however, that the particular tax structure utilized by state and local governments as well as the offshore development itself will be an important determinant of the net fiscal impacts. The conclusions on the fiscal impacts of port development are subject to the same qualifications as analysis of oil and gas development, especially as related to possible location of staging areas from the location of tank farms where oil is brought ashore.

FOOTNOTES

[1]Benefits and Costs to State and Local Governments in Texas Resulting From Offshore Petroleum Leases on Federal Lands, Office of the Governor, Austin, Texas, November 14, 1974; and Offshore Revenue Sharing: An Analysis of Offshore Operations on Coastal States, Gulf South Research Institute, Baton Rouge, Louisiana. Differences between the results of these studies and results from the following analysis are briefly indicated in Appendix A.

[2]Per capita revenues and expenditures for coastal states are presented in Appendix Table 3. Differences between revenues and expenditures for a single year are likely to balance out over several years.

[3]An important exception to this generalization would occur if extensive exploratory activity were undertaken and no oil and gas were discovered. If this happened State and local governments would bear the costs of serving the population engaged in exploration but virtually no revenues would be received because there would be no onshore tank farm, gas plant or pipeline construction.

[4]The most important volumes of the report are Final Report, A Study of New Use Demands on the Coastal Zone and Offshore Areas of New Jersey and Delaware, Vol. II Oil and Gas Development in the Baltimore Canyon and Vol. III, Deep-water Port Development in the Mid-Atlantic, The BDM Corporation, Vienna, Virginia, December, 1975. These reports were done for the Office of Technology Assessment, United States Congress, as part of Contract OTA-C-8.

[5]Business personal property taxes on tangible goods are levied in all coastal states except Delaware, Hawaii, New York, and Pennsylvania.

[6]State corporate income taxes are levied in all coastal states except Texas and Washington.

[7]The precise base and type of tax equivalent to the sales tax will vary from state to state. A sales tax will be collected on goods and services, including the contract price of construction in most states, sold for use within the state. All coastal states also collect a use tax on items sold in another state that are imported into their state for final use. Thus if a company purchases its pipelines, gas plants and tank farm from contractors it will be taxed under the sales tax. If the company constructs its own facilities, goods and services purchased will be taxed under either the sales or use tax, depending on their state of origin but the labor element of construction will not be taxed. Thus sales and use tax revenue estimates will be 10 to 15 percent high. The state sales tax rate is used as an approximation of the sales tax--use tax rate likely to be applicable to facilities construction within different states.

APPENDIX A

OTHER FISCAL IMPACT STUDIES

Both the Texas[1] and Louisiana[2] studies involve the use of complex forecasting models to trace secondary effects of fiscal impacts. While those studies are more complex, their complexity is not the source of differences between their conclusions and the conclusion reached in this study--that except for the first three years for Texas and first three plus 8th year for Louisiana the fiscal impacts should be positive. The differences are primarily related to simple omissions in the Texas and Louisiana studies. For example, the Louisiana study estimates a net deficiency of $38 million between the revenues from offshore activities and expenditures on 390,990 direct and indirect employees and dependents associated with offshore oil and gas production. This deficit equals $97 per capita--an amount more than made up by the omission of $133 per capita federal transfers (in 1971-their data year) which should have been subtracted from the expenditure figure used to get "expenditures from own revenues"--the proper base for a comparison of revenues and costs associated with offshore oil and gas development.

The Texas study is more difficult to analyze, except to note that it attributed <u>zero</u> tax revenues to both businesses and their employees engaged in offshore activities. It is very unlikely that offshore activities involve no onshore components (tanks, pipes, etc.) and it is equally unlikely that employees escape all sales, residential property, selective excise taxes and user charges in Texas. The Texas study, like the Louisiana study, also neglects to adjust per capita expenditures for federal transfers so

that comparisons can be based on expenditures from their own tax revenues. Given these basic deficiencies one should be very cautious of accepting its conclusions.

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[1] Benefits and Costs to State and Local Governments in Texas Resulting From Offshore Petroleum Leases on Federal Lands, Office of the Governor Austin, Texas, November 14, 1974.

[2] Offshore Revenue Sharing: An Analysis of Offshore Operations on Coastal States, Gulf South Research Institute, Baton Rouge, Louisiana.

APPENDIX B

SUPPLEMENTARY

TABLES AND FIGURES

TABLE 4

PER CAPITA REVENUES AND EXPENDITURES BY STATE AND LOCAL GOVERNMENTS

State	Expenditures	Revenues	Revenues from Federal Govt.	Revenues from Own Sources
	$	$	$	$
Alabama	712	745	199	546
Alaska	2501	1937	653	1248
Calif.	1118	1188	239	949
Conn.	954	989	178	811
Delaware	1055	1106	212	894
Florida	783	825	132	692
Georgia	794	856	204	651
Hawaii	1349	1289	300	989
Louisiana	822	897	210	687
Maine	823	932	228	704
Maryland	1055	1039	185	854
Mass.	1058	1096	207	889
N. H.	774	765	161	604
N. J.	978	1012	164	847
N. Y.	1448	1416	246	1171
N. Carolina	685	745	163	583
Oregon	990	1018	242	776
Pa.	885	930	184	746
R. I.	903	953	224	729
S. Carolina	739	735	175	560
Texas	720	775	158	617
Virginia	821	816	165	652
Washington	1041	1042	202	840

Source: Bureau of the Census, Governmental Finances in 1973 - 74, p. 47.

TABLE 5

PER CAPITA STATE AND LOCAL TAXES PAID BY INDIVIDUALS

State	Residential Property Tax[1]	Personal Income Tax[2]	General Sales Tax[3]	Selective Excises[4]	Charges and Misc. Rev.[5]	Total
	$	$	$	$	$	$
Alabama	28	37	62	77	82	286
Alaska	111	175	0	61	337	684
Calif.	209	79	75	60	93	516
Conn.	242	4	74	85	61	466
Delaware	80	194	0	77	108	459
Florida	96	0	94	93	86	369
Georgia	84	56	74	70	87	371
Hawaii	86	184	187	73	112	643
Louisiana	51	29	55	68	86	289
Maine	180	35	89	70	53	427
Maryland	149	137	58	70	90	504
Mass.	269	138	31	66	61	565
N. H.	195	9	0	82	61	347
N. J.	269	3	65	90	82	512
N. Y.	199	190	59	81	109	638
N. Carolina	57	80	51	77	62	327
Oregon	57	144	0	47	103	351
Pa.	102	16	78	74	66	336
R. I.	176	51	75	88	61	451
S. Carolina	40	59	77	73	69	318
Texas	67	0	50	69	75	261
Virginia	91	91	45	75	71	373
Washington	121	0	152	85	109	467

NOTES FOR TABLE 5

[1]Per capita property taxes (Governmental Finances in 1973-74, p. 47) are multiplied by the percentage of property taxes attributed to residences (Advisory Commission on Intergovernmental Relations, Federal-State-Local Finances: Significant Features of Fiscal Federalism, 1973-74 Edition, p. 168) to estimate per capita residential property taxes.

[2]Per capita general taxes (Gov. Fin. in 1973-74, p. 47) are multiplied by the percentage of general revenue attributed to personal income taxes (ACIR, Significant Features, 1973-74, p. 30) to estimate per capita personal income taxes.

[3]Per capita general taxes (Gov. Fin. in 1973-74, p. 47) are multiplied by the percentage attributed to general taxes to estimate per capita general sales taxes. This amount is then multiplied by .67 to estimate general sales taxes attributable to individuals as distinguished from payments of sales taxes by businesses on their purchases of plant and equipment, The .67 attributable to consumers is derived from Fryman, "Sales Taxation on Producer Goods," National Tax Journal, June 1959.

[4]Per capita general revenues (Gov. Fin. in 1973-74) p. 31) are multiplied by the percentage attributed to selective excises (ACIR, Significant Features, 1973-74, p. 31), to estimate per capita selective excises. Two-thirds of this amount was attributed to individuals.

[5]One-half of user changes and miscellaneous revenues (Gov. Fin. in 1973-74, p. 47) are attributed to individuals.

TABLE 6

REAL ESTATE TRANSFER TAX REVENUE FROM ONSHORE

COMPONENTS OF OFFSHORE GAS AND OIL REDEVELOPMENT

		Taxes per direct population by year of development	
	Rate[3]	2[4]	3[4]
	%	$	$
Alabama	.1	4	3
Alaska	.11	4	3
Calif.	.11	4	3
Conn.	.11	4	3
Delaware	2.00	71	56
Florida	.30	11	8
Georgia	.10	4	3
Hawaii	.05	2	1
Louisiana	-	-	-
Maine	.11	4	3
Maryland	.61	22	17
Mass.	.23	8	6
N.H.	.15	5	4
N.J.	.10	4	3
N.Y.	.11	4	3
N. Carolina	.10	4	3
Oregon	-	-	-
Pa.	1.66	59	47
R.I.	.11	4	3
S. Carolina	.31	11	9
Texas	-	-	-
Virginia	.25	9	7
Washington	.10	4	3
Tax Base (Million $)		9.240	9.240
Direct Population		2595	3279

[1]Land purchases are estimated by BDM to total $18.48 million over a two year period.

[2]Direct Population is defined as the employees and their families associated with offshore oil and gas production. It is calculated by relating employment by year from the BDM scenario to 1972 OBERS Projections, Series E Population.

[3]Real Estate Transfer tax rates were taken from ACIR, Significant Features, pp. 236-237.

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TABLE 7

SALES OR USE TAX REVENUE FROM ONSHORE COMPONENTS OF OFFSHORE GAS AND OIL DEVELOPMENT

Taxes Per Direct Population By Year of Development

State	Rate[3]	3[4]	4	5	6	7	8	9	10	11[4]
	%	$	$	$	$	$	$	$	$	$
*Alabama	1.5	88	1,886	31	23	18	21	28	28	33
Alaska	5	294	6,286	103	75	59	52	69	92	110
California	6	352	7,542	124	90	71	62	83	110	132
Connecticut	6.5	381	8,172	134	97	76	67	89	119	143
Delaware	0	0	0	0	0	0	0	0	0	0
Florida	4	234	5,029	82	60	47	41	55	73	88
Georgia	4	234	5,029	82	60	47	41	55	73	88
Hawaii	4	234	5,029	82	60	47	41	55	73	88
Louisiana	6	352	7,542	124	90	71	62	83	110	132
Maine	5	294	6,286	103	75	59	52	69	92	110
Maryland	4	234	5,029	82	60	47	41	55	73	88
Massachusetts	3	176	3,771	62	45	35	31	41	55	66
New Hampshire	0	0	0	0	0	0	0	0	0	0
New Jersey	5	294	6,286	103	75	59	52	69	92	110
New York	7	410	8,801	144	102	80	70	96	128	154
N. Carolina	4	234	5,029	82	60	47	41	55	73	88
Oregon	0	0	0	0	0	0	0	0	0	0
Pennsylvania	6	352	7,542	124	90	71	62	83	110	132
Rhode Island	5	294	6,286	103	75	59	52	69	92	110
S. Carolina	4	234	5,029	83	60	47	41	55	73	88
Texas	5	294	6,286	103	75	59	52	69	92	110
Virginia	4	234	5,029	82	60	47	41	55	73	88
Washington	5	294	6,286	103	75	59	52	69	92	110
Tax Base (Million$)[1]		19.25	453.25	9.625	9.625	9.625	9.625	12.8	12.8	12.8
Direct Population[2]		3279	3605	4651	6395	8140	9302	9302	6977	5814

* special rate for mining and manufacturing machinery.

TABLE 8

PROPERTY TAX REVENUE FROM ONSHORE COMPONENTS OF
OFFSHORE OIL AND GAS DEVELOPMENT

Business Property Tax Per Direct Population by Year of Development

	Rate[1]	2[2]	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
	%	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
Alabama	.85	30	98	1160	916	678	542	483	495	676	830	952	970	1092	1384	2414	2813	2910
Alaska	1.61	57	189	2190	1734	1283	1028	915	938	1280	1572	1803	1837	2069	2621	4572	5385	5519
Calif.	2.48	88	285	3377	2671	1977	1584	1410	1445	1972	2422	2778	2830	3187	4038	7043	8295	8490
Conn.	2.38	84	273	3241	2563	1898	1520	1353	1386	1893	2325	2666	2716	3059	3875	6759	7961	8149
Delaware	1.26	45	144	1716	1357	1004	804	716	734	1002	1230	1411	1437	1619	2051	3578	4214	4313
Florida	1.41	50	162	1920	1518	1124	900	801	821	1121	1377	1579	1609	1812	2296	4004	4716	4827
Georgia	1.44	51	165	1961	1551	1148	919	818	839	1145	1406	1613	1643	1850	2344	4089	4816	4930
Hawaii	.92	32	105	1253	991	733	587	523	536	731	898	1030	1049	1182	1498	2612	3077	3149
Louisiana	.56	19	64	762	603	446	357	318	326	445	547	627	639	719	911	1590	1873	1913
Maine	2.43	86	279	3309	2617	1937	1552	1381	1415	1932	2373	2722	2773	3123	3957	6901	8128	8319
Maryland	2.24	79	257	3050	2412	1786	1430	1273	1305	1781	2188	2509	2556	2879	3647	6361	7493	7669
Mass.	3.13	111	361	4263	3371	2496	1999	1780	1823	2489	3057	3506	3572	4023	5097	8889	10470	10716
N. H.	3.14	111	361	4276	3382	2504	2005	1785	1829	2497	3067	3517	3583	4036	5113	8917	10503	10750
N. J.	3.01	107	346	4099	3242	2400	1922	1711	1753	2394	2940	3372	3435	3868	4901	8548	10068	10305
N. Y.	2.72	96	312	3704	2929	2169	1737	1546	1585	2163	2657	3047	3104	3496	4429	7724	9098	9312
N. Carolina	1.58	56	181	2151	1701	1260	1009	898	920	1256	1543	1770	1803	2030	2572	4487	5285	5409
Oregon	2.33	82	267	3173	2509	1858	1488	1325	1357	1853	2276	2610	2659	2994	3794	6617	7794	7977
Pa.	2.16	76	248	2941	2326	1722	1379	1228	1258	1718	2110	2419	2465	2776	3517	6134	7225	7395
R. I.	2.21	78	254	3010	2380	1762	1411	1265	1287	1757	2159	2475	2522	2840	3598	6276	7392	7566
S. Carolina	.94	33	108	1280	1012	749	600	534	547	747	918	1053	1072	1208	1530	2669	3144	3218
Texas	1.91	68	219	2601	2057	1523	1220	1086	1112	1519	1865	2139	2179	2455	3110	5424	6389	6539
Virginia	1.32	47	151	1797	1421	1052	843	750	769	1050	1289	1478	1506	1696	2149	3748	4415	4519
Washington	1.62	57	186	2206	1745	1291	1034	921	943	1288	1582	1814	1848	2082	2638	4600	5419	5546
Base (Million $)[3]		9.24	37.7	491.	501.	510.	520	529	542	555	568	568	568	568	568	568	568	568
Direct Population[4]		2595	3279	3605	4651	6395	8140	9302	9302	6977	5814	5070	4977	4419	3488	2000	1698	1659

FOOTNOTES FOR TABLE 7

[1]Investment costs of onshore tank farms, pipelines and gas plants are from BDM's scenario. The total cost of these investments each year was used as the tax base. The precise base and type of tax equivalent to the sales tax will vary from state to state. A sales tax will be collected on goods and services, including the contract price of construction in most states, sold for use within the state. All coastal states also collect a use tax on items sold in another state that are imported into their state for final use. Thus if a company purchases its pipelines, gas plants and tank farm from contractors it will be taxed under the sales tax. If the company constructs its own facilities, goods and services purchased will be taxed under either the sales or use tax, depending on their state of origin but the labor element of construction will not be taxed. Thus sales and use tax revenue estimates will be 10 to 15 percent high. The state sales tax rate is used as an approximation of the sales tax--use tax rate likely to be applicable to facilities construction within different states.

[2]Direct Population is defined as the employees and their families associated with offshore oil and gas production. It is calculated by relating employment by year from the BDM scenario to 1972 OBERS Projections, Series E Population.

[3]State plus local sales tax rates (ACIR, Significant Features, p. 238.)

[4]There are no taxable investments prior to year 3 nor after year 11.

FOOTNOTES FOR TABLE 8

[1]The effective property tax rate on residences was used (ACIR, Significant Features, 1973-74, p. 174). This must be viewed as an approximation but no source of effective rates on real industrial property is available. Use of "legal" rates would generate higher, but less likely, estimates.

[2]There are no taxable investments onshore prior to year 2.

[3]The property tax base is the cumulative total of the cost of land and onshore capital investments.

[4]Direct Population is defined as the employees and their families associated with offshore oil and gas production. It is calculated by relating employment by year from the BDM scenario to 1972 OBERS Projections, Series E Population.

TABLE 9

PROPERTY TAXES FROM ONSHORE COMPONENTS

OF OFFSHORE PORT DEVELOPMENT

	Rate[3]	Taxes per direct population by year of development: 4[4]	5-18 (annual amt)
	%	$	$
Alabama	.85	340	1700
Alaska	1.61	644	3220
Calif.	2.48	990	4960
Conn.	2.38	920	4760
Delaware	1.26	540	2520
Florida	1.41	560	2820
Georgia	1.44	575	2880
Hawaii	.92	368	1840
Louisiana	.56	224	1120
Maine	2.43	972	4860
Maryland	2.24	895	4480
Mass.	3.13	1251	6260
N.H.	3.14	1255	6280
N.J.	3.01	1203	6020
N.Y.	2.72	1087	5440
N. Carolina	1.58	631	3160
Oregon	2.33	932	4660
Pa.	2.16	864	4320
R.I.	2.21	885	4420
S. Carolina	.94	376	1880
Texas	1.91	764	3820
Virginia	1.32	528	2640
Washington	1.62	648	3240
Tax Base (Million $)[1]		46.5	93
Direct Population[2]		1163	465

[1]The tax base is the cumulative cost of onshore tank farm construction.

[2]Direct Population is defined as the employees and their families associated with offshore oil and gas production. It is calculated by relating employment by year from the BDM scenario to 1972 OBERS Projections, Series E Population.

[3]The effective property tax rate on residences was used. (ACIR, Significant Features, 1973-74, p. 174). This must be viewed as an approximate but no source of effective rates for industrial property is available.

[4]There are no significant onshore land or investments prior to year 4.

TABLE 10

SALES AND USE TAX REVENUES FROM ONSHORE COMPONENTS OF

OFFSHORE PORT DEVELOPMENT

State	Rate[3]	Taxes per direct population by year of development: Year 4[4]	Year 5[4]
	%	$	$
Alabama	1.5[5]	600	1500
Alaska	5	2000	5000
Calif.	6	2400	6000
Conn.	6.5	2600	6500
Delaware	0		
Florida	4	1600	4000
Georgia	4	1600	4000
Hawaii	4	1600	4000
Louisiana	6	2400	6000
Maine	5	2000	5000
Maryland	4	1600	4000
Mass.	3	1200	3000
N.H.	0		
N.J.	5	2000	5000
N.Y.	7	2800	7000
N. Carolina	4	1600	4000
Oregon	0		
Pa.	6	2400	6000
R.I.	5	2000	5000
S. Carolina	4	1600	4000
Texas	5	2000	5000
Virginia	4	1600	4000
Washington	5	2000	5000
Tax Base (Million$)[1]		46.5	46.5
Direct Population		1163	465

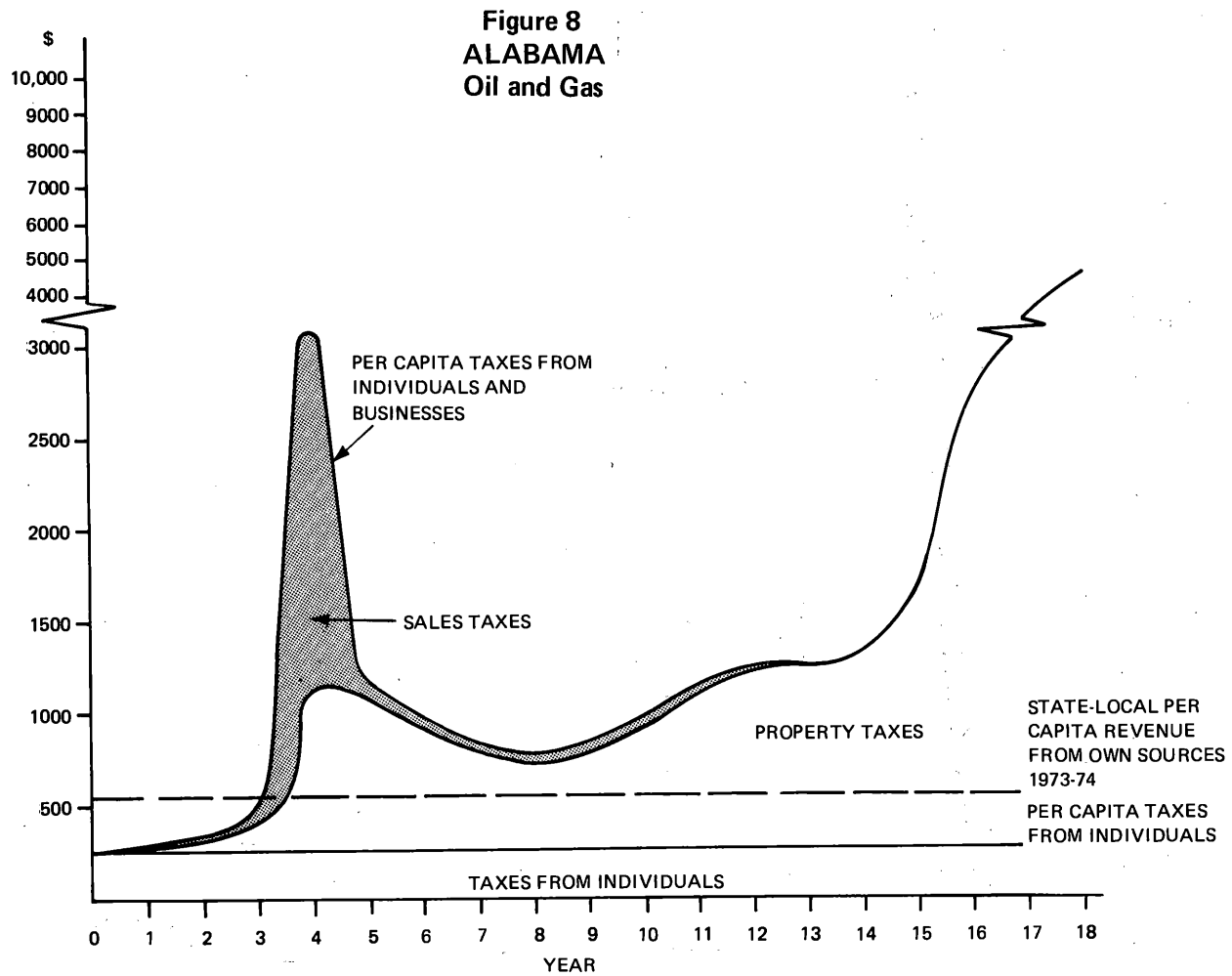
[1]Investment costs of onshore tank farms are from BDM's scenario. The total cost of the investment each year was used as the sales tax base. (See Note 1, Table 7 for explanation of base).

[2]Direct Population is defined as the employees and their families associated with offshore oil and gas production. It is calculated by relating employment by year from the BDM scenario to 1972 OBERS Projections, Series E Population.

[3]State plus local sales tax rates (ACIR, Significant Features, 1973-74, p. 238).

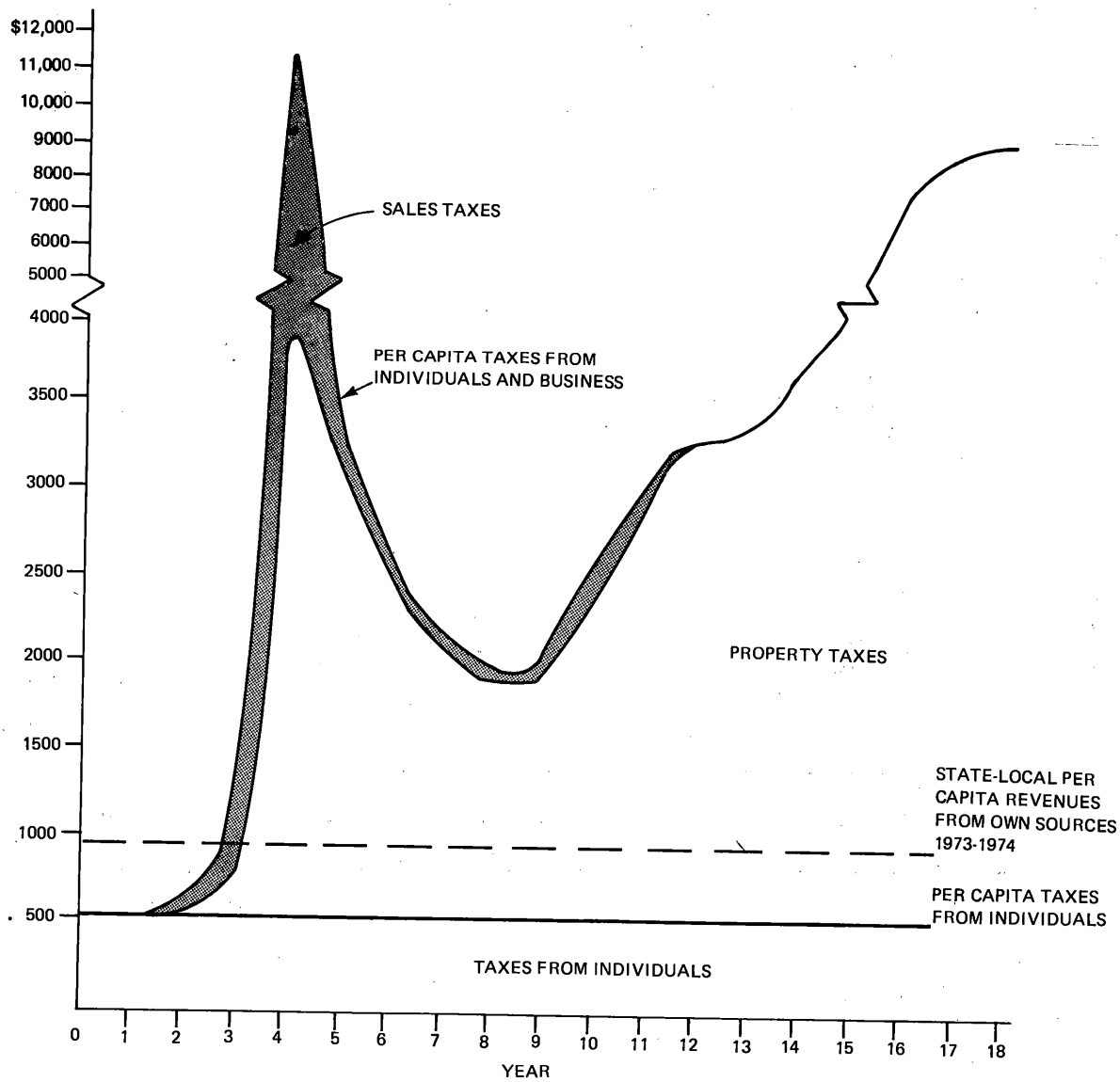
[4]There are no significant onshore investments before year 4 nor after year 5.

[5]Alabama has a special rate for mining and manufacturing machinery.



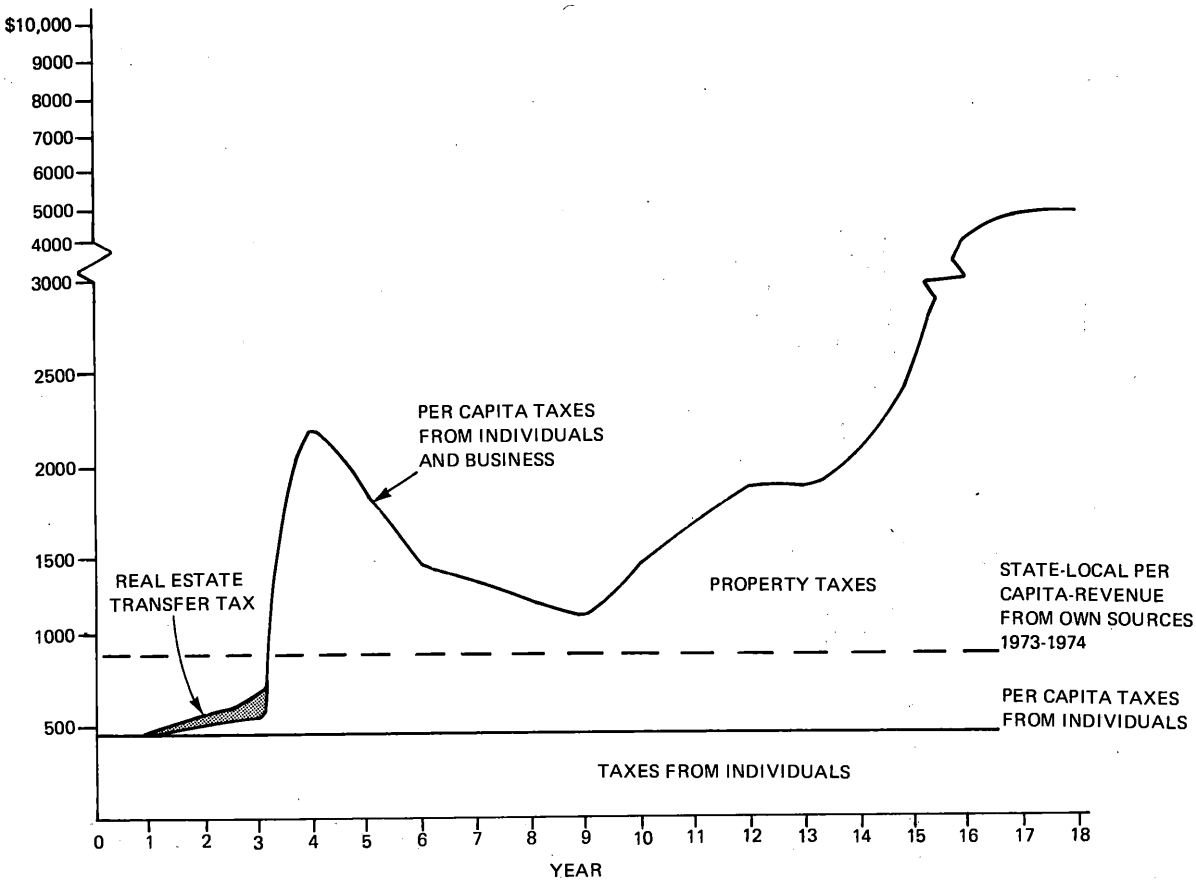
State-Local Revenue Per Employee and their Families from OCS Oil-Gas Development.

Figure 9
CALIFORNIA
Oil and Gas



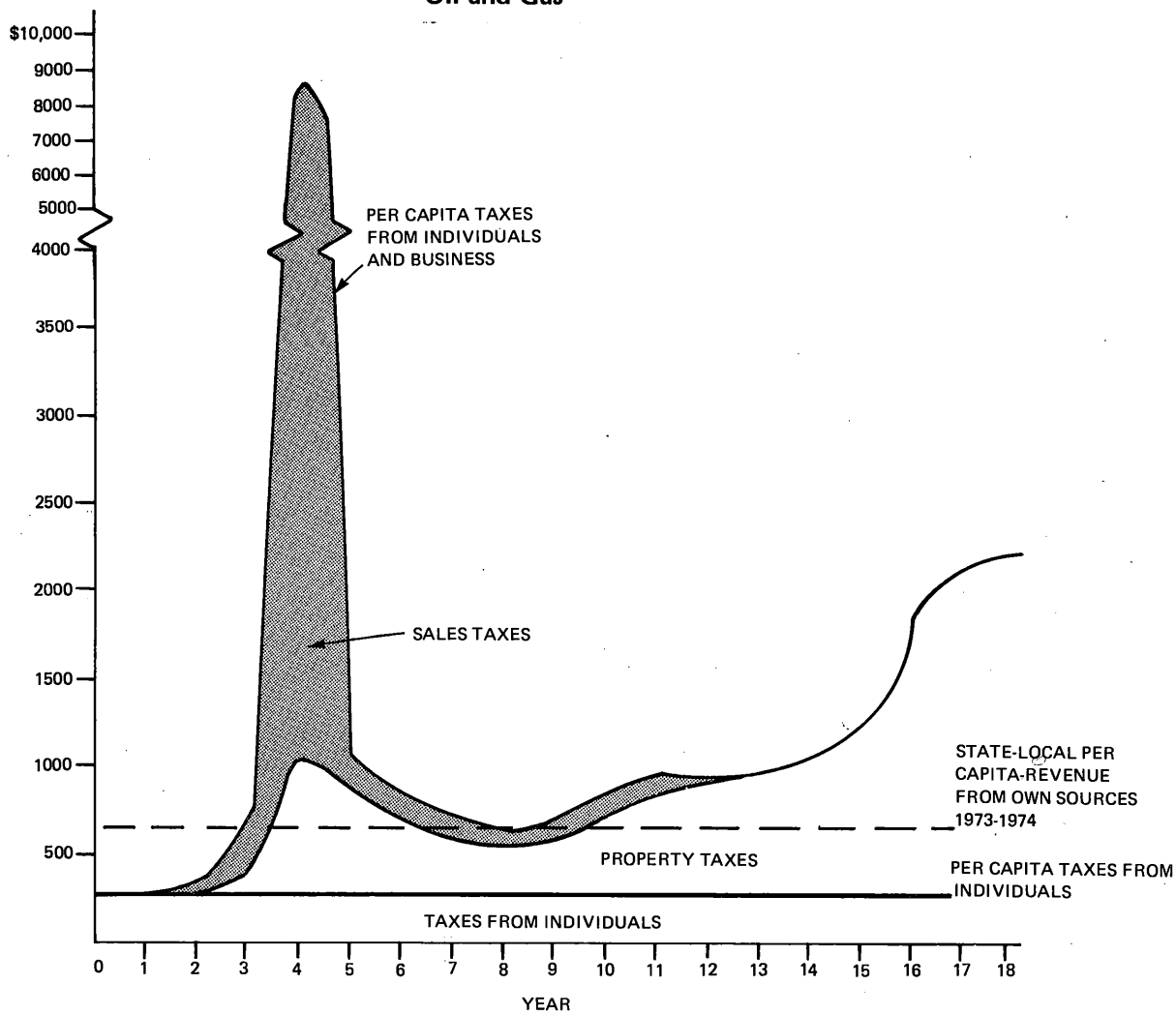
State-Local Revenue Per Employee and their Families from OCS Oil-Gas Development.

Figure 10
DELAWARE
Oil and Gas



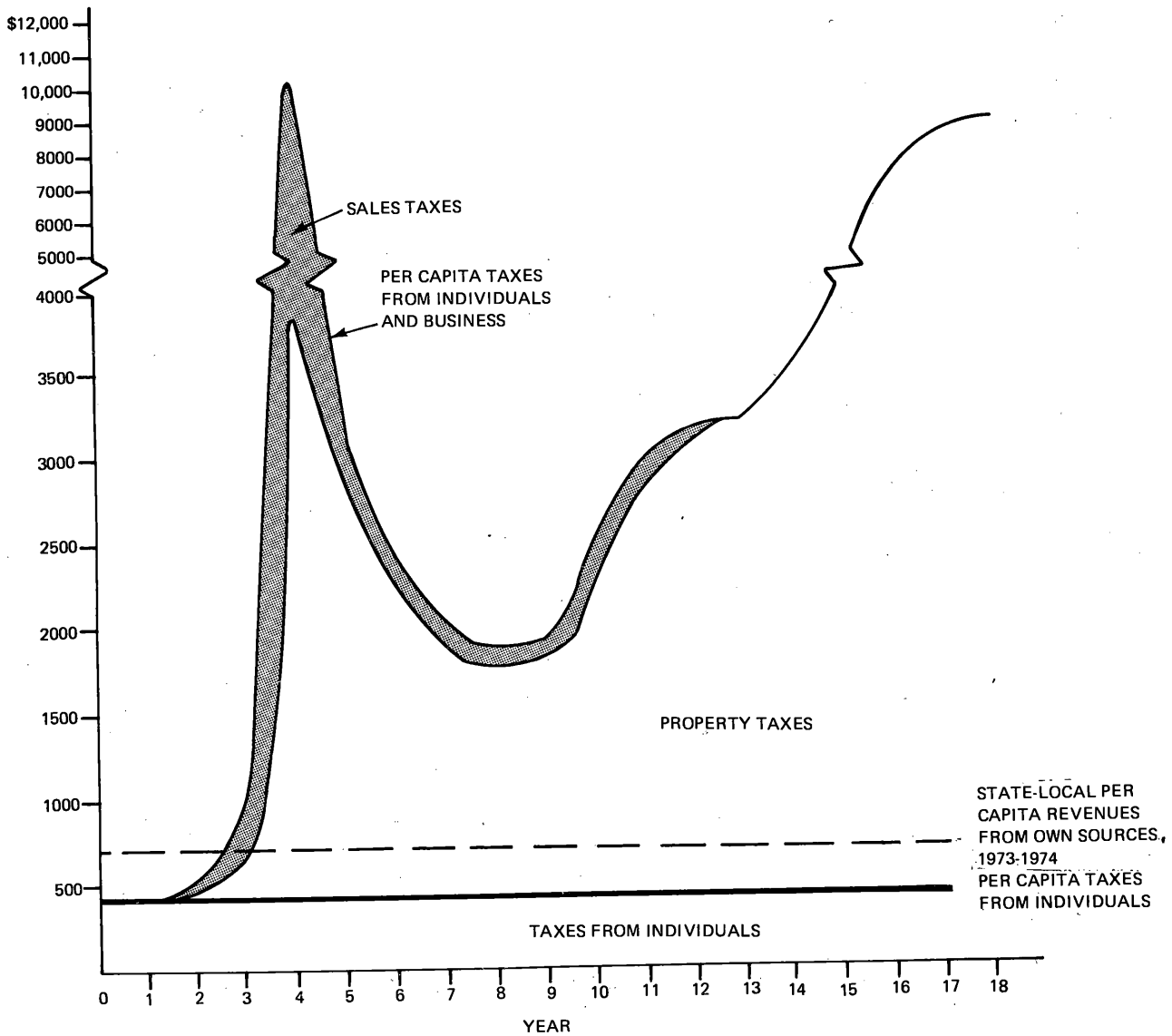
State-Local Revenue Per Employee and their Families from OCS Oil-Gas Development.

Figure 11
LOUISIANA
Oil and Gas



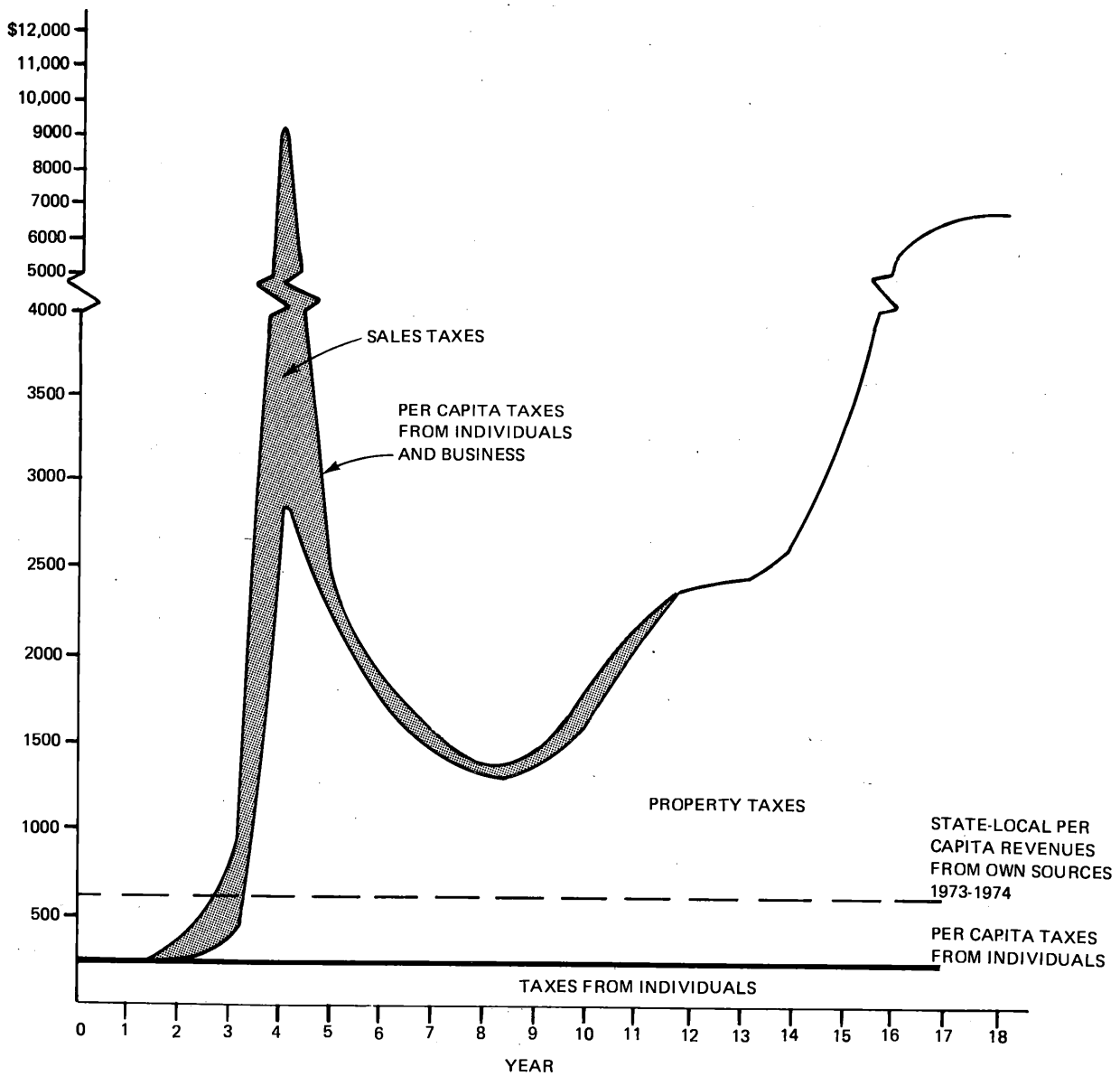
State-Local Revenue Per Employee and their Families from OCS Oil-Gas Development.

Figure 12
MAINE
Oil and Gas



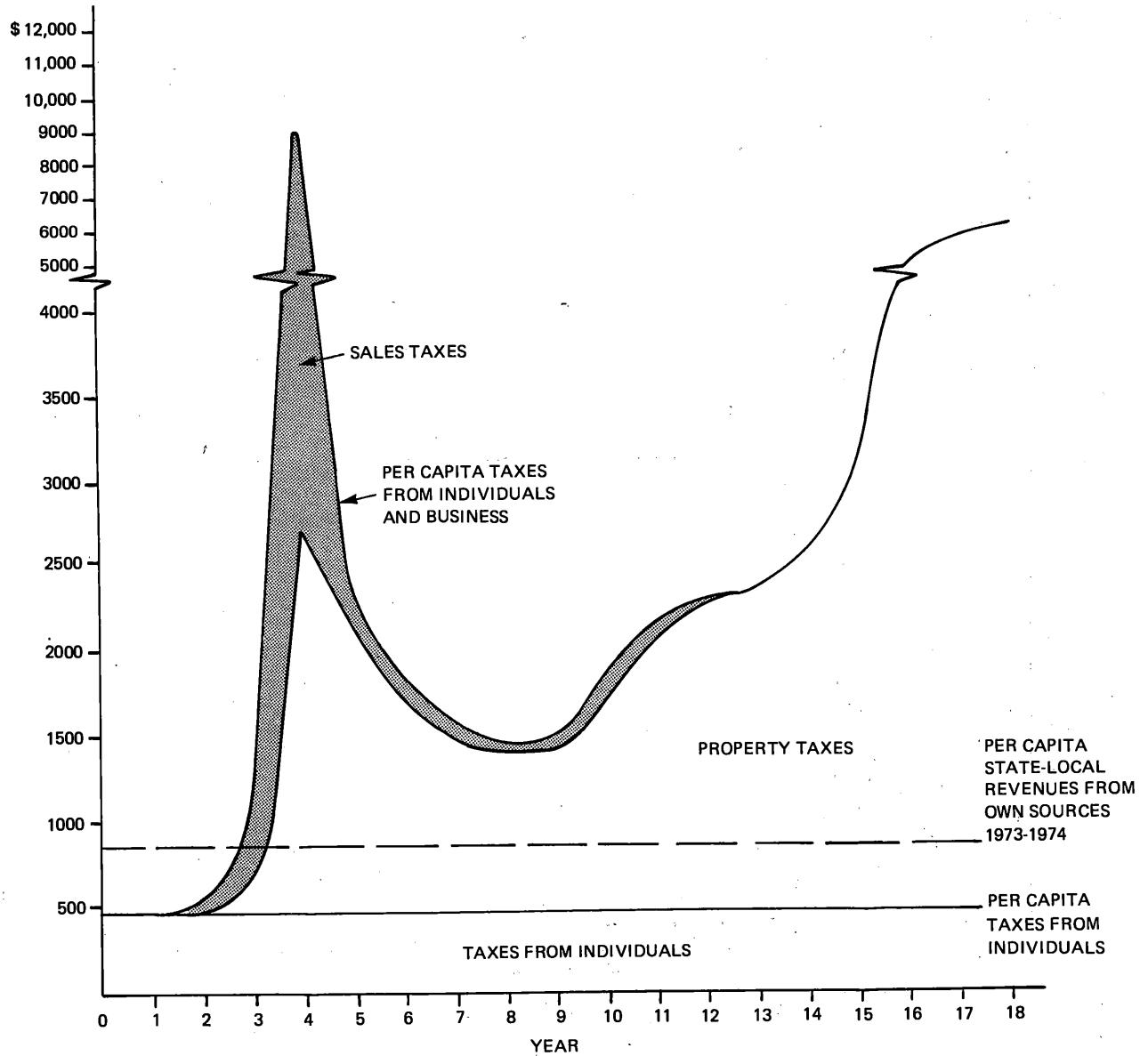
State-Local Revenue Per Employee and their Families from OCS Oil-Gas Development.

Figure 13
TEXAS
Oil and Gas



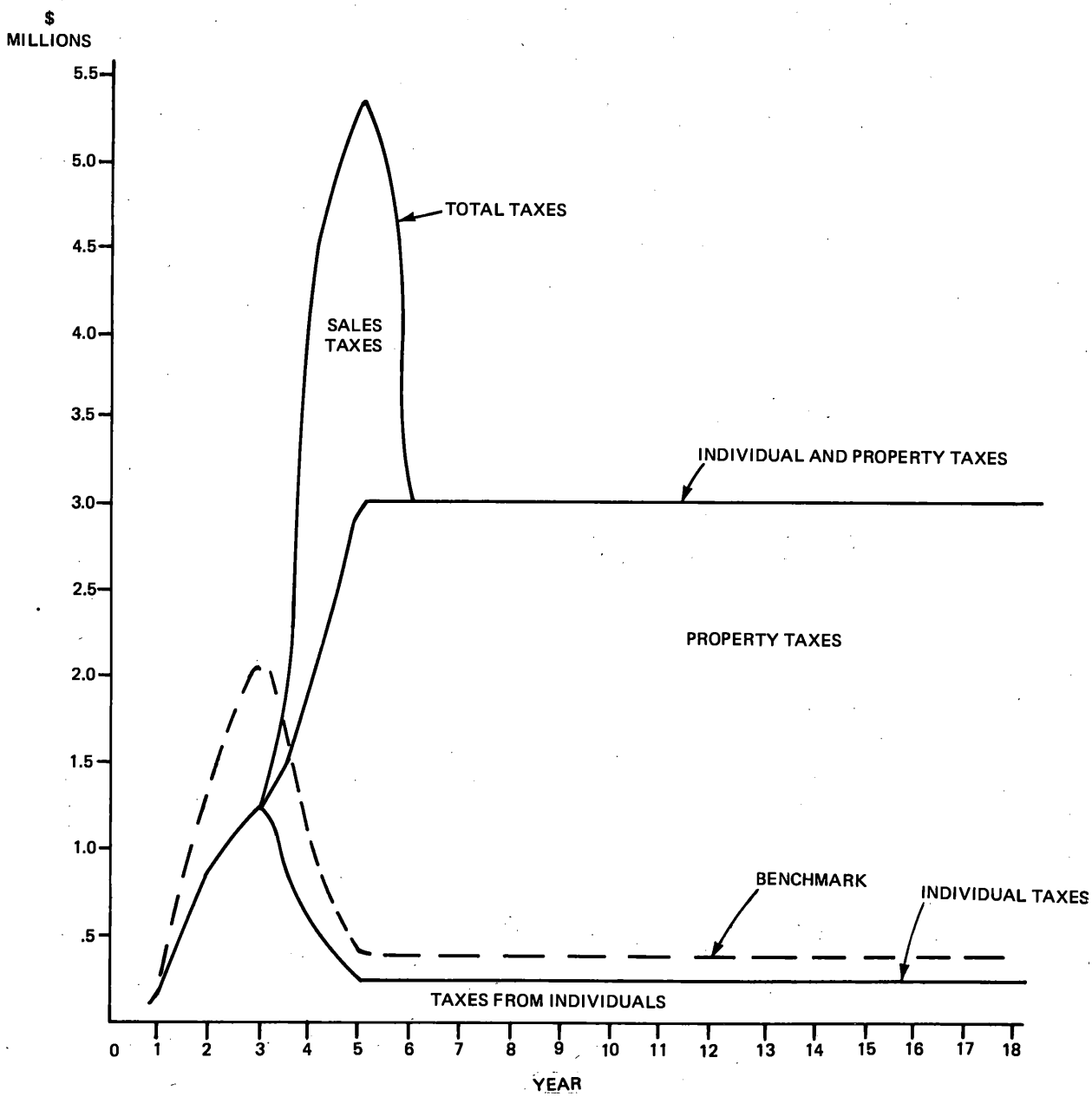
State-Local Revenue Per Employee and their Families from OCS Oil-Gas Development.

Figure 14
WASHINGTON
Oil and Gas



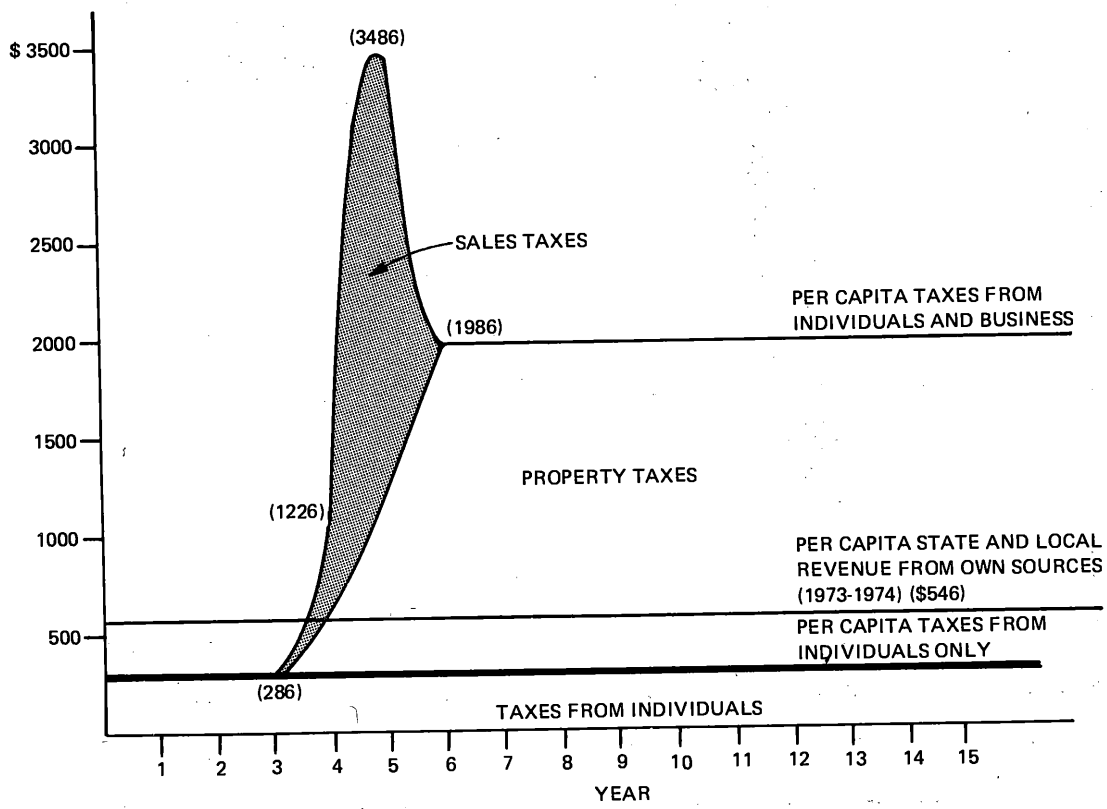
State-Local Revenue Per Employee and their Families from OCS Oil-Gas Development.

Figure 15
NEW JERSEY
Total Tax Revenue—Deepwater Port



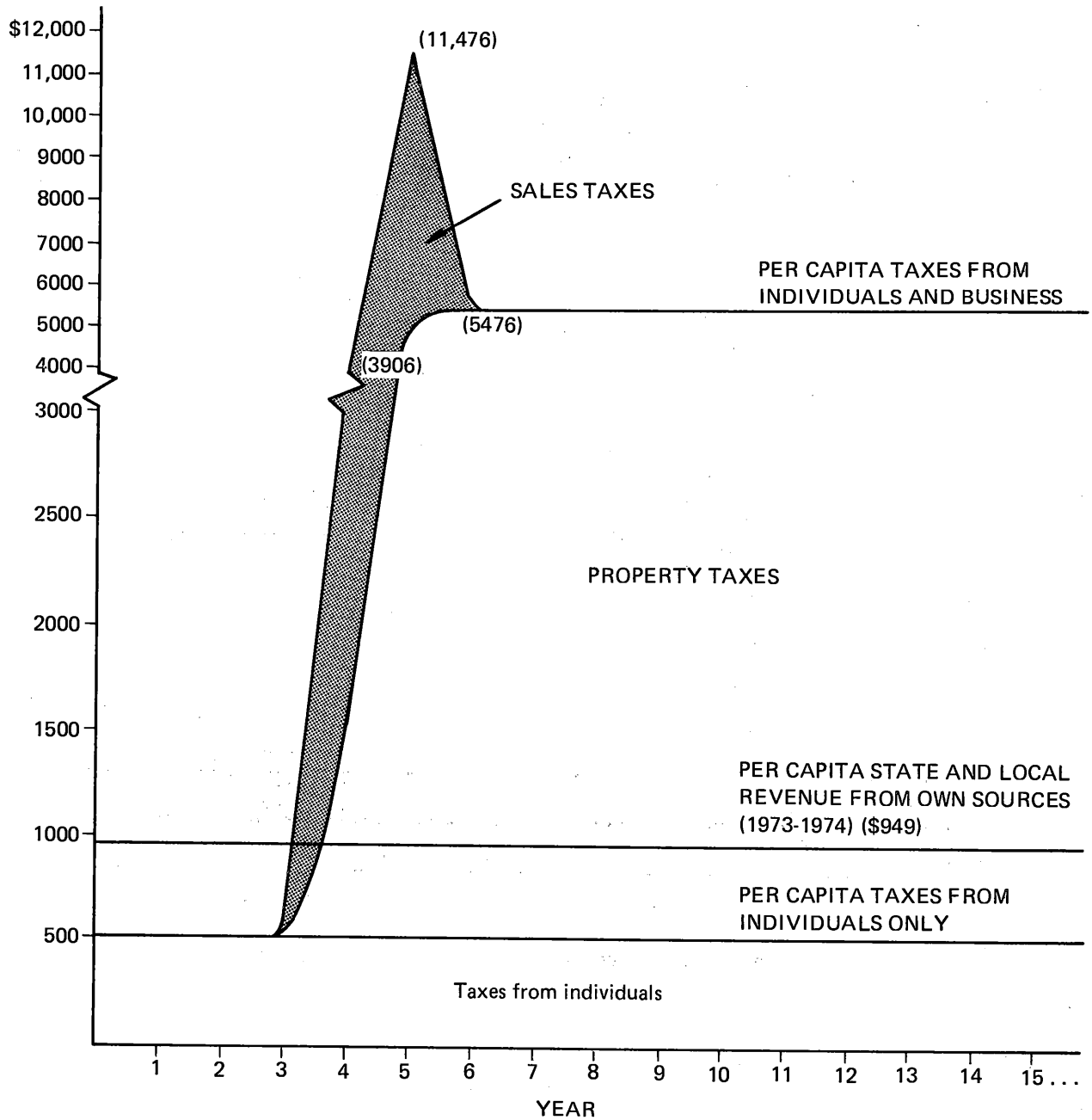
Benchmark: Direct Population Times Per Capita State and Local Tax Revenue.

Figure 16
ALABAMA
Deepwater Port



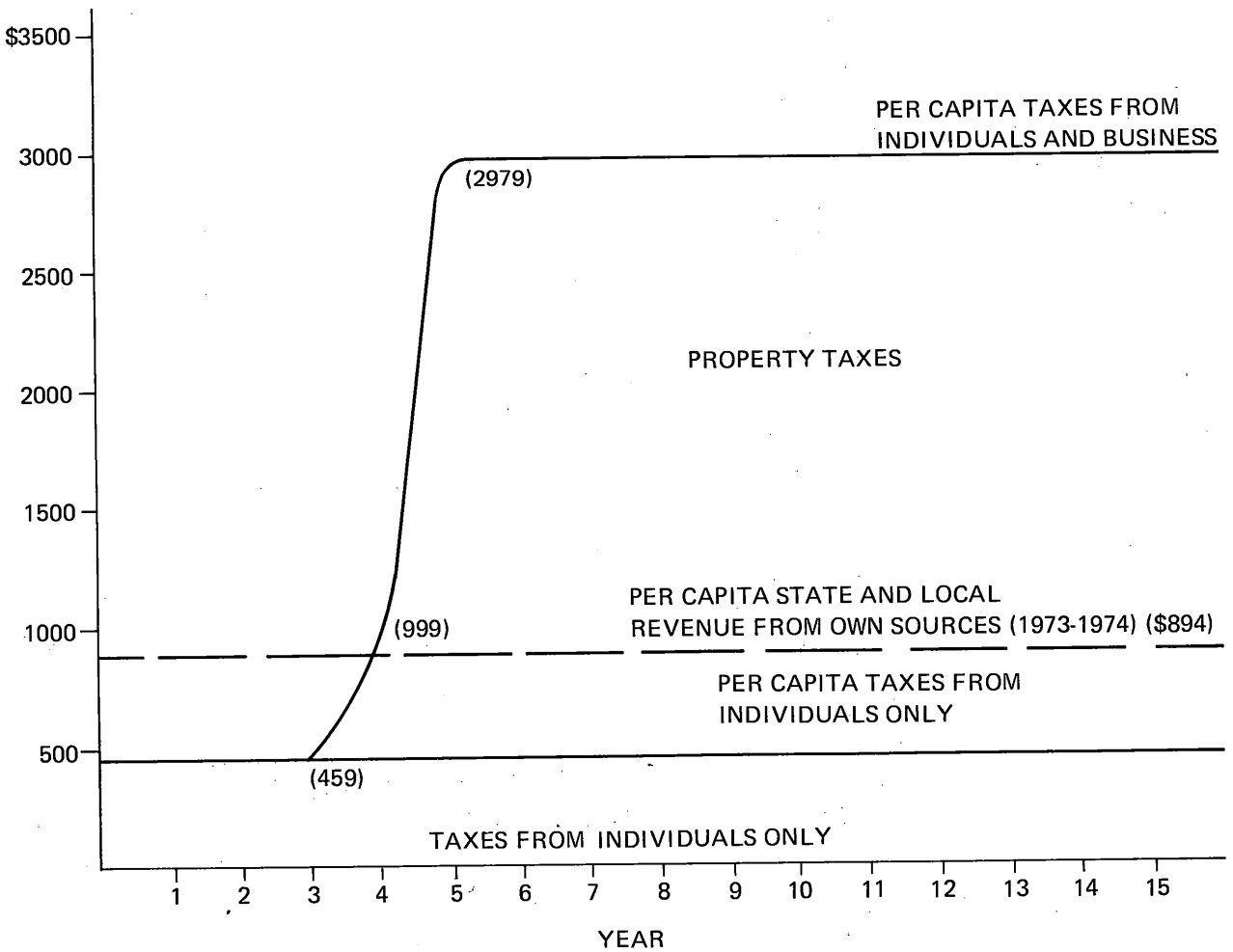
State and Local Revenue Per Employee and their Families from Deepwater Port Development.

Figure 17
CALIFORNIA
Deepwater Port



State and Local Revenue Per Employee and their Families from Deepwater Port Development.

Figure 18
DELAWARE
Deepwater Port



State and Local Revenue Per Employee and their Families from Deepwater Port Development.

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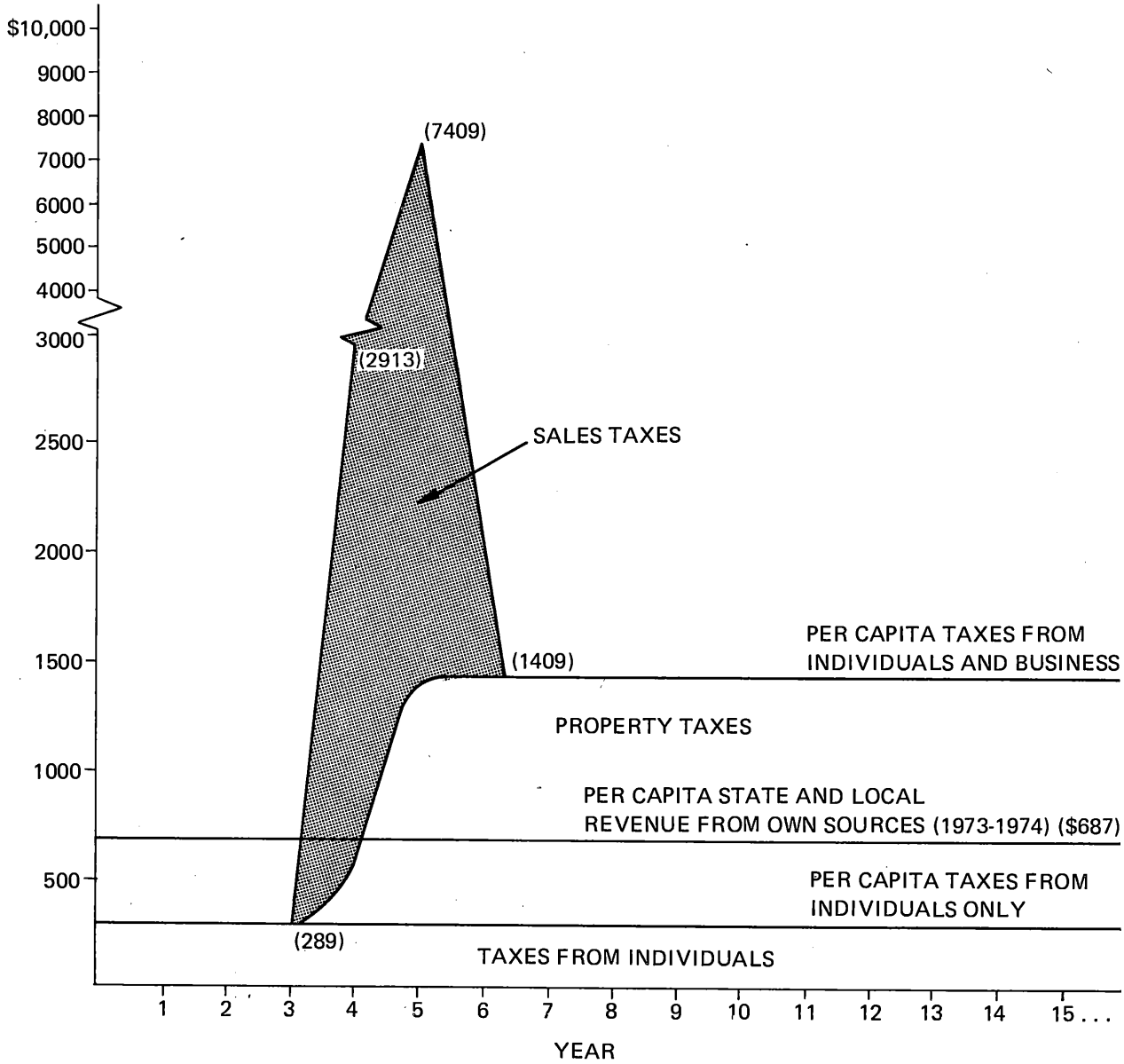
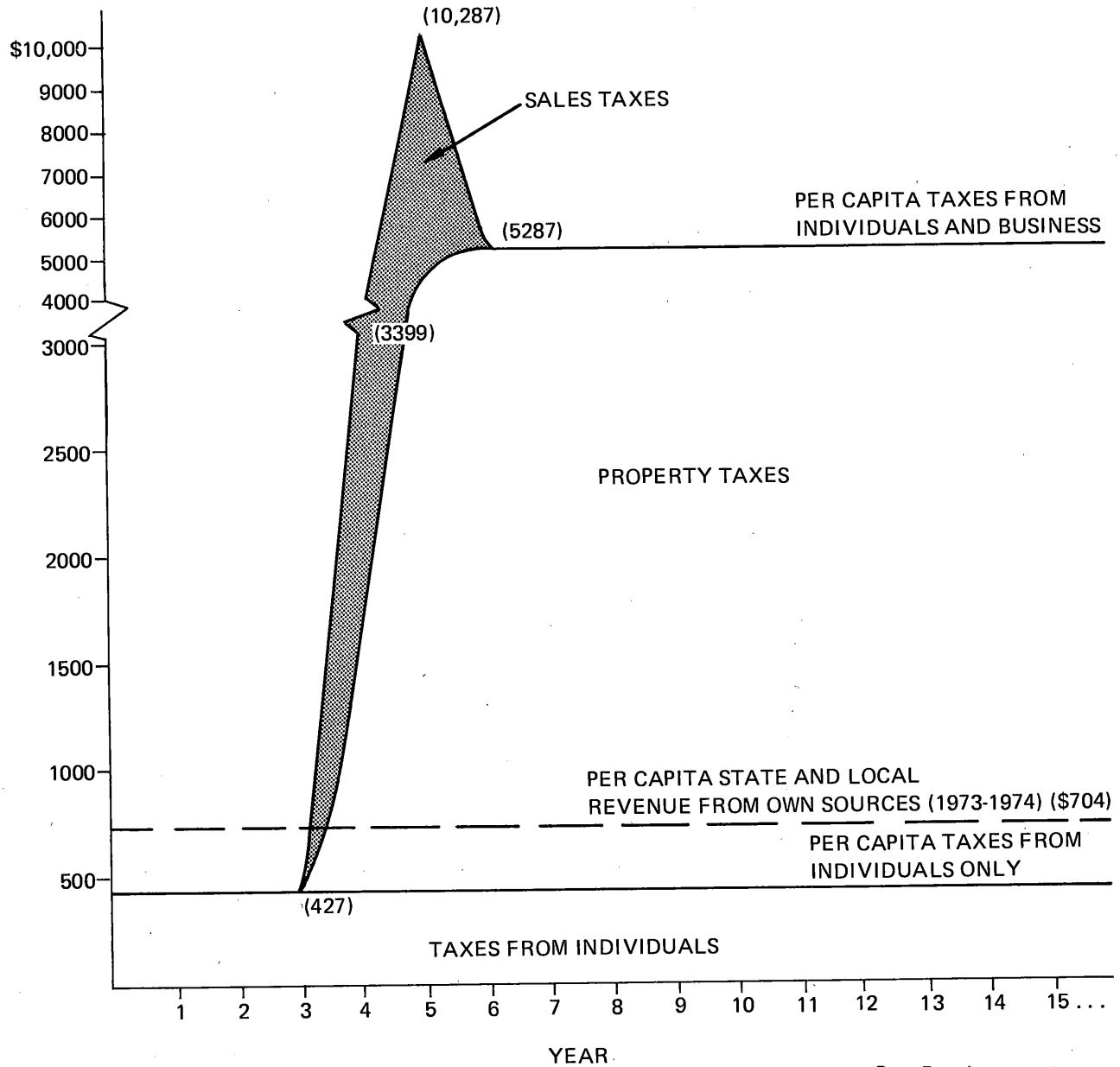
Figure 19
LOUISIANA
Deepwater Port



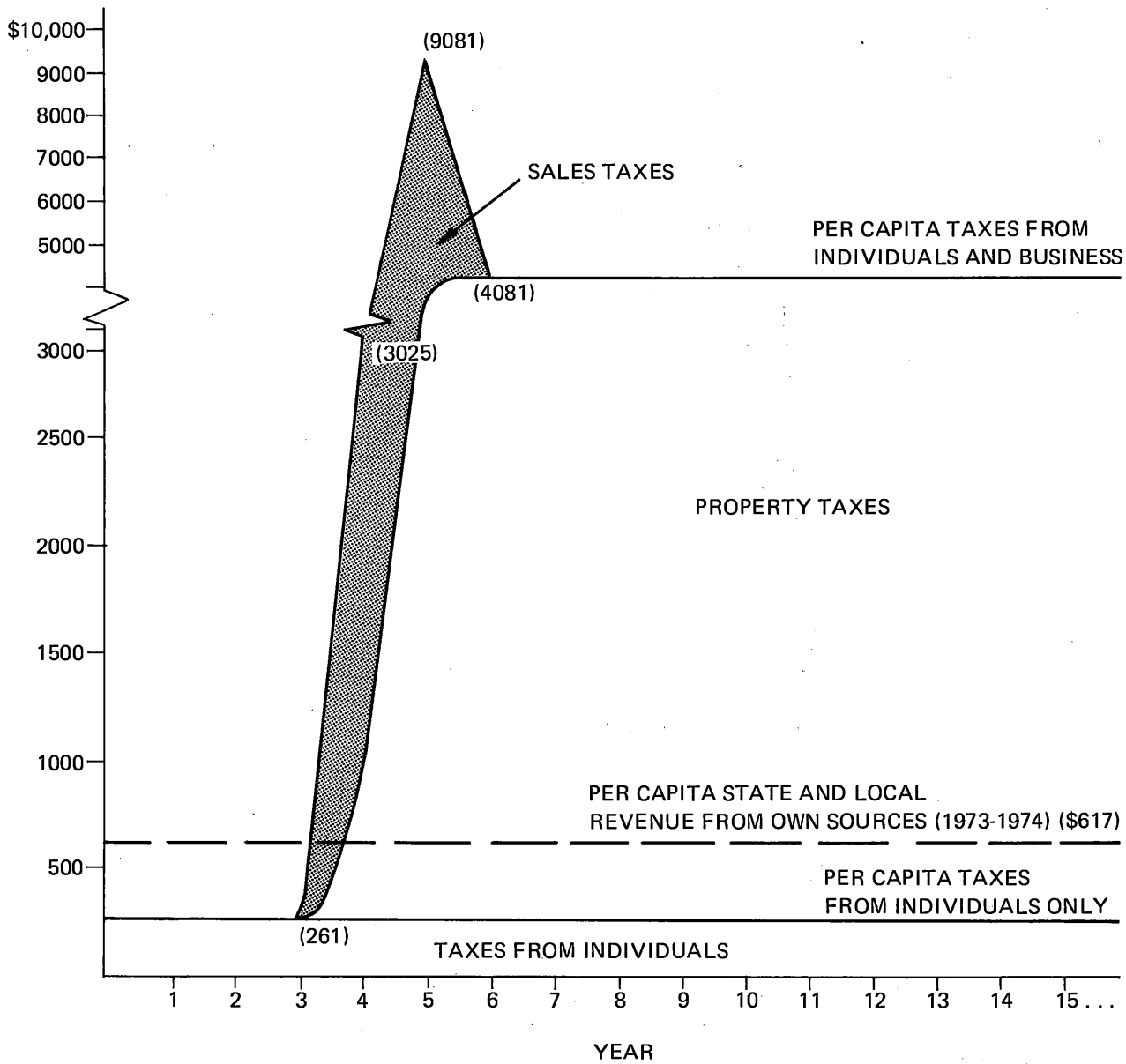
State and Local Revenue Per Employee and their Families from Deepwater Port Development.

Figure 20
MAINE
Deepwater Port



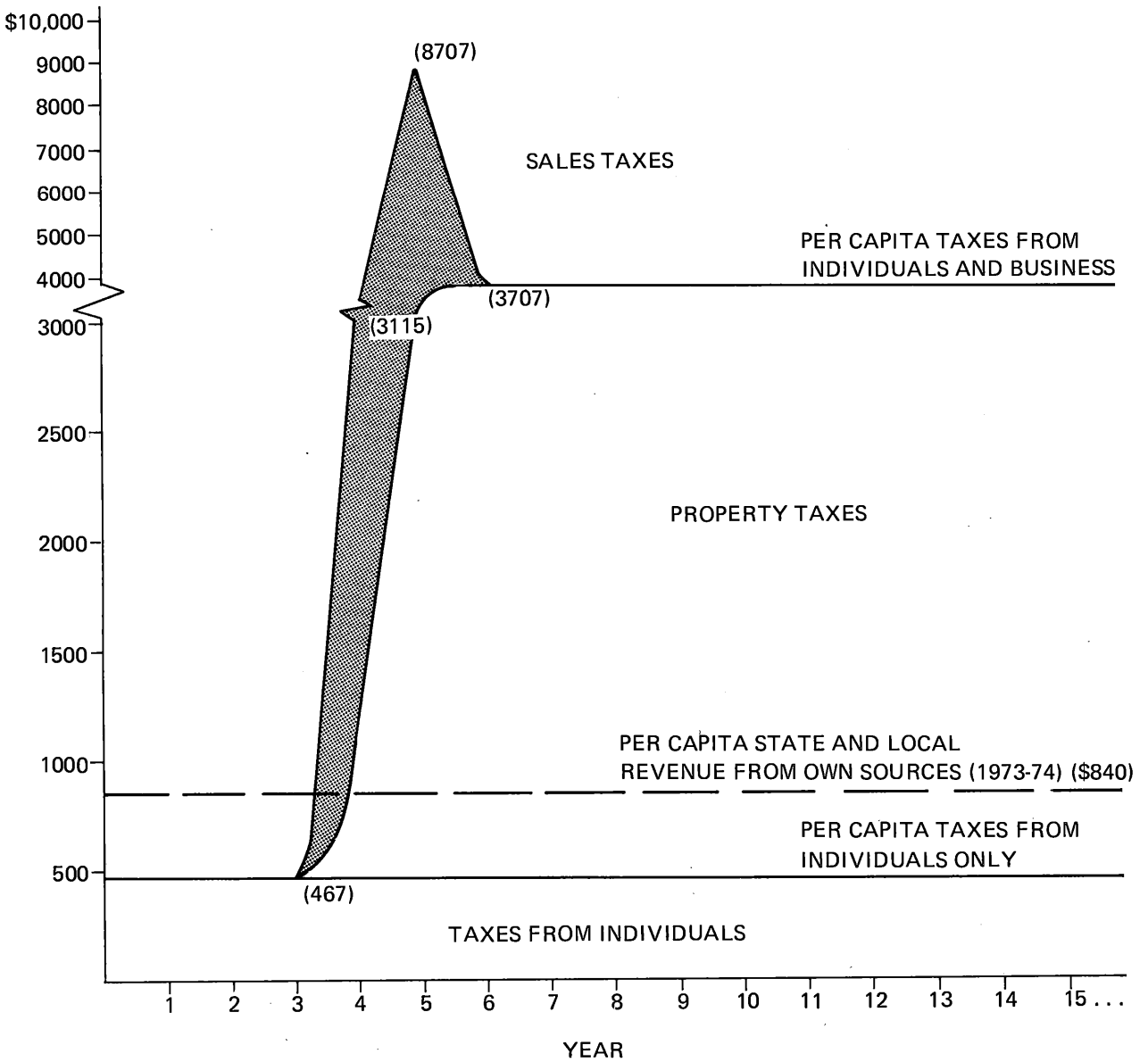
State and Local Revenue Per Employee and their Families from Deepwater Port Development

Figure 21
TEXAS
Deepwater Port



State and Local Revenue Per Employee and their Families from Deepwater Port Development.

Figure 22
WASHINGTON
Deepwater Port



State and Local Revenue Per Employee and their Families from Deepwater Port Development.

Working Paper #7

Environmental Studies for OCS Oil and Gas Development

Prepared for OTA
by: Michael J. Conoy, William Barbee,
Andre LaBonte and OTA Oceans Project Staff

September 1976

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I.

FOREWORD

This working paper presents a general analysis of the status of the Environmental Study Program for OCS development, currently underway at the Bureau of Land Management. There are areas in this program that are quite good and others that are questionable. In addition, some projects are so poorly described that it is difficult to tell whether or not they are satisfactory. The history, the basic concepts, and the validity of methods needs to be examined and this evaluation is a beginning look at the total program and major components.

Large sums of money are presently allocated for baseline and monitoring studies. The FY-76 budget is estimated at $41.7 million and the FY-77 budget request is $46.6 million. "Special Studies" take up 14% of the FY-76 budget ($6.0 million) and an estimated 17% (7.9 million) of the FY-77 budget.[1/]

It appears that most of the budget is directed toward long range general studies or broad baseline studies. It also seems that most studies are planned on the basis of very general goals.

This paper will first examine the general goals and then some of the specific study plans and activities. In this way some problems can be illustrated and improvements suggested.

II.

INTRODUCTION

The OCS Environmental Study Program is usually described by BLM in three parts: Baseline Studies, Monitoring, and "Special Studies."[2/]

Baseline studies are intended to (a) provide an information base to assist management, (b) establish a predevelopment reference point (benchmark) and (c) help plan for monitoring and special studies. The purposes of baseline studies are to characterize the environmnet by compiling and analyzing all existing pertinent data and developing original research projects to fill gaps in existing data.

Monitoring is the systematic collection of data from regions where baselines are established to detect any environmental changes after development begins.

Special studies are conducted during baseline and monitoring studies and are meant to contribute to the understanding of important cause and effect relationships between oil and gas development and marine environmental changes. The objectives of special studies are:

1. to provide information about the OCS environment that will allow the Department of the Interior to make management decisions;

2. to fill the information needs of management, regulatory, and advisory agencies for a broad range of OCS activities, including the preparation and review of environmental impact statements.

Baseline Studies:

The specific objectives of baseline studies emphasize the management, predictive, and evaluative requirements of a good program.

1. To provide information suitable for making predictions of the effects of OCS development on components of the ecosystems.
2. To provide a description of the existing physical, chemical, geological, and biological elements of the systems and their interactions, against which changes or impacts can be measured.
3. To identify the critical parameters which should be included in the monitoring program.
4. To identify areas of need for special studies to meet the previous objectives and to conduct these special studies.

Two important factors in these studies are timing and design. The studies are to provide pre-development information for use in prediction and post facto evaluation of the hazards and environmental effects of OCS development. This requires a statistical design to define the limits of variation and to detect changes at the 90-95% confidence level.[3/] The studies should be designed to provide statistical discrimination and should reach the discriminatory stage before decisions are made.

The present program can be expected to: (a) improve the hazard assessment, (b) set up "baseline" levels for key trace metals and hydrocarbone, (c) improve our understanding of qualitative biotic relationships, (d) improve prediction of target (select) pollutants and activities and (e) begin modeling of shelf circulation.

The 12-18 month Baseline Studies conducted in most OCS regions will not, however, be sufficient to fulfill the overall objectives. That will require a longer study period and/or more rigorous statistics.

The complete environmental studies program should have been developed much earlier in the OCS planning process. The plan should have been included in a leasing, exploratory, and development management plan. As of September 1976, a complete, cohesive plan still has not been prepared.

Some key questions which need to be addressed in all environmental study programs are:

(a) Is the information available already? Are the existing data sufficient for decision making?

(b) Are the study elements achievable given time and resource constraints? Are they sufficiently critical to warrant increasing resources or relaxing time constraints?

(c) Are the study elements scientifically sound, i.e. quantifiable and statistically valid?

(d) What study results are important for management decisions; when are they needed; and how are they used?

Our investigations have indicated that most of these questions have not been addressed in many of the studies now underway.

III.

- PLANNING FOR ENVIRONMENTAL STUDIES -

A. Procedures

According to statements from the "Draft of the Program Plan for the Bureau of Land Management OCS Environmental Studies" concerning coordination of study program planning activity, the procedure for initiating environmental studies is as follows:[4/]

1. BLM discusses study plans with the OCS Environmental Studies Advisory Board.

2. BLM has a coordinating mechanism through Secretarial Order 2974 with the Fish and Wildlife Service, and the USGS for review of study plans. In practice, the other agencies receive the plans and have about 30 days to read and review them.

3. BLM solicits comments and recommendations for environmental study plans through the mechanism of open conferences. They may or may not use the recommendations in the study plan and the work may not necessarily follow the study plan.

4. BLM takes these recommendations, and in a series of meetings with Federal and State representatives, forms them into a multi-year plan for a given area. Thus far this has only happened in Alaska.

This multi-year plan is subsequently sent to the OCS Environmental Studies Advisory Board for review and comment; then instituted by either a) BLM funding of a study on studies by another Federal agency already involved in related research, or b) by issue of Requests For Proposals (RFP) with contracts established on a competitive bidding basis.

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B. Content of the Studies

The studies are usually designed to cover four major subject areas: (1) biological, (2) physical, (3) geological and (4) chemical. These are described below.[5/]

1. Biological Subprogram: The objectives of the biological program are to: (a) determine population density distributions, (b) determine areas of feeding, spawning and nurseries, and migration routes for key species, (c) identify the causes for major variations observed, (d) evaluate systematic effects of pollutants on selected species, (e) determine the means and natural variation for levels of pollutants in selected species or communities.

It is very difficult to analyze population density distributions or identify the causes of major variations. The OCS Environmental Studies Advisory Committee has repeatedly commented on this. (March 1976, October 1975, August 1976)

The use of terms such as "key" or "select" species implies that a "selection" process exists to determine which species are "key". There is no evidence that there is such a process.

The criteria used in deciding whether a species is "key" or not should be: (a) importance to man, (b) probability of adverse impact, (c) tractability for study, (d) importance to the ecosystem. Since so little is known about ecosystem dynamics, the other elements are generally used to select subjects for study.

The biological elements include both baseline and special studies. The special studies, as pointed out earlier, are supposed to be related to problems and information gaps found during baseline studies.

The biological baseline studies for the OCS program are supposed to include:

a. Benthos -- Significant in this area are species composition and numbers and identification of indicator species sensitive to, or concentrators of, petro-chemical hydrocarbons. These are three requirements for this approach: (1) the original data must be extensive and must be subjected to rigorous statistical reduction; (2) the three parameters of species diversity, population levels, and changes in indicator species must be used; (3) the evaluations must be done by a trained ecologist. The most sensitive and most critical benthic areas are intertidal and shallow subtidal. These areas include estuaries, mud flats and salt marshes.

b. Birds: The studies of avifauna should be concentrated on areas of breeding and feeding, areas overlapping migration routes, concentration of pollutants in food chains, and potential spill trajectories.

c. Mammals -- These studies should be similar to birds.

d. Fisheries: Intensive stock assessment and stock recruitment studies must be conducted.

e. Plankton: Statements concerning species diversity, production, population levels and other parameters of community structure are non-scientific under the present program (or any reasonably expected changes) due to the extreme variation of all phytoplankton and holozo-

oplankton. To reduce statistically the data to meaningful numbers for decision-making would require taking literally thousands of samples taken at least quarterly. It may be better to perform very broad analyses of the relative numbers and biomass of classes or families. The reduction in detail would allow for more samples to be processed.

2. Physical Oceanographic/Meteorology Subprogram: The physical oceanographic and meteorological factors are necessary to evaluate operational hazards, spill trajectories, and to locate biological and chemical sampling stations. Design factors include current patterns, movement of dissolved and particulate pollutants, as well as probability and degree of severity for events.

The assessment factors should include temperature, salinity, current direction and velocity for surface and bottom, and the meteorologic limits and frequency of rare events. Much of the data are historical except in the area of Alaska. A two year program such as that described by the Environmental Studies Advisory Committee should be adequate if the existing data are surveyed completely.

Expected Study Design Elements:

a. Description of large scale shelf circulation patterns.

b. Develop time and space scales for current events.

c. Full inventory of historical data supplemented with widespread synoptic studies.

3. Geological and Bathymetric Subprogram: Geologic studies cover potential hazards to development, potential hazards from development, and the transport of pollutants. Examples of specific items are bottom

bearing capacity, tectonic activity (especially seismic), slumping rate, sedimentation rates, and sediment transport.

Major elements to be studied should include:

a. Crystal mobility and seismicity

b. Mass movement of sediments

c. Erosion and sedimentation

d. Bathymetry (profiling)

4. Chemical Subprogram: The chemical composition of the offshore regions is less variable than other aspects with a longer time scale for change. This simplifies sampling and statistical analysis.

Chemical assessment should be directed toward determining the level of natural biogenic hydrocarbons versus man-introduced hydrocarbons, nutrient levels, trace element concentrations, and other man-introduced compounds.

Design elements in the chemical subprogram include:

a. Distribution of normal and introduced compounds.

b. Statistical analysis of variation within time and space.

c. Baseline levels and natural variation within selected species.

d. Baseline levels and natural variation for nutrients in the water column

C. Study Relationship to OCS Leasing

The following diagrams (Figures 1 and 2) were distributed by BLM to the OCS Governors Conference (Nov. 1974) and, at a later date, to CEQ. It is of interest to note that Environmental Studies and Leasing/

Figre 1

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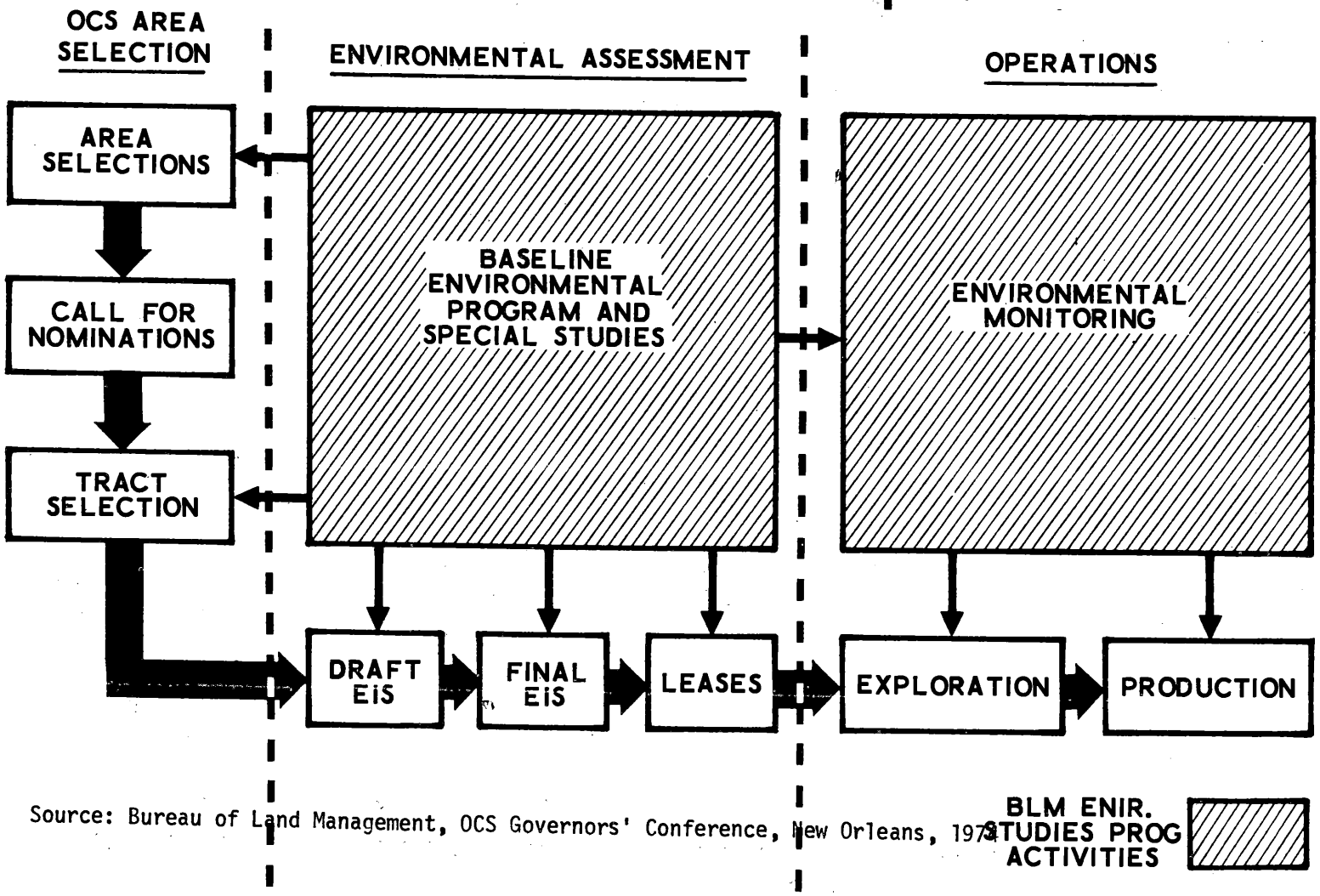
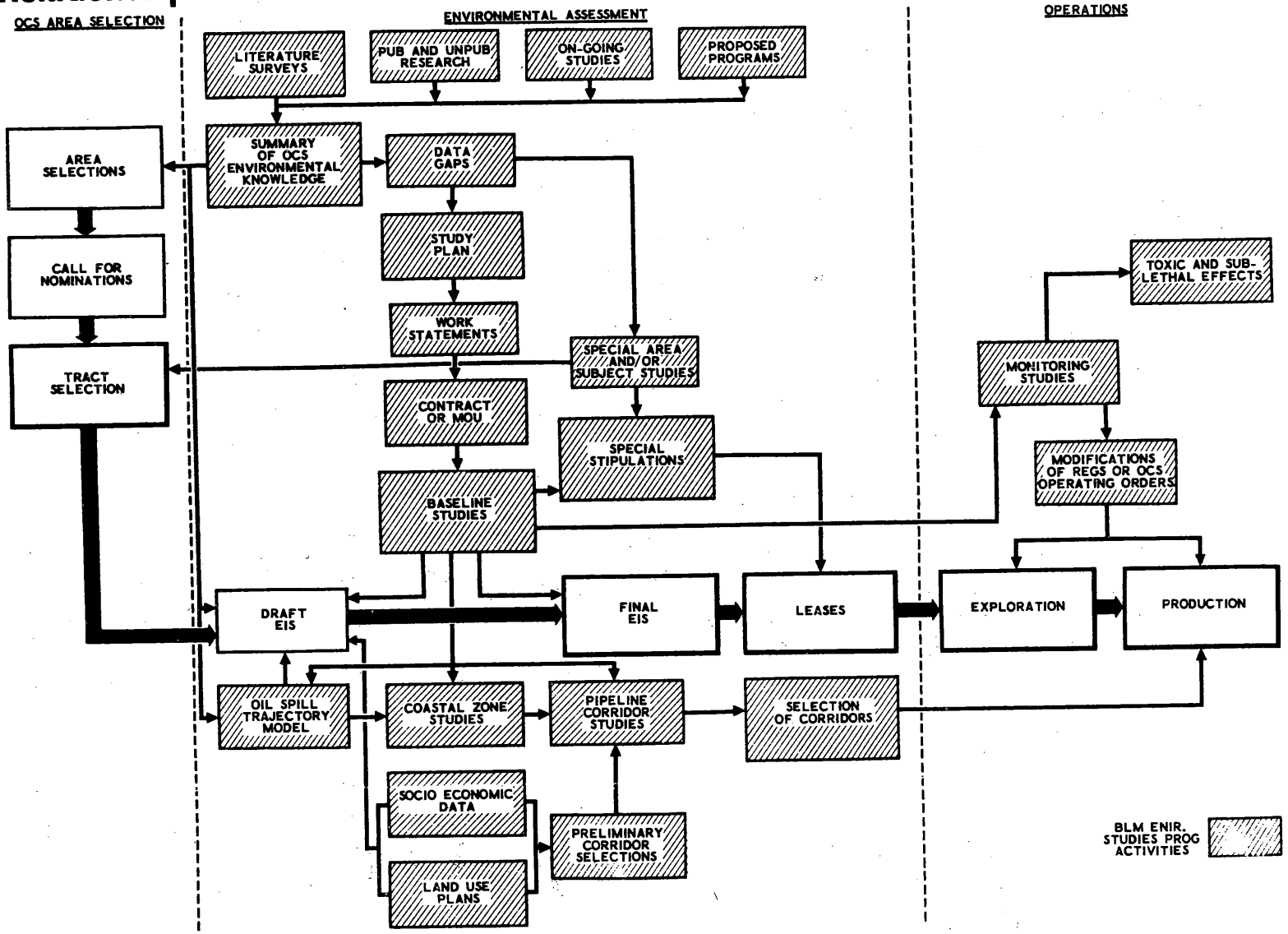
Relationship of BLM Environmental Studies Program to OCS Minerals Development



Source: Bureau of Land Management, OCS Governors' Conference, New Orleans, 1973

Figure 2

Relationship of BLM Environmental Studies Program to OCS Minerals Development



Source: Bureau of Land Management, OCS Governors' Conference, New Orleans, 1974

Development activities do not overlap. While the Environmental studies have some input to Development, they are not mainline items in decision making.

Specifically, (Figure 2) the only connection between the environmental assessment studies and the EIS process is in cases where there is an input of existing data (environmental knowledge) to the EIS. The only other line of flow is from baselines into monitoring and pipeline corridor selection. Even this is unclear since all pipeline corridor studies and selection actually come after exploration and before production.

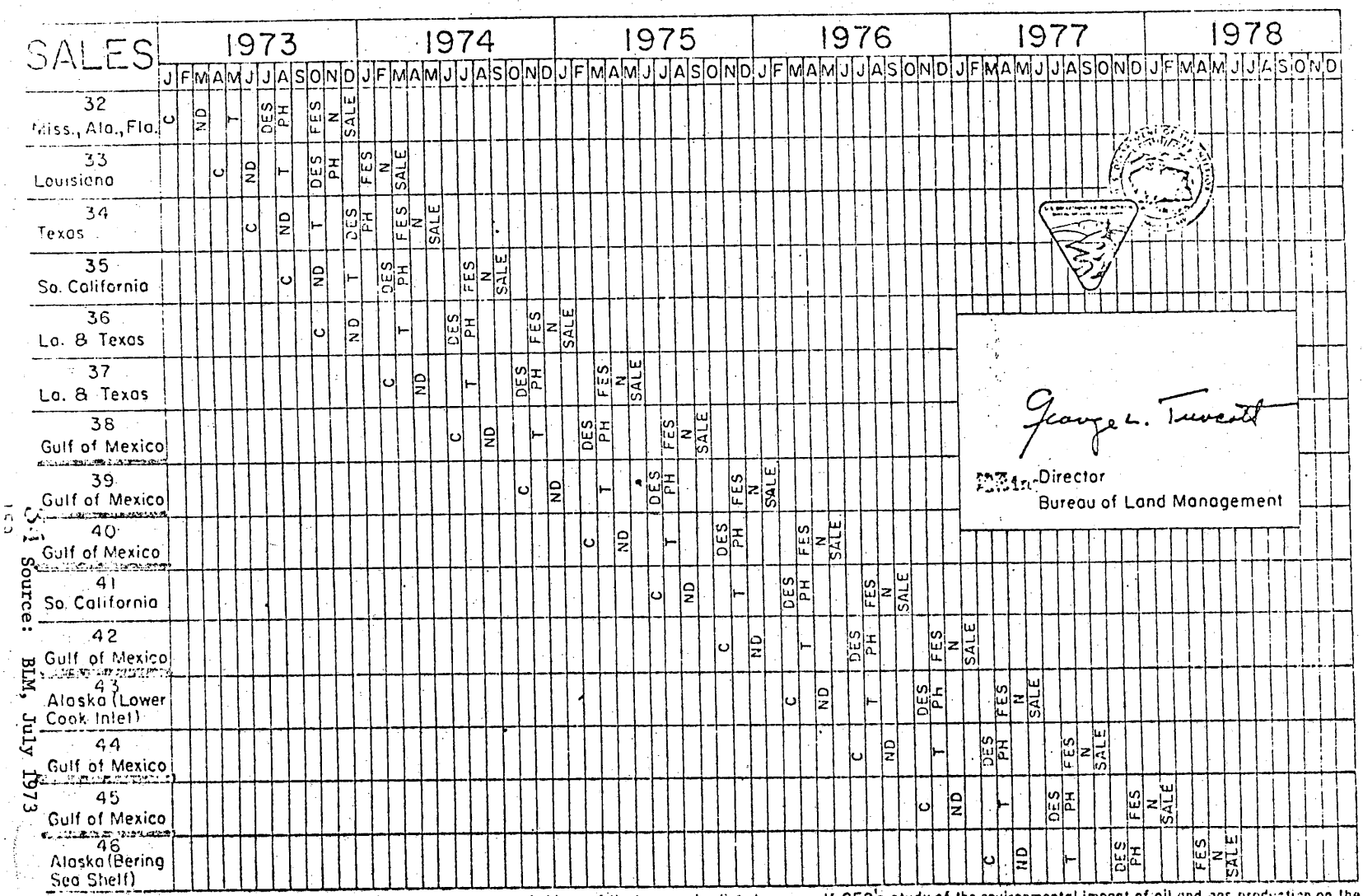
The stated goals and study plan flow sheets are logical and represent a workable plan; however, the actual program does not usually follow these plans.

A graphic example of the problems in the study design and execution is seen in Figures 3-5. Figure 3 was released in July 1973, while Figure 5 was released in June 1975. The former shows an orderly schedule producing a sale every 2-3 months and allowing 10 months from nomination to final EIS.

This schedule did not include the time required to conduct studies. In the succeeding figures, in spite of an accelerated leasing program the whole program has slipped by several months. Even with these dates (showing a sale every 1-2 months from 1976-78) none of the 1975-76 baselines preceded the EIS. Also, as pointed out by a member of the OCS Environmental Studies Advisory Committee (Oct. 1975) the whole order of the events in the South Texas sale is reversed.

PROPOSED SCHEDULE - PROVISIONAL OCS LEASING

July 1973



George L. Turcott
Director
Bureau of Land Management

C = Call for nominations
ND = Nominations Due
T = Announcement of Tracts
DES = Draft Environmental Statement
PH = Public Hearing
FES = Final Environmental Statement
N = Notice of Sale

A decision whether to hold any of the lease sales listed will not be made until completion of all necessary studies of the environmental impact and the holding of public hearings; as a result of the environmental, technical, and economic studies employed in the decision-making process, a decision may, in fact, be made not to hold any sale on this schedule.

If CEQ's study of the environmental impact of oil and gas production on the Atlantic Outer Continental Shelf and in the Gulf of Alaska determines that development in these areas can proceed in an environmentally satisfactory manner, lease sales in one or both areas will be added to this proposed schedule at the earliest practicable time.

The holding of sale 43 is contingent upon the outcome of pending litigation with Alaska regarding jurisdiction over this area.

Source: BLM, July 1973

Figure 3

PROPOSED OCS PLANNING SCHEDULE

NOVEMBER 1974

SALE AREA		1974 J	1974 A	1974 S	1974 O	1974 N	1974 D	1975 J	1975 F	1975 M	1975 A	1975 M	1975 J	1975 J	1975 A	1975 S	1975 O	1975 N	1975 D	1976 J	1976 F	1976 M	1976 A	1976 M	1976 J	1976 J	1976 A	1976 S	1976 O	1976 N	1976 D	1977 J	1977 F	1977 M	1977 A	1977 M	1977 J	1977 J	1977 A	1977 S	1977 O	1977 N	1977 D	1978 J	1978 F	1978 M	1978 A	1978 M	1978 J	1978 J	1978 A	1978 S	1978 O	1978 N	1978 D
South Texas	37		DES	PH		BSI FES	N	Sale																																															
Central Gulf	38	ND			T		DES	PH		FES	N	Sale																																										
Southern California	35		T				DES	BSI	PH			FES	N	Sale																																								
State - Federal Cook Inlet	1/					DES	PH		FES						Sale																																							
Gulf of Alaska	39	BSI				C	ND	T			DES	PH				FES	N	Sale																																				
Mid-Atlantic	40					C	ND	BSI	T			DES	PH				FES	N	Sale																																			
MAFLA, Gulf of Mexico (Deep)	2/ 41					C	ND	T			DES	PH				FES																																							
North Atlantic	42										C		ND	BSI	T			DES		PH	N		FES	N	Sale																													
South Atlantic	43											C		ND	BSI	T			DES		PH			FES	N	Sale																												
Southern California	44													C		ND	T				DES			PH			FES	N	Sale																										
Bering Sea (St. George)	2/ 45					C	ND	BSI	T			DES	PH				FES											N	Sale																										
Gulf of Alaska Including Kodiak	46													BSI			C		ND		T			DES		PH			FES	Sale	N																							
Gulf of Mexico (Deep)	47																		C		ND		T			DES		PH			FES	Sale	N	Sale																				
So. California (Deep)	48																					C		ND			T			DES		PH				FES	N	Sale																	
Mid-Atlantic (Shallow & Deep)	49																	BSI						C		ND		T			DES	PH				FES	N	Sale																	
Beaufort Sea	50							BSI																		C		ND		T		DES				PH		FES	N	Sale																
Outer Bristol Basin	51							BSI																			C		ND		T		DES			PH		FES	N	Sale																
North Atlantic (Shallow & Deep)	52													BSI															C		ND		T			DES		PH		FES	Sale															
So. California (Deep)	53																														C		ND		T			DES		PH		FES	N	Sale											
South Atlantic (Blake Plateau)	54														BSI	BSI																		C		ND		T		DES		PH		FES	Sale										
Bering Sea (Norton Basin)	55														BSI	BSI																				C		ND		T		DES		PH		FES	Sale									
Gulf of Alaska - Aleutian Shelf	56																							BSI														C		I/D		T			DES		PH		FES	N	Sale				
No. California, Wash., & Oregon	57																							BSI	BSI														C		ND		T			DES		PH		FES	N	Sale			
Chukchi Sea (Hope Basin)	58																							BSI	BSI																C		ND		T			DES		PH		FES	N	Sale		

Source: BLM, November 1974

BSI Baseline Studies Initiated
C Call for Nominations
ND Nominations Due
T Announcement of Tracts
DES Draft Environmental Statement
PH Public Hearing
FES Final Environmental Statement
N Notice of Sale

Baseline studies scheduled are contingent upon scientific personnel and equipment being available to perform the studies.

The holding of sales in the Atlantic is dependent upon the outcome of pending litigation with the Atlantic States regarding jurisdiction over this area.

Sales are contingent upon technology being available for exploration and development. A decision whether to hold any of the lease sales listed will not be made until completion of all necessary studies of the environmental impact and the holding of public hearings; as a result of the environmental, technical, and economic studies employed in the decision-making process, a decision, may, in fact, be made not to hold any sale on this schedule.

1/ State may conduct sale.

2/ These sales could be contingency sales for either Gulf of Alaska (39) or Mid-Atlantic (40).

Curt Berklund
Director,
Bureau of Land Management

Figure 4

PROPOSED OCS PLANNING SCHEDULE

JUNE 1975
(REVISES NOVEMBER 1974 SCHEDULE)

SALE AREA		1974						1975												1976												1977												1978											
		J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
SOUTH TEXAS	37		DES	PH		FES		N	Sale					S	A	L	E		H	E	L	D		I	N		F	E	B	R	U	A	R	Y		1	9	7	5															
CENTRAL GULF	38	ND			T		DES	PH		FES	N	Sale							S	A	L	E	.	H	E	L	D		I	N		M	A	Y		1	9	7	5															
CENTRAL GULF	38A	ND			T		DES	PH		FES	N			Sale																																									
SOUTHERN CALIF.	35		T						DES			PH	BSI			FES	N	Sale																																				
COOK INLET	1/	P	E	D	E	R	A	L		I		S	T	A	T	E		S	A	L	E		I		D	A	T	E		U	N	C	E	R	T	A	I	N																
GULF OF ALASKA	39	BSI				C	ND			T			DES		PH		FES	N	Sale																																			
GULF OF MEXICO (GENERAL)	41						C	ND		T				DES		PH			FES	N	Sale																																	
MID-ATLANTIC	40									C			BSI ND		T		DES		PH			FES	N	Sale																													
NORTH ATLANTIC	42												C			ND	BSI	T		DES		PH			FES	N	Sale																										
GULF OF MEXICO (DRAINAGE)	44																		T			DES		PH			FES	N	Sale																									
SOUTH ATLANTIC	43													C			BSI ND			T			DES		PH			FES	N	Sale																								
GULF OF ALASKA (INCLUDING KODIAK)	46													BSI			C		ND		T			DES		PH			FES	N	Sale																							
BERING SEA (ST. GEORGE)	45						C	ND				BSI		T													DES		PH			FES	N	Sale																				
GULF OF MEXICO (DEEP)	47																			C		ND			T			DES		PH			FES	N	Sale																			
SO. CALIFORNIA	48																					C		ND			T			DES	PH			FES	N	Sale																		
MID-ATLANTIC	49																	BSI						C		ND			T		DES	PH			FES	N	Sale																	
BEAUFORT SEA	50											BSI														C		ND			T			DES		PH			FES	N	Sale													
OUTER BRISTOL BASIN	51											BSI																C		ND			T			DES	PH			FES	N	Sale												
NORTH ATLANTIC	52																BSI													C		ND			T			DES		PH			FES	N	Sale									
CALIFORNIA GENERAL INCL. WASH. & OREGON	53																										BSI					C		ND			T			DES		PH			FES	N	Sale						
SOUTH ATLANTIC (BLAKE PLATEAU)	54																			BSI														C		ND			T			DES		PH			FES	N	Sale					
BERING SEA (NORTON BASIN)	55																						BSI													C		ND			T			DES		PH			FES	N	Sale			
GULF OF ALASKA - ALEUTIAN SHELF	56														BSI																						C		ND			T			DES		PH			FES	N	Sale		
CHUKCHI SEA HOPE BASIN	57																									BSI													C			ND			T			DES		PH			FES	N	Sale

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C Call for Nominations
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DES Draft Environmental Statement
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FES Final Environmental Statement
N Notice of Sale
1/ State May Conduct Sale

Baseline studies scheduled are contingent upon scientific personnel and equipment being available to perform the studies.
Sales are contigent upon technology being available for exploration and development. A decision whether to hold any of the lease sales listed will not be made until completion of all necessary studies of the environmental impact and the holding of public hearings; as a result of the environmental, technical, and economic studies employed in the decision - making process, a decision, may, in fact, be made not to hold any sale on this schedule.

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

U.S. DEPARTMENT OF THE INTERIOR
March 3, 1870

Director,
Bureau of Land Management

Source: BLM, June 1975

Figure 5

D. Study Design

The study designs for all the OCS programs share a common problem. There is a lack of internal coherence between the expressed goals of the programs and the projects funded. This is not to say that the projects are, or are not, scientifically valid. It does mean, however, that the answers derived may not be useful for detecting environmental changes, for management decisions, or for assessing environmental impacts.

OCS Science Advisory Committee members have gone on record since early 1975 (July and October 1975 reports) as questioning the applicability of the studies to the stated goals, particularly those of impact assessment and management planning.

In addition, many of the convenors and speakers at the "planning conferences" stated repeatedly (Georges Bank Conference, 1975[8/]; Southern California Conference, 1975[9/]; the South Atlantic Conference, 1975[10/]; and the Gulf of Alaska Conference, 1975[11/]) that it is not possible, with our present level of knowledge, to design studies of practical value within present time and funding constraints. In each conferenc the following points were made:

1. No program should begin until a complete survey of all existing data is done.

2. No data should be collected until the complete standardized data management system is instituted; beginning with a historical data bank and featuring correlative retrieval.

3. If studies are done which include short-lived, highly-variable components, such as plankton, there must be many more samples taken more

frequently; however, the results are probably not worth the effort and money.

4. Some provision should be made for the real use of study results in the EIS process, management decisions, and impact assessment.

E. Description of Environmental Study Elements Prior to Leasing:

Three phases of studies are planned for each OCS region: (1) Summary of Existing Data, (2) Baselines and (3) Special Studies, which can be described and evaluated as follows:

Phase I. Phase I efforts are supposed to center around summarizing all existing data on the Outer Continental Shelf. Out of 1,000 references collected for the Atlantic studies only 69 are specific for the OCS area, 83 are general oceanic, and the remaining over 800 references cover inshore, estuarine, terrestrial, or riverine systems. It appears that more attention to oceanic data is needed.[12/]

The data survey and summary is usually planned to be complete before baseline studies begin, which is reasonable. However, in practice the existing data base has been only partially evaluated in any area prior to initiating both baseline and special studies. The data surveys reflect only references in the open literature and special inhouse reports from the institution(s) involved. Such data sources as the Navy, industry, inhouse reports for State agencies and unpublished university reports are usually not included. This may largely be a function of the time allotted to this phase.

Phase II (Baselines). Phase II is described as beginning after survey of existing data and continuing through oil/gas exploration early phases. The actual studies began in many areas prior to completing the

data surveys. The point of doing Baseline sampling after exploratory work begins is questionable. At present, Baseline and Data Surveys are largely overlapping; Baseline work will also overlap exploration and leasing with little or no provision to evaluate the interrelations between the two.

Phase III (Special). Special studies are supposed to complement and fill in data gaps found in the data survey and baseline studies. Accordingly, they are planned to begin part of the way through the baseline program.

The potential impacts of Outer Continental Shelf development are a focus of these environmental studies. However, there is considerable doubt whether or not the studies will, or can, detect those impacts. Figure 6 summarizes the major impacts that the studies have been planned to address.

Scientists at the planning conferences and individual State representatives have expressed this doubt. The doubts are related to whether the studies will provide information to detect more than the most obvious within the time frame now given. The following section summarizes pertinent aspects of studies to date to illustrate the difficulty encountered in matching studies to potential impacts.

Figure 6

Potential Effects of OCS Operations* on the Offshore Environment

POTENTIAL IMPACTS	SIGNIFICANCE
BIOLOGICAL	
1. DISRUPTION OR ALTERATION OF MARINE HABITATS	1. REDISTRIBUTION OF COMMERCIAL OR SPORT FISH POPULATION
2. OILING OR LETHAL EFFECTS OF SPILLS	2. DISTRIBUTION OF BIRDS AND MAMMALS
3. TOXIC AND SUBLETHAL EFFECTS ON MARINE ORGANISMS FROM CHRONIC POLLUTION	3. DISRUPTION OF FOOD WEB; CONCENTRATION OF TOXIC FRACTION THROUGH FOOD WEB
4. LOSS OF UNIQUE ENVIRONMENTS	4. LOSS OF RECREATIONAL RESOURCES
NON-BIOLOGICAL	
1. NAVIGATION HAZARDS	1. HAZARDS TO COMMERCIAL SHIPPING, SPORT FISHING CRAFT, FISHERMAN
2. MULTIPLE USE CONFLICTS	2. EXCLUSION OF AREAS FOR COMMERCIAL FISHING INTERESTS
3. DAMAGE TO ARCHAEOLOGICAL SITES	3. LOSS OF SITES WITH AESTHETIC HISTORICAL OR RECREATIONAL VALUE

* Drilling, Platform and Pipeline Construction, Oil and Gas Recovery

Source: Bureau of Land Management, OCS Governors' Conference, New Orleans, 1974

IV.

STATUS OF SELECTED ENVIRONMENTAL STUDIES

Early in 1974, BLM requested help from NOAA to develop a proposed program of studies. Two working papers were prepared by NOAA in October, 1974. One was the report of the NOAA Committee on Marine Environmental Assessment, which dealt with a variety of marine development impacts and studies to assess those impacts. The other paper was a draft proposal for an environmental study of the Baltimore Canyon Trough, specifically requested by BLM. The participants in this proposal were from USGS (Interior) Woods Hole Oceanographic Institute, Atlantic Oceanographic Marine Laboratory, National Marine Fisheries Service, and Environmental Research Laboratory, with input from NODB, EDS, and U.S. Fish and Wildlife Service (Interior). The study objectives in both documents are identical and they have been incorporated with very little modification in all subsequent planning documents, including the OCS Advisory Guidelines put out in mid-1976.[13/]

By mid 1976, some aspect of environmental studies was underway in all of the major OCS frontier regions. Those with some significant history have been selected and summarized below. These are: the Gulf of Alaska study, the South Texas study, the Mid Atlantic Study and the North Atlantic Study.

A -- Gulf of Alaska Study

The following work is presently in progress in the Gulf of Alaska under a contract with the National Oceanic and Atmospheric Administration scheduled for completion in late 1976:[14/] [15/] [16/]

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1. Assembly of baseline information concerning identification, distribution, and numbers of marine mammals, marine birds, pelagic fish, demersal fish, benthos, littoral biota and plankton. Information on primary production, the microbial community, pathology of certain organisms, and existing levels of hydrocarbons and trace metals will also be collected.
2. Evaluation of the effects of contamination on organisms considers acute and chronic toxicity, sublethal effects, uptake and depuration, bioaccumulation, transformation, and physiological effects.
3. Circulation studies of the Gulf of Alaska are to assemble data pertaining to standard hydrographic parameters in addition to information concerning river input, climatology, meteorology, and wave measurement.
4. Modeling through application of short period circulation models and long period models with support data from meteorological model development is intended to lead to a final distribution of variables model which should simulate the early trajectory of an oil spill.
5. Assembly of standard geological baseline data is complemented by inclusion of information pertaining to coastal morphology and sedimentation, beach profiles, dynamics of near-shore sea ice, geologic hazards, and seismic studies.

B -- South Texas Study

The following work is underway with contract to several organizations and agencies.17/ 18/

1. National Ocean Survey (NOS) has completed tasks to assemble existing information on standard hydrographic data, currents, tidal and extreme storm data; to establish standard baseline data from existing information on zooplankton and ichthyoplankton information including seasonal abundance of commercial fish stock, eggs and larvae, evaluation of information on dominant species and standing stock of commercial and/or recreational finfish and crustacea on a seasonal basis.
2. The University of Texas is completing a contract for sampling to obtain baseline information covering analysis of plankton and benthic organisms for purposes of identification, establishment of abundance, diversity, trace metal and hydrocarbon concentration levels, and productivity.
3. The Geologic Survey is working on a contract for collection of sediment samples in order to analyze for benthic organisms, hydrocarbons, trace metals, carbonates, organic carbon, texture, clay mineralogy, and heavy minerals.
4. Texas A&M has been under a special study contract for reconnaissance of certain geologic features of the Western Gulf of Mexico.
5. The National Ocean Survey has been issued a Memo of Understanding for preparation of bathymetric maps.

C -- Mid-Atlantic Study

The following study work is underway or specifically planned for the mid-Atlantic region.[19/ 20/ 21/ 22/]

1. The Virginia Institute of Marine Science is under contract for seasonal collection and analysis of data on the benthic biota and chemical composition of the plankton, water column, and sediments.
2. The USGS has a Memorandum of Understanding requiring USGS to supply information concerned with 1) potential hazards due to shallow and intermediate depth features, sediment transport and seismicity, 2) description of sedimentary environments in Baltimore Canyon Trough region, 3) establishment of trace metal and hydrocarbon benchmark data in the area, and 4) description of possible bottom pollutant pathways and rates of transmission.
3. It is planned that NOAA would be funded to:
   1) organize oceanographic, meteorological, and climatology data;
   2) have NMFS do fish community structure and other analyses from existing data;
   3) develop physical oceanography data focused on model development.

D -- North Atlantic Study

No work has been started in the North Atlantic but the following tasks are specifically planned.[23/]

1. Agreements between BLM and Environmental Data Service (EDS) of NOAA are anticipated for synthesis of existing climatological data.
2. NMFS will be tasked for analysis of existing data from previous collections of benthic fauna.
3. A contract is planned for a survey of published and unpublished data on mammals of the North Atlantic area and for nearshore marine environmental data.

4. A contract is planned, to obtain field data pertaining to physical oceanographic parameters encompassing surface current patterns, mass transport, propagating disturbances (e.g. ocean eddies, storm surge, river run-off).
5. An interagency agreement is planned with National Data Buoy Office (NDBO) of NOAA for acquisition and installation of one meteorological buoy on the Georges Bank for recording standard meteorological observations and measuring waves.
6. A Memorandum of Understanding is planned with USGS to address areas of sediment mobility over seabed, concentration, distribution, and flux of suspended particulate matter, characteristics and distribution of sediments, geological hazards such as faults and unstable sediment locations.
7. A contract is planned, to procure baseline and descriptive chemical and biological data encompassing study of high molecular weight hydrocarbon and specific trace metal concentrations in the marine biota and sediments, including measurement of existing levels in seawater and zooplankton.

E -- Comparison of Studies

It is very difficult to make a realistic comparison of the studies in various stages of planning or actual accomplishment. The following comparison is based only on what appears to be planned and underway from both printed documents and discussions with certain individuals involved with the programs. Both of these sources are sometimes conflicting and, since the programs are evolving, changes are constant.

In any case, the following are specific points of comparison.

1. The Gulf of Alaska study, carried out by NOAA, appears to be the most thorough overall environmental study plan implemented to date. This study consists of a rather complete baseline assessment of significant parameters, e.g. mammals, birds, fishes, benthos, littoral biota, plankton, microbes, pathology, hydrocarbon and trace metal ambient levels, standard physical and geological oceanographic data. In addition to extensive baseline information, significant emphasis appears to be placed on study of potential effects and hazards of OCS oil exploration and production. The effects under consideration include study of acute, chronic and sublethal effects of hydrocarbons on organisms. The Gulf of Alaska study does not strictly dictate that studies be carried out at offshore sites only, but is continuous from offshore through nearshore and coastal areas of concern.

2. All other BLM-OCS environmental study programs appear to have more limited scope, with an overall pattern indicating greatest effort and emphasis being placed on the study and collection of data relating to levels of hydrocarbons and trace metals in the benthic and water column components.

   This pattern presently appears to be true almost to the exclusion of studies concerned with potential effects, hazards, coastal impact, and circulation studies for prediction of spill movement. Figure 7 illustrates the differences in study contents for the four regions investigated.

Figure 7

Contents of Environmental Studies

Comparison in Four OCS Regions

The following is a comparison of which elements are included in actual or planned field data collections for each region.

X = Included O = Not Included

1. Biological Data	Gulf of Ala	South Texas	Mid-Atlantic	North Atlantic
Mammals	X	O	O	O
Birds	X	O	O	O
Fish	X	O	O	O
Plankton	X	X	X	X
Benthos	X	X	X	X
Microbial	X	O	X	X
Littoral Biota	X	O	O	O
Pathology	X	O	O	O
Plankton Hydrocarbon and Trace Metals	X	X	X	X
Benthos Hydrocarbon and Trace Metals	X	X	X	X
Contaminant Effects	X	O	O	O
2. Physical Oceanographic Data				
Hydrographic	X	X	X	X
Circulation Modeling	X	O	O	O
Surface Waves	X	O	X	O
Meteorologic	X	O	O	X
Extreme Events	X	O	O	X
Mass Transport	X	O	O	X

Figure 7 (Cont'd.)

3. Geologic Data	Gulf of Ala	South Texas	Mid-Atlantic	North Atlantic
Hydrocarbons & Trace Metals in Sediments	O	X	X	X
Sediment Distribution	X	X	X	X
Sediment Transport	X	O	O	X
Sediment Mapping	X	X	O	O
Fault Location	X	O	X	X
Seismic	X	O	X	X
Coastal Morphology	X	O	O	O
4. Chemical Data				
Trace Metals in Water	X	O	X	X
Nutrient Levels in Water	O	X	X	X
Hydrocarbon Levels in Water	X	X	X	X

3. All studies appear to have similar time constraint problems and a lack of time to adequately identify problems for consideration during leasing. The average time for study available to four (4) of the largest study programs in progress (Gulf of Alaska, South Texas, Mid and North Atlantic) is about 16 months for collection, organization, and development of understanding of significant factors. Accepting, as valid, the assumption that four seasons (12 months) of data collection is the absolute minimum necessary for establishment of basic seasonal patterns and influences in nature necessary before planning a study, the question arises as to whether there exists sufficient time for making use of this year's data, still in need of assimilation, organization and development, to the state of understanding that permits its use for influencing decisions concerning the subsequent OCS lease sales and their related activities. Figure 8 compares the planned and actual schedules for studies in the four regions.

4. For all regional studies, concern has been expressed not only for the limited amount of time granted to environmental studies preceding lease sales, but also for the actual technical/scientific value and potential usefulness of the type of data being collected within the limited time frame of these studies.[24/] [24/]

Figure 8

Environmental Studies and Leasing Schedules

Comparison of Four OCS Regions

Region	Start Env. Studies		Lease Sale Date		Months from Start of Studies to Lease Sale	
	Planned	Actual	Planned	Actual	Planned	Actual
1. Gulf of Alaska	Jan'74	July'74	Dec'75	Feb'76	24	20
2. South Texas	Nov'73	Jan'74	Feb'75	Feb'75	15	13
3. Mid-Atlantic	Jun'75	Nov'75	Aug'76	Aug'76	14	9
4. North Atlantic	Sept'75	Feb'76	Jan'77	--	15	

V.

IMPROVEMENTS IN THE ENVIRONMENTAL STUDIES PROGRAM

A. General

OTA's analysis of the OCS environmental study program indicates the existence of a number of deficiencies and inconsistencies which, in turn, indicate problems of effectiveness and efficiency. Several suggestions for improvement have been made recently. These are discussed below:

I. Planning and Priorities:

A resolution introduced at the February 1976 OCS Research Advisory Committee meeting suggests that BLM, incooperation with NOAA and its various branches, Fish and Wildlife Service, Geological Survey, the affected States, and others, as necessary, develop the following:

a) identification of all decisions which must be made and of all data that must be available to make those decisions.

b) identification of specific data needs, including insofar as possible, acceptable ranges of variance for satisfying users' needs.

c) a prioritization of acquisition of data responsive to the timing of decision-making relative to OCS exploration and development for each region.[26/]

2. Identification of Information Needs:

Certain coastal State representatives, scientific research program administrators, and oil industry representatives, seem to believe that certain types of environmental studies could be performed which will result in data of greater value to existing needs. It would appear that

reorganization of the existing environmental study programs to allow more effective response to environmental information needs could represent a constructive correction.

3. Industry methods and needs:

The oil companies are sometimes not recognized as a potential source of environmental study recommendations, even though they have accumulated significant time, data, and experience working in the offshore environment.[27/] It appears that some industry groups have made an accurate inhouse assessment of the present environmental study program which indicates that most of the data being collected is of no immediate use. They also fear that the link between the environmental program and OCS development may lead to future data inadequacies with accompanying litigation, delays, and inefficiencies. Specific types of information relating to OCS environmental conditions that can be relatively valuable to industry have yet to be identified. Identification of this information and development of methods for effectively and efficiently obtaining such data could be constructive.

4. Existing data:

There are many who suggest vast quantities of data relating to OCS environmental considerations presently exist, but must be identified, organized, and interpreted. It may be valuable to establish a mechanism for more thoroughly defining and organizing existing data. A hazardous sediment slump region on the South Texas OCS lease area was discussed at a February 1976 OCS Research Advisory Committee meeting. This was

supposed to represent a prime example for usefulness of data collected by environmental study programs.[28/]

The oil industry has recently become well aware of the potential hazards posed by massive movements of bottom sediments following the loss, by Shell Oil, of a platform in S. Pass block 60 during hurricane Camille (1969). They have been and are continuing to carry out research on this subject.

All members were in agreement that preliminary geophysical reconnaisance data, as collected by the USGS for the South Texas environmental study program, was valuable for initial qualitative identification of potential slump hazards but is too sparse to be of any further value, thus requiring more intensive site specific surveys by the oil industry itself.

The geophysical data identifying this slump region and appearing as a part of the South Texas environmental study program <u>were not</u> collected during field collection activity of the study program, but were in fact existing data previously recorded by independent contractors under contract to the Conservation Division of the USGS, and subsequently purchased by the Geologic Division of the USGS for incorporation in the OCS environmental study data. Such events illustrate the issue of usefulness of environmental field studies vs. better analysis of existing data.

5. Program Reviews:

Finally, some reviews and internal critique of the entire program are now underway. There are two evaluative studies on the subject.

one by BLM explaining the rationale of the program, completed in the summer of 1976, and the other contracted with the National Academy of Sciences in August, 1976, for completion in the Spring of 1978. The latter study will treat the scientific validity and adequacy of the program design.

B. Congressional Needs

It appears that the major portion of both baseline and monitoring, and special studies efforts is presently directed toward long-range, broad based oceanographic research. A smaller portion is directly related to site specific data which may affect such OCS decision as tract selection or lease sales. For example, the Alaskan environmental studies program is about 50% of the total funding (over $21 million). Specific baseline information for the Gulf of Alaska where lease sales are planned is $2.6 million, and studies of geologic, seismic and ice hazards in the Gulf of Alaska is $0.7 million (FY 76). Much of the Alaska budget appears to be for either general, very broad baseline information in areas where lease tracts are not yet defined, or for studies on ocean transport and oil spill effects questions. Management and logistics are also major portions in Alaska. In other regions, such as Mid-Atlantic, South Texas and Southern California, site specific or management decision related data is being collected but the efforts on specific information is much less than general research efforts here as well.

The total environmental studies program is now being managed and directed by a very small staff at BLM. The funding for Alaska studies is transferred to NOAA which manages and directs that effort. The FY 77

budget including many new programs and new regions appears to be more than the present staff could be expected to manage.

There is a great need to plan and evaluate these studies. The broad-based research needs to be separated from the short-range, site specific investigations. A long range look at methods for monitoring is needed because no monitoring of developed areas appears to be included in these present studies and, depending on method, these could be the major efforts. A total long-range plan is most urgently needed so all the parts can be evaluated.

A five-year plan for the environmental studies program would be of substantial use to Congress. Presently available BLM documents on the program do not provide a clear picture of short-range and long-term objectives of the program. Thus, it is difficult to determine what percentage of the effort contributes directly to OCS-related management decisions, and what portion contributes to broad-based ocean research.

A five-year program plan should include a description of the studies planned or projected for the five-year period, including these specific elements of the environmental studies program:

1. Surveys of existing literature
2. Baseline or benchmark studies
3. Monitoring studies
4. Special studies

For each of these components, the plan could detail level of funding required or projected for each year; number and qualifications of staff required for each component, and involvement by other government agencies at the Federal of State level in each study component, including approximate level of effort by each of these agencies.

The plan could also list the specific management decisions at Federal and State levels for which data will be provided for each study component. In other words, for each decision point, the plan could specify the types of data provided by the studies and how it will be used in the decision-making process. The method by which this data will be prepared and transmitted or made available for such use in management also could be included.

Finally, the plan could identify and provide a detailed justification for any element of the study which is not directly needed for management purposes, and indicate what proportion of the total program resources is required for these studies.

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Working Paper #8

Safety Analysis for Floating Nuclear Power Plants

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ABSTRACT

This report presents the results of an effort undertaken for the Office of Technology Assessment (United States Congress). The effort consisted of (1) evaluating the probability of core melt for floating nuclear plants, and (2) assessing the analytical techniques and assumptions being used by others to evaluate the consequences of a core melt-through for floating nuclear plants.

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I. CONCLUSIONS

As a result of the effort described in subsequent sections of this report, the following conclusions have been derived:

A. Assessment of Core Melt Probability

1. In other reviews (eg, Reference 1) of the Floating Nuclear Plant (FNP), no potentially significant areas were found which would render invalid the application of WASH-1400 core melt probabilities to the Floating Nuclear Plant (FNP).

2. In this study, several areas were found which render invalid the direct application of WASH-1400 numerical core melt probabilities to the FNP. However, a preliminary scoping study indicates that the probability of an FNP core meltdown is similar to that assessed in WASH-1400, although additional effort is required to verify the validity of the results.

B. Consequences of Core Melt-through

1. The current effort to determine the consequences of a core melt in the FNP being conducted under the guidance of the Nuclear Regulatory Commission (NRC) appears to be adequate in all areas except the following:

   a. There appears to be little, if any, effort devoted to a determination of the potential economic consequences of a core melt-through in the FNP.

   b. There appears to be little, if any, effort directed towards a determination of the likelihood and consequences of an airborne release associated with a core melt-through accident in the FNP. This could be an important omission relative to assessing the consequences of an FNP core meltdown accident, since, unlike the WASH-1400 assessment, every FNP core melt-through appears to result in a significant airborne release due to the ice condenser

containment design of the FNP and the potential effects of the ocean water during core melt-through.

2. There appears to be a substantial amount of applicable information available relative to assessing the consequences of a core melt-through for the FNP. In addition, research programs are underway to provide additional applicable information. There do not appear to be any significant information needs which are not available or forthcoming from active research programs.

3. Providing a successful molten core catcher for the FNP appears to be a feasible, though difficult, task. Depending on the design requirements for the molten core catcher, substantial expense and significant design changes could be required. However, the need for, and benefits of, an FNP molten core catcher have not been established.

4. The probability of a core melt accident in a land-based plant of the FNP design should not be significantly different from that of the FNP plant itself, providing that (a) the reliability of offsite power is not a factor, and (b) the potential for core melt accidents from external causes is not a factor. The consequences of a core melt accident could be substantially different depending on local site conditions and the consequences of fission product dispersal in the sea.

II. RECOMMENDATIONS

Based on results of the study described herein, the following are recommended:

1. The economic consequences of a core melt-through accident in the FNP at the Atlantic Generating Station site should be assessed. The assessment should consider loss of revenue to the affected area from possible restricted recreational use of oceans and beaches, as well as loss of revenue due to potential restrictions on fish harvesting. An economic analysis of this type is apparently not being considered (see Section IV.B.1 of this report).

2. A review of the literature and programs described in Appendix C of this report should be undertaken by those responsible for the liquid pathway study (LPS) to determine if any pertinent information has been overlooked.

3. A definitive risk assessment for the FNP should be undertaken. This assessment should include (1) a determination of core melt probability for the FNP using appropriate design details, and (2) a consequence analysis considering the extent of airborne releases from FNP core melt accidents using the Atlantic Generating Station (AGS) site characteristics. It appears that a complete risk assessment from core melt accidents is not being carried out for the FNP and, for reasons discussed in Section IV.B.1 of this report, the risks from a significant airborne release from the FNP could be of concern.

III. INTRODUCTION

In January 1973, Offshore Power Systems, a wholly-owned subsidiary of Westinghouse Electric Corp., filed an application with the Nuclear Regulatory Commission for a license to manufacture eight floating nuclear power plants (FNPs) at its facilities in Jacksonville, Florida. Public Service Electric and Gas (PSE&G), a utility in New Jersey, has purchased four of the plants. It is proposed that two of these plants, scheduled to go into operation in 1985 and 1987[2], will be sited 2.8 statute miles off the coast of New Jersey, about 11 miles northeast of Atlantic City[3]. The two plants, called Atlantic Generating Station (AGS) Units 1 and 2, will be towed from the manufacturing facility in Jacksonville to the site and permanently moored inside a large, man-made breakwater.

The basic design of the floating nuclear plant consists of a conventional four-loop pressurized water reactor (PWR) of the Westinghouse design mounted on a barge. The containment building consists of the Westinghouse ice condenser system with double wall containment similar to the design of the land-based Sequoyah nuclear plant[4].

In 1974, the Office of Technology Assessment (OTA), an agency established by Congress, was asked on behalf of the Senate National Ocean Policy Study (NOPS) to "take a detailed and comprehensive look at ocean and coastal zone issues and policies"[5]. Further, Senator Clifford P. Case (N.J.) urged that the OTA study focus on New Jersey and Delaware since this is the only area in the nation for which all three major offshore energy technologies [(1) deep-water ports for oil tankers, (2) offshore drilling to discover and recover oil, and (3) offshore nuclear power plants] are being considered.

In April 1976, OTA awarded a contract to Intermountain Technologies, Inc. (ITI) for the purpose of reviewing some of the areas relative to risks from potential accidents in the FNP. The specific tasks were:

<u>Subtask A</u> - Evaluation of the Probability of Core Melt for Floating Nuclear Plants. Tasks included:

1. A determination of the significance of the areas of nonapplicability of the WASH-1400[6] core melt probabilities as identified by others.

2. A determination and description of additional significant areas, if any, where the WASH-1400 core melt probability analysis does not apply to the FNP.

Subtask B - Assessment of the Analytical Techniques, Including the Assumptions, for Determining the Consequences of Core Melt-through for the FNP. Tasks included:

1. Review the applicability of available information which currently exists relative to assessing FNP core melt-through accidents. The review includes an assessment of ongoing and planned effort in this area. It will also identify additional information needed and plans, if any, to obtain that information.

2. Review pertinent technical information relative to proposed molten core catcher concepts.

IV. ANALYSIS

This section presents the analysis of each of the tasks described at the conclusion of the previous section (Section III, Introduction). Where appropriate, appendices to the report have been provided in conjunction with and in support of the analysis.

A. Assessment of Core Melt Probability

This task consists generally of determining the applicability of the WASH-1400[6] core melt probability to the FNP. The WASH-1400 core melt accident probability assessment for land-based PWRs is based on an analysis of the Surry[7] reactor, which is a 3-loop pressurized water reactor (PWR) designed by Westinghouse Electric Corp.

Two specific efforts were identified as part of this task: (1) a determination of the significance of items identified by others (eg, Reference 1) as potential areas of nonapplicability relative to the direct application of WASH-1400 core melt accident probabilities to the FNP at the AGS site, and (2) an assessment of areas which were found, in addition to those identified by others, which appeared to have the potential for rendering the WASH-1400 core melt probability assessment invalid for the FNP at the AGS site. A preliminary scoping assessment of FNP core melt probabilities was also completed as part of this effort.

1. Significance of areas of WASH-1400 nonapplicability identified by others

There appear to be nine major areas mentioned in Reference (1) and also identified by intervenors and other parties during hearings associated with the FNP which can be construed as differences between land-based plants and the FNP and which could lead to a difference in core melt probability. These areas are listed in Table I. The following discussion considers each of the nine areas and determines the apparent significance of them from the standpoint of changing the core melt probability.

TABLE I

DIFFERENCES BETWEEN LAND-BASED PLANTS AND THE FNP

1. Electrical transmission from shore to FNP

   a. electrical cable section between barge and breakwater
   b. electrical cable interface at breakwater
   c. offsite power failure
   d. sustained offsite power failure

2. Auxiliary feedwater system including onsite diesel generators

   a. shock induced auxiliary feedwater delivery system failure with cable break

3. Shock induced pipe break and damage to containment spray injection system

4. "Slamming" shock failure of critical safety systems

5. Earthquake induced failures

   a. Offsite power cable seismic failure

6. Tornado induced failures

7. Flood induced failures

8. Tidal wave and hurricane induced failures

9. Hazards induced by shipping

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Electrical Transmission from Shore to FNP

The electrical transmission from shore to the barge-mounted plant has been identified as a potential problem because loss of power to the site is the assumed initiating event for a transient accident sequence which is a significant contributor to risks for a land-based plant as assessed in WASH-1400. The transmission cable system for the AGS design consists of two redundant cables which are divided into two segments. One segment is buried 10 feet beneath the sea floor and connects the on-shore switching station with the breakwater. The second segment is an above-water line connecting the barge to the breakwater.

For the AGS, the undersea portion of the transmission lines is buried 10 feet in the ocean floor[9]. The burial depth is based on Coast Guard studies which indicate that anchors will penetrate the ocean floor to a depth no greater than 7.4 feet[12]. The sea above the buried cable is used only by small pleasure and fishing boats with small anchors[9]. The basis for the 7.4-foot anchor penetration (maximum) has not been reviewed, but, as will be shown in the following section, OPS estimates of the likelihood of failure of the transmission line could be increased substantially without affecting the core melt accident probability for the plant. The effect of sediment movement or "scouring" from ocean currents has also been considered[12] as a mechanism to reduce the 10-foot burial depth. (Such a possibility is described in Reference 10.)

The potential failure of the undersea portion of the transmission cable has been evaluated by OPS, and they have arrived at a failure probability of 1.45×10^{-5}/year for loss of both (redundant) undersea cables[8]. The analysis leading to this probability has not been reviewed, but, as will be shown in the following section, a substantial increase would be required before this failure becomes significant in terms of changing the core melt accident probability.

In summary, although providing power to the plant by buried undersea cables represents a design difference compared to a land-based plant, this feature is not expected to increase the core melt accident probabilities. In fact,

the apparent high reliability of offsite power, as compared to that assumed in WASH-1400 for land-based plants, appears to decrease the core melt accident probability from this accident initiating event for the FNP (see Section IV.A.2).

The above-sea cable section connecting the barge with the breakwater is a unique feature of the FNP. However, the design of this section of cable appears to be sound, with barge motion and environmental deterioration considered[9,11,12]. OPS has estimated[8] that the probability of loss of power due to equipment failures at the site is $2x10^{-4}$ per year. Again, the basis for this value has not been reviewed, but the failure probability could be substantially raised without changing the core melt probability (see Section IV.A.2).

The probability of offsite power loss was also reviewed. The probability of power loss used in WASH-1400 is once in every five years ($2x10^{-1}$ per year). A much lower power failure probability of $1x10^{-5}$ per year was obtained from OPS[8]. (An even lower number was obtained from PSE&G[13].) While the basis for the $1x10^{-5}$ failure probability was not reviewed, Reference 12 presents apparently valid arguments for a high (unquantified) grid reliability. As will be seen in Section IV.A.2, the offsite electrical power failure probability could be orders of magnitude higher than $1x10^{-5}$ per year before this failure would influence the core melt accident probability. Also, the time for recovery of offsite power becomes unimportant when the probability for the initial power loss is low.

In conclusion, it appears that the reliability of offsite power will tend to reduce the probability of core melt in the AGS compared to WASH-1400 analyses.

"Shock" Induced Failures

The possibility of "shock" induced failures has been recognized and is accounted for in the design of the FNP. Section 2.4.5 of Reference 12 discusses potential water level fluctuations in the breakwater basin for which the plant is designed. The effect of storm surges (frontal storms, squalls,

hurricanes) are considered, as well as seiches, astronomical tides, basin wave resonances, and wave runup. It thus appears that "shock" induced failures have been accounted for. (The plant is also designed for seismic occurrences[11].)

"Grounding" Failure of Critical Safety Systems

The plant is designed such that grounding (contact between the ocean floor and the barge) is prevented[9], even during hurricanes, tornadoes, or earthquakes[11].

Earthquake Induced Failures

Due to shock attenuation in the water, it is possible that the FNP could be "safer" with regard to earthquake failures. However, based on the WASH-1400 assessment for land-based plants, potential earthquake failures are a negligible contributor to the core melt probability. (See Appendix XI, Section 15 of WASH-1400 for discussion.) Thus, this difference for the FNP would not affect the core melt probability.

Regarding earthquake induced failure of the shore-to-breakwater transmission cables, no specific indication that seismic events were considered in the cable design could be found. However, in view of the extremely low probability of major seismic events[14] which would be required to sever both buried cable segments, it does not appear that this failure mode is significant.

Tornado Induced Failures

The possibility has been suggested that onsite emergency diesel generator power supplies, as well as the breakwater-to-plant cable segment, could fail, leaving the plant without a.c. power, possibly resulting in a core melt. Although no specific indication could be found that the plant-to-breakwater cable segment for the FNP was designed to withstand tornadoes, the emergency diesel generators are[11]. In addition, the diesels are located in separated watertight compartments with thick concrete walls. The diesel compartments

are also designed to withstand various tornado generated airborne missiles[11]. Thus, in view of the low probability of a tornado striking the plant, coupled with the diesel generator building design, it appears that this accident potential is not significant.

Flood Induced Failures

Floods are not a factor for the FNP. However, since flood-induced accidents are not significant contributors to the core melt probability for land-based plants, this factor will not have an influence on the FNP core melt probability relative to the land-based plant assessed in WASH-1400.

Tidal Wave and Hurricane Induced Slamming

It has been suggested that the potential for shock due to "slamming" caused by tidal waves and hurricanes may not have been considered. As mentioned previously in this section, the plant design does include a consideration of vertical water movement from these sources (as well as others) and is designed to prevent grounding. A consideration of vertical barge movement from these sources relative to the plant-to-breakwater cable segment integrity is discussed in Reference 9.

Hazards Induced by Ships Entering the Breakwater

Ships accidentally entering the breakwater basin have been considered[12]. However, the probability of a ship inadvertently entering the AGS breakwater seems exceedingly small since:

1. The breakwater is a large and well-marked structure.
2. The breakwater is not located in the major shipping lanes[3].
3. Only two relatively small openings exist in the breakwater structure.

It thus does not appear that severing the power cable from ship collision inside the breakwater is a credible event.

It is concluded that none of the foregoing concerns will have a significant effect on the core melt probability for the FNP at the AGS site.

2. Identification and Assessment of Additional Areas of WASH-1400 Nonapplicability

This section describes the AGS site and the design features of the FNP which appear to have the potential for altering the core melt probability from that assessed in WASH-1400 for the Surry[7] reactor. Also included in this section is an assessment of the individual significance of each of the items, and an overall assessment of the core melt probability for the FNP as compared to that assessed in WASH-1400,considering the composite effect of the differences. The general approach used in arriving at a core melt probability for the FNP was as follows: (1) those site and plant design differences which appeared to have the potential for changing the core melt probability were identified; (2) a numerical assessment was derived for the differences,in a format suitable for a WASH-1400 analysis; (3) the accident sequences leading to core melt in WASH-1400 were identified,and selected components of these sequences were altered as appropriate to account for the FNP differences as assessed in (2); and (4) the sequences leading to core melt were then recomputed for the FNP and a summation made in order to arrive at a core melt probability. It should be emphasized that there are numerous potential pitfalls and uncertainties in this approach, and, therefore, the results should be considered as preliminary scoping calculations.

In an effort to determine the significance of the uncertainties in the approach, an assessment was made of the more obvious problems, as follows:

a. Incomplete assessment of the FNP design - It is stated in WASH-1400 that, in order to perform a detailed core melt probability analysis, it was necessary to select a plant "...very near the commencement of operation to ensure the availability of final designs plus operating, test, maintenance, and emergency procedures needed for detailed analysis." Obviously, this information for the FNP is unavailable since construction has not started. Another related problem is that,

in the time provided for this effort, it was not possible to do a comprehensive review of the FNP design, as it currently exists, in an attempt to identify all potential differences affecting the core melt probability. Thus, it is possible that (1) design features and operating, test, and maintenance and emergency procedures which have not been finalized for the FNP could have an effect on the core melt probability; (2) design features and operating procedures which exist today may change by the time the plant operates, and these changes could have a potential effect on the core melt probability; and (3) design features and operating, test, etc, procedures which have a significant effect on the core melt probability could have been overlooked in this brief study.

It is not, however, considered likely that the problems described above will become important relative to the FNP core melt probability, for the following reasons:

- Plant designs and operating, test, maintenance, and emergency procedures have tended to become more standard from plant to plant, and thus major changes would not be expected.

- The core melt probabilities as assessed in WASH-1400 are generally insensitive to most design feature and operating, etc, procedure changes. This has been claimed by the authors of WASH-1400 and has been generally confirmed by at least one independent assessment of WASH-1400[18].

b. Applicability of WASH-1400 to 100 land-based plants - Quite apart from the applicability of the WASH-1400 results to the FNP, as modified herein, is the question of the applicability of the results to the 100 land-based plants for which the analysis is claimed to apply. Much criticism has been generated from numerous reviewers regarding the applicability of the assumptions, methods, and techniques used in WASH-1400 relative to the core melt probability for land-based plants. Some of this criticism is discussed in Appendix XI of the WASH-1400 Final Report. One criticism[18] was that the results of the WASH-

1400 analysis, which used the 3-loop Surry (Westinghouse) reactor design, may not apply to the more numerous and more recent 4-loop Westinghouse design. The FNP is, with only a very few apparent differences, a floating version of the contemporary Westinghouse 4-loop design. In a recent assessment[18], selected design differences between the Surry reactor and a representative 4-loop Westinghouse design (Trojan[19]) were investigated to determine if differences existed which would make the results inapplicable. Although no important differences were found, due to several uncertainties it could not be concluded that the WASH-1400 results apply to the 4-loop plant. It should also be noted that WASH-1400 states (Section 17, Appendix XI and also in Chapter 7 of the Main Report) that more work in this area would be useful. It is also maintained (Section 17, Appendix XI) that the extrapolation from the results based on Surry to the 100 reactors which the study is said to apply is conservative. This is based on the contention that "...the applicable codes and standards and safety design requirements have been significantly improved since the designs of the plants in the study were undertaken," and also "...such extrapolation (to the 100 plants) is likely to be conservative (due to)...improved implementation of design requirements."

It is difficult to assess the significance of these arguments relative to the applicability of the WASH-1400 analysis to a land-based plant similar to the FNP design. No significant improvements in design, codes, standards, or implementation of design requirements are apparent. Also, it is expected that many such improvements would not significantly change the core melt probability since, as noted previously, the results appear to be generally insensitive to most such changes.

c. Nonapplicability of the WASH-1400 results beyond 1980 - It is stated in WASH-1400 (Main Report, Section 1.9) that "If the safety of nuclear power plants continues to improve with time, then it would not be appropriate to extrapolate the results of this study beyond 100 reactors and about 5 years (1980), since the extrapolation would yield unrealistically high results." It would thus appear that the FNP is excluded from extrapolation since it is not included in the 100 reactor

population, and is not scheduled for operation until 1985. The arguments that plant safety may be improved, and thus core melt probability reduced, may be valid for the FNP. However, the WASH-1400 argument in this regard appears weak. The implication is given by the use of the phrase, "...continues to improve...," that nuclear power safety has improved in the past. However, since there have been no core melt accidents, it is not clear how this assessment applies in the context of core melt probabilities. Also, WASH-1400 (Main Report, Section 1.9) compares the expected improvement in nuclear power safety with that experienced with the automobile and airplane. Such comparisons do not appear valid since safety improvements in automotive and aircraft travel can be attributed in large part to experience with actual crashes and destructive tests. Comparable events have not and will be unlikely to happen in the near future for power reactors.

d. ECCS functionability - In the WASH-1400 analysis for land-based plants, it is assumed that if the ECC systems operate as designed, then the core is always adequately cooled. Thus, there is no adjustment of the WASH-1400 core melt probability values to account for the possibility that, due to thermal-hydraulic uncertainties, the ECC systems may not always be adequate to prevent core melt for the various accidents considered. WASH-1400 does consider (Appendix XI, page XI 7-1 and Appendix V, Section 4.2) the possibility of ECC nonfunctionability for large break LOCAs and concludes that "...even if values as high as 10^{-1} for ECF (emergency coolant functionability) failure were to be used (for large break LOCAs only), any contribution made could be within the accuracy of the overall calculations." An assessment of the WASH-1400 consideration of ECC functionability is given in Reference 48.

The issue of ECC functionability for the FNP is somewhat different from that of the land-based plants for two reasons: (1) different containment backpressure during a LOCA, and (2) the addition of

upper head injection to the FNP. It has been shown experimentally[49] that a low containment pressure during ECC reflood reduces the effective heat transfer from the core. The containment pressure during reflood for the FNP is only about 10 psig[22], while for the land-based Surry plant used in the WASH-1400 study, it is about 40 psig (Appendix VIII, WASH-1400). The quantitative significance of this difference is not known, but, if all other factors are similar, it would tend to decrease ECC effectiveness in the FNP and could lead to an increased core melt probability. The upper head injection system, part of the FNP ECC system, may offset this effect by augmenting the ECC reflood heat transfer. In any event, the issue of ECC functionability for the FNP has not been evaluated and could potentially influence the probability of core melt. It should be noted that the acceptability of and permissible assumptions regarding UHI effectiveness are currently being deliberated within NRC[20], and an official NRC position on this matter is expected to be established in a month or two.

Due primarily to the foregoing four factors, the FNP core melt probability assessment presented in this report must be considered a preliminary scoping effort, subject to revision pending a more extensive assessment.

As indicated previously, the first effort in the approach to calculating FNP core melt probability was the identification of AGS site and FNP design differences with the potential of changing the core melt probability from that assessed in WASH-1400. The effort initially consisted of ascertaining whether there existed any potential hazards external to the FNP plant which could affect the core melt probability. Such events were considered in WASH-1400 and assessed to be negligible for land-based plants. For the FNP, due to its possible location in the sea, a potential exists for accident initiating events which are not applicable to land-based plants. These events are primarily hazards from ship collisions and wave activity. Both of these potential events, as well as others, have been extensively considered[9,11,12,21], and it is concluded that no significant potential appears to exist from these causes for initiating core melt accidents in the FNP. It was determined that the frequency of loss of power to the plant

was apparently considerably lower for the FNP than assumed in WASH-1400. Loss of power to the plant initiates a transient accident which, when coupled with other failures, could lead to a core melt.

An investigation was undertaken of design details within the plant to determine if differences existed which could change either the probability of an accident being initiated, or the probability of a core melt after the accident was initiated. Several such design differences were found, and they are listed, along with loss of power to the plant, in Table II. (It was determined that the probability of a pipe rupture, large or small, for the FNP should not be significantly different from that assumed in WASH-1400.)

The second effort consisted of assigning to each item a numerical assessment suitable for use in a WASH-1400 analysis. The second column in Table II shows the results of this effort. The third column shows the comparable value used in WASH-1400. After the items were assessed, core melt accident sequence probabilities were computed. The details of the computations are given in Appendix A.

The numerical assessment of each of the eight items listed in Table II was based on the following:

a. Failure of power to AGS site - The value obtained for the AGS[8] is considerably lower (2.28×10^{-4} per year) than that used in WASH-1400 (0.2 per year). While the value for the AGS appears to be much too low based on the WASH-1400 value, reasonable arguments[12,13] appear to exist which support the low value, and it is suspected that the WASH-1400 value may be too high and based on inappropriate data. In addition, as indicated in Appendix A, the AGS value could be substantially higher without affecting the FNP core melt probability.

b. Rupture through Low Pressure Injection System (LPIS) check valves - This accident initiating event consists of a double check valve failure in the LPIS which allows reactor primary system fluid at 2250 psi

TABLE II

SUMMARY OF DIFFERENCES BETWEEN THE FNP AT THE AGS SITE AND LAND-BASED PLANT USED IN WASH-1400 WITH THE POTENTIAL FOR CHANGING CORE MELT PROBABILITY

Item	Description and/or Failure Probability	
	FNP	WASH-1400 Plant (Surry)(7)
1. Failure of Power to Plant	2.28×10^{-4} per year	0.2 per year (pg 64, Main Report)
2. Rupture through LPIS Check Valves	4×10^{-7} per year	4×10^{-6} per year (pg V-44, Appendix V)
3. Failure of UHI System	2×10^{-3}	N.A.
4. Rupture through UHI Check Valves	4×10^{-7} per year	N.A.
5. ECCS Failure from Containment Failure	No direct relationship	Containment failure always leads to ECCS failure (pg I-41)
6. High Pressure ECC System Failure	1.9×10^{-2}	8.6×10^{-3} (pg II-144)
7. Accumulator System Failure	1.4×10^{-3}	9.5×10^{-4} (pg II-131)
8. LPRS Heat Removal	Uses containment spray system (no change in failure probability)	None (pg II-176)

to flow into the LPIS, most of which is located outside the containment. This occurrence was assumed in WASH-1400 to lead to a relatively severe accident resulting in core melt. The WASH-1400 assessed probability of this occurrence is 4×10^{-6}/year (Appendix V, Section 4.4, pg V-43). It is maintained in WASH-1400 that a periodic testing program to assure the integrity of the valves could lead to a reduction in the probability of this failure. On page 63 of the Main Report, it is claimed that "...a monthly independent test of these valves to assure their seating integrity could lower the probability of their combined failure by a factor of about 20." Page V-44 (Appendix V) states "... at least an order of magnitude decrease in the failure probability for the LPIS check valves can be obtained by a reasonable testing program." Discussions and review of design drawings with OPS personnel[21] revealed that testing provisions for the valves have been incorporated in the FNP design, and a testing program will be implemented, although the details of the program have apparently not been established. It was thus concluded that a factor of 10 reduction of the WASH-1400 value for the LPIS check valve failure accident could reasonably be applied to the FNP, as indicated in Table II.

c. Failure of UHI System - The FNP design contains, in addition to those emergency core cooling (ECC) systems normally found on Westinghouse PWRs (including Surry as used in WASH-1400), an upper head injection (UHI) system. This system is designed to aid in cooling the core for certain primary system pipe break accidents. The OPS Plant Design Report[22] (PDR) states (pg 6.3-21) that "Emergency core cooling is provided for small (primary system pipe) ruptures primarily by high head injection pumps and UHI accumulators. Small ruptures are those with an equivalent diameter of 6 inches or less which do not immediately depressurize the Reactor Coolant System below the accumulator discharge pressure." However, in checking on the UHI system, NRC personnel stated[23] that UHI is required for ECC when the pipe rupture is 1 ft^2 (13.5" diameter) or greater. OPS later confirmed this requirement[24].

In order to assign a failure probability to the UHI system, it was necessary to consider the design details of the system. The UHI

system is basically an ECC injection system which is designed to inject water into the upper head of the reactor vessel when the primary system pressure falls to about 1300 psi following a postulated pipe rupture. The system consists of two interconnected tanks separated by a rupture disc. One tank contains nitrogen and the other water. These tanks are located outside the FNP containment building and are connected through the containment to the upper head by a pipe which contains two check valves and four normally open isolation valves. The check valves are designed to automatically open when the primary system pressure falls below 1300 psi. As the pressure continues to drop, the rupture disc is designed to fail, allowing the nitrogen to force the water in the injection tank into the vessel head. When the water in the injection tank reaches a preset level, the isolation valves are designed to automatically close, preventing the injection of nitrogen into the upper head.

In order to assess the failure probability for the system in the manner used in WASH-1400, a fault tree would have to be drawn, and component failure probabilities would have to be obtained. In addition, test and maintenance of the system would have to be considered, as well as the possibility of system failure from subsystem malfunction (surge tank, nitrogen pressurization system, etc). Also, the criteria for system failure leading to core melt would have to be established (eg, would failure of the isolation valves lead to core melt?). It was not possible to perform such a detailed assessment due to limited resources for the study. Thus, a failure probability had to be estimated.

The UHI failure probability was estimated to be $2x10^{-3}$ based on the fact that it is a "semi-passive" system, and thus its failure rate should be between the normal totally passive accumulator system provided on PWRs (failure probability assessed at $9.5x10^{-4}$ in WASH-1400, pg II-132) and the totally active LPIS system (failure probability of $4.7x10^{-3}$, pg II-137). As can be determined from Appendix A, the UHI failure probability is not critical to the total FNP core melt probability since the large break loss of coolant accident is not a significant contributor.

It was conservatively assumed that UHI was required for any break greater than 6" in diameter (WASH-1400 definition of a large break). This assumption was made to simplify the calculations and will not have any effect on the core melt probability for the FNP, as can be seen in Appendix A.

d. Rupture through UHI check valves - The UHI system, since it is located outside the containment system, provides the possibility of an accident similar to the LPIS double check valve rupture described in 2. above. It was thus assumed that the likelihood of this accident was 4×10^{-7}, identical to the LPIS accident since the check valves can and will be tested, based on discussions with OPS personnel[21].

e. ECCS failure from containment failure - WASH-1400 assumed (pg V-47) that containment failure would result in ECC failure since ECC pumps drawing water from the containment sump would cavitate from loss of sufficient pump suction head. In the FNP, the ECC pumps are designed to operate with no containment overpressure[21], thus this accident sequence, which leads to core melt in WASH-1400, is not applicable to the FNP. This sequence has been eliminated from the FNP accident sequences in Appendix A.

f. High pressure ECC system failure - The reactor used in the WASH-1400 assessment (Surry) has a single high pressure injection system (HPIS) to prevent core overheating during small primary system pipe rupture accidents. In the FNP (as in apparently all 4-loop Westinghouse reactors of contemporary design) core protection from small break accidents is afforded by two high pressure systems, the high pressure injection system and the safety injection system. The difference between the WASH-1400 assessment for the single Surry system and the 4-loop dual system was analyzed in Reference 18, and it was concluded that the application of the WASH-1400 analysis of HPIS failure to the dual system was not justified. Due to differences in injection requirements, injection capacities and system designs (see Reference 18 for details), it would require a rather extensive analysis to determine the failure probability for the FNP HPIS. However, based on the analysis in

Reference 18, and in the absence of further information, it was concluded that a reasonable approximation would be that the FNP HPIS may have about twice the failure probability of that used in WASH-1400 for the Surry HPIS failure (8.6×10^{-3}). Accordingly, as seen in Table II, the FNP HPIS failure probability has been assessed at 1.9×10^{-2}.

g. Accumulator System failure - In the Surry 3-loop design, following a large pipe rupture, 2 accumulator systems (one in each unruptured loop) are assumed to be required to prevent core melt. The probability of a failure of either of the two systems was assessed to be 9.5×10^{-4} in WASH-1400 (pg II-132). For the FNP 4-loop design, 3 accumulator systems (injecting into the three intact loops) are required[23] following a pipe rupture in the fourth loop. Thus, as a reasonable approximation, it appears that the failure probability of any one of the three accumulators would be 1.5 times the value used for Surry (assuming the designs are similar). Accordingly, an accumulator failure probability of 1.4×10^{-3} was assumed for the FNP.

h. Low Pressure Recirculation System (LPRS) heat removal - The LPRS system for the Surry plant, as analyzed in WASH-1400, does not have a heat removal system. The LPRS for the FNP shares a heat removal system with the containment spray recirculation system. Thus, the LPRS failure rate for the FNP should be greater to account for potential failure of the heat removal system. The failure of the FNP heat removal system should be equivalent to the containment heat removal system (CHRS) assessed in WASH-1400, due to similarity of design. The CHRS failure probability is assessed as 8.5×10^{-5} (pg II-170) in WASH-1400, which is insignificant when compared to LPRS failure (1.3×10^{-2}). Thus, the same failure probability was used for the FNP LPRS as was used in WASH-1400.

i. Onsite emergency power - An item which is not in Table II due to insufficient and conflicting information is the availability of onsite emergency power following a power loss to the site. In the Surry design, three diesel generator units are provided to supply two

reactors. One unit is required to supply sufficient power to safely shut down a single plant. For a loss of offsite power event, each plant would require one unit for safe shutdown and prevention of core melt. The third unit is a "swing" unit which can replace either of the committed units in the event of failure. For each FNP, four diesel generator units are provided, but it is not clear how many are required for safe shutdown. The SER[11] states (pg 109) that "...three of the four diesels are required to provide emergency power for accident conditions." In testimony before the ACRS[20] (pg 102 of the transcripts), OPS stated that "...only two of the four diesel generators...are required to safely shut down the plant." Thus, it is not clear what emergency onsite power requirements exist to prevent core melt in the event of loss of power to the site. However, as shown in Appendix A, the low probability of loss of power to the FNP compared to the WASH-1400 assumption makes the availability of onsite emergency power an insignificant issue.

In summary, the calculation of core melt probability for the FNP proceeded in the same manner as that done in WASH-1400 except that:

- the probability of loss of power to the FNP was reduced
- the probability of an accident initiated by rupture of the FNP LPIS check valves was reduced
- the probability of an accident initiated by rupture of the FNP UHI check valves was included
- the possibility of failure of the UHI system leading to core melt was included in the FNP calculations
- ECCS failure due to containment failure alone was eliminated from the FNP accident sequences
- the failure probability of the FNP HPIS was increased a factor of 2 over the WASH-1400 value
- the FNP accumulator failure probability was increased by 50 percent over the WASH-1400 value.

Table III gives the results of the Appendix A calculations. As can be seen, based on a preliminary scoping analysis, the core melt probability for the FNP is essentially the same as the WASH-1400 result for land-based PWRs. It appears that the most significant uncertainty for the FNP is the HPIS

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TABLE III

PRELIMINARY SCOPING ESTIMATE OF FNP CORE MELT PROBABILITY COMPARED WITH WASH-1400 RESULTS

Accident Type[1]	PWR Core Melt Probability/reactor year	
	WASH-1400	FNP
Large LOCA	1.9×10^{-6}	2.1×10^{-6}
Small Break (S1)	6.7×10^{-6}	1×10^{-5}
Small Break (S2)	2.4×10^{-5}	3.3×10^{-5}
Interfacing systems[2]	4×10^{-6}	8×10^{-7}
Transients	1×10^{-5}	(negligible)
TOTAL	4.66×10^{-5}	4.59×10^{-5}

(1) Accident types identical to those defined in WASH-1400.

(2) Includes LPIS double check valve failure for both plants, and UHI double check valve failure for the FNP.

failure probability. This system is needed for both "S1" (equivalent to a hole 2 to 6" in diameter) and "S2" (equivalent to a hole 1/2 to 2-1/2" in diameter) initiated accidents, both of which dominate the FNP core melt probability. For reasons discussed earlier in this section, the failure probability of the FNP HPIS has been increased a factor of two over that used in WASH-1400. Since, as noted earlier, the FNP HPIS is quite complex (actually two systems) and since failure data for HPIS components are apparently not readily available, a definitive failure probability analysis, similar to that used in WASH-1400, could not be accomplished within the scope of this study.

It is concluded, based on a preliminary scoping study, that the probability of a core melt accident in the FNP is equivalent to that assessed in WASH-1400 for land-based PWRs. Additional effort is required (and recommended in this report) to validate this conclusion.

B. Consequences of Core Melt-through

This section presents the results of an investigation to determine (1) if the current efforts being conducted by NRC and OPS will lead to a definitive and complete assessment of the consequences of a core melt-through for the FNP, and (2) if a molten core catcher appears feasible for the FNP.

1. Assessment of Current Effort

The only active effort which could be found relative to assessing the consequences of a core melt-through for the FNP is the Liquid Pathway Study (LPS) currently being conducted by OPS under the guidance of NRC. (Discussions with a representative[47] of NRC's group responsible for WASH-1400 confirmed that no effort is underway and no definite plans exist to do a WASH-1400 type analysis of FNP risks.) The LPS is designed to assess the consequences of dispersion of radionuclides into the sea from an hypothetical core melt-through accident. Since the study is not scheduled to be completed until September 1976, it is obviously not possible to perform a complete assessment of the results. However, numerous interim documents, including meeting minutes, have been published, and it is these documents, plus discussions with OPS and NRC personnel, that form the basis for the interim assessment reported herein.

The two main conclusions from the general assessment of the current effort to determine FNP core melt-through consequences are as follows:

a. The Liquid Pathway Study, with two exceptions, appears to be a reasonable effort likely to lead to a valid assessment of some of the consequences of a molten core entering the sea from the FNP. This assessment is based on reviewing several documents[41-45] describing various facets of the Study, discussions with NRC and OPS personnel[22,29,30] involved in the Study, and reviewing numerous NRC meeting minutes relative to the Study, as well as ACRS meeting minutes. The Office of Nuclear Reactor Regulation in the Nuclear Regulatory Commission, the Advisory Committee on Reactor Safeguards, and Off-Shore Power Systems are all taking a substantial, active role in either preparing, directing

or monitoring the Study. In addition, each group has hired appropriate consultants. It should be noted that various hearings and other interim reviews of the LPS could influence the content of the final LPS report. These changes could alter the assessment presented herein.

The two exceptions noted in the foregoing are:

- It does not appear that the economic consequences of an FNP core melt dispersal in the sea are being considered. These consequences include loss of local revenue due to possible inaccessibility of beaches and ocean for recreational purposes, as well as loss of revenue from potential loss of fish harvest in the area of the plant.

- It appears that some applicable information either from past or existing programs which may bear on the technical aspects of the study is not being considered. However, since a number of groups, with consultants, are involved in the Study and it has not been completed as of this writing, a definitive assessment of the inclusion of all applicable information could not be made. Appendix B discusses this subject further and lists relevant information sources found as a result of this investigation.

b. There appears to be little or no effort directed at a determination of the risks of an airborne release following a core melt-through in the FNP, and this omission could be a very serious shortcoming in FNP risk assessment at the AGS site. The general feeling within NRC seems to be that the probability and consequences of an airborne release in the FNP at the AGS site are roughly comparable to the WASH-1400 assessment, and since the WASH-1400 results indicated a relatively low risk, there is no need to be concerned. However, it appears that (1) the probability of an airborne release from the FNP could be significantly greater than that assessed in WASH-1400, (2) the extent of airborne release could be substantially different from that assumed in WASH-1400, and (3) due to factors and parameters specific to the AGS site, the public health effects from an airborne release at the AGS site are not

expected to be similar to those calculated in WASH-1400. The following presents a discussion of each of these items in more detail:

Probability of FNP airborne release - It was determined from a preliminary scoping calculation in Section IV.A.1, that the probability of a core melt in the FNP was comparable to that computed in WASH-1400 for land-based PWRs, notwithstanding several qualifications and unknown factors, some of which could be important. The next obvious concern is the likelihood of a significant airborne release following a core melt accident. In WASH-1400, most PWR core melt accidents resulted in no significant airborne release since the above ground containment integrity was maintained, and the core eventually melted through the containment base mat and into the geologic media beneath the plant. On the other hand, for the FNP it appears that every core melt accident will result in an elevated containment rupture causing a significant airborne release. Since the FNP containment is small compared to a land-based PWR, and the design pressure is much less (12 psig vs about 50 psig) any abrupt energy release to the containment immediately threatens its integrity. In the FNP, the sources for such releases appear to be somewhat more numerous than a land-based PWR of the type analyzed in WASH-1400. The first source occurs when the molten core falls into water that may be left in the bottom of the reactor vessel following a LOCA. A steam explosion may occur which would be a particularly severe loading on the containment. The potential for this steam explosion should be no more likely for the FNP than that assessed for the land-based plant in WASH-1400 or any plant equipped with an ice condenser (there are at present 10 land-based PWRs with ice condenser containment). Rapid steam generation and release from this interaction will surely occur; an energy release for which the containment structure is not specifically designed. The second energy impulse released to the containment will occur when the core melts through the reactor vessel bottom head and impacts the water in the reactor vessel cavity. (Discussions with OPS[21] have confirmed that the water inventory in the containment following a postulated LOCA will be sufficient to fill the reactor vessel cavity. Reference 46 also concludes that the reactor vessel cavity would be filled following a LOCA in an ice condenser plant.) This potential, according to WASH-1400, does not exist for a land-based

PWR with dry containment since water cannot spill into the reactor vessel cavity. Again, the possibility of a steam explosion exists. In this case, a large molten mass will be involved since a significant portion of the reactor vessel bottom head will likely be molten and have become part of the molten core mass. This larger molten mass will likely increase the amount of steam produced and released to the containment, again threatening its integrity. The molten mass will continue to melt downward, eventually breaching the primary containment and entering the annulus separating the primary and secondary containment structures. This annulus exists continuously throughout the exterior of the primary containment and is interconnected. Thus, the primary containment melt-through will result in release of the contents of the primary containment into the annulus. This event will abruptly pressurize the annulus and create the potential for rupture of the secondary containment since it is designed for only 3 psig. A final energy impulse from steam production (with again the possibility for a steam explosion) will occur when sea water rushes into the large hull when the steel hull has been sufficiently weakened by the heat effects of the molten mass, which by this time has grown even larger due to melting of additional structural materials below the primary containment.

In addition to these energy sources from steam formation, the production of hydrogen from metal-water reactions, and the generation of noncondensible gasses (such as CO_2) from chemical reactions associated with the melt-through processes both contribute to an elevation of the containment pressure.

A detailed assessment of the foregoing scenario with the associated likelihood of containment failure is beyond the scope of the present effort. However, in a detailed analysis conducted for OPS[25], it was concluded that "In the plant design considered (floating nuclear plants of the AGS design), overpressurization appears to be the dominant mode of containment failure in the event of a core meltdown, even assuming operability of the containment safeguards." The BMI study[25] concluded that the containment pressure prior to penetration of the barge by the core melt would approach very nearly the failure point and that "Whether the primary containment fails by

overpressure or melt-through, the failure will overpressurize and fail the secondary containment, resulting in a puff release of radioactivity to the environment." In addition, Reference 46 calculates that the upper limit containment failure pressure is exceeded upon melt-through of the containment floor for an ice condenser containment (either land-based or floating). (The additional potential for containment failure upon annulus penetration or due to energy release from molten core-sea water interaction was not considered in this [46] study.) It would thus appear reasonable to assume, in the absence of more definitive analyses, that FNP containment failure will occur for every hypothetical core melt accident. Since the lower containment structures are supported by, reside within, and are attached to many compartments and other structures within the barge, an elevated containment rupture (above the barge deck) from overpressurization during a core melt would appear more likely. It also appears, based on the foregoing, that the containment failure sequence for a land-based ice condenser plant would not be significantly different from the FNP since containment failure appears likely prior to any consideration of molten core-sea water interaction.

Following the determination that the probability of a core melt accident in the FNP is comparable to the WASH-1400 assessment (as is indicated in the preliminary scoping analysis in Section IV.A.2), and that every FNP core melt leads to containment failure resulting in a significant airborne release, a study was undertaken to compare the likelihood of a significant airborne release from PWRs as assessed in WASH-1400 with the FNP. Details of this study are presented in Appendix B. The results indicate that, for PWRs as assessed by WASH-1400, only 1 in 7 core melt accidents result in a significant airborne release. Thus, it appears that the probability of a significant airborne release for the FNP is 7 times greater than assessed by WASH-1400 for land-based plants of the Surry design.

The airborne fission product release probability is of particular concern since, as determined in WASH-1400, essentially all of the biological risks (deaths, cancer incidence increases, genetic effects, etc) to humans are a direct result of airborne releases. However, as will be discussed in subsequent parts of this section, for reasons associated with the FNP design

and site characteristics, the consequences of FNP airborne releases may be significantly less than those for the land-based plant considered in WASH-1400.

FNP Airborne Release Considerations - There exist two factors which may reduce the airborne fission product inventory for the FNP following containment rupture. These are:

a. The FNP containment has a volume of 1,066,000 ft^3 (22), while the equivalent land-based dry containment has a volume of just over 2,000,000 ft^3 (48). Thus, the FNP containment, being smaller than typical dry containment land-based plants, has a larger surface-to-volume ratio. Also, the presence of the ice container device increases this ratio even further. Unless surfaces become saturated, this feature should tend to enhance surface plateout of released fission products, particularly iodine. This plateout fraction will not be available for airborne release.

b. The ice in the ice condenser contains a chemical (sodium tetraborate) which, along with water, tends to trap iodine. Since the ice condenser is a passive system, this removal mechanism is presumably always available if the iodine release occurs prior to complete melting of the ice, which appears likely since the ice inventory is more than sufficient to absorb all energy from blowdown.

c. As was also determined for land-based plants in WASH-1400, the above-ground containment failure model in the FNP can significantly affect the quantity and distribution of airborne fission products released. However, there appear to be potential differences between the FNP containment failure-fission product release sequences and those assessed in WASH-1400 for land-based plants. If the FNP containment fails early in the accident sequence from hydrogen combustion, metal-water reaction energy release, steam generation, CO_2 gas generation, or a combination of these (see Reference 25 for further discussion), the release should be equivalent to the WASH-1400 release from similar postulated containment failure modes, except for the potentially

important differences noted in a. and b. above. However, for the FNP, subsequent releases may also occur as the molten core mass contacts water in the reactor vessel cavity or, especially, sea-water. These events could cause the release of large amounts of steam which would result in an additional airborne release by (1) purging the containment of existing airborne radioactivity and (2) fragmenting the molten core material, enhancing the release of entrapped radioactive gas and possibly causing the production and discharge of radioactive particulates. The potential for these secondary releases does not appear to exist in the land-based plant analyzed in WASH-1400.

It thus appears that the FNP "source term" for airborne release could be significantly different from the corresponding release assessed in WASH-1400. A determination of the magnitude of this difference is beyond the scope of the effort reported herein.

Site Factors Relevant to the FNP - There exists an obvious site factor for the Atlantic Generating Station which tends to reduce the consequences from an FNP airborne release. This factor is isolation from population and includes the fact that the Station is just under three miles off the New Jersey shore. In addition, there is no permanent population for long distances out to sea in a large sector around the plant extending from the northeast to the southwest. The significance of this isolation depends in large measure on the local meteorology (especially the frequency, persistence, and velocity of winds) coupled with seasonal fluctuations of the transient population (eg, tourists, commercial and pleasure boaters). Obviously, the WASH-1400 consequences for an "average" land-based site do not apply to the FNP located at the AGS.

It is concluded that (1) the current NRC directed effort in assessing FNP core melt accident risks is deficient in not considering airborne releases and in not determining economic consequences, (2) the probability of a significant airborne release in the FNP, based on preliminary scoping studies presented herein, is about seven times greater than in the land-based plants as assessed in WASH-1400, and the consequences of such a release from the FNP is probably less. Additional effort is needed to verify and further quantify these conclusions.

Comparison of FNP with Land-Based Ice Condenser PWRs - As noted in Reference 25, the only significant differences in containment design between the FNP and a land-based ice condenser plant which could influence the postulated core melt-through accident are (1) the land-based ice condenser primary containment has a thick concrete foundation mat which the FNP does not, and (2) the potential for and consequences of interaction between the molten core debris and ground water upon containment melt-through for the land-based plant could be different than the molten core-sea water interaction for the FNP. The first difference would tend to increase the primary containment pressure buildup since additional potential from gas generation due to metal-water reaction and concrete off-gassing exists in the land-based plant. The second difference could, as mentioned previously, tend to provide an additional source of containment pressure generation for the FNP as a result of molten core-sea water interactions. Also, a containment purging and core fragmentation potential exists from this interaction (see previous discussion) which may not be present for the land-based plant, depending on the potential for and extent of molten core-ground water interactions.

Both the Reference 25 and 46 reviews, as well as the assessment contained herein, indicate that the ice condenser containment, either the FNP or land-based design, will likely fail during a postulated core meltdown accident prior to melt-through of the containment structure. Thus, the potential for above ground containment failure from overpressure following a postulated core meltdown accident in a PWR with an ice condenser containment appears similar for a land-based plant and a floating plant. The airborne releases should be comparable for the two sites, except that for the FNP the potential exists for a secondary release caused by the molten core-sea water interaction. The potential also appears to exist in the land-based plant, depending on the site, for molten core-ground water interactions which could cause a secondary release. This release would come later in time in the postulated melt-through sequence due to the thicker containment base mat in the land-based plant.

2. Review of Molten Core Catchers

The feasibility and design of molten core catchers have been studied at various times over a period of many years[31-40]. Molten core catchers

have been proposed and even designed for land-based PWRs. Molten core catchers have been recently evaluated for FNP application[11,25,26], and current experimental efforts are underway (see Appendix C) to determine some of the chemical-physical parameters postulated to be involved in a core melt accident. Thus, it is concluded that a successful core catcher for the FNP is, or soon will be, feasible although it would very likely entail substantial expense and significant design changes. However, it should be emphasized that, until results of the Liquid Pathway Study are available as well as an assessment of potential airborne risks discussed in Section IV.B.1, it is not clear that a successful core catcher would significantly reduce risks from the FNP. Such a determination should also depend on the design details of the core catcher itself (eg, whether the catcher would merely retain the melt or retain and freeze it). One report[25] discusses some of these points in more detail.

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VI. GLOSSARY

FNP	Floating Nuclear (Power) Plant
AGS	Atlantic Generating Station
NRC	Nuclear Regulatory Commission
LPS	Liquid Pathway Study
PSE&G	Public Service Electric and Gas
PWR	Pressurized Water Reactor
OTA	Office of Technology Assessment
NOPS	National Ocean Policy Study
ITI	Intermountain Technologies, Inc.
AFS	Auxiliary Feedwater System
LPIS	Low Pressure Injection System
ECC	Emergency Core Cooling
UHI	Upper Head Injection
PDR	Plant Design Report
HPIS	High Pressure Injection System
LPRS	Low Pressure Recirculation System
CHRS	Containment Heat Removal System
LOCA	Loss of Coolant Accident
ACRS	Advisory Committee on Reactor Safeguards

APPENDIX A

PRELIMINARY SCOPING CALCULATION OF FNP CORE MELT PROBABILITY USING WASH-1400 TECHNIQUES

This Appendix describes the results of a calculation of the core melt probability for the Floating Nuclear Plant. The calculation is essentially identical to the WASH-1400[6] technique in that the same accident sequences are formulated. Changes which have been made are those described in Section IV.A.2 of this report.

Table A-1 defines the symbols used in formulating the accident sequences. These symbols are identical to the ones used in WASH-1400.

The FNP core melt probability calculation was divided into five parts to correspond to the five accident categories used in WASH-1400: Large Loss of Coolant Accidents (LOCA), Small Break (S_1) Accidents, Small Break (S_2) Accidents, Interfacing Systems Accidents, and Transient Accidents. Each of the five categories will be considered separately as follows:

1. Large LOCA

There are 17 large break LOCA accident sequences considered in WASH-1400. Table A-2 shows the probability values assumed for each event used in the 17 sequences, and Table A-3 is a list of the 17 sequences with values shown for both the WASH-1400 analysis and those computed for the FNP. As can be seen, the total values are essentially identical.

2. Small Break (S_1) LOCA

Table A-4 lists the important events associated with the small break LOCAs, designated S_1 (equivalent to a hole 2 to 6 inches in diameter). Table A-5 lists the 21 S_1 initiated accident sequences which were found in WASH-1400 to have the potential for contributing to the core melt and probability for land-based plants. As can be seen, the FNP core melt probability is slightly greater than that calculated in WASH-1400.

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TABLE A-1

DEFINITION OF SYMBOLS USED IN ACCIDENT SEQUENCES

A	-	Large LOCA
B	-	Failure of electric power to ESFs
B'	-	Failure to recover either onsite or offsite electric power within about 1 to 3 hours following an initiating transient which is a loss of offsite AC power
C	-	Failure of the containment spray injection system
D	-	Failure of the emergency core cooling injection system
F	-	Failure of the containment spray recirculation system
G	-	Failure of the containment heat removal system
H	-	Failure of the emergency core cooling recirculation system
K	-	Failure of the reactor protection system
L	-	Failure of the secondary system steam relief valves and the auxiliary feedwater system
M	-	Failure of the secondary system steam relief valves and the power conversion system
Q	-	Failure of the primary system safety relief valves to reclose after opening
S_1	-	A small LOCA with an equivalent diameter of about 2 to 6 inches
S_2	-	A small LOCA with an equivalent diameter of about 1/2 to 2 inches
T	-	Transient event
V	-	LPIS (and UHI) check valve failure

TABLE A-2

LARGE BREAK LOCA EVENT PROBABILITIES USED FOR FNP AND WASH-1400 ACCIDENT SEQUENCES

	WASH-1400	FNP
A	10^{-4}	10^{-4}
B	10^{-5}	10^{-5} (1)
C	2.4×10^{-3}	2.4×10^{-3}
D	5.6×10^{-3}	8.1×10^{-3} (2)
F	1.0×10^{-4}	1.0×10^{-4}
G	8.5×10^{-5}	8.5×10^{-5}
H	1.3×10^{-2}	1.3×10^{-2}

(1) This value should be lower for the FNP due to lower failure probability for loss of offsite power. However, as shown in Table A-3, it is already insignificant.

(2) This value was computed by adding the FNP accumulator failure probability (1.4×10^{-3}), the FNP LPIS failure probability (4.7×10^{-3}, same as WASH-1400) and the FNP UHI failure probability (2.0×10^{-3}). The derivation of these values is given in Section IV.A.2. All of these systems are assumed to be required to prevent core melt following a large break LOCA.

TABLE A-3

LARGE BREAK LOCA ACCIDENT SEQUENCE PROBABILITIES

Sequence	WASH-1400	FNP
AH	1.3×10^{-6}	1.3×10^{-6}
AG	ε	ε
AHG	ε	ε
AF	ε	N.A. (does not lead to core melt)
AHF	ε	ε
AD	5.6×10^{-7}	8.1×10^{-7}
ADG	ε	ε
ADF	ε	ε
ACH	ε	ε
ACG	ε	ε
ACHG	ε	ε
ACF	ε	N.A. (does not lead to core melt)
ACD	ε	ε
ACDG	ε	ε
ACDF	ε	ε
AB	ε	ε
TOTAL	1.9×10^{-6}	2.1×10^{-6}

ε = insignificant (10^{-8} or less)

TABLE A-4

SMALL BREAK (S_1) LOCA EVENT PROBABILITIES
USED FOR FNP AND WASH-1400 ACCIDENT SEQUENCES

	WASH-1400	FNP
S_1	$3x10^{-4}$	$3x10^{-4}$
B	10^{-5}	10^{-5} (1)
K	$3.6x10^{-5}$	$3.6x10^{-5}$
C	$2.4x10^{-3}$	$2.4x10^{-3}$
D	$9.5x10^{-3}$	$2.0x10^{-2}$ (2)
F	$1.0x10^{-4}$	$1.0x10^{-4}$
G	$8.5x10^{-5}$	$8.5x10^{-5}$
H	$1.3x10^{-2}$	$1.3x10^{-2}$

(1) This value should be lower for the FNP due to lower failure probability for loss of offsite power. However, as shown in Table A-3, it is already insignificant.

(2) This value was computed by adding the FNP accumulator failure probability ($1.4x10^{-3}$) and the FNP HPIS failure probability ($1.9x10^{-2}$). Both of these systems are required for core protection (see pg II-129 of WASH-1400). The FNP failure probabilities are derived in Section IV.A.2.

TABLE A-5

SMALL BREAK (S_1) ACCIDENT SEQUENCE PROBABILITIES

Sequence	WASH-1400	FNP
S_1H	3.9×10^{-6}	3.9×10^{-6}
S_1G	2.5×10^{-8}	2.5×10^{-8}
S_1HG	ε	ε
S_1F	3×10^{-8}	N.A. (does not lead to core melt)
S_1HF	ε	ε
S_1D	2.8×10^{-6}	6×10^{-6}
S_1DG	ε	ε
S_1DF	ε	ε
S_1CH	ε	ε
S_1CG	ε	ε
S_1CF	ε	N.A. (does not lead to core melt)
S_1CD	ε	ε
S_1CDF	ε	ε
S_1K	1.1×10^{-8}	1.1×10^{-8}
S_1KG	ε	ε
S_1KF	ε	ε
S_1KC	ε	ε
S_1KCG	ε	ε
S_1KCF	ε	ε
S_1B	ε	ε
S_1BK	ε	ε
TOTAL	6.8×10^{-6}	9.9×10^{-6}

ε = negligible (10^{-8} or less)

3. Small Break (S_2) LOCA

Table A-6 lists the events associated with an S_2 (1/2 to 2" equivalent diameter) initiated LOCA, and Table A-7 shows the probabilities for the 20 important sequences listed in WASH-1400. The FNP core melt probability from these sequences is slightly greater than the WASH-1400 result.

4. Transient Initiated Accident

Table A-8 shows the probabilities of the important events associated with a transient initiated accident, and Table A-9 shows the core melt probabilities for the transient induced accidents. According to WASH-1400 (pg 64 of Main Report), the only transient events of significance relative to core melt probabilities are those intiated by loss of offsite power. As indicated in Table A-9, none of the transient initiated accidents are of significance for the FNP due to the low probability of offsite power loss.

5. Interfacing Systems Rupture Accident

Table A-10 shows the probability of core melt accidents initiated by double check valve failures through ECC systems which interface with the primary system. For the land-based plant used in WASH-1400 (Surry), only one such system (LPIS) exists. For the FNP, two systems exist, LPIS and UHI. However, for the FNP, the probability of check valve failure is reduced by a factor of 10 (based on WASH-1400 arguments) since periodic monitoring of the valves is possible.

TABLE A-6

SMALL BREAK (S_2) LOCA EVENT PROBABILITIES
USED FOR FNP AND WASH-1400 ACCIDENT SEQUENCES

Event	WASH-1400	FNP
S_2	$1x10^{-3}$	$1x10^{-3}$
B	10^{-5}	10^{-5} (1)
K	$3.6x10^{-5}$	$3.6x10^{-5}$
L	$1.3x10^{-3}$	$1.3x10^{-3}$
C	$2.4x10^{-3}$	$2.4x10^{-3}$
D	$8.6x10^{-3}$	$1.9x10^{-2}$ (2)
F	$1.0x10^{-4}$	$1.0x10^{-4}$
G	$8.5x10^{-5}$	$8.5x10^{-5}$
H	$1.3x10^{-2}$	$1.3x10^{-2}$

(1) This value should be lower for the FNP due to lower failure probability for loss of offsite power. However, as shown in Table A-3, it is already insignificant.

(2) This value is for the FNP HPIS failure probability (only ECC system assumed to be needed for the S_2 LOCA), and is derived in Section IV.A.2.

TABLE A-7

SMALL BREAK (S_2) ACCIDENT SEQUENCE PROBABILITIES

Sequence	WASH-1400	FNP
S_2H	1.3×10^{-5}	1.3×10^{-5}
S_2G	8.5×10^{-8}	8.5×10^{-8}
S_2HG	ε	ε
S_2F	1×10^{-7}	N.A.
S_2HF	ε	ε
S_2D	8.6×10^{-6}	1.9×10^{-5}
S_2DG	ε	ε
S_2DF	ε	ε
S_2C	2.4×10^{-6}	N.A.
S_2CD	2×10^{-8}	2×10^{-8}
S_2L	1×10^{-6}	1×10^{-6}
S_2LG	ε	ε
S_2LF	ε	ε
S_2LC	ε	ε
S_2K	3.6×10^{-8}	3.6×10^{-8}
S_2KG	ε	ε
S_2KF	ε	ε
S_2KC	ε	ε
S_2B	ε	ε
S_2BK	ε	ε
TOTAL	2.6×10^{-5}	3.3×10^{-5}

ε = negligible (10^{-8} or less)

TABLE A-8

TRANSIENT EVENT PROBABILITIES USED FOR WASH-1400 AND FNP ACCIDENT SEQUENCES

Event	WASH-1400	FNP
T(1)	0.2	2.3×10^{-4}
M	0.2	__(2)
L	1.5×10^{-4}	1.5×10^{-4}
K	3.6×10^{-5}	3.6×10^{-5}
Q	10^{-2}	10^{-2}
B'	0.5	__(2)

(1) This event is loss of offsite power; the only transient accident initiating event found to be of significance in WASH-1400.

(2) These events, recovery of offsite power after a specified time period, are not known for the FNP. However, due to the low offsite power failure for the FNP, they are insignificant.

TABLE A-9

TRANSIENT ACCIDENT SEQUENCE PROBABILITIES

Sequence	WASH-1400	FNP
TMLB'	$3x10^{-6}$	ε
TML	$6x10^{-6}$	ε
TKQ	$8x10^{-8}$	ε
TKMQ	$1.6x10^{-8}$	ε
TOTAL	$1.0x10^{-5}$	ε

ε = negligible (10^{-8} or less)

TABLE A-10

PROBABILITY OF RUPTURE THROUGH INTERFACING SYSTEMS

	WASH-1400	FNP
LPIS	$4x10^{-6}$	$4x10^{-7}$
UHI	N.A.	$4x10^{-7}$
TOTAL	$4x10^{-6}$	$8x10^{-7}$

APPENDIX B

COMPARISON OF WASH-1400 CALCULATED AIRBORNE RELEASE LIKELIHOOD WITH FNP

This appendix presents the results of a study to determine the relative probability of a significant airborne fission product release from land-based PWRs (as assessed in WASH-1400) and the FNP. For the land-based plants analyzed in WASH-1400, five modes of containment failure were postulated, four of which resulted in some loss of above ground containment integrity. The fifth consisted of core melt-through without loss of above ground integrity. The four above ground failure modes resulted in a significant release of radioactivity which became airborne and caused essentially all of the important consequences from a core melt accident. The core melt-through without loss of containment integrity was assumed to result in very little airborne release and caused only minimal consequences.

In order to determine the likelihood of an above ground airborne release, the probability of all core melt accident sequences terminating in above ground containment failure were summed and compared with the probability summation of the melt-through, no above-ground-containment-failure, sequence. The probability values for the various sequences were obtained from Table V 3-14 (pg V-25 in WASH-1400) and included some 80 separate sequences. As a result of performing these summations, the following table was constructed.

TABLE B-1

PROBABILITY OF PWR CONTAINMENT FAILURE MODES
AS ASSESSED IN WASH-1400

Containment Failure Mode	Probability	Significant Airborne Release
Steam Explosion	4×10^{-7}	Yes
Overpressure (H_2 burn)	7×10^{-7}	Yes
Overpressure (other sources)	4.3×10^{-6}	Yes
Isolation Failure	4.8×10^{-8}	Yes
Melt-through	3.5×10^{-5}	No

By appropriate summing of the above probability values, it is seen that the probability of a core melt leading to a significant airborne release is about 5.5×10^{-6}, while the probability of a containment melt-through accident without a significant airborne release is 3.5×10^{-5}, over 6 times greater. This means that only about one of seven core melt accidents results in a significant airborne release. For the FNP, on the other hand, every core melt appears to result in containment failure (see Section IV.B.1). Thus, assuming that the probability of a core meltdown accident in the FNP is equivalent to that assessed in WASH-1400 (see Section IV.A.2), the probability of a significant airborne release for the FNP is about six times as great as that assessed in WASH-1400 for PWRs.

APPENDIX C

INFORMATION AVAILABLE PERTINENT TO CONSEQUENCES OF FNP CORE MELT-THROUGH ACCIDENTS

This appendix presents the results of a literature search to determine the existence of pertinent information relative to the understanding of a core melt-through accident in the FNP resulting in dispersal of fission products in sea water. It was determined that 18 active programs currently exist relative to various aspects of the hypothetical core meltdown accident. These programs are as follows:

Existing Programs*

1. Sandia Laboratories - Purpose is to characterize chemical and physical interactions between prototypical materials likely to be encountered during hypothetical core melt accidents in light water reactors.

2. Ohio State University - Purpose is to develop correlations for determining heat transfer rates by natural convection from enclosed fuel volumes (such as molten cores) having internal heat generation.

3. Sandia Laboratories - Purpose is to identify and characterize the physical conditions which must be met in order for a steam explosion to occur when molten LWR core materials contact water.

4. Argonne National Laboratory - Purpose is to develop fission product release model for LWR fuel undergoing accidental overheat conditions.

5. Argonne National Laboratory - Purpose is to identify and understand the physical conditions which must be met to trigger steam explosions between molten core materials and water.

6. Oak Ridge National Laboratory - Purpose is to provide data pertaining to the Zirconium metal water oxidation phenomena.

7. Kraftwerk Union AG (Germany) - Purpose is to determine the extent and effect of fission product release to the containment during LOCA.

8. Kraftwerk Union AG (Germany) - Purpose is to investigate the hypothetical molten core vessel melt-through event.

9. Kraftwerk Union AG (Germany) - Purpose is to develop analytical techniques describing the core meltdown process.

10. Projekt Nukleare Sicherheit/GFK Karlsruhe (Germany) - Purpose is to investigate the core melting process.

11. T.V. Hannover (Germany) - Purpose is to investigate the thermohydraulic behavior of a molten core at the bottom of a reactor vessel.

12. Kraftwerk Union AG (Germany) - Purpose is to investigate the metallurgical and chemical interactions between molten phases of the reactor core and the pressure vessel.

13. Euratom CCR Ispra and University of Stuttgart - Purpose is to investigate the potential for and consequences of molten core steam explosions.

14. Projekt Nukleare Sicherheit/GFK Karlsruhe - Purpose is to investigate fission and activation product release from molten core materials.

15. Battelle Institute-Frankfurt/Main (Germany) - Purpose is to measure physical properties of molten core materials.

16. Euratom - Purpose is to measure the physical properties of molten core materials.

17. Institut fur Kernenergetik der University Stuttgart - Purpose is to investigate important parameters affecting a hypothetical core meltdown accident.

18. Projekt Nukleare Sicherheit/GFK Karlsruhe - Purpose is to investigate chemical interactions between molten core materials.

* Additional information regarding the domestic programs may be found in "Water Reactor Safety Research, Division of Reactor Safety Research (NRC),

Status Summary Report," published monthly by NRC. For further information on foreign programs, see "Research Reports (Annual Reports) End of 1974, GERRSR-3."

In addition, a literature search was requested through the Nuclear Safety Information Center (Oak Ridge National Laboratory). The search resulted in the following number of citations in the subject categories requested:

TABLE C-1

RESULTS OF LPS LITERATURE SEARCH

Subject	Citations	Applicable to LPS
Core Meltdown	155	43
Fission Product Dispersion in water	200	48

The third column indicates the number of citations which appear to be applicable to various areas of the Liquid Pathway Study. These citations are as follows:

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Working Paper #9

Analysis of Fuel and Waste Handling and Decommissioning for Floating Nuclear Powerplants

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SUMMARY REPORT OF FUEL HANDLING, WASTE PROCESSING AND DECOMMISSIONING OF FLOATING NUCLEAR POWER PLANTS

1. Introduction

Nuclear Energy Services has performed the following work scope in accordance with a letter request from the Office of Technology Assessment of February 12, 1976:

1. Review the offshore Environmental Impact Statement and selected sections of the Council on Environmental Quality/Interagency Task Force Study of Offshore Nuclear Power Plants.

2. Investigate the differences between offshore nuclear power plants (FNP) and land-based plants (LNP) of the same type for:

    a. Processing of wastes generated during normal plant operations.

    b. Fuel handling during operations.

    c. Decommissioning of the plant.

3. Summarize the questions raised by this investigation.

In order to provide a more meaningful commentary, the FNP Environmental Report, Part II with supplements and the NRC Safety Evaluation of the FNP were also reviewed.

2. Conclusions

There are no significant differences between the FNP and LNP as to the expected annual releases of liquid, gaseous and solid radioactive wastes. Both plants should be able to meet the criteria of Appendix I to 10 CFR 50.

Fuel handling in an FNP will entail additional cask handling evolutions, i.e. loading and unloading of the transfer barge between the FNP and land. Although logical statements are made in the reports reviewed as to expected safety of the operation, there is insufficient information to substantiate a low risk assessment.

Decommissioning is treated inadequately in all reports reviewed.[1-5] Specifically, conclusions are reached without reference to the magnitude, composition and location of the radioactive inventory of concern. As a result, the conclusions are erroneous.

3. Processing of Wastes Generated During Normal Operation

A comparison was made between the FNP and typical LNP PWRs of the same type and size as to the processing of liquid, gaseous and solid radioactive wastes generated during normal operation. The two 1150 MWe LNPs considered were the Donald C. Cook Nuclear Plant Unit 1 and the Sequoyah Nuclear Plant Unit 1.

The waste treatment methods employed by the FNP are basically similar to the methods of the LNP. Since the plants are similar, one could expect that the volumes, masses and activities processed should be the same. However, the estimated quantities of liquid, gaseous and solid wastes generated and released are somewhat different. This could be due to prevailing analytical techniques at the time of Environmental Report preparation. The important factor is not the quantitative differences but that liquid and gaseous releases from the FNP and the LNP are expected to meet Appendix I of 10 CFR 50 "as low as practicable" guidelines.

A comparison of the calculated annual liquid, gaseous and solid waste releases from the FNP and the two LNPs is shown in Table 1.[1,6,7]

A system-by-system comparison of the waste processes of the FNP and the D. C. Cook plant was made to verify close similarity of the methods used. The results of the comparison are presented in the following sub-sections.

3.1 Liquid Wastes

The methods used to process FNP and LNP liquid wastes are almost identical. In summary:

1. Segregation of liquid wastes by source is maintained.

TABLE 1

ANNUAL WASTE RELEASES FROM THE FNP AND TWO LNPS

RADIOACTIVE SOURCE TERM / PLANT	LIQUID WASTE (Ci/Yr)		GASEOUS WASTE (Ci/Yr)			SOLID WASTE (Ci/Yr)	
	Total (except Tritium)	Tritium	Noble Gases	Iodine 131	Tritium	Wet	Dry
Floating Nuclear Plant PWR (Westinghouse 1150 MWe (net)	.4	*350	10,600	.067	1,040	*6,000	*<5
Donald C. Cook Nuclear Plant Per Unit PWR (Westinghouse 1093 MWe (net)	5.3	*350	3,400	.20	Not Available	*9,200	*<5
Sequoyah Nuclear Plant Per Unit PWR (Westinghouse 1125 MWe (net)	1.98	*350	9,747	.006	300	*10,491	*10

* Release rates are based on evaluation of similar reactors and operating reactor data.

2. The processes of demineralization, evaporation, filtration and holdup for radioactive decay are common to both plants.

3. Both plants recycle treated water.

4. Cross-connections between the sub-systems provide alternate process methods.

5. The specific treatment process utilized will be dependent on the source, activity, and composition of the liquids. Treated liquid waste will be handled on a batch basis to permit optimum control of the FNP and LNP disposal process.

3.1.1 Steam Generator Blowdown System

Function/Source: both systems process steam generator blowdown continuously.

Process: The FNP blowdown is cooled and depressurized then passed through two cations and two mixed-bed nonregenerative demineralizers and a down stream filter. The LNP blowdown is cooled and depressurized in a flash tank then passed through three anion demineralizers.

End Use: The FNP treated blowdown will be sampled and analyzed and either routed to the condensate storage tank for reuse or discharged to the ocean. The LNP treated blowdown will be sampled and analyzed before being released to the condenser cooling water return to Lake Michigan.

3.1.2 Borow Recovery System

Function/Source: both systems treat shim bleed from the reactor coolant system letdown stream and water from the reactor coolant drain tank.

Process: The FNP and LNP coolants will be processed through the mixed-bed demineralizers, filtered and routed to recycle holdup tanks. Valve leakoffs and equipment drain wastes in the reactor containment will also be transferred to the recycle holdup tanks. The liquid in these tanks will be evaporated and the distillate passed through an anion demineralizer and filter, and conserved in a recycle tank. The concentrates will be filtered and sent to a concentrate holding tank.

End Use: The FNP and LNP distillate will either be discharged (ocean or Lake Michigan), returned to the primary water storage tank for reuse in the reactor, or recycled for reprocessing.

3.1.3 Waste Disposal System

Function/Source: the FNP and LNP waste disposal system collects and processes the other liquid wastes. The sources include recyclable wastes, e.g. equipment drains, sampling system sink drain, excess letdown; the sources also include non-recyclable wastes, e.g. floor drains non-reactor coolant leakage, "hot" laundry and showers, rinse water, laboratory drains and chemical wastes.

Process (FNP Recyclable Waste): The FNP and LNP "clean" waste will be collected in waste holdup tanks. This waste will be pumped through filters, a mixed-bed demineralizer, and a waste evaporator. The FNP distillate will be passed through a demineralizer and filter and stored in a distillate tank. The LNP distillate will be routed to a waste condensate tank.

End Use (FNP Recyclable Waste): The FNP distillate will be transferred to the reactor makeup water storage tank for reuse in the plant, or monitored and released to the ocean, or reprocessed. The LNP condensate will either be discharged to Lake Michigan or reprocessed.

Process (Non-recyclable Wastes): The FNP and LNP non-recyclable liquid wastes will be collected in individual drain tanks associated with the source. The liquids from these tanks will then be pumped through a filter, mixed-bed demineralizer and a followup filter (if required), then transferred to a waste monitor tank. An alternate path permits the liquid waste (e.g. chemical waste) to be processed through the waste evaporator.

End Use: After sampling and analysis of both the FNP and LNP waste tanks, the liquid will either be reprocessed or released under controlled conditions to the ocean or Lake Michigan.

3.2 Gaseous Wastes

The gaseous waste processing systems of the FNP and LNP are quite similar. The variance in estimated annual releases as shown in Table 1 is not clear with the extent of information available in the documents reviewed.

3.2.1 Gaseous Waste Treatment System (GWTS)

Function/Sources: The FNP and LNP GWTS collect and process gases stripped from primary coolant along with various tank cover gases. The gases emanate from the gas stripper; reactor coolant holdup, control and drain tanks; and evaporator vents.

Process: The FNP and LNP gaseous wastes will be collected, compressed, recombined (FNP only), and stored in gas radioactivity decay tanks (8, 600 ft^3 tanks for the FNP and 6, 600 ft^3 tanks for the LNP).

End Use: After sampling and analysis, both the FNP and LNP gases will either be reused as cover gas or released through the plant vent to atmosphere.

3.2.2 Containment Purge System

Function/Sources: Both the FNP and LNP systems treat radioactive gases released inside the reactor containment when primary system components are opened or when leakage from the primary system occurs. The system also maintains a negative pressure in the containment during normal operation.

Process: In both FNP and LNP systems the containment atmosphere is circulated through an internal cleanup system consisting of HEPA filters and charcoal adsorbers. The containment atmosphere is then released to the containment vent through additional HEPA filters and charcoal adsorbers.

3.2.3 Auxiliary Building Ventilation System

Function/Sources: The FNP and LNP systems control and process the release of radioactive gases from the auxiliary building due to primary coolant leakage from components; and area exhausts from the sampling room, drumming area, and chemistry laboratory.

Process: Ventilation air from both FNP and LNP auxiliary buildings is monitored and, if required, processed through HEPA filters and charcoal adsorbers prior to release through the containment vent.

3.2.4 Turbine Building Ventilation System

Function/Sources: The FNP and LNP systems monitor any radioactive gases released to the turbine building due to leakage from the secondary (steam) system or from the gland seal exhaust system.

Process: Ventilation air in both systems will be monitored and then released from the turbine building roof vent without treatment.

3.2.5 Main Condenser Off-Gas System

Function/Source: The FNP and LNP systems process the off-gas from the main condenser air ejectors.

Process: The off-gas is passed through a charcoal adsorber prior to release.

3.2.6 Fuel Handling Area Exhaust System

Function/Sources: The FNP and LNP systems process any radioactive gases released during fuel handling or storage in the fuel handling area.

Process: The exhausts to both systems is passed through HEPA filters and, if required, through charcoal adsorbers prior to release to the containment ventilation system.

3.3 Solid Wastes

Processing of solid wastes for a FNP and LNP is quite similar and, as shown in Table 1, the estimates of annual solid waste generation are quite close.

A comparison of the processes is shown below.

3.3.1 "Wet" Radioactive Solid Wastes

Sources: Wet solid wastes contain significant moisture which must be removed prior to shipment. For both the

FNP and LNP, wet wastes include spent demineralizer resins, filter sludges, evaporator bottoms, and concentrates including chemical drain tank concentrates.

Process: The wet wastes of both the FNP and LNP will be transferred in batches to the drumming station, dewatered (if required) and mixed with appropriate binders and fillers such as cement and vermiculite to form a solid matrix in a steel drum. Shielding will be provided as necessary for off-site disposal at a licensed burial ground.

3.3.2 "Dry" Radioactive Solid Wastes

Sources: Dry solid wastes are generated in the FNP and LNP from ventilation air filters, contaminated clothing and paper, and miscellaneous items such as tools and laboratory glassware.

Process: In both plant types, the dry waste will be compacted in 55 gallon drums and shipped off-site for disposal at a licensed burial ground.

4. Fuel Handling During Operations

A comparison was made between the FNP and two 1150 MWe PWR LNPs, the D. C. Cook and Sequoyah plants. In summary, there are no generic differences between the plants as to the amount of fuel handled or the general procedures to be followed. There are, obviously, specific differences in fuel and cask handling associated with the transfer of a shipping cask from land to a transfer barge and from the transfer barge to the floating barge (and the reverse), and with the handling of fuel on the FNP under a condition of 1/2° combined pitch and roll. Insufficient information is presented in the reports to verify that the FNP poses no significantly greater risk than a LNP due to these specific procedures. However, engineering judgement indicates that the cask transfers and the other fuel handling operations can be engineered and performed without undue risk.

The areas of comparison between the FNP and LNPs included fuel type and radioactive inventory, transportation of new and irradiated fuel, in-plant fuel handling, new fuel storage, spent fuel storage, and fuel handling accidents.

4.1 Fuel Type and Radioactive Inventory

Both the FNP and LNP cores will contain 193 fuel assemblies. Each assembly will contain 264 fuel rods in a 17x17 matrix. The fuel rod is a Zircaloy-4 alloy sealed tube containing Uranium Dioxide pellets with a nominal content of 3.3% U^{235}. The operating cycle of both the FNP and LNP will require an annual discharge of about 1/3 of the core, i.e. 65 assemblies. Therefore the quantity, frequency of handling and radioactive content of fuel handled will be the same for the FNP and LNP.

4.2 Transportation of New and Irradiated Fuel

The shipping containers to be used for transport of fresh and irradiated FNP and LNP fuel are similar. All casks and containers meet the USNRC and USDOT regulatory requirements. Fresh fuel is housed in two-assembly containers and irradiated fuel in 10-assembly shipping casks. The fresh fuel containers include sealed closures, humidity control and shock and vibration isolation of the fresh fuel. The spent fuel shipping casks are designed to withstand a 30 foot free fall impact on an unyielding surface (272 g's). Therefore, there are no significant differences in the packaging of fresh and irradiated FNP and LNP fuels.

Land transportation of FNP and LNP fuel is identical. The barge transfers do pose the possibility of unique risks (see Section 4.6) due to unique cask drops. The barge transfers will also result in some additional exposure to the barge personnel but it will be very small. The total annual exposure to all barge personnel is estimated at 0.04 man-Rem.[4] The probability of collision with the transfer barge is approximately the same as the probability of a rail or truck accident i.e., there is no significantly greater risk associated with barge transport than with land transport. The risk for either plant is directly proportional to total number of miles traveled.

4.3 In-Plant Fuel Handling

The handling of fresh and irradiated fuel on a FNP and LNP is quite similar. The fuel containers and casks are off-loaded by crane to the plant, transferred by rail car to the fuel (auxiliary) building, and dispositioned by building crane. All irradiated fuel is handled underwater in both plants until after loading in the shipping cask. The unique parameter of FNP fuel/cask handling is the possibility of a change in barge attitude during handling. To prevent a fuel handling accident caused by barge motion, all handling operations will be suspended if combined pitch and roll exceed 1/2°. In addition, the cask transfer rail car is so designed to preclude overturning of the cask at the maximum barge design condition of 3° roll.

4.4 New Fuel Storage

New fuel in both the FNP and LNP is stored dry and in a vertical position. The fuel is on 21 inch centers. A maximum of 70 fresh assemblies can be stored in both plants.

The storage racks are designed to meet the site seismic criteria. This is obviously more severe for the LNP than the FNP. On the other hand, FNP new fuel should be stored in a manner that precludes movement during the design basis roll of 3°. Although not indicated in the reports, this functional design requirement is not difficult to achieve.

4.5 Spent Fuel Storage

The planned storage of spent fuel at the FNP is different than the original design of the LNP spent fuel storage. The FNP will store spent fuel under water on 15 inch centers whereas the original LNP design criteria is underwater on 21 inch centers. This does not pose an increase in risk however since 15 inch spacing meets the NRC criteria for sub-critical fuel storage arrays. In fact, the D. C. Cook Plant operator (American Electric Power) is currently soliciting quotations for an increase in spent fuel storage capacity of 1200 - 1400 assemblies. This will be accomplished by racks designed for fuel on 12 inch centers.

Again, the FNP spent fuel storage racks should also preclude fuel movement during the design basis roll of 3°. This is not difficult to achieve.

4.6 Fuel Handling Accidents

The following accidents were reviewed for both the FNP and LNP:

1. fuel bundle drop
2. heavy object drop on fuel in core
3. heavy object drop on fuel rack
4. fuel cask drop

The conclusion from this comparison is that the FNP dose level as a function of distance from the plant is significantly less than the LNP (D. C. Cook) for accidents 1, 2 and 3. A comparison of the whole body dose at a distance of 612 meters from each plant is shown in Table 2. (Note: 612 meters is the D. C. Cook site boundary distance).

TABLE 2

FUEL HANDLING ACCIDENT COMPARISON

Accident	WHOLE BODY DOSE AT 612 METERS, mRem	
	D. C. Cook	FNP
1. FUEL BUNDLE DROP	7.5	0.4
2. HEAVY OBJECT DROPPED ON FUEL IN CORE	130	7
3. HEAVY OBJECT DROPPED ON FUEL RACK	19	0.3
4. FUEL CASK DROP	Not Calculated	0.6

Although the differences in dose levels may be due to variations in dispersion models and/or methodologies, it can be safely concluded that the FNP fuel handling accidents pose no greater risk to public exposure than a typical LNP.

The cask drop accident of the FNP is significantly different than that of an LNP in that the possibility of a drop into the water must be considered. As noted previously, the cask used for shipping FNP spent fuel will be designed to sustain a 30 foot drop onto an unyielding surface. The design basis water drop accident is a 76 foot free fall into an equivalent depth of water. This has been shown to be 1/15 as severe as the 30 foot cask design drop therefore cask rupture will not occur. It should be noted that the dose data of Table 2 for the FNP cask drop is based on the conservative assumption that the cask will rupture on impact with the sea bottom and that the cask contains a full complement of 10 assemblies.

The second postulated cask drop is into the cask loading pit. An energy absorbing pad is located on the bottom of the FNP pit which would crush under impact of a dropped cask thus preventing cask rupture and also preventing cask penetration into the bottom of the pit. A similar "crash pad" concept has been designed and licensed by NRC for the LaCrosse BWR. It is currently being fabricated.

Accidents pertaining to new fuel shipments are significantly less severe than for spent fuel except for a postulated criticality. In this case the only difference between the FNP and LNP is the possibility of an underwater accident occurring for the FNP. This is much less severe than for an LNP since there would be no radiation effect beyond 3 feet from the fuel due to water shielding.

5. Decommissioning of the Plant

The CEQ/Interagency Task Force Study, the offshore EIS and the BDM report are all based on the Environmental Report, Part II, prepared by Offshore Power Systems (Docket No. STN 50-437). The most definitive information on decommissioning is contained in Supplement No. 1 to the report, dated March, 1974. However, this supplement did not go as far as calculating the end-of-life radioactive inventory. It was estimated as 1.2×10^6 curies in the supplement based on extrapolation of the decommissioning of small (<50 MWe) power reactors. Actually, the inventory will be approximately 15×10^6 curies after 40 years of operation. This is too great a disparity and, as a result, the statements made as to ultimate disposition of an FNP are in error. Therefore, the reports mentioned above are also in error relative to decommissioning.

The following sections will discuss the factors pertinent to decommissioning of an FNP and present certain conclusions as to modes, effects and costs.

5.1 Radioactive Inventory and Distribution

The inventory of radionuclides resulting from 40 years operation at an 80% factor for an 1150 MWe (3411 MW_{th}) PWR is shown in Table 3. As can be seen, the total activity immediately after shutdown (datum) is about 15 million curies. This will decay to approximately 74,000 curies in 50 years and to 21,000 in 500 years. The most activated component is the pressure vessel internal structure which contains about 80% of the total activation inventory. The distribution by nuclides is 6% Ni^{63}, 51% Fe^{55} and 40% Co^{60}. A small amount (~4,000 curies) of Ni^{59} will also be present in the vessel internals immediately after shutdown. The Co^{60} is the main direct radiation exposure concern for any work activities but the Ni^{59} will be of long term direct radiation concern because of its long half-life. At shutdown the peak Ni^{59} contact dose level will be 30 mR/hr as compared to 400,000 R/hr for Co^{60}. However, the Ni^{59} dose will still require control for thousands of years. Ni^{63} will be the controlling ingestion hazard nuclide.

5.2 Post-decommissioning Licensing Period

Current NRC regulations require a possession-only license to be maintained for as long as there is significant residual radioactivity in the decommissioning facility. The license conditions require that the plant be protected to preclude a negative effect on public health and safety. Three radiation criteria govern the required duration of the licensing period. They include limits on surface contamination, contact dose level due to activation, and specific activity. The latter two will be covered by NRC on a case basis but will, invariably, be the controlling criteria. The contact dose level criteria is related to direct exposure to personnel whereas the specific activity criterion is tied to allowable ingestion limits.

For an 1150 MWe PWR (FNP or LNP) the required licensing period will extend for 500,000 years due to Ni^{59} content in the vessel internals and for about 490 years due to the Ni^{63} content in the internals. If the licensee were to remove these internals and dispose of them at a licensed burial ground, then the required period would be 89 years as controlled by the Co^{60} content of the pressure vessel stainless steel cladding.

NOTE: Removal and disposal of the internals would require extensive remote operations since the internals contact dose level would be about 4×10^4 R/hr at shutdown. In fact internals removal at shutdown would be about 1/3 the cost of total dismantling/disposal. A delay of about 100 years would permit single removal of the internals after which the license could be terminated.

TABLE 3 3411 MWth PWR

ACTIVITY OF MAJOR CONTRIBUTORS AS A FUNCTION OF TIME, IN CURIES

COMPONENT	RADIOACTIVE ISOTOPE	ACT. AT DATUM	ACT. AT 2 YRS.	ACT. AT 5 YRS.	ACT. AT 10 YRS.	ACT. AT 20 YRS.	ACT. AT 50 YRS.	ACT. AT 100 YRS.	ACT. AT 200 YRS.	ACT. AT 500 YRS.
Pressure Vessel	C 14	2.2011E-04	2.2006E-04	2.1998E-04	2.1984E-04	2.1958E-04	2.1878E-04	2.1746E-04	2.1485E-04	2.0719E-04
	V 49	5.6980E+00	1.2285E+00	1.2298E-01	2.6544E-03	1.2365E-06	1.2500E-16	2.7421E-33	1.3196E-66	1.4708-166
	MN 54	5.0501E+03	9.9655E+02	8.7359E+01	1.5112E+00	4.5221E-04	1.2117E-14	2.9073E-32	1.6737E-67	3.1935-173
	FE 55	6.2542E+04	3.5100E+04	1.4758E+04	3.4824E+03	1.9390E-02	3.3474E-02	1.7917E-08	5.1326E-21	1.2067E-58
	CO 57	2.2413E+01	3.4838E+00	2.1350E-01	2.0337E-03	1.8453E-97	1.3786E-19	8.4794E-40	3.2080E-80	1.7371-201
	CO 60	9.2133E+03	7.0716E+03	4.7553E+03	2.4543E+03	6.5380E+02	1.2359E+01	1.6579E-02	2.9835E-08	1.7385E-25
	NI 63	1.3193E+03	1.2996E+03	1.2705E+03	1.2235E+03	1.1347E+03	9.0519E+02	6.2106E+02	2.9237E+02	3.0501E+01
	NI 59	6.1203E+00	6.1202E+00	6.1200E+00	6.1172E+00	6.1192E+00	6.1176E+00	6.1150E+00	6.1097E+00	6.0938E+00
	TOTALS	7.81587E+04	4.44790E+04	2.08775E+04	7.16791E+03	1.98858E+03	9.23697E+02	6.27193E+02	2.98477E+02	3.65946E+01

COMPONENT	RADIOACTIVE ISOTOPE	ACT. AT DATUM	ACT. AT 2 YRS.	ACT. AT 5. YRS.	ACT. AT 10 YRS.	ACT. AT 20 YRS.	ACT. AT 50 YRS.	ACT. AT 100 YRS.	ACT. AT 200 YRS.	ACT. AT 500 YRS.
Lower Core Support Structure	C 14	1.1554E-04	1.1551E-04	1.1547E-04	1.1540E-04	1.1526E-04	1.1484E-04	1.1415E-04	1.1278E-04	1.0876E-04
	V 49	1.5049E+02	3.2445E+01	3.2480E+02	7.0104E-02	3.2657E-05	3.3013E-15	7.2422E-32	3.4853E-65	3.8844-165
	MN 54	2.4219E+03	4.7792E+02	4.1895E+01	7.2472E-01	2.1687E-04	5.8110E-15	1.3943E-32	8.0268E-68	1.5313-173
	FE 55	6.7006E+04	3.7606E+04	1.5811E+04	3.7310E+03	2.0774E+02	3.5864E-02	1.9195E-08	5.4990E-21	1.2928E-58
	CO 57	1.8110E+02	2.8150E+01	1.7251E+00	1.6433E-02	1.4911E-06	1.1139E-18	6.8516E-39	2.5921E-79	1.4037-200
	CO 60	5.2881E+04	4.0588E+04	2.7293E+04	1.4087E+04	3.7526E+03	7.0937E+01	9.5159E-02	1.7124E-07	9.9784E-25
	NI 63	8.1009E+03	7.9798E+03	7.8014E+03	7.5130E+03	6.9678E+03	5.5582E+03	3.8135E+03	1.7952E+03	1.8728E+02
	NI 59	3.7580E+01	3.7580E+01	3.7579E+01	3.7577E+01	3.7574E+01	3.7564E+01	3.7548E+01	3.7515E+01	3.7418E+01
	TOTALS	1.30778E+05	8.67499E+04	5.09904E+04	2.53692E+04	1.09657E+04	5.66671E+03	3.85119E+03	1.83275E+03	2.24703E+02

COMPONENT	RADIOACTIVE ISOTOPE	ACT. AT DATUM	ACT. AT 2 YRS.	ACT. AT 5 YRS.	ACT. AT 10 YRS.	ACT. AT 20 YRS.	ACT. AT 50 YRS.	ACT. AT 100 YRS.	ACT. AT 200 YRS.	ACT. AT 500 YRS.
Core Barrel And Shroud	C 14	1.2918E-02	1.2915E-02	1.2911E-02	1.2903E-02	1.2887E-02	1.2941E-02	1.2763E-02	1.2610E-02	1.2160E-02
	V 49	1.9191E+04	4.1376E+03	4.1421E+02	8.9401E+00	4.1647E-03	4.2101E-13	9.2357E-32	4.4446E-63	4.9537-163
	MN 54	3.0886E+05	6.0948E+04	5.3428E+03	9.2422E+01	2.7656E-02	7.4106E-13	1.7781E-30	1.0236E-65	1.9531-171
	FE 55	7.4962E+06	4.2071E+06	1.7689E+06	4.1740E+05	2.3241E+04	4.0122E+00	2.1475E-06	6.1520E-19	1.4463E-56
	CO 57	2.3095E+04	3.5899E+03	2.2000E+02	2.0956E+00	1.9015E-04	1.4206E-16	8.7376E-37	3.3057E-77	1.7900E-198
	CO 60	5.9175E+06	4.5419E+06	3.0542E+06	1.5763E+06	4.1992E+06	7.9380E+03	1.0648E+01	1.9162E-05	1.1166E-22
	NI 63	9.0575E+05	8.9221E+05	8.7227E+05	8.4002E+05	7.7906E+05	6.2145E+05	4.2639E+05	2.0072E+05	2.0940E+04
	NI 59	4.2018E+03	4.2017E+03	4.2016E+03	4.2014E+03	4.2011E+03	4.2000E+03	4.1982E+03	4.1945E+03	4.1836E+03
	TOTALS	1.46748E+07	9.71416E+06	5.70549E+06	2.83806E+06	1.22642E+06	6.33592E+05	4.30595E+05	2.04917E+05	2.51237E+04

TABLE 3 3411 MWth PWR, continued

COMPONENT	RADIOACTIVE ISOTOPE	ACT. AT DATUM	ACT. AT 2 YRS.	ACT. AT 5 YRS.	ACT. AT 10 YRS.	ACT. AT 20 YRS.	ACT. AT 50 YRS.	ACT. AT 100 YRS.	ACT. AT 200 YRS.	ACT. AT 500 YRS.
Neutron Shield Pads	C 14	7.8371E-05	7.8352E-05	7.8324E-05	7.8277E-05	7.8182E-05	7.7899E-05	7.7429E-05	7.6498E-05	7.3772E-05
	V 49	2.9067E+01	6.2667E+00	6.2735E-01	1.3540E-02	6.3077E-06	6.3764E-16	1.3988E-32	6.7317E-66	7.5027-166
	MN 54	4.6778E+02	9.2310E+01	8.0920E+00	1.3988E-01	4.1887E-05	1.1224E-15	2.6930E-33	1.5504E-68	2.9581-174
	FE 55	4.5312E+04	2.5430E+04	1.0692E+04	2.5230E+03	1.4048E+03	2.4252E-02	1.2981E-08	3.7186E-21	8.7424E-59
	CO 57	3.4980E+01	5.4372E+00	3.3320E-01	3.1740E-03	2.8800E-07	2.1515E-19	1.3234E-39	4.0067E-80	2.7111-201
	CO 60	3.5716E+04	2.7414E+04	1.8434E+04	9.5143E+03	2.5345E+03	4.7911E+01	6.4271E-02	1.1566E-07	6.7395E-25
	NI 63	5.4948E+03	5.4126E+03	5.2916E+03	5.0960E+03	4.7262E+03	3.7700E+03	2.5867E+03	1.2177E+03	1.2703E+02
	NI 59	2.5491E+01	2.5490E+01	2.5490E+01	2.5488E+01	2.5486E+01	2.5480E+01	2.5469E+01	2.5477E+01	2.5380E+01
	TOTALS	8.70796E+04	5.83859E+04	3.44523E+04	1.71590E+04	7.4266E+03	3.84345E+03	2.61221E+03	1.24313E+03	1.52414E+02

COMPONENT	RADIOACTIVE ISOTOPE	ACT. AT DATUM	ACT. AT 2 YRS.	ACT. AT 5. YRS.	ACT. AT 10 YRS.	ACT. AT 20 YRS.	ACT. AT 50 YRS.	ACT. AT 100 YRS.	ACT. AT 200 YRS.	ACT. AT 500 YRS.
Upper Core Support Structure	C 14	7.3083E-05	7.3065E-05	7.3039E-05	7.2995E-04	7.2906E-05	7.2642E-05	7.2204E-05	7.1336E-05	6.8794E-05
	V 49	1.2488E+02	2.6924E+01	2.6953E+00	5.8174E-02	2.7100E-05	2.7395E-05	6.0097E-32	2.8922E-65	3.2234-165
	MN 54	2.0097E+03	3.9659E+02	3.4766E+01	6.0139E-01	1.7996E-04	4.8221E-15	1.1570E-32	6.6609E-68	1.2709-173
	FE 55	4.2439E+04	2.3818E+04	1.0014E+04	2.3630E+03	1.3158E+02	2.2715E+02	1.2158E-08	3.4828E-21	8.1882E-59
	CO 57	1.5028E+02	2.3360E+01	1.4315E+00	1.3636E+02	1.2373E-06	9.2437E-19	5.6856E-39	2.1510E-79	1.1648-200
	CO 60	3.3511E+04	2.5721E+04	1.7296E+04	8.9268E+03	2.3780E+03	4.4953E+01	6.0302E-02	1.0851E-07	6.2322E-25
	NI 63	5.1241E+03	5.0474E+03	4.9346E+03	4.7522E+03	4.4073E 03	3.5157E+03	2.4122E+03	1.1355E+03	1.1846E+02
	NI 59	2.3771E+01	2.3770E+01	2.3770E+01	2.3769E+01	2.3766E+01	2.3760E+01	2.3750E+01	2.3729E+01	2.3668E+01
	TOTALS	8.33823E+04	5.50570E+04	3.23073E+04	1.60665E+04	6.94066E+04	3.58444E+03	2.43599E+03	1.15927E+03	1.42131E+02

COMPONENT	RADIOACTIVE ISOTOPE	ACT. AT DATUM	ACT. AT 2 YRS.	ACT. AT 5 YRS.	ACT. AT 10 YRS.	ACT. AT 20 YRS.	ACT. AT 50 YRS.	ACT. AT 100 YRS.	ACT. AT 200 YRS.	ACT. AT 500 YRS.
Neutron Shield Tank	C 14	4.8566E-06	4.8555E-06	4.0537E-06	4.8508E-06	4.8449E-06	4.8273E-06	4.7982E-06	4.7405E-06	4.5716E-06
	MN 54	4.0829E+02	8.0569E+01	7.0628E+00	1.2218E-01	3.6560E-05	9.7963E-16	2.3505E-33	1.3532E-68	2.5819-174
	FE 55	1.2834E+03	7.2030E+02	3.0285E+02	7.1463E+01	3.9791E+00	6.8693E-04	3.6767E-10	1.0533E-22	2.4762E-60
	CO 57	1.2809E+00	1.9910E-01	1.2201E-02	1.1623E-02	1.0546E-08	7.8787E-21	4.8460E-41	1.8334E-81	9.9279-203
	CO 60	5.8791E+01	4.5125E+01	3.0344E+01	1.5661E+01	4.1720E+00	7.8866E-02	1.0580E-04	1.9038E-10	1.1094E-27
	NI 63	6.4797E+00	6.3828E+00	6.2402E+00	6.0095E+00	5.5733E+00	4.4458E+00	3.0503E+00	1.4360E+00	1.4980E-01
	NI 59	3.0056E-02	3.0055E-02	3.0055E-02	3.0053E-02	3.0051E-02	3.0043E-02	3.0030E-02	3.0004E-02	2.9926E-02
	TOTALS	1.75830E+03	8.52605E+02	3.46538E+02	9.32859E+01	1.37546E+01	4.55543E+00	3.08049E+00	1.46597E+00	1.79735E-01

5.3 Acceptable Decommissioning Modes

At present, NRC acknowledges thee basic modes- mothballing, entombment and dismantling. The first two require a possession-only license as previously discussed. The primary difference in the degree of protection required is the additional requirement of a full-time security force for the mothballed plant. The entombed plant would have greater built-in security and not require this guard force. A dismantled facility has no licensing requirements after completion of the dismantling and disposal activities. Combinations, such as mothballing followed by dismantling, will be acceptable. In fact, that mode will probably prove to be the norm. NRC will accept mothballing as a permanent decommissioning form, but, the maintenance and security required over a 500,000 year period makes this form uneconomical and not credible.

5.4 Evaluation of FNP Decommissioning Alternatives

Three alternatives have been postulated by Offshore Power Systems for the decommissioning of an FNP. They are:

1. Sinking of Activated Plant -

   All plant fuel and wastes removed; activated materials placed in the pressure vessel; reactor compartment filled with concrete; plant towed to deep-sea and sunk.

2. Mothballing at Approved Storage Site -

   All plant fuel and wastes removed; plant secured and continuously monitored at storage site.

3. Dismantling -

   All plant fuel and wastes removed; plant towed to site where dismantling and disposal will occur.

4. Mothballing/Dismantling -

   The mothballing mode endures for 50 years at which time the plant will be dismantled.

5.4.1 Sinking of Activated Plant

The practicality of this approach is related to the integrity of the sealed enclosure(s) which contain the activated materials of the vessel, internals and surrounding structure. As noted above, structural integrity would have to be maintained for about 500,000 years. This could not be demonstrated. Past parallel experience has indicated that 200 years may be the limit of credibility for such an entombment structure. The BONUS facility was entombed by encasing the pressure vessel and all other residual activated materials within a solid poured concrete structure integral with the biological shield. However, a portion of the core internals had to be removed and disposed of at a burial ground due to excessive Ni^{63} specific activity which would have required entombment structural integrity for a period greater than 200 years. For this reason, NES does not consider the sinking alternative as viable. It might be only after the pressure vessel internals were removed and integrity of the sealed structure could be demonstrated for the required design life (about 89 years) under the corrosive effect of continuous exposure to seawater.

5.4.2 Mothballing at Approved Storage Site

This is a viable alternative. The obvious question is how long can the licensee afford to carry out this alternative. With the vessel internals in-place, the required protective storage period is 500,000 years. The surveillance costs plus the major maintenance necessary to prevent deterioration over that time span would be prohibitive. Technically, the mode does meet current regulatory requirements but it is not logical.

5.4.3 Dismantling

The dismantling alternative as presented for the FNP is viable and correct. Dismantling, either in place or at a prepared site, is technically feasible and consistent with the experience gained during removal of the Elk River Reactor. Dismantling of the FNP will require the same type of tooling development as required for any LNP light water reactor. That includes remotely operated automatic vessel and internals segmenting equipment such as a plasma torch manipulator. There are no unique risks or unique engineering developments required for the FNP relative to the LNP.

5.4.4 Mothballing/Dismantling

This combination of modes postulated for the FNP is reasonable. It is the most likely scenario that will occur for any PWR or BWR. The error in the reports is the assumed adequacy of a 50 year mothball period at which time dismantling can easily be accomplished. That assumption is incorrect. It will be necessary to mothball the plant for approximately 110 years before simple dismantling is feasible. After the 110 year decay period the contact dose level of the PWR internals (core shroud) will have decayed to a level of 300 mR/hr. Manual cutting of the internals with appropriate shielding is considered feasible at that radiation level. At 50 years, the contact dose level of the internals would still be high and require the same remotely operated tooling as at shutdown. Once the internals are removed (at 110 years) the license can be terminated and the facility salvaged or disposed of by conventional means.

5.5 Evaluation of FNP Decommissioning Costs

	Alternative	Initial Cost $	Annual Cost $
1.	Sinking of Activated Plant	5.6×10^6	--
2.	Mothballing	13.6×10^6	225,000
3.	Dismantling	86.1×10^6	--
4.	Mothballing/Dismantling	64×10^6	--

The costs of the first three alternatives are defined in Supplement No. 1 to the Offshore Power Systems Environmental Report. The cost of the mothballing/dismantling combination is only presented in the BDM report. It is neither explained nor understood.

The costs of all alternatives do not include the cost of maintaining the operating staff during the period from plant shutdown till termination of the operating license or imposition of the possession-only license. This could amount to an additional four million dollars initial cost.

The cost of mothballing is considered reasonable. The 13.6 million dollars includes 8.4 million dollars for site preparation and a mooring system.

The 86.1 million dollar cost of dismantling includes 75 million dollars for disassembly, transportation and burial of irradiated components. NES has recently completed a study which estimates this cost at 31 million dollars (1975 value). Therefore, NES would estimate FNP dismantling cost to be 42 million dollars in lieu of 86.1

The cost of mothballing followed by dismantling would include the initial cost of mothballing, the annual cost of maintenance and the future cost of dismantling. Therefore, the total cost of this combination in current dollars (excluding the time value of money) is:

$$13.6M + (225KO(110) + 11.8M = 50 \text{ Million Dollars}$$

The 11.8 million dollars is the cost, calculated by NES, to dismantle an 1150MWe PWR after a decay period of 110 years.

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Working Paper #10

Economic Considerations for Floating Nuclear Powerplants

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FLOATING NUCLEAR POWER PLANTS

I. The Capital Costs of Nuclear Power Plants Continue to Increase

Cheap electricity from Light Water Reactors (LWR's) remains a hope rather than an accomplishment because of continuing increases in the capital costs of nuclear power plants. Fig. 1 is a plot of nuclear unit cost trends. The solid black line is the originally estimated average cost per installed kw of newly ordered units at the time of order. The solid grey line shows the trend of actual capital costs as the units came into operation. The dashed grey line represents present (i.e. early 1976) estimates of costs for plants not yet complete. On the average, though, less than 50% of the construction work is complete for plants ordered after 1969. Hence the anticipated convergence of actual and estimated costs may very well not materialize.

Fig. 2 shows that the cost increases for nuclear plants have consistently exceeded overall inflation rates. Although the nuclear industry and even recent government publications maintain that this will not happen in the future, there is no evidence whatever that the real, i.e. constant dollar, costs of nuclear power plants have begun to stabilize. In fact, quite to the contrary, all available evidence points unambiguously to further constant dollar increases in nuclear plant capital costs.

The most important conclusion of my review of the Offshore Power Systems' (OPS) floating nuclear plant (FNP) concept is that it offers real promise as a partial solution to this unsatisfactory state of affairs.

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II. The Existence of Monetary Inflation Significantly Complicates the Issue

There are many confident explanations for the unexpected cost increases of nuclear power plants since the first large-scale plants were ordered in 1965-1966. But contrary to what one might infer from the literature on nuclear power economics, the precise nature as well as the relative importance of these forces is by no means clear. Consider Fig. 4.[1] This histogram suggests that we understand with considerable quantitative precision what has happened over the past 8 to 9 years. The quantitative certainty implied by this representation is not justified by any existing data. Moreover, I have serious reservations about the validity of the inferences which this particular representation invites. Without detailed information about the inflation rates which prevailed (and varied) between any two points, it is invalid to make comparisons of the magnitude of any given component of one bar with the same component of another.

The source of the difficulty is the way the electric utility industry customarily handles the problem of inflation in estimating the cost of a power plant which will require many years to design and build. The company building the plant may know that a particular pump would cost $100,000 if it were to be delivered today. The pump will, however, not be delivered until sometime in the future. The utility must therefore estimate a future price for this piece of equipment. If price inflation

1. This particular representation is from: H. A. Bethe, "The Necessity of Fission Power," Scientific American, Vol. 234, No. 1, January 1976. Essentially similar representations have appeared in a large number of both pro- and anti-nuclear economic analyses. See, for example, USAEC, WASH 1345, October 1974; Holliday and Taylor, "The Uncertain Future of Nuclear Power," California Arms Control Foreign Policy Seminar, August 1975.

is predicted to be 6% per year for this item, and it is to be delivered one year hence, the purchase price will be estimated at $106,000. In developing an overall estimate of the cost of a power plant, $100,000 is included as the estimated "present-day" cost of the pump and $6,000 is included under the heading"escalation". This process is repeated for all of the items--materials, equipment, and labor--in the total cost estimate.[2] The cost components labeled "escalation" in Fig. 4 are merely the sum of the individual estimates (or contractual guarantees) for the various labor, material, and equipment components of a power plant. As Fig. 4 suggests, this sum is in turn simply added to the total of the estimated "present-day" prices (together with interest, taxes, licensing fees, etc.) to arrive at an estimated cost of plant at the day of commercial operation.

A moment's reflection will suggest that while this practive may be useful for accounting or bookkeeping purposes, it produces cost estimates whose economic meaning is far from clear. If the company building the power plant has been perfectly accurate in predicting the future price behavior of the multitude of labor, material, and equipment items and/or has contractually secured these predictions, the ultimate reckoning of the payments made for them will equal the original estimate of what the plant would cost to build. Hence, this method of dealing with inflation is quite satisfactory for internal control purposes. It is, however, much less helpful as an analytical tool for assessing and comparing the real costs of various power plant alternatives. This is because the

2. In many cases, the "escalation" component of an item represents something more substantial than a prediction; it is a contractual guarantee by a vendor.

dates of payments for various items and the relative variations in the purchasing value of money are not taken into account and therefore, both the cost component labeled "escalation" in Fig. 4 and the total estimated cost at commercial operation are heterogeneous aggregates of monetary units of different purchasing values. Subtracting the "escalation" component does not give the constant dollar cost of a power plant; to get it each dollar paid out has to be deflated to some common base of an appropriate index. This will produce a total cost estimate which is substantially different from both of the estimates used in normal industry and government practice--the "present-day" cost and "cost at date" of commercial operation. None of the published analyses of nuclear power economics (or the economics of alternative power plant technologies, for that matter) adequately deal with this problem. The effect is two-fold. First, it is impossible to be quantitatively precise about the relative magnitude of the numerous causes of past cost increases. Second, it is equally impossible to make precise quantitative comparisons of the estimates of alternative power plants ordered today for operation as much as 10 to 12 years in the future. This second point is a crucial one for this report. It means that the apparent quantitative precision of comparisons of, say, Public Service Gas & Electric's (PSG&E) proposed Atlantic Generating Station (AGS) with land-based, or coal-fired alternatives is specious.

In weighing the potential costs and benefits of FNP's (or indeed any large power generating technology), it is critically important constantly to bear this uncertainty in mind.

III. The Architect-Engineer's Role in Power Plant Construction

The construction process of electricity generating plants in the United States has been dominated by the architect-engineer (A-E) industry. It is the A-E, typically hired by the utility on a cost-plus basis who assembles a variety of raw materials, -cement, wire, etc.-; labor -skilled and unskilled-; and manufactured components -pumps, instrumentation-, into a complete power plant.

It is my opinion that this process has failed to capture the economies of production we have come to expect from other, less complex, manufacturing enterprises. I can only offer this as an hypothesis suggested by episodic and qualitative evidence, not as a conclusion supported by systematic analysis.

The Nuclear Regulatory Commission (NRC), for example, has observed that the earliest construction completion date filed with the government by an applicant upon receipt of a CP has never been met. Part of the problem is related to the reactor safety controversy--unanticipated requirements during FSAR review. But another part seems to be due to characteristics inherent in the manufacturing process: equipment delivery problems labor difficulties and strikes, deteriorating productivity. The suspicion that the A-E system itself may be one cause of nuclear power's capital cost problems is reinforced by the reported--thought not independently confirmed--ability of the utilities who build their own plants, notably Duke Power Company, to systematically bring plants on line at costs far below the industry average. Duke's "Oconee" station, for example, was built between 1966 and 1974 for less than $265/kw (constant 1975 dollars). Other nuclear stations built in the United States during the same period averaged about $400/kw. Duke is currently estimating the total cost of its "Catawba" station (2x1153 MWe units) to be about $1,100

million ("escalated" dollars). Meanwhile, Northeast Utilities' most recent estimate for "Millstone 3", a single 1150 MWe unit, was $900 million--almont twice Catawba's cost per kw.

The OPS concept, in my opinion, holds the promise of meeting these problems. The offshore floating nuclear plant, assembly line produced in a controlled factory environment and identical from site to site, presents the first real opportunity for stabilizing and eventually reducing the real cost of nuclear power plant construction through the phenomenon of "learning".

IV. Learning Curves and Nuclear Plant Costs

Considerable confusion has been introduced into the public debate about nuclear power economics by constant loose references on the part of both government and industry to so-called "learning" or "experience" curves. Let me try to clarify a few points.

As originally formulated, a "learning curve" was an empirically derived description of the realtionship between the direct labor hours required to complete a task and the total number of times that task had been performed. In a typical activity, hours per unit were found to decrease by a constant percentage each time total repetitions of the activity doubled. This percentage varied widely; but, for a very broad range of tasks, it was found to be about 15%. This discovery gave rise to the notion of an "85% learning curve", meaning that the labor cost of unit #2n would be 85% of the cost of unit #n. Presumably what explained this phenomenon was that each time you repeat a task, you usually get better at it in some respect.

It is important to emphasize that the cost reduction occurs with respect to total units and not time. The cost-time relationship, a much more complex one, requires the introduction of a production growth rate variable. A rapid decrease in costs occurs early in an activity's production life, but, because of the increasingly large number of units required to achieve a total production doubling as production continues, the rate of apparent learning diminishes almost to the vanishing point. Although the learning rate (with respect to total units) has not changed, the learning rate with respect to time has decreased since output doubling takes a much longer time.

In recent years the phenomenon of "learning" effects has been broadened into the closely related notion of "experience" effects. The Boston Consulting Group (BCG) has claimed that the cost of doing any repetitive task, or sets of tasks, will decrease as the total number of repetitions increases. In theory, any task of a repetitive nature, including those carried out by management, should exhibit some sort of experience effect. Such an effect is thought to arise from five principal sources: learning effects, scale economies, substitution, redesign and technology. Scale effects occur because capacity costs do not increase as rapidly as capacity. The process industries' famous "six-tenths" formula, whereby capital costs invariably increase by the six-tenths power of the increase in capacity, provides evidence for a scale effect. Substitutions of cheaper materials or less expensive processes over time also contribute to the experience effect. Redesign, or design refinement, can also serve to reduce costs if it is carried on routinely. New technologies in any part of the production and distribution process can similarly decrease costs, quite frequently by large amounts at a time.

Now, it cannot be too strongly emphasized that experience effects do not occur without conscious action on the part of management and workers. Costs do not fall by natural inclination--they rise. Without steady pressure to lower costs, there is neither a theoretical nor an empirical reason to expect the benefits of experience effects to be obtained in any given manufacturing process.

This is the real point with respect to the continuing increases in land based nuclear plant (LBNP) costs. Are management and labor taking actions to reduce costs? Or, put somewhat differently, is the overall design and construction process being managed in such a way that the cost benefits of experience are being realized? My strong impression is that it is not.

Except where two plants have been built on the same site, LBNP's have received almost no benefits from experience effects. Under the A-E dominated system, virtually every construction activity for every plant is in some sense being done for the first time.

The chief and highly significant attraction of the OPS construction concept is a drastic modification of this situation. The OPS concept in my opinion is an imaginative attempt to bring to electric power plant construction a system which is known to have produced real cost reductions in a variety of other complex activities. It does so, moreover, within a contractual framework which, in comparison with the standard A-E arrangement, greatly reduces the financial risk to the electric utility. For an FNP as currently being marketed by OPS, a substantial fraction of the financial risk inherent in any large-scale, lengthy construction process is shifted from the buyer to the seller.

V. Distribution of Risks in FNP Construction

In purchasing an FNP, an electric utility is buying from the manufacturer a "black box" at a price which is subject to change only according to pre-defined and contractually secured rules. Approximately 80% of the total anticipated cost of the complete power plant is delivered to the utility on this "firm price" basis. The utility, in turn, pays OPS by the month over the entire plant construction period. Each monthly payment constitutes a pre-defined fraction of the total base cost of the plant adjusted to current dollars (i.e. dollars at the time of payment) according to an "escalation" formula. The idea of monthly payments is to avoid the interest charges (to either party) that would inevitably be associated with payments over longer time periods. The integral of these monthly payments is termed the "payment curve" for the FNP. The shape of the FNP payment curve differs from the typical shape of the curve for a LBNP in that the utility pays a somewhat higher proportion of the total costs at an earlier time than is normally the case for a LBNP. I will comment on the financial implications of this later.

Each monthly payment is determined according to the following formula:

$$\text{Payments} = \text{monthly base cost } [0.10 \frac{G}{G_0} + 0.35 \frac{M}{M_0} + 0.55 \frac{L}{L_0}]$$

where: G, M, and L are the monthly values of three indices, and G_0, M_0, and L_0 are their respective base values. The philosophy behind this particular indexing scheme appears to have been straight-forward. First, OPS concluded that the two principal components of the FNP were labor and materials. Of the available labor indices, the most pertinent seemed to

be "shipbuilding" and repair labor (SIC 3731). Of the available materials indices, the most appropriate seemed to be "steel mill products" (Code 1013). Because OPS overhead was also likely to escalate, the GNP deflator was added as a third weighting factor. Each component was weighted according to its estimated share of total plant costs: 35% for materials; 55% for labor; and 10% for overhead.

The principal marketing advantage that OPS enjoys over the vendors of LBNP's stems directly from these considerations. In a typical arrangement for the construction of an LBNP, the A-E, acting as the utility's agent, is able to obtain a firm price from the manufacturers of heavy equipment for a portion of the total plant cost. This fraction of the total is, however, only about 20% compared with 80% of the FNP (Fig. 5). This means, at a minimum, that the uncertainty about the final cost of the plant to the utility is greatly reduced for the latter over the former.

But there is more than a reduction in uncertainty. Equally, if not more, important is the matter of responsibility for project management. LBNP construction experience strongly suggests that A-E firms working on a cost-plus basis have little effective incentive to insure the coordination of activities necessary to meet cost estimates. In the case of FNP's, OPS clearly has such an incentive. OPS bears all cost overruns for their "black box". A more detailed breakout of the division of responsibilities associated with various areas of risk is contained in Table 1, supplied to me by OPS.

Land-based nuclear plant experience indicates there are four areas that represent a high risk of cost overruns to the utility. Cost overruns attributable to labor availability and/or productivity (total labor hours), engineering man hours and drawing delays, and material and equipment quantity changes, coupled with potential delivery problems, and rework due to poor quality are all related to the owner's cost responsibility. As Table 1 suggests, many of these risks are transferred to OPS for an FNP. OPS is solely responsible for any cost overrun of additional man-hours of manufacturing labor, additional engineering man-hours, labor work rules, and material and equipment quantity increases; and equipment, materials and quality assurance which in the past have resulted in delays and cost overruns. This tabulation compares the cost responsibility for the areas of risk for a LBNP and a FNP.

Another factor which has affected the accuracy of cost estimates is that the A-E "estimator" has no financial incentive to insure their accuracy. The A-E is not actually submitting a firm-price bid at his "estimated" cost but is in most cases submitting an estimate to a prospective utility client. Since he is in competition with other A-E firms to obtain the design and construction contracts for the project, his incentive is to submit the lowest estimate. Should the utility client proceed with the project and retain his services to design and/or construct the plant, the project progresses on a time and material-cost contractual basis.

VI. The Breakwater

There are self-evident financial risks to the utility associated with the cost of the breakwater. At least three areas of uncertainty could have serious cost implications: (1) the offshore location itself with its potential vulnerability to a hostile marine environment; (2) the prodigious amounts of materials involved in breakwater construction; and (3) the sheer novelty of certain aspects of the construction enterprise.

I have discussed these matters with several informed persons. It is their view that realistically there is an uncertainty of 50% in *a priori* breakwater cost estimates. The crucial question, therefore, is whether cost overruns here could cancel the savings relative to LBNP's that other aspects of the FNP concept appear to promise.

To get some feel for this, I have developed an independent comparative estimate of AGS 1 and 2 vs. a LBNP that might have been ordered at approximately the time OPS and PSG&E reached agreement on the final delivery date for the first two plants for which the former has firm orders. I have adjusted estimates supplied by OPS and other published sources to reflect my own judgment about long-term inflation rates. This data is contained in Table 2. I then further adjusted the cost estimates according to what seem to me to be reasonable contingency levels. These, it should be noted, are considerably higher than the contingencies commonly used throughout the nuclear industry. My contingency adjusted estimates are contained in Table 3.

The most important result of these related exercises is that the total cost estimates for the two types of nuclear plants are *extremely close*. It is critically important here to recall the earlier

discussion about the difficulties in making quantitatively precise comparative assessments that are caused by the way inflation is handled in this type of analysis. The fact is that the apparent 10% difference in the final contingency adjusted cost of the two plants is well within the range of uncertainty about real dollar costs which stems from this problem alone.

It should also be stressed that the current dollar value of each of the cost estimates is a heterogeneous aggregate of monetary units of potentially very different real value over a period beginning (in this case) in late 1974 and continuing over the construction periods of both plants. For either an FNP or an LBNP ordered today, the absolute current dollar values in each category would differ from these figures. However, because of OPS progress in licensing its "black box" (Fig. 6) combined with the lack of any evidence that the real costs of LBNP's have begun to stabilize, I would think that there is very little chance that the present situation could be less favorable to the FNP concept than the conditions surrounding AGS 1 and 2. OPS believes that significant design modifications to its "black box" are highly unlikely at this stage of the licensing process. If that belief is correct, it is certainly plausible to conclude that the cost uncertainty of the "black box" has been reduced in the past 2 years. In any event, it should be kept in mind that overruns in the firm-price portion of an FNP will be at OPS' expense.

The principal conclusion, therefore, of my own attempt to judge the comparative FNP/LBNP cost situation is that under the worst circumstances for the former, its costs should be no higher than those

of an LBNP. Moreover, it does seem to me to be reasonable to expect, though impossible to demonstrate definitively, that the FNP concept could be the source of some significant cost savings to the owner over an LBNP. On balance, the FNP concept seems to hold the real and reasonable promise of solving a significant part of the nuclear capital cost problem.

VII. Operating and Maintenance Costs

It is obvious that operating and maintenance (O&M) costs for an offshore electric generating station will be higher than those for an equivalent land-based station. It is equally obvious that the net financial impact on generating economics is inconsequential. The extra operating costs would be due to additional personnel ($0.5 million/year), boat and hotel services ($0.25 million/year), and hull maintenance ($0.1 million/year). There are two alternative ways of getting a sense of how important these costs are with respect to overall plant economics. The first is to look at the capitalized cost of this stream of differential payments compared with total plant costs. The capitalized cost would be less than $10 million which is trivial in comparison with total plant capital costs. The second method is to spread the incremental O&M costs over the electricity generated during a given period of time. This amounts to 0.5-1 mill/kwh depending on capacity factor assumptions. This 0.5-1 mill/kwh should then be compared with probable total bus-bar power costs in the range of 35$\pm$5 mills/kwh.

VIII. Nuclear vs. Coal Economics

The development of comparative cost estimates of nuclear plants with coal-fired plants is an enterprise which today supports a minor industry in its own right. I have written extensively on this subject elsewhere. Here I will only reiterate the main conclusion of this research. The range of uncertainty about all the critical parameters is today so large that without highly specific knowledge of a particular project, it is possible to make a determinate case for other alternatives only by systematically picking a set of "best case" assumptions for one technology, while simultaneously doing the opposite for the other.

To cite merely a single example. Although it has not been widely noted, there is today uncertainty of at least a factor of 4 about the real fuel cycle cost of LWR's in the United States. It can be shown (Fig. 7) that this fact, in itself, makes the economic choice between nuclear power and coal indeterminate over a very broad band of the other critical parameters --all of which are themselves subject to uncertainty ranging between 25% and a factor of 2-3 (constant dollars).[3] In these circumstances, comparative present value analyses with purported 3-digit precision should be viewed with considerable skepticism.

IX. Financial Implications of the FNP Payment Curve

Another potential disadvantage of the FNP from the owner's point of view is that it requires a larger fraction of payments earlier in the construction period than a LBNP. Because of the time value of money, this is undesirable to the buyer. However, the relative certainty of the

3. These parameters are, of course: coal costs; coal as well as nuclear capital costs; and capacity factors.

magnitude and timing of payments should essentially compensate for this --recall that payments to OPS are contractually secured.

A related matter which has the potential of becoming a significant advantage to the FNP concept is the possibility of "project financing". This is possible for an FNP because it is a much more liquid asset to the owner than a LBNP. For example, if a given utility in one region was unable to meet payments at time of delivery, the FNP could in principle be resold to another utility in an entirely different geographical location. This obviously would be impossible with an LBNP. Hence, a financing consortium would be much less likely to assume all or part of the risks. For the utility, project financing offers the possibility of avoiding interest during construction--a considerable attraction indeed.

X. Parallel Construction and Licensing

OPS marketing efforts have stressed the potential time (and hence dollar) savings associated with the FNP parallel construction and licensing schedules, compared with the sequential schedule typical of LBNP construction (Fig. 8). For a given site it is reasonable to expect such savings to materialize. However, it is equally possible that the total project costs of an FNP at location "A" (say, Houston) would not be less than those of an LBNP at location "B" (say, Miami) due to extreme site related licensing problems at the first.

XI. Inshore FNP Siting

It has been my feeling since first looking into the FNP concept 2 1/2 years ago that the area of easily the most serious economic concern was the cost uncertainty associated with the breakwater. The more recent thinking at OPS seem to reflect the same judgment. The company's current marketing efforts are concentrating on a variety of "inshore" siting options. This can only make the comparative economics of the concept more favorable.

XII. Conclusion

I have stressed the firm price characteristics of the OPS marketing approach as the key to FNP economics. In light of recent events having to do with uranium supply agreements, it is only natural to question the degree to which contractually secured price guarantees really are "firm". For Westinghouse, however, (the OPS parent) the argument clearly cuts both ways. If only because of the uranium situation, one would expect OPS to be exceedingly reluctant to succomb to the possible temptation to attempt to modify a contract with PSG&E or any other customer if the cost situation becomes unfavorable.

On balance, then, the OPS/FNP concept, as the "black box" is currently designed, continues to appeal to me as an innovative and imaginative attempt to come squarely to grips with some of the severe economic problems which have troubled the nuclear industry during the past ten years.

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Fig. 1

FLOATING NUCLEAR POWER PLANTS

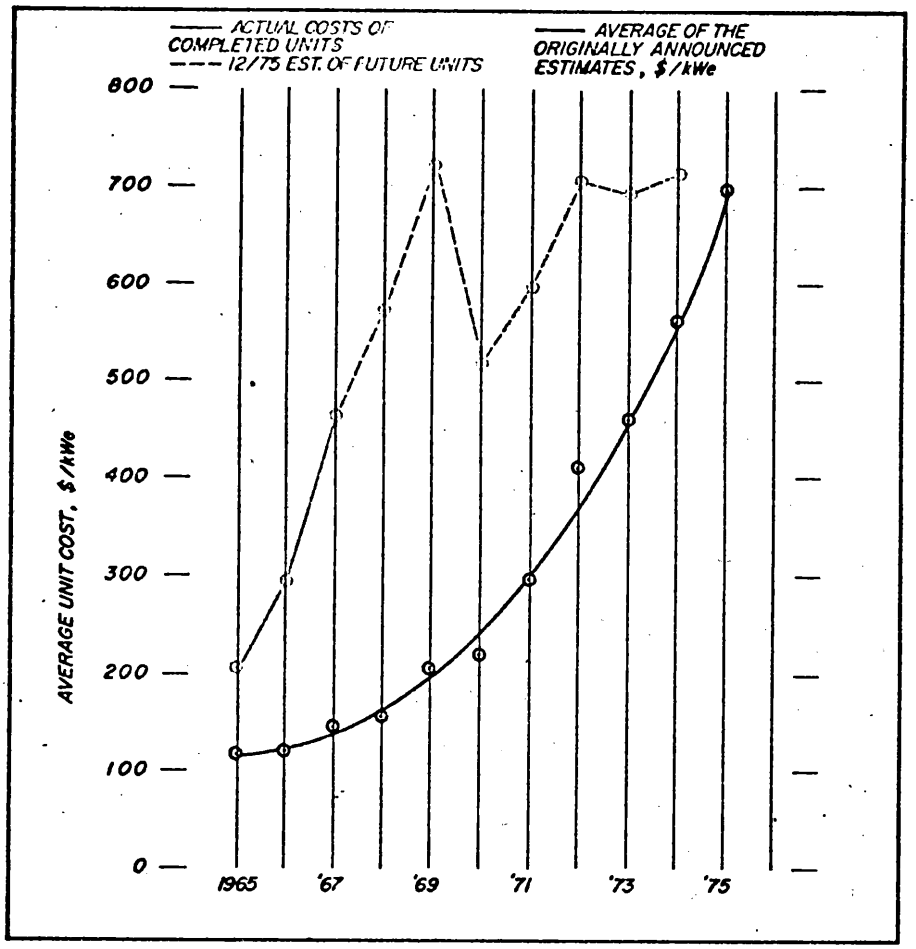
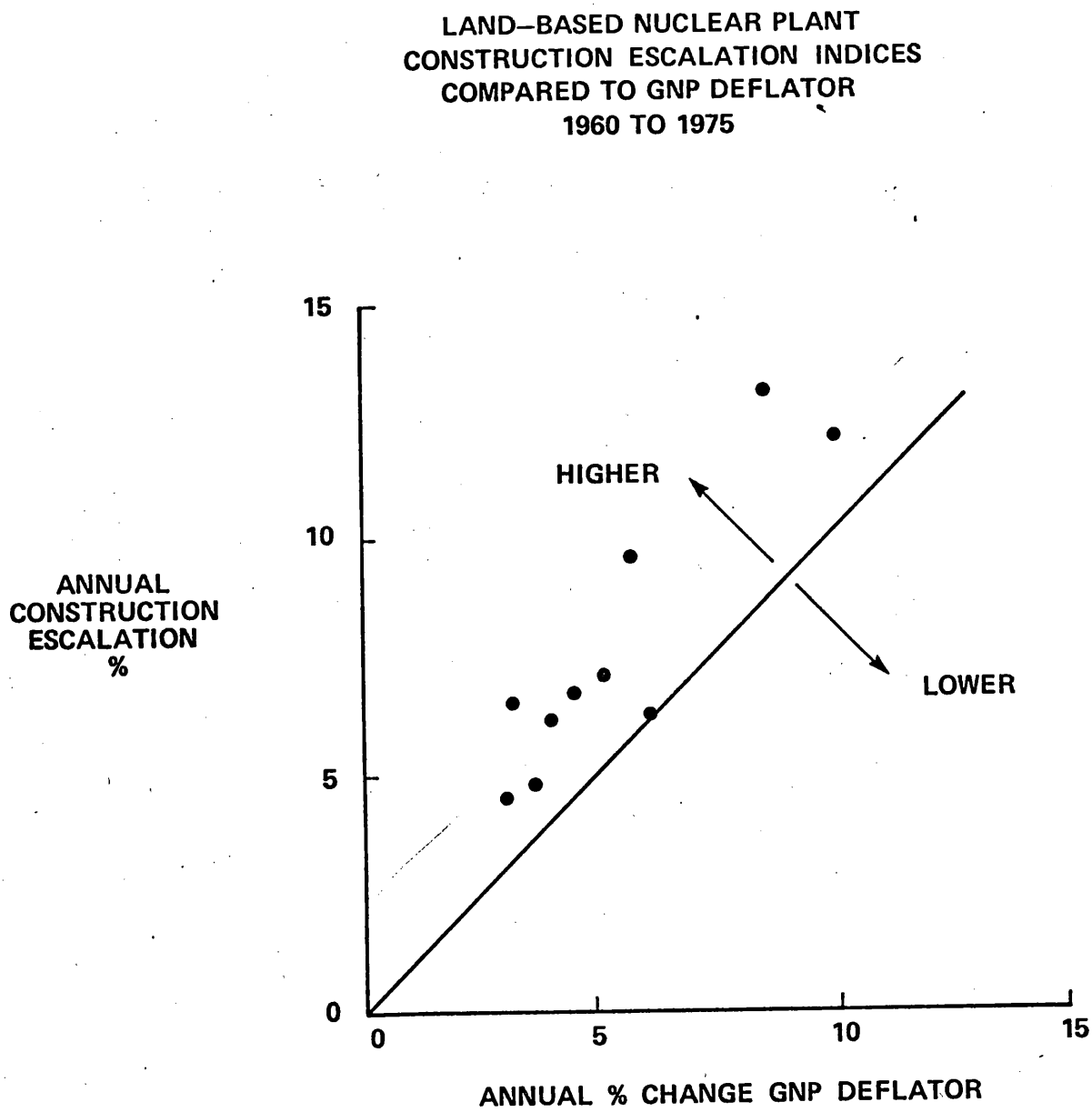


Figure. Cost estimates of nuclear units at time of order vs actual finished cost or estimate as of Dec. 1975.

Source: F. C. Olds, "What Happened to the Nuclear Plant Program in 1975?," Power Engineering, 4/76, pp. 83-85.

Fig. 2

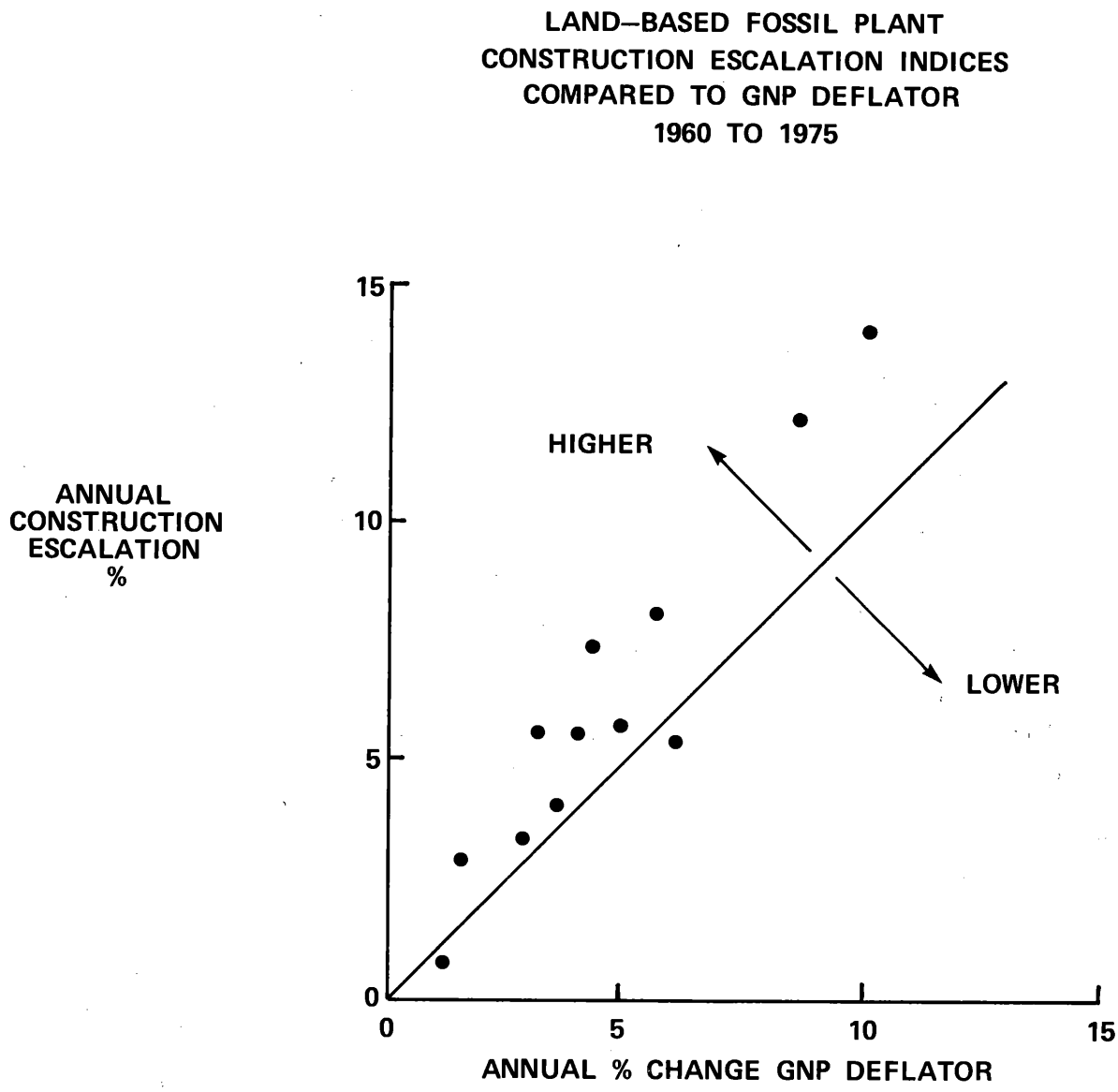
FLOATING NUCLEAR POWER PLANTS



Note:
Plant Construction Escalation Indices do not include cost increases caused by design changes or construction labor productivity changes.
Source: 'Power Plant Economics', H.F.Brush, Bechtel Power Corporation, testimony given before the Connecticut Public Utilities Control Authority, January 21, 1976.

Fig. 3

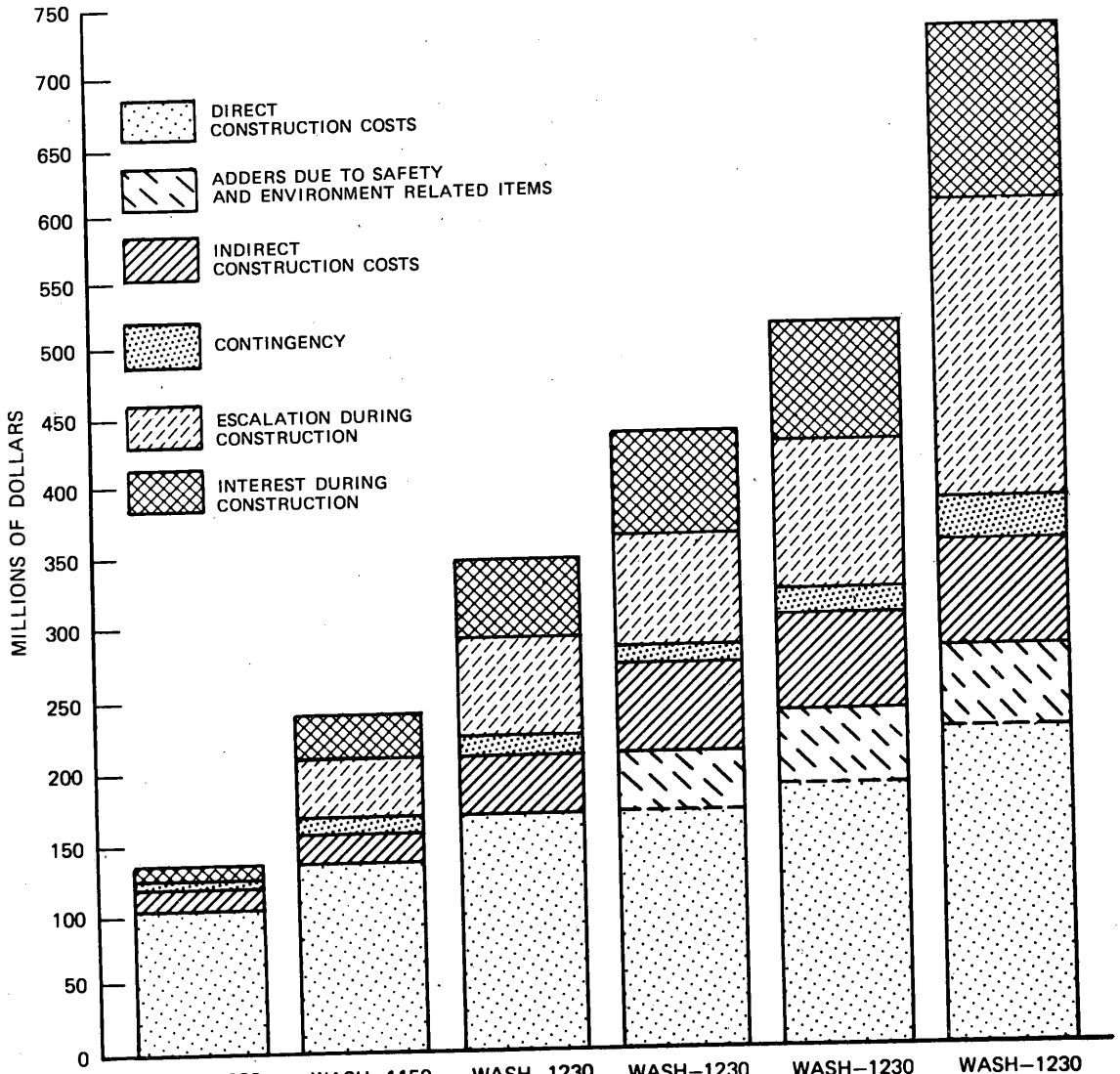
FLOATING NUCLEAR POWER PLANTS



Note:
Plant Construction Escalation Indices do not include cost increases caused by design changes or construction labor productivity changes.
Source: 'Power Plant Econonics', H.F.Brush, Bechtel Power Corporation, testimony given before the Connecticut Public Utilities Control Authority, January 21, 1976.

Figure 4

FLOATING NUCLEAR POWERPLANTS



EVALUATION :	WASH–1082	WASH–1150	WASH–1230	WASH–1230 REVISED	WASH–1230 REVISED	WASH–1230 REVISED
EXPERIENCE :	MARCH 1967	JUNE 1969	JAN. 1971	JAN. 1973	JAN. 1973	JAN. 1973
START–OF–PROJECT :	MARCH 1967	JUNE 1969	JAN. 1971	JAN. 1971	JAN. 1973	MID–1974
COMMERCIAL OPERATION :	LATE 1972	MID–1975	JAN. 1978	JAN. 1978	JAN. 1981	JAN. 1983

Fig. 4 Comparison of nuclear plant cost estimates [total investment cost for 1000-MW(e) units].

Source: WASH-1345, Figure 1

Fig. 5

FLOATING NUCLEAR POWER PLANTS

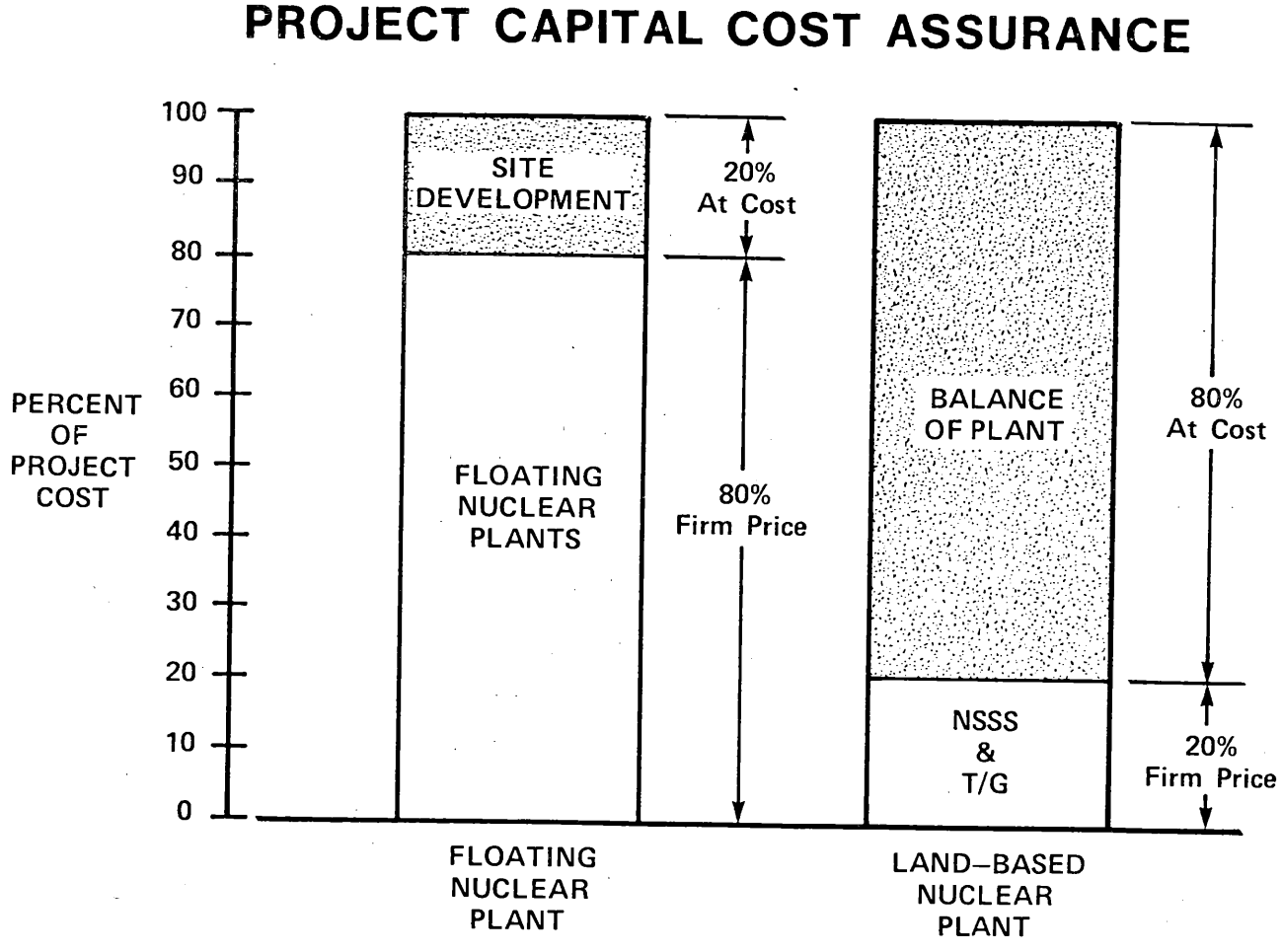


Fig. 6

FLOATING NUCLEAR POWER PLANTS

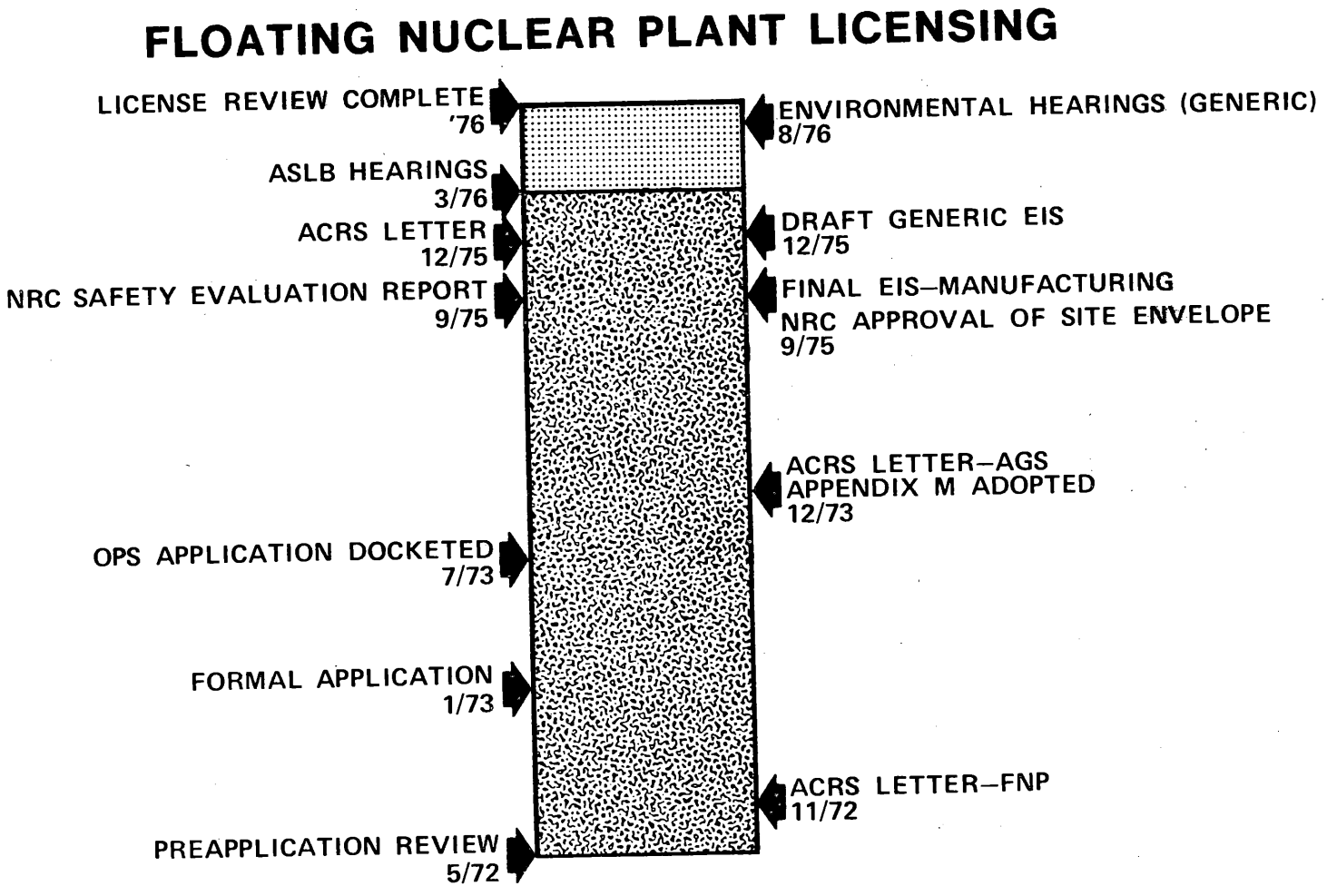
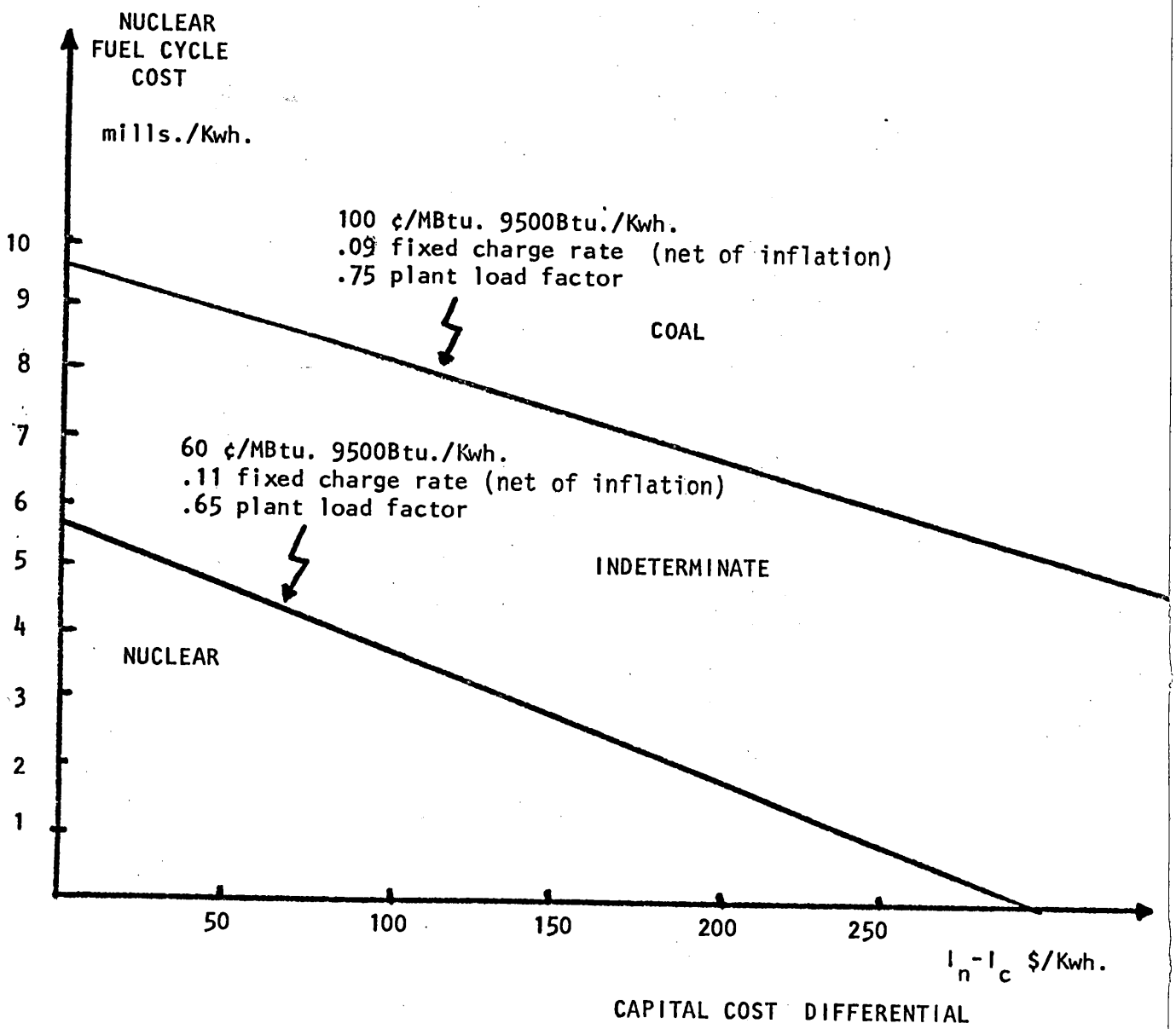


Fig. 7
FLOATING NUCLEAR POWER PLANTS

BREAK EVEN NUCLEAR FUEL CYCLE COST ANALYSIS



OTHER ASSUMPTIONS:
same fixed charge rate and plant load factor for coal and nuclear.
capital costs in constant 1975 dollars.

Fig. 8

FLOATING NUCLEAR POWER PLANTS

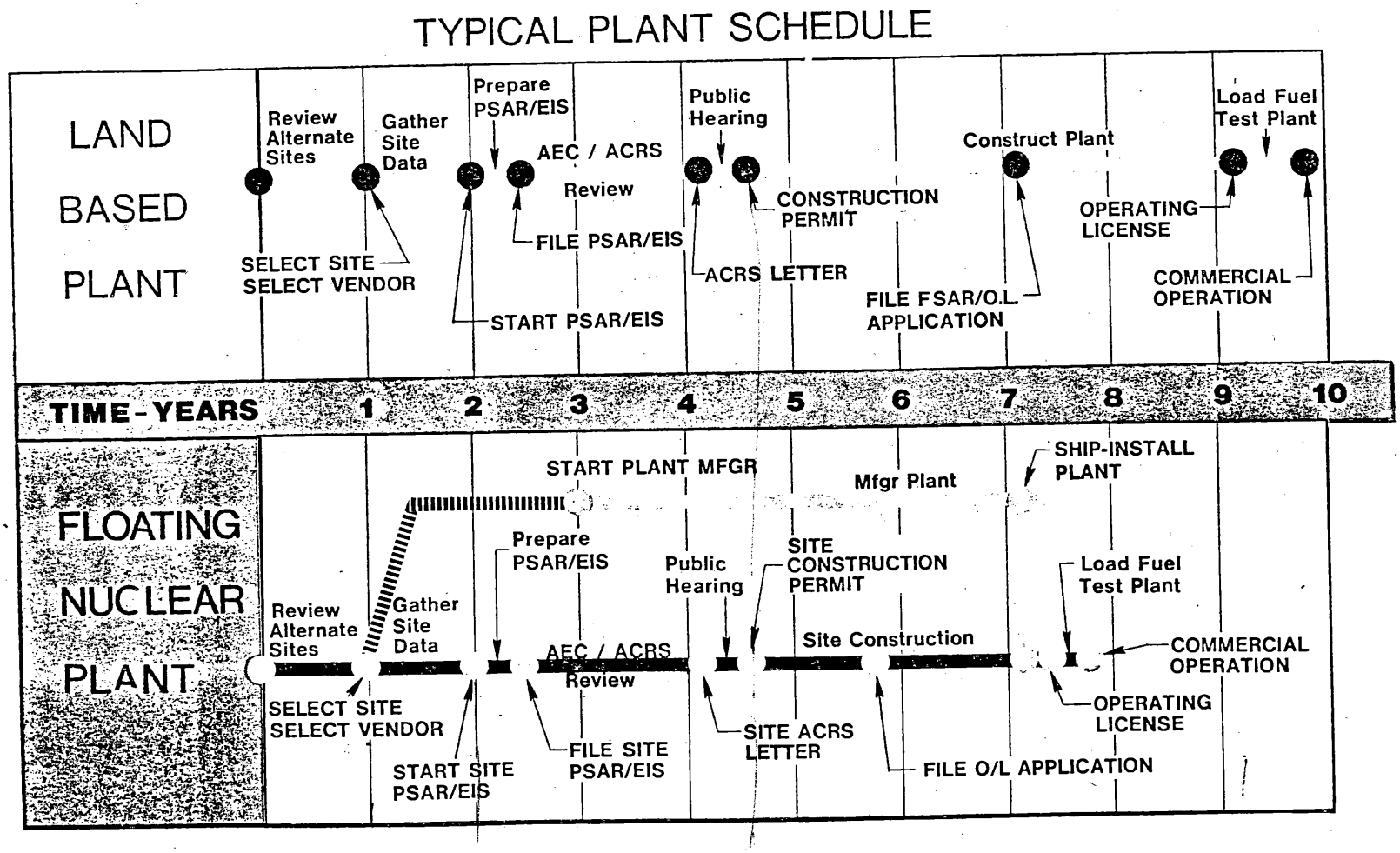


Table 1

FLOATING NUCLEAR POWER PLANTS

DESIGN & CONSTRUCTION RISK ANALYSIS

LAND PLANT CONSTRUCTION VS.

FLOATING NUCLEAR PLANT MANUFACTURE

AREA OF RISK	COST RESPONSIBILITY LAND PLANT	FNP
1. Architect Engineering		
(a) Insufficient engineering hours in estimate	Owner	OPS
(b) Increase in the number of drawing details	Owner	OPS
2. Construction Drawings		
(a) Late Drawings		
(1) Construction schedules delayed or revised to less than optimum	Owner	OPS
(2) Construction sequence changed to more costly methods	Owner	OPS
(3) Changes in schedules and sequences resulting in revised labor requirements. Can cause layoff of some crafts, require hiring of others that are in short supply at the time, both of which tend to increase labor costs	Owner	OPS
(4) Revised schedules and sequences cause added rental and use of on-site erection equipment, cranes, etc.	Owner	OPS
(5) All of above indirectly add to labor overruns	Owner	OPS
(b) Inaccurate Drawings		
(1) Re-engineering required to correct errors	Owner/A-E	OPS
(2) Modification to completed work necessary to accommodate corrections. May include extensive structural, piping, and electrical re-work	Owner/A-E	OPS
(3) All of (a) above also apply	Owner	OPS
(c) Design Changes After Construction		
(1) Completed systems or structures may have to be re-tested prior to acceptance	Owner	OPS
(2) Additional material required to accommodate change (i.e., cut out concrete and re-pour)	Owner	OPS
(3) All of (a) and (b) above may also apply	Owner/A-E	OPS

Table 1 (continued)

DESIGN & CONSTRUCTION RISK ANALYSIS

LAND PLANT CONSTRUCTION VS.

FLOATING NUCLEAR PLANT MANUFACTURE (CONT.)

AREA OF RISK	COST RESPONSIBILITY LAND PLANT	FNP
3. Construction Labor		
(a) Overtime to attract sufficient qualified craft	Owner	OPS
(b) Unstable migratory work force, constant retraining required	Owner	OPS
(c) Startup delay due to large decrease in craft productivity as job nears end	Owner	OPS
(d) Productivity decreases with job situation, other work availability	Owner	OPS
(e) Labor disputes causing delays, slippages, etc.	Owner	OPS
(f) All overruns in construction labor also carry an additional construction management overrun	Owner	
(g) Original estimates based on target labor man hours: Actual hours have greatly exceeded estimates (some small sharing may be available)	Owner/A-E	OPS
4. Components, Equipment and Materials		
(a) Late Items		
(1) Same effects as late drawings	Owner	OPS
(2) Causes re-engineering of completed drawings, has "domino" effect on interfacing equipment and structure	Owner/A-E	OPS
(b) Incorrect Items		
(1) Same effects as late and inaccurate drawings	Owner/A-E	OPS
(2) Schedules delayed while waiting for new equipment or changes	Owner	OPS
(3) Startup delays for many items not discovered until testing	Owner	OPS
(c) Additional materials required in final design	Owner	OPS
(d) Additional equipment required in final design	Owner	OPS

Table 1 (continued)

DESIGN & CONSTRUCTION RISK ANALYSIS

LAND PLANT CONSTRUCTION VS.

FLOATING NUCLEAR PLANT MANUFACTURE (CONT.)

AREA OF RISK	COST RESPONSIBILITY LAND PLANT	FNP
5. Quality Assurance		
(a) Delays due to NRC audits of construction site activities	Owner	OPS
(b) Owner's large field quality control group	Owner	OPS
(c) Delays in field due to improper documentary evidence of procured material	Owner	OPS
(d) Field rework due to quality control inspection with resulting rejection of non-conformances	Owner	OPS
(e) Cost of maintaining huge documentation control center during construction	Owner	OPS
6. Plant Output Warranty		
(a) Net plant output	Owner	OPS

Source: Offshore Power Systems

Table 2

FLOATING NUCLEAR POWER PLANTS

Base Core FNP Costs Estimate without Contingencies

FLOATING NUCLEAR PLANT PROJECT COSTS

2-1150 MW PWR Units

1983 and 1984 Commercial Operation

Base Costs:	
2 Floating Nuclear Plants (including Turbine Generators) (Firm Price)	$750,000,000
Site Development (breakwater, $180,000,000; cable, $70,000,000)	250,000,000
Projected Escalation:	
Escalation on Plants (@ 6%/year)	358,000,000
Escalation on Site Development (@ 10%/year)	256,000,000
Owner's Cost (towing, insurance, on-shore station)	10,000,000
Interest - During Construction (@ 8.5%/year)	255,000,000
TOTAL	$1,879,000,000

Table 2

FLOATING NUCLEAR POWER PLANTS

Base Core LBP Costs Estimate without Contingencies

LAND BASED NUCLEAR PLANT PROJECT COSTS
2-1150 MW PWR Units
1983 and 1984 Commercial Operation

Base Costs:	
Construction Labor (15.0 MHours/KW @ $10.00/Hr.)	$ 345,000,000
Nuclear Steam Supply System (Firm Price)	80,000,000
Turbine Generators (Firm Price	80,000,000
Balance-of-Plant Equipment	212,000,000
Engineering, Construction Management, Construction Facilities, Equipment and Services	242,000,000
Projected Escalation:	
Construction Labor (@ 10%/year)	344,000,000
Nuclear Steam Supply System (@ 6%/year)	38,100,000
Turbine-Generator (@ 6%/year)	38,100,000
BOP Equipment (@ 6%/year)	108,400,000
Engineering, etc. (@ 10%/year)	165,900,000
Owner's Cost	15,000,000
Interest - During Construction (@ 8.5%/year)	332,500,000
TOTAL	$1,999,000,000

Table 3

FLOATING NUCLEAR POWER PLANTS

"Risk Adjusted" Capital Cost Comparison
($ Millions)

	FNP	LBNP
Total Cost		
Firm price components (with escalation)	1,108	236
Non-firm price components (with escalation)	506	1,416
Owner's cost	10	15
Interest-during-construction	255	332
Total (before contingency)	1,879	1,999
Contingency		
Firm price components (2%)	22	5
Non-firm price components (50% FNP, 25% LBP	253	354
Interest-during-construction	16	43
Contingency	291	402
Total cost (with contingency)	2,170	2,401

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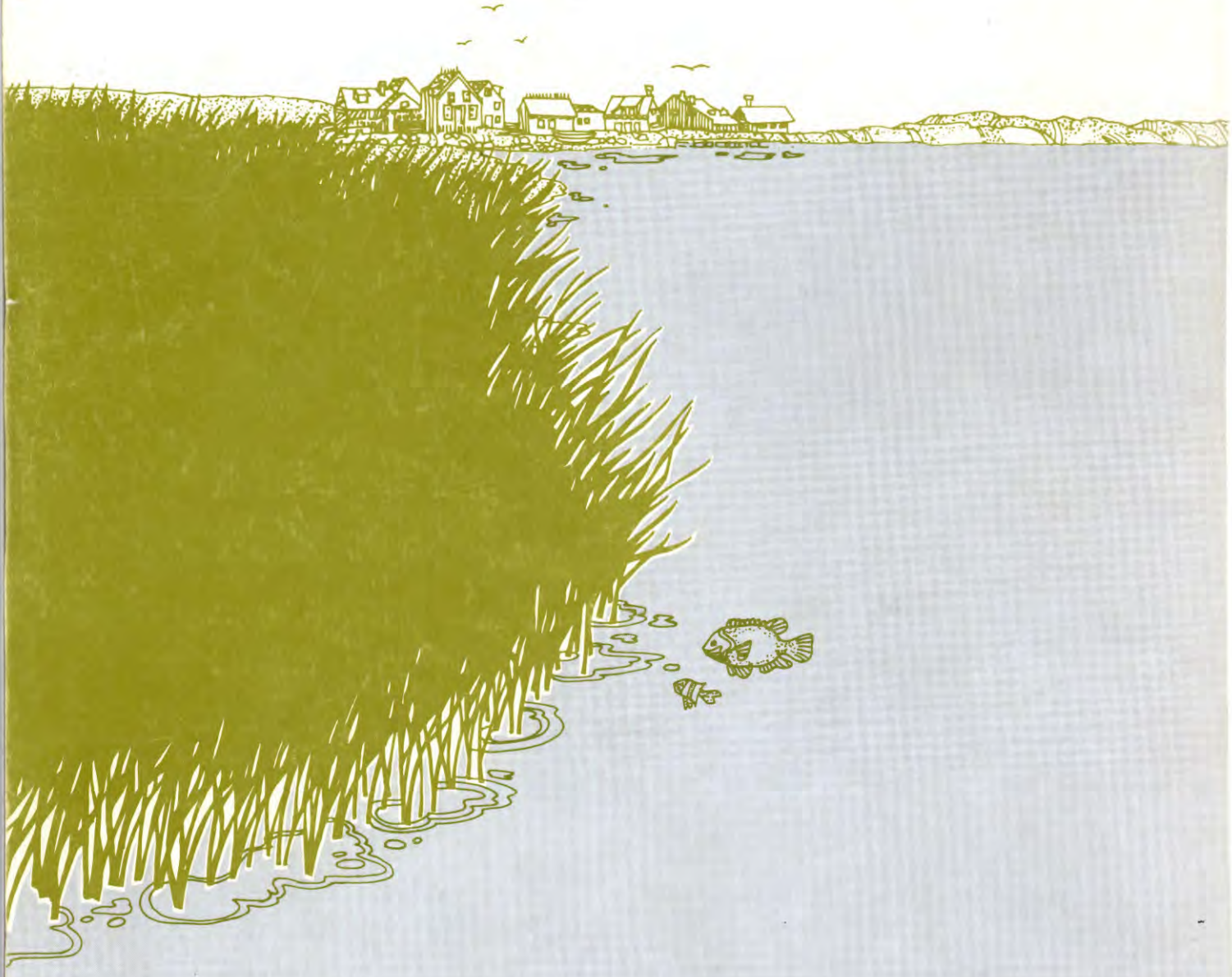

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