W.P.

AN ENERGY FACILITIES SUBPLAN FOR
NASSAU AND SUFFOLK COUNTIES

DRAFT

State Dept. of State

DRAFT

AN ENERGY FACILITIES SUBPLAN FOR NASSAU AND SUFFOLK COUNTIES

DRAFT

Prepared by

Nassau-Suffolk Regional Planning Board
H. Lee Dennison Office Building
Veterans Memorial Highway
Hauppauge, N.Y. 11787

Dr. Lee E. Koppelman
Project Director

15 July 1977

Contract Number D93967

The preparation of this report was financially aided through a Federal grant from the Office of Coastal Zone Management, National Oceanic and Atmospheric Administration under the Coastal Zone Management Act of 1972, as amended. This report was prepared for the New York State Department of State.

AN ENERGY FACILITIES SUBPLAN FOR NASSAU AND SUFFOLK COUNTIES

Table of Contents

Page

LIST OF FIGURES

LIST OF TABLES

Nassau-Suffolk Regional Planning Board

AN ENERGY FACILITIES SUBPLAN FOR NASSAU AND SUFFOLK COUNTIES

1.0 Introduction

1.1 Objectives

The Coastal Zone Management Act of 1972 (P.L. 92-583), as amended by the Amendments of 1976 (P.L. 94-370), requires (Section 305 (b)(8)) that the management program for each coastal state shall include, among other requirements, a planning process for energy facilities likely to be located in, or which may significantly affect, the coastal zone. Such a planning process must include, but not be limited to, a process for anticipating and managing the impacts from such facilities.

The federal regulations, which provide guidance to States for implementing these requirements (1) discuss a number of approaches that could be used. Among these is the following:

> "...the State could develop performance standards or other regulations that particular types of energy facilities would have to meet irrespective of their coastal zone location. Under this approach, no sites would be specifically reserved, but neither would any be specifically excluded."

In view of the high level of development in the Bi-County area, a variety of alternative sites may not be available for any given facility type. Consequently, this plan may call for the reservation of specific sites, simply to ensure that sites will be available when needed.

The federal regulations (1) continue:

> "(Another) option, a variant of the (previous), would combine a performance standard approach with specific exclusions of all or particular types of facilities in selected coastal zone locations."

The regulations then proceed to spell out the kinds of environmental, safety, and policy factors on which such exclusions/restrictions could be based. This, generally, is the overall approach followed in the Nassau-Suffolk energy facilities subplan.

1.2 Scope

This subplan will establish energy demand projections for the years 1985 and 2000, and will cover electric power, all kinds of liquid and gaseous fuels, and coal. From these projections, an estimate will be made of the capacity of the facilities required in those years. These estimates will then be compared to the existing inventory of installations, taking into account current plans for their expansion, retirement and replacement. From this review will come a list of additional required facilities.

The list of required facilities, together with all the possible types of onshore facilities associated with Outer Continental Shelf (OCS) oil and gas exploration, development and production, will be reviewed as to land use requirements, need for waterfront locations, and environmental impacts. The review will also include an examination of the types of exclusion/restriction factors discussed in the federal regulations(1), where relevant.

The final list resulting from this review will then be checked against the inventory of feasible locations within the coastal zone, and "matches" will be established wherever possible.

2.0 Population and Household Projections

2.1 Population

Over the past several years, the various authorities engaged in generating population projections for the Nassau-Suffolk area have continually revised their estimates downward. The current rate at which population is growing is somewhat lower than that projected some years back. The slower trend is expected to continue, in the light of current and expected economic conditions.

Thus, a demographic study of the New York Bight area(2) quotes a 1972 projection of 3,339,012 persons in the bi-county area in 1985, and 4,070,008 in the year 2000. A Brookhaven National Laboratory (BNL) study on energy demands(3) uses 1974 projections of 3,343,000 and 4,078,000 for the same years. However, LILCO's population survey, dated 1976(4), cites 1975 population projections, by the New York State Economic Development Board, of 2,903,000 (for 1985) and 3,216,000 (for 2000). These were the populations used by LILCO in the 1977 energy demand projections submitted by the New York State Power Pool to the Public Service Commission(5).

Since then, LILCO has issued their 1977 population survey(6), and cites population projections(7) by the Nassau-Suffolk Regional Planning Board (NSRPB). These numbers are slightly higher than the previously cited ones(4), i.e., 3,017,817 for 1985 and 3,325,000 for 2000. (The latter is extrapolated from the numbers tabulated through 1995 in the referenced publication).

Population projections were made for each of the 108 municipalities and the 126 school districts in Nassau and Suffolk Counties. The projections of population by relatively small areas were developed through the use of a methodology based upon land capacity analysis. Since the approach starts with small area analysis and projection, the results tend to be more useful for municipal, school district and other planning purposes than those produced for the nation or the state as a whole and apportioned to counties or sub-county areas. Recent efforts to preserve farmland, shorefronts, wetlands and other areas of great environmental or recreational value have been taken into account in the projections and it was assumed that should these efforts succeed, the growth rate in the affected areas would be slower than might otherwise be anticipated. It was also assumed that as the population of an area approaches saturation, the growth rate would decline since the most desirable, moderately priced, easy to develop land would have already been utilized.

These were the population projections utilized in this report.

2.2 Persons Per Household

A projection of residential energy demands requires an estimate of the number of residential customers. This is not precisely the same as the number of households, but they are close, and most projections of demand employ the number of households for the purpose. Given a population projection, the number of households depends on an estimate of the number of persons per household.

LILCO(5) projects 927,945 households in 1985 and 1,177,000 in 2000. Based on the population figures they used, i.e., 2,903,000 in 1985 and 3,216,000 in 2000, the persons per household are 3.13 and 2.73 respectively.

In their study of energy demands(4), BNL used 3.31 persons per household for 1985 and 3.09 in 2000. This yielded 1,010,000 and 1,320,000 households for the two years of interest.

The NSRPB believes that both sets of numbers are too low, and result in numbers of households that are excessively high. The values they project (8) are 3.58 persons per household in 1985, and 3.49 in 2000, yielding 842,533 and 952,262 households for the two years.

2.3 Single- and Multi-Family Dwellings

The energy demand patterns of single-family houses and apartments are substantially different. Consequently, in order to derive reasonably accurate demand projections for the residential sector, dependable estimates of the division between the two categories is important.

BNL(4) project that 80% of all dwellings in 1985 will be single family houses, and 78% in 2000, as compared to 84% in 1972. Thus BNL predicts that the trend is fairly strongly toward building more apartment buildings.

LILCO(5) estimate that 86.6% of all dwellings are single-family houses in 1977. The numbers they predict for 1985 and 1997 are 83.2% and 77.7% respectively.

From a detailed review of individual municipalities and school districts, NSRPB predicts(8) that 83% of homes in Nassau-Suffolk will be single-family units in 1985, but that the number will drop only slightly, to 82% by 2000.

3.0 Commercial and Industrial Projections

Projecting the future scope of commercial and industrial activities, from the point of view of energy use, presents many more problems than population. Most of the literature in the field discusses large scale trends at the national, state, and multi-state level (14, 15, 16, 17, 18, 19, 20). This material is of little help for preparing detailed estimates for Long Island.

BNL have made energy demand projections (3) based on estimated future total floor area, combining both commercial and industrial in one group. Using 1972 as the base year, with an inventory of 412,000 sq. ft., they assume an annual growth rate of 2% from 1972 to 1985, and 1.5% from 1985 to 2000. This projects 531,000 sq. ft. for 1985 and 664,000 sq. ft. for the year 2000. These floor areas are then used for generating demands for electricity, residual oil, distillate, gas and coal.

LILCO, concentrating on electricity demands (5), and having available to them the historical record of numbers of customers, prefer to perform linear regressions, and extrapolate the regression lines to the years of interest.

For commerical customers, LILCO relates these to the number of residential customers. Using data for the period 1966 - 1975, they derive the following regression equation:

$$Y = 14,735 + 0.07156X$$

where X is the number of residential customers
and Y is the number of commercial customers

Utilizing NSRPB numbers for households, we arrive at the following comparison:

	LILCO		NSRPB	
Year	X	Y	X	Y
1985	927,945	81,143	842,533	75,027
2000	1,177,000	98,961	952,262	82,879

Thus, by this method, NSRPB arrives at 7.54% fewer commercial customers than LILCO in 1985, and 16.25% fewer in 2000.

LILCO relates the number of industrial customers to time, and, for historical data from 1966 to 1975, derives the following regression equation:

$$Y = 3031 + 144.76T$$

where T is the number of years after 1965,
and Y is the number of industrial customers.

(The intercept of the regression line was reduced by LILCO in order to join the long range forecast to the short range forecast that they had prepared through the year 1981.)

When examining the historical data for the years 1966 - 1975, we see that the number of industrial customers rose sharply through 1968, and the growth rate thereafter was markedly slower. The slower trend is expected to continue, so that if data for the first three years is removed, and a regression line run on the remainder, we obtain the following equation:

$$Y = 4083 + 107.1T$$

where T is the number of years after 1968.

The intercept has to be reduced by 90 to intersect the LILCO line at the year 1982 (i.e. to join it to the short range forecast). Thus, the new regression equation is:

$$T = 3993 + 107.1T$$

This yields the following comparison of industrial customers:

Year	LILCO	NSRPB
1985	5,926	5,814
2000	8,098	7,420

a reduction, below LILCO values, of 1.89% in 1985 and 8.37% in 2000.

For estimates of electricity demand, the above regression equations will be used, modified, as noted. For other energy sources, the BNL (3) model will be followed.

4.0 Projections of Other Categories

In their computations of power requirements (5), LILCO list the following additional consumptions:

a. "Other Public Authorities"
These are:
Brookhaven National Laboratory
Pilgrim State Hospital
New York City
Long Island Railroad

The total demand for these is cited as 252×10^6 kwh per year, constant for 1985 through 2000.

b. Streets and Highway Lighting
Estimated as constant at 200×10^6 kwh/year, 1985 through 2000.

c. Railroads
LILCO estimates this at 187×10^6 kwh/year, but lists it only through 1982, the period of their short range forecast.

d. Company Requirements
These are tabulated only through the year 1997. In 1985, the demand is listed as $1,942 \times 10^6$ kwh/year. By extrapolation, the demand in 2000 is found to be $3,180 \times 10^6$ kwh/year.

None of these categories is explored in any depth, and the first three are small, in any case. For the purposes of this study, they will be incorporated without further question.

This leaves vehicular transportation as the only other substantial energy user to be considered. BNL breaks this down (3) into three categories: automobile, commercial, and railway.

They again take 1972 as the base year, and establish that automobile transportation covered a total of 13.4 vehicle miles in that year, commercial transportation consumed 262.8 million gallons of fuel (76% gasoline, the rest diesel), and the railways covered 1.2 billion passenger miles.

Automobile vehicle-miles are then projected to increase 3.5% annually from 1972 to 1985 and 1.4% annually from 1985 to 2000. This yields 20.9 and 25.6 billion vehicle-miles in 1985 and 2000 respectively.

Commercial fuel consumption is assumed proportional to population. Thus, pro-rating the 1972 consumption by the increased populations, 328.5 million gallons are estimated to be consumed in 1985, and 400.8 million in 2000. Using NSRPB population estimates, the corresponding figures are 296.6 million gallons in 1985 and 326.8 million in 2000. BNL assumes that the proportion of gasoline will be constant at 76%.

As far as railroad passenger mileage is concerned, no trend can be seen for any significant change by the end of the century. BNL assumes that the present situation will continue, with 56% of the passenger-miles carried by electric power, 38% by locomotives firing residual oil, and 6% by diesel locomotives.

5.0 Conservation and Alternative Energy Sources

5.1 General

The energy demand projections developed in this subplan incorporate certain improvements in energy utilization based on what is considered to be a reasonable scenario for the future. Precisely what form these improvements should take, and the extent of their implementation, is a subject for debate. The literature on the subject of energy conservation and alternative technologies is considerable, and references 22 through 38 are only a selection.

The Administration's published "National Energy Plan" (22) covers the topics in a convenient form, however, and they are discussed in the following, in the same sequence.

5.2 Conservation

Conservation is treated under six headings, transportation fuel efficiency, buildings heating and cooling efficiency, domestic appliances, industrial fuel efficiency, cogeneration and district heating, and utility rate structure reform.

5.2.1 Transportation

Twenty six percent of United States energy is consumed in transportation, and approximately half of this, about 5 million barrels of oil per day, is used in automobiles. To improve this state of affairs requires an attack on two fronts. One is to implement new development patterns, such that homes, schools, shops, place of work, etc., are within walking distance of each other, or no more than a short bus ride. The other approach is to encourage the manufacture and sale of lighter, more efficient automobiles. Needless to say, the second way offers the possibility of quicker savings in fuel use. Whereas the average U.S. car did 14 miles to the gallon in 1974, the Administration is requesting that, by 1980, new cars achieve 20 m.p.g., and 27.5 m.p.g. by 1985. This is to be brought about by a graduated excise tax on new automobiles, with rebates for those whose new cars perform better than the official standards. Furthermore, the tax system is to be employed to make the use of mass transportation more attractive financially. Finally, enforcement of the 55 m.p.h. speed limit, and the automobile emissions portion of the Clean Air Act, is to be made more effective. An overall improvement of 10% is hoped for by 1985.

In this subplan (see Section 6.4), automobile gas mileage will be assumed to be 27.5 m.p.g. in 1985 and 30 m.p.g. in 2000. Diesel engines will be assumed to yield 40 m.p.g. in 1985 and 50 m.p.g. in 2000.

5.2.2 Buildings

The heating and cooling of buildings currently consumes about 20% of United States energy. Considerable savings could be realized if the existing housing stock were to be retrofitted. This would mean the installation of ceiling and roof insulation, weather-stripping at doors and windows, caulking cracks, and installing clock thermostats (to maintain lower temperatures at night) and improved furnace burners. It was originally hoped that 90% of houses (and many public buildings) could be so retrofitted by 1985. However, the target was recently amended to 60%. In Section 6.1, the effect of retrofitting 30% by 1985 is also examined.

The Administration expects to effect the retrofit program by the following measures:

a) Tax credits to be given to homeowners who carry out any of a list of eligible conservation measures.

b) The regulated utilities to provide customers with a conservation service, the cost to be repaid through additions to the normal monthly bills.

c) The Government to help make additional capital available to banks, for them to make residential energy conservation loans.

d) Funds to be made available to the poor, so that they may weatherize their homes.

e) The U.S. Dept. of Agriculture has already begun a program for energy conservation in rural homes, in cooperation with rural electricity cooperatives. Loans are available through the

Farmers Home Administration.

f) Tax credits for businessmen who undertake retrofit operations in their places of business.

g) A Federal grant program to be instituted for retrofitting schools, hospitals, etc.

h) A Local Public Works program to be instituted for State and local government buildings.

All Federal agencies are under notice to upgrade their buildings. New residential building is to be made more energy efficient, and the U.S. Dept. of Housing and Urban Development is to make improved building standards mandatory by 1981.

5.2.3 Appliances

Major home appliances consume about 20% of U.S. energy. These include furnaces, air-conditioners, water heaters, and refrigerators. It is believed that most of these could be designed to achieve significant reductions in energy use for little additional cost. The present voluntary program for improvement will eventually be replaced by mandatory minimum standards.

5.2.4 Industrial Fuel Efficiency

Industry accounts for 37% of U.S. energy consumption. Of all the areas for possible improvement, industry is the most advanced, because of the obvious economies to be achieved. Much, however, remains to be done, particularly in comparison to such countries as Sweden and West Germany. They have always had the spur of expensive energy, and eventually the same situation will pertain here.

Tax credits will be available for investments in energy saving equipment.

5.2.5 Cogeneration and District Heating

It is estimated that approximately one quarter of industrial energy use is lost in waste heat, and it is known that about two-thirds of the heat generated in power stations is wasted.

Cogeneration is the term applied to a power generation system in which the steam is allowed to leave the turbines at a sufficiently high pressure, so that it can be used for process heating in industrial plants and/or for heating adjacent residential areas. In the industrial process heat context, the United States has retrogressed. In 1950, cogeneration accounted for 15% of U.S. energy. Now it accounts for 4%! One of the effects of unrealistically cheap fuel.

To encourage the installation of cogeneration systems, the proposed Administration plan will:

a) Assure firms generating electricity of fair rates for the surplus power they sell to utilities and the backup power they buy.

b) Exempt cogeneration facilities from the State and Federal regulation that public utilities are subject to, and permit them to use public utility transmission systems.

c) Provide a 10% tax credit for investment in cogeneration equipment.

In fiscal '78, the Government will fund a program to use waste heat generated by ERDA facilities on site, and to pipe steam and hot water to nearby households, industry and agricultural operations.

5.2.6 Utility Rate Structure Reform

Hitherto, conventional utility pricing has encouraged waste. Rate structures will, in future, have to be reformed to encourage conservation, as a prerequisite to any further rate increases.

5.3 Power Plant Alternatives

In this content, the National Energy Plan discussed coal, nuclear energy and hydroelectric power. The latter is irrelevant to Long Island, and nuclear energy has long been in the public eye. Only the the place of coal in the power generation picture will be discussed here. The same points will generally be valid in the industrial picture.

Coal comprises 90% of U.S. conventional energy reserves, but supplies only 18% of U.S. energy consumption. It is believed that, in general, the nation's transportation system is adequate for delivering increased coal supplies, and the use of coal by industry and utilities is expected to grow considerably in the densely populated Eastern and Mid-West regions.

Expansion of coal production is believed to be essential a) to maintain economic growth while reducing oil imports, and b) to relieve the demand on the supply of natural gas, and make more available for residential use.

A coal conversion program is proposed, consisting of tax and regulatory measures. Industry and the utilities would be banned from burning oil and natural gas in new boilers, with certain limited environmental and economic exceptions.

Government will finance a study on the long-term effects on the atmosphere of carbon dioxide from the combustion of coal and other hydrocarbons. Furthermore, research efforts will be pursued in the following areas:

a) Flue-gas desulfurization systems.

b) The control of fine particulates and sulfure oxide emissions by "front-end" coal cleaning, i.e., grinding and washing before feeding to the boiler.

c) The solvent-refining of coal.

d) Coal gasification for the production of both low-Btu and high-Btu gas (the latter as a replacement for natural gas).

e) The manufacture of synthetic crude oil from coal.

5.4 Nonconventional Sources

5.4.1 Solar Energy

The better known of the solar energy devices are the roof-mounted receptors already in use for heating domestic hot water and for space heating. Nearly as well-known are the photovoltaic devices that convert the sun's light directly into electricity. However, there are other sources which, ultimately, receive their energy from the sun. These include wind-power, agricultural and forestry residues for use as fuel (often referred to as "biomass"), and ocean thermal energy (which makes use of the temperature difference between surface and deeper waters in the ocean).

A temporary Federal program is proposed to stimulate the development of the market for water and space heating devices, and the infrastructure of manufacturers and installers that is necessary. Also tax credits will be given for installing these devices, both to home-owners and to businesses.

The Administration's fuel conversion program includes incentives to industry and the utilities to shift away from oil and gas to biomass. Finally, increased funding is proposed for research and development in photovoltaics, small wind-generator systems, solar cooling, and other solar technologies.

5.4.2 Municipal Solid Waste for Energy Production

This covers a group of well-established technologies, which can help to solve major environmental problems and reduce municipal disposal costs. Energy can be produced by direct combustion, or by pyrolysis to yield liquid, gaseous, and solid fuels.

Direct combustion, the simplest technology, has the potential of reducing solid waste volume by 98%, and providing an inert residue, which may even have value as a building material. The dearth of suitable landfill sites in Long Island makes it particularly attractive here. It has the further advantage of lending itself to cogeneration and district heating.

5.4.3 Other Technologies

The National Energy Plan mentions geothermal power and fusion power. The former is irrelevant to Long Island, and the latter is not expected to achieve practical application before the year 2000.

6.0 Demand Computations

6.1 Residential

Table VIII-1 summarizes the projection of population, households and proportions of single to multi-family dwellings on which the residential energy demands are based. These numbers were discussed in Section 2.0.

Residential energy demands have been broken down into the categories established for the disaggregation methodology used in a BNL report (9), a methodology that they employed in several studies (10, 11 12, 13). Unit demands were taken from another BNL study (3), using 1972 values as the basis, and modifying them according to the conservation measures and/or technological improvements assumed to have been introduced by the years of interest. These measures and improvements are considered reasonable by the NSRPB, neither too optimistic nor too conservative.

6.1.1 Residential Space Heat: Single-family Dwellings

6.1.1.1 Unit Demand.

The average dwelling, in 1972, used 51.2×10^6 Btu/year. Current economic conditions indicate that smaller houses will be constructed in the future, which would imply that the average unit demand will decrease. However, the trend is unclear, and no credit is taken for it.

6.1.1.2 Thermostat Setback.

It is expected that the public will come to appreciate the need for economy, and will tend to keep their houses cooler. A saving of 8% in fuel use is anticipated, giving a unit demand of 47.104×10^6 Btu/year.

6.1.1.3 Home Retrofit.

The Federal Energy Program includes a section on the need to improve the insulation and heat-retention capability of existing dwellings. The

TABLE VIII-1

Basic Assumptions for Residential Energy Demands

	1985	2000
Population	3,017,817	3,325,000
Persons per Household	3.58	3.49
Number of Household	842,533	952,262
Percent Single Family Dwellings	83%	82%
No. of Single-family Dwellings	698,636	780,298
No. of Multi-family Dwellings	143,897	171,964

Administration has recently downgraded its original target, and now forecasts that 60% of existing dwellings will retrofitted by 1985. A reasonable pessimism indicates that even this target may be too high. Consequently, two sub-cases are proposed:

a) 30% retrofitted by 1985, and 60% by 2000.

b) 60% retrofitted by 1985, and 100% by 2000.

The unit demand will be reduced 15% thereby, to 40.038×10^6 Btu/year. It is assumed that existing dwellings using electric heat will already be so well insulated as not to require retrofitting.

6.1.1.4 New Dwellings.

New construction will incorporate thicker insulation, windows with better thermal characteristics, and more closely fitting doors. Such construction will yield a 27% improvement in unit demand, to 34.386×10^6 Btu/year. Furthermore, 10% of new construction is expected to conform to even more stringent FHA-MPS standards, with a 42% improvement in unit demand, to 27.320×10^6 Btu/year.

6.1.1.5 Burner Efficiency.

Retrofitted dwellings and new dwellings will have new burners whose efficiencies will be, on the average, 5 percentage points higher than the old.

Gas burner efficiency will go from 0.34 to 0.39.

Oil burner efficiency will go from 0.28 to 0.33.

6.1.1.6 Electric Space Heat.

15% of homes built after 1972 are assumed to use electric space heat, For houses built after 1985, half of the electrically heated ones will employ heat pumps. Power requirements for the latter were calculated assuming an average coefficient of performance of 3.0, a conservative value.

6.1.1.7 Gas Heat.

The base case for this study assumes no new gas users. As a sub-case, it is assumed that offshore developments in the region make additional gas available after 1985, and that, by the year 2000, 15% of all homes built after 1972 have been connected to the gas supply system. The sub-case further assumes that one-third of this number are deducted from the number of oil-heated homes and two-thirds from the number of electrically heated homes, with all the remaining electrical homes using heat pumps.

6.1.1.8 Solar Heating

The Administration has recently predicted (4) that 1.3 million homes in the United States will have some form of solar heating installed by 1985. On the basis of housing projections for the entire country (72), this is approximately 1.5%. Applying the nationwide ratio to Nassau-Suffolk, an estimated 12,638 homes will have solar heat by 1985. For the year 2000, it is assumed that 5% or 67,613 homes, will have solar heat.

Installations for the solar heating of water are much simpler and cheaper than those for space heat. For the purposes of this study, it will be assumed that <u>all</u> such installations are for heating water. (See below.)

6.1.2 Residential Space Heat: Multi-family Dwellings

6.1.2.1 Unit Demand.

The average dwellings, in 1972, used 31.0×10^6 Btu/year.

6.1.2.2 Thermostat Setback.

A saving of 8% will be realized by setting thermostats lower, giving a unit demand of 28.52×10^6 Btu/year.

6.1.2.3 Home Retrofit.

As for single-family homes, two sub-cases are considered:

a) 30% of homes retrofitted by 1985, and 60% by 2000.

b) 60% of homes retrofitted by 1985, and 100% by 2000.

The unit demand is reduced 13% to 24.812×10^6 Btu/year.

No existing electrically-heated homes will be retrofitted.

6.1.2.4 New Dwellings.

New construction will yield a 26% improvement in unit demand, to 21.105×10^6 Btu/year. Furthermore, 10% of new homes will conform to even tougher specifications giving a saving of 41%, or a unit demand of 16.827×10^6 Btu/year.

6.1.2.5 Burner Efficiency.

Retrofitted dwellings and new dwellings will have new burners whose efficiencies are, on the average, 5 percentage points higher than the old.

Gas burner efficiency will go from 0.43 to 0.48.

Oil burner efficiency will go from 0.36 to 0.41.

6.1.2.6 Electric Space Heat.

20% of homes built after 1972 are assumed to use electric space heat. For homes built after 1985, half of the electrically heated ones will employ heat pumps, having a coefficient of performance of 3.0.

6.1.2.7 Gas Heat.

As for single-family homes, the base case assumes no new gas users, but a sub-case is proposed for more gas to be available after 1985. By the year 2000, 15% of the homes built after 1972 will be assumed to have gas heat. The numbers of oil-heated and electrically-heated homes will be accordingly reduced, one third being deducted from the number of oil-users and two thirds from the number of electricity users. The remaining electricity users will have heat pumps.

6.1.2.8 Solar Heating.

As for single-family homes.

6.1.3 Residential Water Heat

6.1.3.1 Unit Demand.

The average dwelling, in 1972, used 16.4×10^6 Btu/year.

6.1.3.2 New Dwellings.

For houses built between 1972 and 1985, it will be assumed that 23% have electrically-heated hot water, and for those built between 1985 and 2000, 30%. The rest will be oil-heated.

6.1.3.3 Heater Efficiency.

New heaters will have efficiences 5 percentage points higher than the old ones.

Gas heater efficiency will go from 0.75 to 0.80.

Oil heater efficiency will go from 0.63 to 0.68.

6.1.3.4 Gas Heat.

As for space heat, the base case assumes no new gas users. A sub-case is proposed for the year 2000, in which 15% of houses built after 1972 are assumed to be additional gas users. One third of the number are deducted from the oil users, and two thirds from the electricity users.

6.1.3.5 Solar Heat.

As stated previously, it is assumed that <u>all</u> solar domestic installations will be for heating water. Certainly, <u>most</u> will be, for reasons of simplicity and cost.

1.5% of homes will be assumed to have solar heat by 1985, in line with government predictions. By 2000, the percentage is assumed to grow to 5.

The Solar installation operates only when sunshine is available, and therefore does not eliminate the conventional system, which must be available when needed. Claims vary as to the fraction of the unit demand that solar heat will carry. A value of 60% is assumed here. If anything, this value is on the conservative side. A saving of 60% means a unit demand of 6.56×10^6 Btu/year.

<u>6.1.4 Residential Air Conditioning.</u>

6.1.4.1 Unit Demand.

Three categories of air conditioning systems are considered. Their average unit demands, in 1972, were:

single-family central a/c.	27.6×10^6 Btu/year.
multi-family central a/c.	19.0×10^6 Btu/year.
room a/c.	3.0×10^6 Btu/year.

6.1.4.2 Thermostat Advance.

A saving of 10% in unit demand is expected from the public acceptance of higher temperatures. The unit demands become:

S-F central a/c	24.75×10^6 Btu/year.
M-F central a/c	17.10×10^6 Btu/year.
room a/c.	2.70×10^6 Btu/year.

6.1.4.3 Coefficient of Performance.

By 1985, technological improvements are expected to achieve a substantial increase in equipment efficiency.

Coefficients of performance are expected to go up by 40%, as follows:

S-F central a/c: from 2.5 to 3.5.

M-F central a/c: from 2.5 to 3.5.

room a/c: from 2.0 to 2.8.

6.1.4.4 Number of Units

In 1972, 9% of single-family houses and 3.1% of multi-family homes were served by central air conditioners. Of the remaining homes, some had no air conditioners and others had more than one. In total, the number of room air conditioners was 79.4% of the number of homes without central air conditioning. By 1985, it is assumed that 10.5% of single-family houses and 15% of multi-family homes will be served by central air conditioners, and that each of the remaining homes will, on the average, have exactly one room unit. By 2000, these numbers are projected to go to 11.5%, 20% and 1.2, respectively.

6.1.5 Residential Lighting.

The unit demand of 1972 is retained unchanged, namely 4.4×10^6 Btu/year.

6.1.6 Residential Range.

6.1.6.1 Unit Demand.

Unit demand is 4.1×10^6 Btu/year.

6.1.6.2 New Gas Users.

The base case is for no new gas users.

However, as was done for space heat and water heat, a sub-case is proposed in which additional gas becomes available after 1985, and, by the year 2000, 15% of homes built after 1972 have gas ranges, in addition to the users existing prior to 1972. All remaining ranges, in both cases, are electric.

6.1.7 Residential Refrigerators.

It is assumed that any increase in unit demand in the future, due to larger units, is offset by improvements in unit efficiency. Unit demand is taken as 5.1×10^6 Btu/year.

It is further assumed that, in 1985, 5% of homes had the equivalent of two refrigerators, and in 2000, 10%.

6.1.8 Residential Major Appliances.

This category includes such items as dishwashers, clotheswashers, dryers, etc.

6.1.8.1 Unit Demand.

The 1972 unit demand of 10.1×10^6 Btu/year is expected to decline by 10% because of technological improvements. This would bring it down to 9.09×10^6 Btu/year.

6.1.8.2 Numbers of Units.

In 1972, the numbers of major appliances in use in the area was equivalent to 39% of all homes being equipped with a complete "set". By 1985, it is assumed that about 50% of all homes will be so equipped on the average, and by 2000, 60%.

6.1.9 Residential Miscellaneous Electric Users.

This category covers small electric motors, electronic equipment, etc.

6.1.9.1 Unit Demand.

In 1972, the number of such devices in use in the area made for a unit demand of 4.9×10^6 Btu/year, averaged over all homes.

By 1985, improvements in technology are expected to reduce the unit demand by 10% to 4.41×10^6 Btu/year.

6.1.9.2 Numbers of Units

By 1985, these devices are expected to proliferate to such an extent that each home would, on the average, have a demand equivalent to 1.25 times the 1972 unit demand. By 2000, the figure would rise to 1.35.

6.1.10 Computed Demands.

The projections for the residential sector are presented in Table VIII-2.

TABLE VIII-2

Residential Energy Demand Projections

1985

Fuel	Sub-case 1	Sub-case 2
Natural gas, 10^6 ft. ^{3}/year	23,868	22,550
Distillate, 10^6 gal./year	778	723
Electricity, 10^6 kwh/year	6,238	6,238

Sub-case 1: 30% of existing homes retrofitted.

Sub-case 2: 60% of existing homes retrofitted.

Clearly, retrofitting has little overall impact, and negligible impact on electricity use.

2000

Fuel	Sub-case 1	Sub-case 2	Sub-case 3	Sub-case 4
Natural gas, 10^6 ft. 3/year	22,549	20,790	25,722	23,963
Distillate, 10^6 gal./year	799	726	790	717
Electricity, 10^6 kwh/year	7,728	7,728	7,432	7,432

Sub-case 1: 30% of existing homes retrofitted.
No new gas users.

Sub-case 2: 100% of existing homes retrofitted.
No new gas users.

Sub-case 3: 60% of existing homes retrofitted.
New gas users permitted.

Sub-case 4: 100% of existing homes retrofitted.
New gas users permitted.

As was the case for the 1985 figures, retrofitting does not have a large impact. However, if a new gas supply is available after 1985, it could have a significant effect on electricity use.

6.2 Commercial and Industrial

Table VIII - 3 summarizes the projections of commercial and industrial electricity customers, and of total commercial and industrial floor areas, on which the energy demands are based. These numbers were discussed in Section 3.0.

6.2.1 Electricity Demand

In the disaggregation methodology of the BNL energy demand study (3), commercial and industrial demands were broken down as follows:

Process Heat

Space Heat

Air-conditioning

Lighting

Miscellaneous electrical users

The last three categories are clearly consumers of electricity. In addition, BNL forecast that small percentages of space heating would be provided by electricity in the years 1985 and 2000. LILCO (5) lump all electricity demands into one and project future demands per customer by a regression technique that includes some adjustment for a reasonable degree of conservation. They arrive at the following unit demands:

	1985	2000
Commercial customers, kwh/yr	91,074	113,811
Industrial customers, kwh/yr	278,647	265,613

6.2.2 Fossil Fuel Demand

At present, most process heat in industry is provided by oil and gas, with a small percentage supplied by coal. BNL assume that the gas consumption will not increase in the future, and that coal use

Table VIII-3

Basic Assumptions for Commercial and Industrial Energy Demands

	1985	2000
No. of commercial electricity customers	75,027	82,879
No. of industrial electricity customers	5,814	7,420
Total commercial and industrial floor area	531,000	664,000

will be phased out by 1985, with the remainder of the load carried by distillate and residual oils. They also assume that total demand rises 2.6% per year, from the base demand (in 1972) of 7.6×10^{12} Btu/year. This gives a total demand in 1985 of 10.6×10^{12} Btu/year, and in the year 2000 of 15.4×10^{12} Btu/year. All these assumptions are based on the available literature, and will be accepted for this report.

As far as space heat is concerned, a basic unit demand of 134,200 Btu/ft^2/year has been determined, and a reduction of 10% by 1985 is assumed, by virtue of thermostat setback. Heating is by gas and distillate oil. The current level of gas consumption is maintained constant, and future demand increases are to be filled by the use of distillate oil.

6.2.3 Computed Demands

The projections for the commercial-industrial sector are presented in Table VIII-4

Table VIII-4

Commercial/Industrial Energy Demand Projections

Fuel	1985	2000
Natural gas, 10^6 ft.^{3}/year	16,105	16,105
Distillate, 10^6 gal./year	800	1,033
Residual Oil, 10^6 gal./year	51	59
Electricity, 10^6 kwh/year	8,453	11,404

6.3 Transportation

Table VIII-5 summarizes the projected bases used for the transportation energy demands, as discussed in Section 4.0.

6.3.1 Automobile Demand

As mentioned in Section 5.0, gasoline engine performance is assumed to reach 27.5 m.p.g. in 1985 and 30 m.p.g. in 2000. Diesel engine performance will be 40 m.p.g in 1985 and 50 m.p.g. in 2000.

In 1982, it is assumed that 2% of vehicle-miles will be by diesel, and 4% in 2000. Further in 2000, 10% of vehicle-miles are assumed to be by electric cars. Since the recharge of car batteries can be relegated to non-peak hours, the electricity demand is not included, since it does not contribute to the peak demand, and therefore plays no part in computing the installed capacity (see below).

The quantities of fuel per vehicle-mile are computed to be as follows:

	1985	2000
Gasoline	0.0364 gal.	0.0334 gal.
Diesel	0.0250 gal.	0.0200 gal.

6.3.2 Commercial Demand

The quantities are as stated in Table VIII-5

6.3.3 Railroad Demand

As noted in Section 4.0, the annual electrical demand for the electrified section is given by LILCO (5) as 187 x 10^6 kwh. For the non-electrified section, fuel requirements are computed to be:

Residual oil	0.020 gal./passenger-mile
Diesel oil	0.022 gal./passenger-mile

Table VIII-5

Basic Assumptions for Transportation Energy Demands

	1985	2000
Automobile vehicle - miles	20.9×10^9	25.6×10^9
Commercial fuel consumption	296.6×10^6 gal.	326.8×10^6 gal.
percent gasoline	76	76
percent diesel	24	24
Railroad passenger - miles	1.2×10^9	1.2×10^9
percent electricity	56	56
percent residual oil	58	38
percent diesel	6	6

6.3.4 Computed Demands

The projections for the transportation sector are presented in Table VIII-6

Table VIII - 6

Transportation Energy Demand Projections

Fuel	1985	2000
Gasoline, 10^6 gal./year	1,004	1,046
Diesel oil, 10^6 gal./year	85.5	110.5
Residual oil, 10^6 gal./year	9.4	9.4
Electricity, 10^6 kwh/year	187	187

6.4 Other Energy Demand Categories

As discussed in Section 4.0, LILCO (5) lists several miscellaneous electricity demands. They are:

a) "Other Public Authorities" - 252 x 10^6 kwh/year in both 1985 and 2000.

b) Street and Highway Lighting - 200 x 10^6 kwh/year in both 1985 and 200.

c) LILCO's own requirements - 1,942 x 10^6 kwh/year in 1985, and 3,180 x 10^6 kwh/year in 2000.

In addition LILCO's own fossil fuel requirements for power generation must be estimated. In their report to the Public Service Commission (5), LILCO estimates that, in 1982, they will consume 924 x 10^6 gal. of residual oil, and 29.4 x 10^6 gal. of distillate oil. By 1982, LILCO will have Northport 4 (residual oil) on the line, Mitchel Gardens (solid waste fired) and Shoreham (nuclear). They are further to receive 18% of the output of Nine Mile Point 2 (nuclear) after that date. Thereafter, they will be faced with the retirement of old plants, and any new capacity will almost certainly be coal-fired or nuclear. For 1985, we will assume the 1982 estimates. By 2000, it is estimated that approximately 19% of currently existing capacity will have been retired. Consequently, for 2000, the 1982 figures will be prorated downward by this percentage, i.e., to 749 x 10^6 gal. of residual oil and 24 x 10^6 gal. of distillate oil.

LILCO also uses some natural gas, from time to time, in start-up operations, usually in off-peak hours.

7.0 Summary of Total Demands

7.1 Electricity

Electricity, unlike ordinary fuels, cannot be stored. It must be used as it is generated, and, as demand varies during the day, there must be generating equipment of sufficient capacity available to satisfy the demand at all times. So far, we have computed demand in kilowatt hours per year, whereas plant capacity is measured in kilowatts. If demand did not vary through the day, then the required plant capacity would simply be the annual kilowatt hour demand divided by 8760, the number of hours in the year. However, since demand does indeed vary during the day, a larger installed capacity is required than would be computed in this way. Actual capacity could be determined from the annual demand by dividing by some hypothetical number of hours less than 8760. This is a purely empirical concept, but is, indeed in use. The ratio of this hypothetical number of operational hours to 8760 is called the "Peak Load Factor". There are seasonal variations in the mode of power consumption, and the summer peak required capacity is usually different from the winter peak. (In Long Island, the summer peak is greater.) Consequently, there are both Summer and Winter Peak Load Factors. In the New York State Power Pool's report to the Public Service Commission (5), values are given for the Power Pool as a whole, namely Summer Peak Load Factor 63.4% and Winter Peak Load Factor 66.1%. LILCO, in the same report, uses other methods to derive required capacity from demand figures, but one can compute the peak load factors, and one finds that their summer one is considerably lower.

Summer Peak Load Factor	49.9%	-	49.1%
Winter Peak Load Factor	62.8%	-	62.5%

(LILCO finds that the values vary slightly with time. The ranges given are from 1982 to 1997.) The lower the load factor, the sharper the peak. Under pressure from the government, utilities will, in the future, have to reform their rate structures in order to "shave" the peak, and thus reduce the amount of installed capacity required to handle it. LILCO has instituted "Time of Use Metering" for certain of their larger customers as of February, 1977, and expect to extend its application in the future (see below). Table VIII-7 lists those demands which contribute to the peak load. Thus, we exclude the consumption by electric automobiles, since their batteries can be recharged during off-peak hours.

Since the Summer Peak Load in Long Island is greater than the Winter Peak, we will compute only that.

1985 The effective load factor used by LILCO for 1985 is 49.7%.

Annual demand = 17,272 x 10^6 kwh.

Summer Peak Load = 3,968 megawatts.

"Time of Use Metering" adjustment projected by LILCO = 137 MW.

1985 Summer Peak Forecast = 3821 MW

2000 The effective load factor, extrapolated to 2000 from LILCO's tabulation, is 49.0%.

Annual demand = 22.951 x 10^6 kwh.

Summer Peak Load = 5,347 MW

"Time of Use Metering" adjustment extrapolated to 2000 from LILCO's tabulation = 377 MW.

2000 Summer Peak Forecast = 4,970 MW

To the peak forecasts, LILCO adds 18% as a safety margin, to determine the required capacity. Thus:

Table VIII- 7

Electrical Demands Contributing to the Peak Load
(10^6 kwh/year)

	1985	2000
Residential	6,238	7,728 (1)
Commercial/Industrial	8,453	11,404
Railroad	187	187
Other Public Authorities	252	252
Street and Highway Lighting	200	200
LILCO Internal	1,942	3,180
	17,272	22,951

(1) A limited increase in the number of gas customers reduces this by approximately 300 x 10^6 kwh/yr. (See Section 6.1)

Required capacity in 1985 = 4,370 MW

Required capacity in 2000 = 5,856 MW

7.2 Distillate and Residual Oils

Table VIII-8 summarizes all the projected demands for distillate and residual fuel oils. Various degrees of housing retrofit, and, in 2000, some increase in the permitted number of gas customers (see Section 6.1), result in a possible reduction in the overall distillate demand of the order of 4%. For planning purposes, this difference is not significant, and we will use the maximum values, which are those tabulated.

LILCO is under notice by the Federal Government to reconvert the Port Jefferson units 3 and 4 to coal firing. If that should actually be carried out, there would, of course be a reduction in the residual oil demand, and a coal demand instead. It is unwise to simply replace a certain amount of oil demand by its heating value equivalent of coal. Firing coal may change the economics of operation of the Port Jefferson plant enough to make it preferred for base load operation. This would mean it would stay on the line longer each day than at present, and some other, less economic plant would be loaded less than at present. If the two units were to operate 24 hours a day, they would consume 13,600 barrels of oil per day, or 3,360 tons of coal a day. In practice, in the present oil-firing situation, Port Jefferson 3 and 4 operate at full load approximately 45% of the time. If the units are converted back to coal, and if the economics justify it, they might operate as much as 72% of the time. Thus the exchange could be 2,420 tons of coal per day for 6,120 barrels (257,040 gal.) per day consumed at Port Jefferson plus an undetermined amount of oil saved in some

Table VIII - 8

Summary of Demand Projections for Distillate and Residual Fuel Oils (10^6 gal./year)

	1985		2000	
	Dist.	Resid.	Dist.	Resid.
Residential	778[(1)]		799[(2)]	
Commercial/Industrial	800	51	1,033	59
Transportation		9.4		9.4
LILCO Internal	29.4	924	24	749
	1,607.4	874.4	1,856	817.4

(1) Based on 30% of existing homes retrofitted.
If 60% retrofitted, the distillate demand is 723 x 10^6 gal./yr.

(2) Based on 60% of existing homes retrofitted, and no new gas users.
If 100% retrofitted, and a limited number of new gas users is permitted, the distillate demand is 717 x 10^6 gal/yr. (See Section 6.1)

other plant that would operate less than before.

7.3 Gasoline and Diesel Fuel

Table VIII-9 summarizes the projected demands for gasoline and diesel fuel.

7.4 Natural Gas

Table VIII-10 summarizes the projected demands for natural gas. In 1985, increasing the percentage of retrofitted houses from 30 to 60 lowers the residential gas demand by 5.5%. In 2000, increasing the percentage from 60 to 100 reduces the residential gas demand by 7.8% and increasing the number of gas customers by 15% increases it by 15.3%.

7.5 Coal

Coal usage in Nassau and Suffolk Counties at this date is not significant. What the future holds for its use in homes, commerce, and industry is uncertain. As discussed in Section 7.2, LILCO may have to fire coal in its Port Jefferson units 3 and 4. In addition, any future power stations authorized in the bi-county region will almost certainly be nuclear or coal-fired. Power station coal handling will be discussed below, in Section 8.5.

Table VIII - 9

Summary of Demand Projections For Gasoline and Diesel Fuel
(10^6 gal./year)

	1985	2000
Gasoline	1,004	1,046
Diesel Fuel	85.5	110.5
	1,089.5	1,156.5

Table VIII-10

Summary of Demand Projections for Natural Gas
(10^6 ft^3/year)

	1985	2000
Residential	23,868 (1)	22,549 (2)
Commercial-Industrial	16,105	16,105
	39,973	38,654

(1) Based on 30% of existing homes retrofitted.
If 60% retrofitted, the gas demand is 22,550 x 10^6 ft^3/yr.

(2) Based on 60% of existing homes retrofitted, and no new gas users.
If 100% retrofitted, and no new gas users, the gas demand is 20,790 x 10^6 ft^3/yr. If additionally, a limited number of gas users is permitted, gas demand is 23,963 x 10^6 ft^3/yr. (See Section 6.1)

8.0 Inventory of Existing and Additional Required Facilities

8.1 General

Much of the information in this section was obtained from personal contacts with officials of county and township agencies, public utilities and private companies. Instead of identifying these sources, individually, as bibliographical references, they are listed in Section 12.0, Coordination.

8.2 Power Plants

Table VIII-11 lists the present inventory of LILCO operating plants, and Table VIII -12 lists the plants they have under construction. In addition, the Village of Freeport has a total generating capacity of 50 MW, of which 18 MW is by combustion turbine and 32 MW by diesel engine, and the Village of Greenport has a small internal combustion plant. The locations of all plants (except Nine Mile Point 2) are shown in Figure VIII-1

Figure VIII-2 presents curves of existing generation capacity and future electrical demand, spanning the period from 1977 to the year 2000. Line (A) traces LILCO's total installed capacity, including that which is under construction. No account is taken of any new plants not yet authorized, and capacity is diminished by the retirement of plants, according to the dates listed in Table VIII-11 Steam turbine plants are usually financed over an assumed life of 35 years, and gas turbine and other plants for 25 years.

However, retirement is usually delayed, and 5 years have been added to each of these terms. The increases in capacity indicated through 1984 are, in sequence, Northport 4, Mitchel Gardens, Shoreham 1 (nuclear), and Nine Mile Point No. 2 (LILCO's share). During this period, Glenwood 2 and 3 are retired.

Line (B) represents an additional availability of power by virtue of a contractual relationship between LILCO and the New York State Power Pool.

Line (C) is a plot of LILCO's estimate of summer peak demand. Their projections run only through 1997 (5), but the curve has been extrapolated to the year 2000. Line (D) is then LILCO's projections

TABLE VIII-11
INVENTORY OF LILCO POWER PLANTS IN OPERATION
1977

Station	Unit	Type	Method Of Fuel Handling(1)	Max. Storage Capacity 10^6 Gal.	Capability - MW Summer	Capability - MW Winter	Type of Cooling System	Start-up Year	Retire-ment Year(4)
Northport	1	Steam Turbine	Water	83.5	386	386	Once-through	1967	2007
"	2	" "	"		386	386	"	1968	2008
"	3	" "	"		386	386	"	1972	2012
"	GT	Combustion Turbine	Truck	0.1	16	20	Air	1967	1997
Port Jefferson	1	Steam Turbine	Water	27.1	49	49	Once-through	1948	1988
"	2	" "	"		49	49	"	1950	1990
"	3	" "	"		196	196	"	1958	1998
"	4	" "	"		196	196	"	1960	2000
"	GT	Combustion Turbine	Truck	0.1	16	20	Air	1966	1996
Glenwood	2	Steam Turbine	Water	6.2(2)	77	77	Once-through	1930	1980
"	3	" "	"	(2)	77	77	"	1938	1980
"	4	" "	"	(2)	114	114	"	1952	1992
"	5	" "	"	(2)	113	113	"	1954	1994
"	1	Combustion Turbine	Truck	0.5	16	20	Air	1967	1997
"	2 & 3	" "	Water	1.5	114	124	"	1972	2002
Barrett	1	Steam Turbine	"	20.2(2)	189	189	Once-through	1956	1996
"	2	" "	"	(2)	191	191	"	1963	2003
"	APG	Combustion Turbine	Truck	0.1	18	22	Air	1966	1996
"	1 - 8	" "	"	3.0(2)	126	151	"	1970	2000
"	9 - 12	" "	"	(2)	162	190	"	1971	2001
Far Rockaway	4	Steam Turbine	Water	2.1(2)	114	115	Once-through	1953	1993
Shoreham	1	Combustion Turbine	Truck	1.0	51	64	Air	1971	2001
West Babylon	1 - 3	" "	"	0.5	52	63	"	1966	1996
" "	4	" "	"	0.5	48	62	"	1971	2001
Southold	1	" "	"	0.126	14	17	"	1964	1994
Southampton	1	" "	"	0.126	11	14	"	1963	1993
Montauk	2 - 4	Internal Combustion	"	0.042	6	6	"	1961	1991
East Hampton	1	Combustion Turbine	"	0.134	20	24	"	1970	2000
" "	2 - 4	Internal Combustion	"	0.055	6	6	"	1962	1992
Holbrook	1 - 10	Combustion Turbine	Water(3)	5.0	528	664	"	1974/5	2004/5

(1) All plants use heavy oil
(2) Alternative gas firing-fuel in by pipeline
(3) Alternative handling by pipeline
(4) Either the date has been announced (Glenwood 2 & 3), or it is assumed that steam turbine units are retired 40 years after start-up, and other units 30 years.

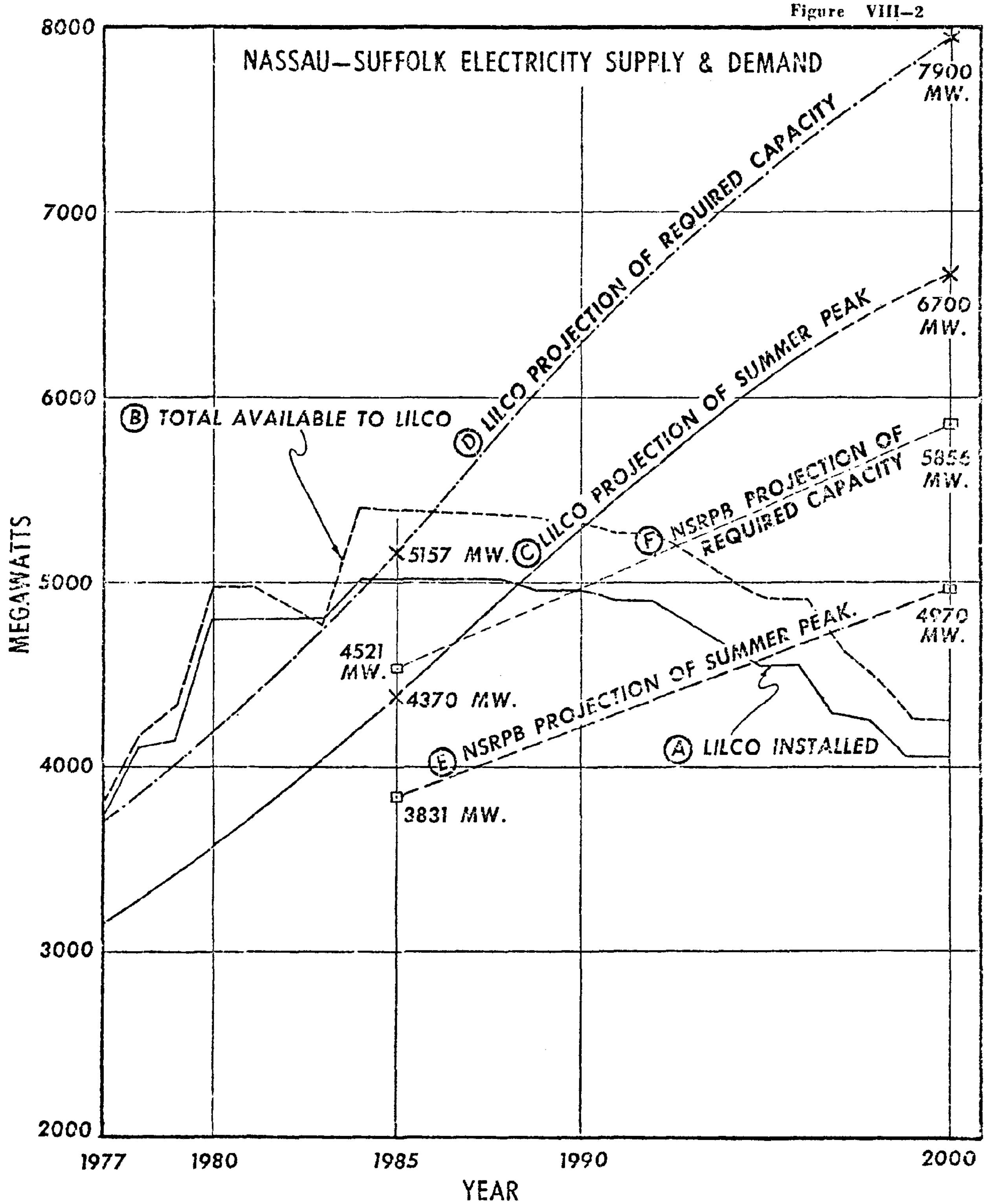
TABLE VIII-12

LILCO POWER PLANTS UNDER CONSTRUCTION

Station	Unit	Type	Fuel	Method of Fuel Handling	Capability MW	Type of Cooling System	Start-up Year
Northport	4	Steam Turbine	Oil	Water	386	Once-through	1977
Mitchel Gardens	1 & 2	" "	Solid Waste	Truck	32		1978
Shoreham	1	" "	Nuclear		820	Once-through	1980
Nine Mile Point	2	" "	"		194(1)	"	1983

(1) LILCO's 18% share of a plant on Lake Ontario

Figure VIII-2



of required installed capacity, being line (C) increased by 18%, their standard margin. The intersection of line (D) with line (B) indicates that LILCO requires additional capacity by 1986, and the supply deficit by the year 2000 is, according to their numbers, approximately 3600 megawatts.

NSRPB has made estimates for 1985 and 2000, and line (E) joins the two points in the figure. There is little reason to suppose that line (E) would <u>not</u> represent a steady increase from 1985 to 2000, although, admittedly, the profile of this increase has not actually been determined. Line (F) is then NSRPB's projection of required capacity, being line (E) with the standard 18% margin.

The intersection of line (F) with line (B) (the total available line) now occurs in 1992, approximately, and the apparent deficit in the year 2000 is now about 1600 megawatts, about 2000 megawatts less than LILCO's projection.

8.3 Handling and Storage Facilities for Petroleum Products

8.3.1 General

Petroleum products are currently delivered by tanker and barge to shoreside terminals in six locations in Nassau north shore bays, seven locations in Hempstead Bay, three locations on the north shore of Suffolk, and one location each in Greenport, Sag Harbor and Patchogue. In addition, LILCO has an offshore oil terminal at their Northport power station, and Northville Industries operates an offshore terminal at Northville, with a storage facility onshore. Finally, the onshore terminal in Port Jefferson Harbor is linked by pipeline to three inland storage facilities, one of them as far away as Plainview, just over the Nassau border.

For a number of pressing reasons of environmental importance, including not only the dangers of oil spills, but also problems of channel dredging and dredge spoil disposal, the NSRPB is proposing a radical revision of the entire oil unloading and storage system in the two counties, including the installation of two more offshore terminals on the north shore, one in Nassau and one in Suffolk. This proposal is spelled out in detail in the Dredging Subplan, which is another part, companion to the Energy Facilities Subplan, of the bi-county Coastal Zone Management Plan. The revised oil handling and storage scheme is reviewed below in more detail, after an inventory of the existing facilities. Future needs for the years 1985 and 2000 will then be discussed. Reference is made to Figure VIII-3 in which the locations of existing and proposed facilities are shown.

It should be noted that, when breakdowns are given by product, these numbers are current ones and temporary. It is quite customary for the same tank to hold one product one month, and another product the next.

8.3.2 Existing Nassau County Facilities

The following information was obtained from the County Fire Commissioner's Office.

a. Great Neck, at the head of Manhasset Bay.
   Total storage 4.1 million gallons, mostly fuel oils, comprising 3.5 million gallons of No. 2, and 600,000 gallons of No. 4.

b. Port Washington, on Sheets Creek in Manhasset Bay.
   Total storage 11.3 million gallons, nearly all No. 2 fuel oil.

c. Roslyn, at the head of Hempstead Harbor.
   700,000 gallons, mostly fuel oil.

d. Glen Cove, on Glen Cove Creek, off Hempstead Harbor.
   Total storage 2.2 million gallons of fuel oil.

e. Glenwood Landing, on Hempstead Harbor.
   Total storage 8.7 million gallons, comprising approximately 4.5 million gallons of gasoline, 3.0 million gallons of fuel oils, and the remainder kerosene and diesel oil.

f. Oyster Bay.
   Total storage 4.8 million gallons, comprising 4.0 million gallons of fuel oils, and the rest gasolene.

g. Meadowmere Park.
   Total storage 11.5 million gallons, including gasoline, kerosene, diesel oil, and heavy fuel oil.

h. Inwood, Doughty Boulevard and Bay Boulevard.

Total storage 18.2 million gallons, comprising approximately 10.0 million gallons of No. 2 fuel oil and the rest gasoline.

i. Inwood, Rogers Avenue.

Total storage 3.3 million gallons, mostly No. 2 fuel oil with some gasoline, and one tank of jet fuel.

j. Inwood, Sheridan Avenue.

Total storage 1.4 million gallons, mostly gasoline, with some No. 2 fuel oil.

k. Island Park, LILCO

Total storage 15.0 million gallons, mostly No. 6 fuel oil, with some No. 2.

l. Island Park, Cibro.

Total storage 17.0 million gallons, approximately two-thirds No. 2 fuel oil, the rest No. 4.

m. Oceanside.

Total storage 15.3 million gallons, approximately half each gasoline and No. 2 fuel oil, plus one tank of diesel oil.

n. Plainview (inland terminal at the end of the pipeline).

Total storage 1.0 million gallons, all in No. 2 fuel oil.

8.3.3 Existing Suffolk County Facilities

The following information is not always up to date, but is the best available.

a. Cold Spring Harbor.

Total storage 2.7 million gallons.

b. Huntington Harbor.

Total storage 2.9 million gallons.

c. Port Jefferson Harbor.

Total storage 3.8 million gallons.

d. East Setauket (inland storage facility).

Total storage approximately 100 million gallons, of which 42 million is gasoline, and the rest No. 2 fuel oil.

e. Holtsville (inland storage facility).

Total storage 13.0 million gallons, of which 8.2 million is gasoline, and the rest No. 2 fuel oil.

Plans have been laid for a 12.8 million gallon expansion.

f. An overland pipeline starts at the Port Jefferson shoreside terminal, and runs south to the Holtsville facility, connecting up with the East Setauket facility enroute. The pipeline then turns westerly, and ends at the Plainview facility in Nassau County.

g. Northville.

Total storage 145.9 million gallons, comprising 86.8 million gallons of residual fuel oil, 28.4 million gallons of gasoline, and 30.7 million gallons of No. 2 fuel oil. Another 44.1 million gallons of storage is under construction.

The storage facility is served by an offshore terminal, with a water depth of 60 feet at mean low water.

h. Village of Greenport.

Total storage 1.3 million gallons.

i. Village of Sag Harbor.

Total storage 1.5 million gallons.

j. Village of Patchogue.

Total storage 10.5 million gallons.

k. Northport, LILCO.

LILCO has an offshore terminal, with 45 feet of water at mean low water, for supplying the Northport power station. Total storage 81.0 million gallons.

8.3.4 Proposed Petroleum Products Handling and Storage System

The NSRPB recommends (59) that offshore terminals be constructed at Hempstead Harbor and Port Jefferson Harbor in water at least 45 feet deep at mean low water, to handle tankers in the 80,000 deadweight ton class (with 43 ft. drafts). The Hempstead Harbor terminal should be located off Prospect Point and should be connected by submarine and land pipeline to a tank farm on industrially zoned property with highway access located on the southwest shore of Hempstead Harbor. The volume of storage to be provided in the new facility should approximate the total of all existing terminals in the north shore bays from Manhasset Bay to Huntington Harbor. (This would comprise items a,b,c,d,e and f in Section 8.3.2, and items a and b in Section 8.3.3.). This total storage volume comes to approximately 38 million gallons. The Port Jefferson Harbor terminal should be located off Mount Misery Point and should be connected by submarine pipeline to the existing land pipeline that runs from the harborfront to East Setauket and Holtsville.

The construction of offshore terminals at Hempstead Harbor and Port Jefferson would eliminate the need to undertake Federal channel dredging projects for Manhasset Bay, Hempstead Harbor, Glen Cove Creek, Huntington Harbor, and Port Jefferson Harbor, for the purpose of supporting petroleum traffic, and would allow for the phasing out of all existing terminals within embayments on the north shore of Nassau County and western Suffolk County.

The present rates of petroleum importation at Northville and the existing storage capacity at that facility are sufficient to supply the North and South Forks and allow for the phasing out of existing terminals in Greenport Harbor and Sag Harbor. Storage facilities for future increased shipments to the Northville terminal should be constructed on properties of the Suffolk County Airport and connected by pipeline to the existing tank farm in Northville. This would allow for easier truck delivery within Southampton Town and to the South Fork via Sunrise Highway.

The Northville - Suffolk County Airport pipeline could also be connected to the existing pipeline and tank farm at Holtsville by a pipeline running along State Route 24 and the Long Island Expressway. Such a pipeline would provide flexibility for the petroleum transportation network, and could serve an additional tank farm in the Yaphank-Upton area of Brookhaven Town (which can be expected to experience rapid growth in the next few years). The existing tank farm facility at Holtsville already allows for the phasing out of the terminal in Patchogue.

An additional storage facility is recommended, located on property of the Pilgrim State Hospital. This facility would be supplied from the existing Holtsville-Plainview pipeline, and would serve the southwest part of Suffolk County, and the southeast part of Nassau.

There is an existing development plan (60) that recommends the extension of the existing pipeline, connecting New Jersey refineries with Kennedy International Airport, to serve existing tank farms in Inwood - Lawrence and Island Park - Oceanside. However, little action has been taken on this proposal since the adoption of the plan, and there remain a number of technical questions regarding the feasibility of transmitting heavy oils by pipeline (e.g., Number 6 residual fuel oil for the LILCO powerplant at Island Park). It is therefore recommended that the channels to existing petroleum and powerplant facilities in Hempstead Bay be maintained at a depth of 15 ft. and a width of 200 ft. while the feasibility of the pipeline extension alternative is explored further.

Another possible alternative system would dispense with all offshore terminals except one. This would be located in water deeper than 100 feet, roughly in the middle of Long Island Sound, between Wading River, Suffolk County, and New Haven, Connecticut. The type of terminal envisaged here is the BOATS design of Parson, Brinckerhof, Quade and Douglas (61). In this design, a vertical cylindrical shaft is supported off the sea floor, and carries a platform arrangement, that can ride up and down with the tide, rotate in response to the current direction, and roll with wave motion. Two 100,000 deadweight ton tankers can be unloaded simultaneously, by means of jointed pipes that can accommodate to the motion of the vessels. The unloading pipes are connected to lines which pass down the vertical shaft to its base. The shaft base is part of a tunnel, which, in this case, would communicate with both the Connecticut and Long Island shores. The pipelines can then be run to land inside the tunnel. The same configuration of overland pipelines would be required as before, (see Figure VIII-3) with the addition of what would now be the main supply line, running south on the William Floyd Parkway right-of-way, to connect into the east-west pipeline at Yaphank. The existing pipeline, which now ends at Plainview, would have to be extended further into Nassau, in order to supply that county. It would end with a terminal that would replace the one recommended for the head of Hempstead Harbor under the scheme calling for an offshore terminal off Sands Point. The tunnel would, of course, accommodate vehicular traffic, as well.

8.3.5 Additional Required Facilities

LILCO's requirements for oil can be expected to reach a maximum in the eighties. Any new power plants thereafter will probably be either nuclear or coal-fired, whereas oil-burning older plants will be successively retired. Present facilitiess should suffice for the future.

If LILCO's needs are deleted from Tables VIII-8 and 9 the requirements by commerce, industry, transportation and homes total 2,729 x 10^6 gal./year for 1985, and 3,058 x 10^6 gal./year for 2000.

The demand for 1985 is little different from current consumption, and represents a "trade-off" between a higher number of users and improved efficiencies. Hence, no additional facilities are envisioned for 1985.

For the year 2000, the demand is 9.2% higher than current consumption, and it is recommended that provision be made for increasing the total storage capacity in the bi-county region by this percentage

Growth in Nassau County is not expected to be significant after 1985, and this additional storage should be installed in Suffolk County, in the three additional facilities mentioned in Section 8.3.4, and indicated in Figure VIII-3.

Total storage now in place, plus the expansion being constructed at Holtsville, is approximately 330 million gallons. (Patchogue's capacity is excluded from the total, since Holtsville's expansion is expected to cover it). Thus, the additional capacity recommended for 2000 is 9.2% of 330 million, i.e. about 30.5 million gallons. This capacity should be distributed between the three recommended new locations, with more going to the easternmost facility (Suffolk County Airport) than to the westernmost one (Pilgrim State), since that would be the trend of new development.

8.4 Gas Handling and Storage Facilities

Figure VIII-4 displays LILCO's domestic gas supply system. Natural gas enters the bi-county region by three pipelines. One is a submarine pipeline from New Jersey, with a landfall at Long Beach. The other two are overland pipelines entering Nassau County from Queens, one at Valley Stream,the other at Lake Success. The gas is distributed by a system of pipelines of various sizes. The southern two-thirds of the island as far as Bellport appear to be reasonably well covered, as is North Hempstead. Small lines extend out from Holbrook to Riverhead and extend southeast through Hampton Bays to Southampton Village. There are gas storage spheres in Riverhead and holders in Inwood but gas holders in Glenwood and Rockaway Park (Queens) have been retired.

When gas demand exceeds the pipelined supply during the daily peaks, additional gas is provided by three Liquid Propane-Air (LPA) plants. In these plants, propane is vaporized from liquid storage, and mixed with a proportion of air, such that the resulting mixture has approximately the density and heating value of methane (natural gas) and requires roughly as much additional air to burn efficiently as methane does. Thus, it is an excellent substitute and supplement for natural gas. These three plants are located in Inwood, Riverhead and Glenwood, the last being larger than the other two.

During those parts of the day when the pipelined supply exceeds the consumption rate, excess gas is liquefied and stored in aLiquefied Natural Gas (LNG) plant at Holbrook. Storage capacity is the liquid equivalent of 600 million cubic feet of gas, whereas the plants liquefaction capacity is 2 million cubic feet per day. This system currently delivers 42 billion cubic feet annually to LILCO's "firm" customers, i.e. those whose supply it is obligated not to interrupt. Interruptible customers account for 5 - 6 billion cubic feet more. The highest daily demand in winter is 375 million cubic feet/day. The highest daily demand in summer is 70 million cubic feet/day.

LILCO does not, at this time, contemplate any changes in the system. An oil-gas plant in Bayshore has been retired, and no replacement is planned.

A new source of supply is possible from offshore oil development in the area. As described in Section 11.5, a gas pipeline landfall might be accommodated at Shirley, on the south shore, leading to a gas purification plant possibly located in Yaphank. It appears that the purified output of such a plant would most economically be piped back offshore in a pipeline to be run parallel to the shore and connected into the New Jersey pipeline. The smallest economical gas purification plant would probably have a capacity far in excess of the peak summer demand in Nassau-Suffolk, and the offshore pipeline would serve to conduct this excess capacity elsewhere.

If such an additional source did become available, provision would have to be made to bring the supply into areas not at present supplied. This would entail extending supply mains along the entire north shore of Suffolk County, and further into Southampton and East Hampton on the South Fork.

8.5 Coal Handling and Storage Facilities

There are no such facilities of any magnitude currently in operation in the bi-county region. The only thing that can be said, with some degree of certainty, is that any future power stations in the area will not be oil-fired. If they are not nuclear, then they will be coal-fired.

LILCO is now under notice to re-convert Port Jefferson units 3 and 4 to coal. However, the coal handling equipment will require work to make it operative, and the original coal storage area is now occupied by oil tanks. Thought is being given to retaining coal barges at dockside, and using them for storage, but this would incur additional demurrage charges.

Power generation facilities to meet the additional capacity requirements projected for the year 2000 will probably be located toward the east end of Long Island. This makes supply by water more likely than by rail and docking facilities will be required, with sufficient water depth. Furthermore, 30 - 45 days supply of coal is considered necessary, and land must be made available for this purpose.

8.6 Onshore Facilities for OCS Development

There are, currently, no such facilities located in Nassau and Suffolk Counties.

The exploitation of oil fields on the outer continental shelf is treated, in much of the literature on the subject, under three headings, namely:

Exploration

Development

Production

The facilities associated with these phases of development are described below.

8.6.1 Exploration

On the basis of preliminary studies performed by the U. S. Geological Survey and the oil companies, a given offshore area will have been identified as overlying potentially oil-bearing formations. The U. S. Government will then sell leases to portions of the area to various interested parties, who then proceed to explore their respective tracts. Exploration involves the drilling of a limited number of wells to determine whether further development is indeed worthwhile, and, if so, which would be the best location or locations at which to place production facilities.

In order to support the exploratory drilling effort, a base is needed at some point on shore convenient to the area of operations. If exploration is unsuccessful, the base will be closed down in a few years.

8.6.2 Development

Having decided that further development is desirable, the oil company authorizes the construction of offshore platforms, and proceeds to install them when built. Construction takes place onshore, in a waterside factory, from which the partially completed structures are towed by tug to the selected sites, and installed. The latter activity is not a simple one, and is carried out with support from an onshore base reasonably close by.

Mounted on the platform are one or more drilling rigs, which are used to drill so-called "development" wells. These will be the production wells, if flow rates are satisfactory. During the development period, well-drilling activity will proceed at a level far higher than during exploration. The support required for these operations is of the same kind as was required during exploration. However, a larger service base is required, because of the greater quantities of materials to be handled, and the larger crews to be transported.

8.6.3 Production

Production normally begins long before development drilling is completed. (In fact, exploratory drilling often continues long after the first production platforms are in place.) At some point, a decision will be made by the oil company to build or not to build, a pipeline. This is based strictly on economic factors, such as expected yield, distance to shore, costs of shipping by tanker, and so on. If the decision is made to build a pipeline, a pipecoating yard is set up, in which lengths of pipe will receive a coat of corrosion-resistant material, and, if necessary, a coat of concrete. The latter is often needed to provide the mass required to weigh the pipe down and keep it in place on the sea-bottom. Once coated, the lengths of pipe are ferried out to the pipeline laying area by barge. However, pipeline laying is also a complex operation, and support is required from a convenient onshore base. If gas is found in commercial quantities, it too would go ashore by pipeline.

Crude oil leaves the well in association with brine and natural gas. Unassociated gas is sometimes found, but this too will have brine with it. Separation of these components, and some degree of purification, is desirable before the oil and gas are transported ashore. Such a partial treatment plant is therefore often located on the offshore platform. However, for economic and/or technical reasons, it could be located ashore.

Crude natural gas is a mixture of methane with other hydrocarbon gases. The methane is separated and fed into the natural gas distribution system. The other components will provide liquified petroleum gas (LPG) and petrochemical feedstocks. This separation is performed in a gas treatment plant, located onshore and fed by gas pipeline.

The economic framework in which an oil company operates may make it advantageous to build an oil storage terminal on, or near, shore. This could receive oil either by pipeline from the offshore oilfield for transhipment into tankers, or by tanker from the offshore field for transhipment elsewhere by tanker and/or by overland pipeline.

8.6.4 Miscellaneous Facilities

Many boats will be employed in transporting personnel, supplies and waste materials to and from offshore rigs, platforms, pipelaying barges, etc. They must operate in all weathers, and will require constant maintenance and repair. It is rather unlikely than an oil company will build a boat yard from scratch. However, such facilities as already exist in the area will expand in response to the demand, and return to previous levels of activity when the demand ends.

Some oil companies may also find it desirable to locate one of their top executives in the area close to the offshore fields, in order to provide better supervision of all activities, both on-and offshore. In that event, a district office might be set up for the purpose.

8.6.5 <u>List of Facility Types</u>

From the foregoing, the following types of onshore facilities can be identified:

1. Temporary Base for Exploratory Drilling
2. Temporary Base for Platform Installation
3. Temporary Base for Pipeline Laying
4. Permanent Service Base
5. Pipeline Landfall
6. Marine Terminal
7. Partial Processing Plant
8. Gas Treatment Plant
9. Oil Refinery
10. Petrochemical Plant
11. Platform Fabrication Yard
12. Pipecoating Yard
13. Boat Repair and Maintenance Yard
14. District Office

Each of these types has certain requirements for acreage, waterfront, personnel, etc., etc., and has certain environmental impacts. The facility types are reviewed below in turn, and their needs and impacts assessed.

9.0 Water Dependence and Land Use Requirements

9.1 Power Plants

Information on power plant needs for land area and waterfront location are drawn from references 5 and 62 through 66.

9.1.1 Coal Fired Plants

Land requirements for the actual power generation equipment of a coal-fired plant, i.e., boilers, turbines, generators and condensors, is quite small. A 1000 megawatt plant would require less than 5 acres. A pair of 800 megawatt units, as considered here, would require a total of perhaps 8 acres. An equal area would be needed for office space, emission control devices, parking lots, etc.

In the Great Lakes Region, a six-month reserve of coal is considered desirable, to allow for winter disruption of shipping (66). In Long Island, 45 days is considered sufficient. For a 1000 megawatt plant, six-months' supply is said to occupy 50 acres (66). In New York State, a multi-unit plant, with a total of 2400 megawatts capacity, requires 75 acres for a 45 day reserve (5). The area required will depend on the height of the coal pile, but it can be assumed that two 800 megawatt plants will require a coal pile of 30 to 50 acres, to ensure a 45 day reserve.

Ash disposal could be another major land need. Ash can be reused in a number of ways, such as construction fill, neutralization of acid mine water, and so on. Of all the fly ash generated nationally, 17.4% is so reused. Even if ash is shipped away, however, a storage pile is still necessary to allow for shipping delays. Since it is expected that no scrubbers will be needed in this area, no sulfur dioxide control wastes will require disposal.

The cooling system employed will be another land use consideration. The alternatives are: once-through cooling, natural draft cooling tower, mechanical draft cooling tower, spary canal, and cooling pond. The last two require so much area that it is unlikely there are any pieces of land available in Nassau-Suffolk that are large enough. On the other hand, it will probably be very difficult to obtain a permit for a once-through system. Realistically, cooling towers are most probable, with the choice lying between natural draft and mechanical draft. As far as land area is concerned, the choice is between approximately 20 acres for the former and 80 acres for the latter.

All in all, two 800 megawatt coal-fired power plants will require about 150 or 200 acres, depending on the type of cooling towers employed.

Approximately 10-11,000 tons of coal will be required per day, and water transport is the most likely route. Thus, the coal storage pile must be located close to the shoreline, and access provided by sea. This means either a shoreside unloading facility, probably requiring channel dredging, or an offshore facility, with a pier carrying a conveyor system, to bring the coal ashore. The largest of barges will probably be used for shipping coal, and these are generally 500 feet long, with a loaded draft of 28 to 30 feet.

9.1.2 Nuclear Power Plants

A nuclear power plant requires less area than a coal-fired one by virtue of not required coal storage. However, the cooling system will be larger, and it will require an exclusion area to ensure safe radiation levels at the periphery. The New York Power Pool 1977 report (5) gives 250 acres as the land-area required for a 2400 megawatt installation, whether nuclear or coal-fired. To be conservative, the same area should be set aside for the 1600 megawatt plant discussed here.

9.2 Handling and Storage Facilities for Petroleum Products

9.2.1 Offshore Unloading Facility and Pipeline Landfall

The landfall should be located where the sea bottom approach is gently sloping, with sufficient depth of sand or shingle to provide 10 feet of cover for the pipeline down to mean low water, and 7 feet of cover from there out to the 50 foot water depth contour. A gentle transition from beach to land is preferable, although a cliff even as high as 100 feet is acceptable, if its composition is soft. The width of waterfront required is less than 100 feet.

The offshore mooring itself has little influence on the actual shorefront needs.

9.2.2 Overland Pipeline

Wherever possible, overland pipelines can be located in public rights-of-way, for instance alongside highways. A corridor of 50 to 100 feet width is required.

9.2.3 Bulk Storage Facility

Reference can be made to Section 9.5.6, Marine Terminals associated with offshore oil development. An existing facility at Holtsville, with 13 million gallons storage, plus room for a 12.8 million gallon expansion, occupies a site of 577 feet by an average of 1175 feet, approximately, i.e. 15.3 acres.

9.2.5 Transport Tunnel

This refers to the alternative oil supply system, described above, which utilizes an oil unloading structure in the middle of Long Island Sound, in conjunction with a Wading River - New Haven vehicular tunnel.

Such a system has not yet reached the stage of tunnel design, and land requirements onshore are not yet developed.

9.3 Gas Handling and Storage Facilities

New gas facilities will be required only when a new supply of gas becomes available because of offshore oil development. The onshore gas facilities associated with that development are discussed in other sections, namely:

9.5.5 Pipeline Landfall

9.5.7 Partial Processing Plant

9.5.8 Gas Treatment Plant

Other facilities needed would then be those associated with distributing the additional supplies to new customers. None of these, apart from the actual distribution mains, need be in the coastal zone.

9.4 Coal Handling and Storage Facilities

Such facilities as are required by power plants are discussed in Section 9.4.1. At this time, forecasts of coal consumption other than in power plants are indeterminate. If any substantial coal use does occur, it will be on a much smaller scale than in power generation. For water transportation, barges of 250 feet length will probably be employed, having a draft, when load, of 10 to 12 feet.

Storage capacity of coal piles, as cited by power industry sources (5, 66), run from 10,000 to 35,000 tons per acre. The latter figure is based on coal piles 40-50 feet high. A figure closer to 10,000 tons per acre would probably be more reasonable.

9.5 Onshore Facilities for OCS Development

Land and waterfront requirement for the various types of onshore facility required by oil and gas developments on the outer continental shelf are summarized in Table VIII-13. The information is expanded on in the following sub-sections. (Source material is drawn from references 39 through 58).

9.5.1 Temporary Base Supporting Exploratory Drilling

Exploratory drilling will begin about one year after lease sale, and will continue for 12 or 13 years, long after platforms have been installed in the area, and production has begun. In fact, exploratory drilling may continue at a low level of activity for several more years. However, at a certain point, servicing of exploratory drilling will be taken over by the permanent base. On the other hand, if exploratory drilling is unsuccessful, it will be discontinued at some point. These considerations lead to the expectation that a temporary support base will be occupied for no more than 4 or 5 years.

As Table VIII-13 indicates, 5 acres of waterfront land will be required per rig, with a dockside frontage of 200 feet, and 15 to 20 feet minimum water depth. The base must be accessible to boats in all weathers, 2 or 3 supply boats and one crew boat being required per rig. When several rigs are served, there are economies of scale and the requirements of land, waterfront and number of boats per rig are lowered.

9.5.2 Temporary Base Supporting Platform Installation

The oil company determines its platform requirements from the results of several years of exploratory drilling. Consequently, the deployment of platforms will not begin until about the fifth year after lease sale. Hence, a temporary support base will start up in year 5, and will remain in operation for about 8 years.

TABLE VIII - 13

Land and Waterfront Requirements for Onshore Facilities For OCS Oil Development Support

Facility	Life time*	Land Area	Water-Front Length	Water Depth	Boat Traffic
1. Temporary Base, Supporting Exploratory Drilling	1st-5th	0.5 acre per rig - warehousing 1.0 acre per rig - open storage 1.0 acre per rig - helipad Parking. Total: 5 acres per rig.	200' per rig (500' for 3 rigs)	15' to 20' minimum all-weather access.	2 or 3 supply boats and one crew boat per rig. Economies when more than one rig. Also, more round trips per boat when distance to offshore point is less. Thus, for 3 rigs:- 200 mi. offshore - 8 or 9 supply boats. 100 mi. offshore - 4 or 5 supply boats.
2. Temporary Base, Supporting Platform installation	5th-13th	5 acres for installing up to 4 platforms per year. Mostly open storage. Includes 1 acre helipad & 10,000 sq. ft. of office & communications space.	200' min., plus 200' for each "spread" of construction & supply vessels.	15' to 20' minimum maneuvering area 5 times width of largest vessel, e.g. derrick barge.	1 supply boat and 1 crew boat for each steel platform being installed. Several barges (e.g., cargo, derrick, etc.), but mostly offshore, with little impact on shore facilities. For each concrete platform, 3 or 4 400 ton barges & 6 workboats with frequent visits dockside.
3. Temporary Base, Supporting the laying of a pipeline.	7th-15th	5 acres, including both covered warehousing & open storage. (The pipe itself is not stored here, but goes direct from pipecoating yard to offshore site.) Also includes 1 acre helipad & 10,000 sq. ft. of office & communications space.	As previous.	As previous.	1 supply boat & 1 crew boat for each lay barge operating. Also several other barges (e.g., cargo, jet, etc.) & tugs, but mostly offshore, with little impact on shore facilities.
4. Permanent Base, Supporting Development Drilling, & Production. (High Find Scenario)	3rd-31st Dev. 6th-13th Prod. 6th-31st Wkover. 14th-29th	50 to 70 acres, depending on offshore activity. Mostly warehouses open storage, plus 10,000 sq. ft. of office & communications space & 1 acre per platform for helipads.	200' per rig or platform. (600' for 4)	15' to 20' minimum all-weather access.	During development drilling, 4 supply boats & 1 crew boat per platform. (15 supply boats for 5 platforms.) During production & "workover", 1 supply boat for 2 platforms, & no crew boat.

TABLE VIII - 13 (Cont'd.)

Land and Waterfront Requirements for Onshore Facilities For OCS Oil Development Support

Facility	Life-time*	Land Area	Water-front Length	Water Depth	Boat Traffic
5. Pipeline Landfall	Installation 7th-9th Operation 9th-31st	50' to 100' right-of-way. 40 acres for (oil) pumping station, if required (200,000 bbl/day capacity). 60 acres for terminal, if required.	up to 100'	Gently sloping approach, with sand or shingle to give not less than 10' of cover down to MLW, and 7' of cover out to 50' water depth. Preferably, gentle transition from beach to land, but cliffs up to 100' acceptable, if rock is soft.	
6. Marine Terminal (shoreside, fixed pier.)	13th-31st	Much of the terminal area required for tank farm, e.g. 17 acres for 1 million bbls. capacity. 50 acres for 3 million bbls. capacity. Up to 40 more acres for equipment, buildings, services. Open space & buffer zone additional.	1000' for 40,000 DWT Tanker	40' minimum for 40,000 DWT Tanker. More in the channel & maneuvering area. The latter's diameter is twice ship's length when tugs used, & four times when not.	EIS for Georges Bank lease sale states 1 Tanker of 40,000 DWT sufficient to transport total production.
7. Partial Processing Plant	5th-31st	15 acres per 100,000 bbl. of oil processed per day.	-	-	(Sometimes, all or part of the processing equipment located on the offshore platform. Sometimes, plant located at the marine terminal or gas processing unit.)
8. Gas Treatment Plant	10th-28th	For capacity of 1 billion cu. ft/day, 75 acres, of which 20 acres are building & structures. For 200 million cu. ft/day, 50 acres, approx.	-	-	-
9. Oil Refinery	Construction 5th-8th Operation 9th-31st	For capacity of 250,000 bbls/day, 1000 acres, of which 200 acres are processing units & 400 acres are building & storage.	-	-	-
10. Petrochemical Plant	11th-29th	For capacity of one billion pounds of ethylene per year, 200-350 acres.	-	-	-

TABLE VIII - 13 (Cont'd)

Land and Waterfront Requirements for Onshore Facilities
For OCS Oil Development Support

Sheet 3 of 3

Facility	Life time*	Land Area	Water-front Length	Water Depth	Boat Traffic
11. Platform Fabrication Yard	4th-13th				
a. Steel Platforms (9 constructed at a time.)		400-800 acres, 55% for fabrication, 45% for storage and support. Flat land (less than 3% gradient), with low water table and high bearing load (approx. 7 tons/sq. ft.). Waterfront required, cleared, but without existing buildings or docks.	Approx. 200' for each plat-	15' to 30' with min. channel width of 200'.	Sea access requires 210' to 350' horizontal & vertical clearance. Materials most economically brought in by barge.
b. Concrete Platforms (One constructed at a time.)		20-50 acres per platform.	As previous	35' to 50', with no channel to be navigated.	400' vertical clearance. For each concrete platform, 2 or 3 3000 ton barges per week of aggregate, 1 barge every 2 weeks of cement.
12. Pipecoating Yard	8th-15th	100-150 acres for a "permanent" yard. (30 acres for a "portable" one.) 95 acres of storage, 2 acres for testing coating. Flat land (less than 3% gradient). Low water table, if high, stockpile height must be less, and storage area greater.	750' minimum to load 2 supply barges at once.	20' to 30', for the 30,000 ton vessels bringing aggregate. 10' min. for the supply barges.	5 to 7 supply barges for 1 or 2 lay barges operating.
13. Repair & Maintenance Yard	These services will be based on existing facilities in the area, which may expand in response to increased demand.				
14. District Office			-	-	-

Legend
* Years after lease sale (NERBC high find scenario)

The platform structure and components will be fabricated elsewhere, so that the support base itself supplies only the basics of food, water, and fuel, and those materials such as welding rod, which are required for platform assembly. Thus, an area of 5 acres provides all the storage space required for handling the installation of as many as four platforms simultaneously, together with helipad and office building.

Waterfront needs are substantial. A minimum of 200 feet is required, plus 200 feet more for each platform being installed. Water depth is the same as for exploratory drilling, i.e., 15 to 20 feet. However, some of the support vessels, such as derrick barges, are much larger, and require a broad maneuvering area, i.e., an entire harbor area is necessary at that depth, not just a channel. Most of the traffic will come from the usual supply and crew boats, and visits to the dockside by the more ungainly barges will be rare, but the maneuvering space must be available.

Steel and concrete platforms, by the nature of their respective designs, generate different levels of boat traffic during installation. Each steel platform requires one supply boat and one crew boat, whereas a concrete platform requires six workboats and three or four barges of 400 ton size.

9.5.3 Temporary Base Supporting Pipeline Laying

The economic justification for installing a pipeline will become evident only after production has begun. At that time, the first production wells will be evaluated, and a better idea obtained of the potential of the entire field.

It is unlikely that each individual oil company will build its own pipeline to shore. In fact, there is a precedent, from the Shetland Island field in the North Sea, for every company participating in the field's exploitation to join together in financing one main pipeline, connected to each platform by a branch line.

Consequently, pipeline laying will run in tandem with platform installation, beginning some 2 years after the first platform goes in, and ending 2 years after the last one. Thus, a temporary base for pipeline laying will be in use from year 7 to year 15 after the lease sale (see Table VIII-13).

Since coated pipe will be barged directly from the pipecoating yard to the lay barge, the temporary base does not have to provide storage for it. Five acres is sufficient for all the storage needed, plus a one acre helipad and office building.

Waterfront needs are similar to those for a platform base, i.e., 200 feet minimum, plus 200 feet for each lay barge operating out in the ocean. Water depth and maneuvering room are also the same as for the other. One supply boat and one crew boat are needed to serve each lay barge. The latter is accompanied by a "spread" of other vessels. These include barges supplying pipe to the lay barge, a jet barge to dig a trough on the sea bottom in which the pipeline is laid, and a fleet of tugs for maneuvering them all. The spread has little impact on the shore base, however. Pipe barges will "commute" to and from the pipecoating yard, and the lay and jet barges will remain at sea until the pipeline is completed.

9.5.4 Permanent Service Base

Permanent bases provide support to offshore platforms during the phases of development drilling, production, and workover. The last phase involves re-working existing wells which have been producing for some years. There is usually a gradual drop in flow rate with time, and flow can be boosted somewhat by working over the well.

Base activity is greatest during development drilling and least during production, but the "permanent" base will remain in operation until the field is exhausted, i.e., from about year 6 to year 31 after the lease sale. By about year 3, however, the viability of the oil-field will have been proven, and the permanent base will start gearing up then, even though the first platform installation is still 2 years in the future.

Land requirements will range from 50 to 70 acres, depending on the nubmer of platforms served. There will be office space, and a one acre helipad for each platform.

200 feet of waterfront will be needed per platform (or rig, when the later phases of exploratory drilling are transferred to the permanent base, and the temporary base is phased out). There will be economies of scale, i.e., four platforms will require 600 feet of dockside. Water depth of 15 to 20 feet is needed, with access in all weathers.

During development drilling, each platform will require 4 supply boats and one crew boat. Again, there will be economies of scale. Thus, 5 platforms will require 15 supply boats. During production and workover, no more than one supply boat will be needed for each two platforms. By that time, platform crews will be so small that it will be more convenient to transport them by helicopter, and no crew boat will be necessary.

9.5.5 Pipeline Landfall

During the approximately 8 years of pipeline laying, it would be logical to run the main line ashore early in the program, so that oil pumping can begin as soon as possible. There is a proven procedure for connecting in branch lines later, as necessary. It is assumed, therefore, that the actual landfall will be constructed in the first 2 years of pipeline laying, i.e., from year 7 to year 9 after the lease sale. The main pipeline will then operate for the remaining lifetime of the field.

Both oil and gas can be conveyed ashore by pipeline, and each presents different problems. Both may require a boost in pressure at this point, i.e., a pumping station for oil and a compressor station for gas. Whereas the landfall itself can be repaired to the extent that it can be rendered invisible, a pumping station or compressor station would be highly intrusive near the shoreline. If the area is already deteriorated, this may not be considered a problem.

There will be pumps and compressors on each platform, and if partial processing takes place there (see below), boosting stations may not be necessary. This is more likely for gas than for oil. Hence, a pumping station associated with an oil pipeline landfall is more probable than a gas compressor station associated with a gas pipeline landfall.

Forty acres is the estimated requirement for a pumping station handling 200,000 barrels per day of oil.

Refer, also, to Section 9.2.1

9.5.6 Marine Terminal

A marine terminal could be employed in one of two basic ways. One is to store oil received by pipeline from offshore wells, and load it into tankers for shipment by sea to a remote refinery. The other is to receive and store oil brought in from offshore wells by tanker, and pump it, via overland pipeline, to an adjacent or remote refinery.

The decision to build a marine terminal, for either purpose, is an economic one, as far as the oil company is concerned. However, the siting and construction of marine terminals is a complicated political process because of environmental considerations. Statistics indicate (49) that the major source of oil pollution, world-wide, is normal tanker operations, i.e., tank cleaning and ballasting. U. S. Coast Guard regulations require that new tankers larger than 70,000 deadweight tons (DWT) have segregated ballast tanks, so that ballast water be excluded from the cargo tanks. This is somewhat larger than the class of vessels considered in this context, however. (See below).

Given that a marine terminal is shown to be feasible, it would have to be operational from approximately year 13 after the lease sale, and remain in operation until the oilfield was shut down.

The land area requirements for a terminal depend on the amount of oil to be stored, and that is a matter of economics, tanker size and scheduling, refinery capacity, and so on. A tank farm for one million barrels of oil (42 million gallons) occupies about 17 acres. For three million barrels storage capacity (126 million gallons), 50 acres would be needed. Another 40 acres would be used for pipeways, transfer equipment, boiler house, electrical sub-station, administration building, and other services.

Waterfront requirements depend on whether the unloading facility is of the shoreside fixed pier type, or the offshore mooring type. In the latter case, the tank farm can be set back from the shoreline, and the actual waterfront corridor can be minimal.

In the shoreside case, the waterfront requirements would depend on the maximum size of tanker to be handled. Table VIII-13 lists information for a 40,000 DWT tanker, simply because this is the size of vessel cited in the draft environmental impact statement that was written for Lease Sale Number 42, Georges Bank Trough (55). Thus, approximately, 1,000 feet of waterfront is cited, and 40 foot water depth.

9.5.7 Partial Processing Plant

Crude oil at the well-head contains natural gas and formation water. The latter is brine, with a high concentration of dissolved and suspended solids. Some of the formation water will be mixed with oil in an emulsion. The water and sediment content of the crude must be reduced to 1 percent or better as soon as possible after leaving the well, because of the corrosive nature of the brine. In addition, any natural gas associated with the crude oil will "boil" off as the oil pressure drops from the formation pressure, as it rises up the well. The separation of gas and brine from the crude oil to acceptable levels of purity is called "Partial Processing".

This is sometimes done at the offshore platform, where it adds, of course, to the platform cost and the complexity of offshore operations. If tanker is the method employed to convey oil to the shore, then partial processing would be done at the platform. If a pipeline is used instead, then partial processing could be done either on the platform or on shore. In the latter case, the plant would probably be located inside the marine terminal boundary.

After separation, the water will require treatment to reduce its oil content to 20 to 50 parts per million, to render it acceptable for discharging.

The natural gas found associated with oil would be one of the products of the partial processing. If non-associated gas is found, it will still have formation water associated with it, and will require separation, to a fairly high degree. Water vapor can condense in long pipelines, causing slugs which increase pipe friction, and thus reduce pipe capacity. Also, moisture in natural gas can react to form bulky solid hydrates, capable of plugging lines and equipment. Consequently, partial processing of gas is more likely to be done on the offshore platform than partial processing of oil.

For an onshore plant to handle 100,000 barrels of oil per day, a site of about 15 acres would be needed. There would be no specific waterfront requirements. In the general scenario considered in this report, production would commence in the 6th year after the lease sale. Construction on the partial processing plant would therefore have to start a year earlier.

9.5.8 Gas Treatment Plant

As mentioned previously, the gas fraction leaving a well is a mixture of methane and other light hydrocarbons. The latter have properties making them worthwhile separating from the methane, and splitting into two basic streams. One stream, essentially propane and butane, has a market value as liquefied petroleum gas (LPG). The other stream, containing ethane and a number of unsaturated compounds (ethylene, propylene, etc.), would be a suitable feedstock for a number of important petrochemical products, such as ethylene oxide, artificial rubber, and many others.

Until exploratory drilling takes place, however, the actual flow rate of the crude gas, and its composition, cannot be known. There is a gas flow rate below which it is uneconomic to pipe the gas ashore at all. In that event, it would be re-pressurized and pumped back into the oil-bearing formation, in order to maintain the crude oil production rate. Above that flow threshold, gas production would be developed, but failing a knowledge of the distribution of the components in it, the specific processing scheme of the gas treatment plant cannot be known. In general, condensibles would be separated from non-condensibles by refrigeration. The non-condensibles fraction (mostly methane) would be fed into the natural gas pipeline, and the condensible fraction could be split up into components by low-temperature distillation.

It can be said, however, that a plant to process one billion cubic feet of gas a day would require approximately 75 acres, of which 20 acres would be occupied by buildings, structures, and processing equipment. The remainder is open storage, parking and buffer space.

A smaller capacity plant would not occupy proportionately less acreage. For instance, a plant for processing 200 million cubic feet of gas a day would still need 50 acres, approximately.

The nature of oilfield operations is such that oil production builds up some years before gas production does, and continues for some years after gas production ends. The gas treatment plant will therefore be in operation from year 10 to year 28 after the lease sale, compared to oil production, which will run from year 6 to year 31.

There is no need for a waterfront location for this type of facility.

9.5.9 Oil Refinery

Like marine oil storage terminals, the siting of oil refineries is subject to powerful, political constraints, by virtue of the significant impact they cause, both in construction and operation (see below). This is clear from the unsucessful attempts by a number of companies, over the past decade, to locate an oil refinery in New England.

Oil refineries require very large amounts of land. A plant to process 250,000 barrels of crude oil per day would occupy approximately 1,000 acres. Of this, the actual processing units would require 200 acres, and another 400 acres would be used for buildings, tank farm, boiler house, cooling tower, and auxiliary services, such as water treatment, waste treatment, etc. The remaining area would be buffer space.

The size of refinery actually built would be determined by economic considerations, and, under certain circumstances, a capacity as low as 50,000 barrells of crude oil a day could be economic. However, the land requirements are not proportional, i.e., such a plant would require much more than one-fifth the acreage of a 250,000 barrel a day plant.

Refineries have often been located at the shoreline, adjacent to the oil-receiving terminals. However, there is nothing inherent in their design or operation that demands a waterfront location, and they can just as well be fed by an overland pipeline.

Large and complex plants of this kind have long construction times. A grassroots refinery, that is, one built from scratch, would require three years to build. The scenario followed in this report would require a refinery to be in operation at year 9 after the lease sale. Hence construction would begin during year 5.

9.5.10 Petrochemical Plant

An important factor in the siting of a petrochemical plant is proximity to the source of raw materials. This means proximity either to an oil refinery, which could provide feedstocks such as naphtha and gas oil, or to a gas processing plant, from which natural gas liquids would be available. For reaons discussed in Section 11.5, an oil refinery is not a likely proposition for Long Island. However, a gas treatment plant is not out of the question. The hydrocarbon gases and liquids separated out of the natural gas are ethane, propanes, butanes, ethylene, propylenes and butylenes. It is not known at this time exactly how big these fractions will be. The propanes and butanes would be utilized in LPG, and bottled and possibly distributed for local sale. The other components could be used in the manufacture of polyethylene, polypropylene, etc. Until exploratory drilling takes place, the actual flow rate of the crude gas, and its composition cannot be known. The possible process schemes for a petrochemical plant are so many that, without this information, one can only guess at land area requirements.

A typical size of plant cited (49) is one that can handle one billion pounds of ethylene per year. A plant of this size would occupy anywhere from 200 to 350 acres, of which perhaps 100 acres would be actual processing area. However, such a plant would require approximately 6.5 million gallons of water per day, mostly for cooling. The plant would also have a peak electricity demand of 5 megawatts, and use an average of 3.3 million kilowatt-hours per month.

Such a plant has no need for a waterfront location, except if it were to employ once-through cooling. This is highly unlikely to be permitted anywhere in the bi-county region, and to satisfy the cooling demand from wells appears to be equally out of the question.

9.5.11 Platform Fabrication Yard

Platforms for offshore oil production can be built of steel or of reinforced concrete. Steel platforms are usually of the fixed-piling type, in which the operating platform is supported well above the ocean surface by legs which are fastened to the sea-floor by steel pilings. This is the commonest type of steel platform, but there are at least two other designs. One is the gravity platform, which rests in place on the sea bottom, by virtue of its own mass. Essentially, the operating platform is supported above an arrangement of tanks. The structure is floated out to the desired location, the tanks are flooded, and the whole assembly settles down into its assigned place. Another steel platform design is the tension-leg type, in which the operating platform actually floats, and is held in place by anchors and cables. The downward pull of the cables submerges the platform somewhat deeper than its own unrestrained buoyancy would allow, and imparts the necessary stability. This design has the advantage of mobility, and therefore permits re-use in marginal fields that would otherwise be uneconomic to develp.

Concrete platforms are usually of the gravity type. In fact, most gravity platforms are built of concrete.

Another variable in the design of offshore platforms is the extent to which they are to be self-contained. At one extreme, the platform may support little more than the drilling rigs, with all other facilities provided by a support vessel tied up alongside. At the other extreme, the platform may accommodate drilling crews quarters, partial processing equipment, waste treatment facilities, and so on, and require only a crew boat to change crews and supply boats to maintain stocks of drilling supplies.

Land for a platform construction yard must be flat (less than 3 percent gradient), have a low water table, and have a high bearing load (approximately 7 tons per square foot). Information available for a facility fabricating nine steel platforms simultaneously indicates that 400 to 800 acres are required, of which 55% would be used for fabrication, and the rest for storage and auxiliary services. Concrete platform construction is less demanding of land, each platform requiring 20 to 50 acres.

About 200 feet of waterfront is needed for each platform under construction. Water depth requirements for steel platforms are 15 to 30 feet, with a channel width of 200 feet. Concrete platforms need deeper water, 35 to 50 feet, and no channel construction, i.e., the facility must be located on a broad harbor or bay.

Platforms are partially erected on land, and then floated out to the ocean site. The sub-assemblies are very large, and require large clearances in their passage from the yard to the open sea. Steel platforms require both horizontal and vertical clearances between 210 and 350 feet, depending on the particular design. Concrete platforms require 400 feet vertical clearance.

Construction materials for both steel and concrete platforms are required in such quantities that they are best brought to the fabrication yard by barge. For example, each concrete platform needs two or three 3,000 ton barges of aggregate a week, and one barge every two weeks of cement. Barge traffic for a steel platform would probably be less.

Platform installation is required to begin in the fifth year after lease sale. Hence, platform construction would have to start in year four. It would continue to year thirteen.

9.5.12 Pipecoating Yard

Most of the land in a pipecoating yard is taken up with pipe storage. The acreage required for the actual coating processes is comparatively small. Flat land is desirable, with a slope no more than 3 percent. A low water table is also desirable for storage purposes, since it permits a greater height of stock-pile.

Pipecoating involves two processes. First a coat of corrosion resistant material is applied. After storage for curing, the coat is tested for integrity, and any small penetrations are patched. Then a coat of concrete is applied to give the mass required to hold the pipe down on the sea bottom.

A permanent yard, coating 300 to 350 miles of pipe per year, would occupy 100 to 150 acres. Of this, 95 acres would be used for pipe storage. Two acres would be required for the testing of the corrosion coat, and about the same for the actual coating operation. A so-called "portable" yard could operate in about 30 acres, but the smaller pipe storage capacity would make the scheduling of shipments more critical.

Coated pipe would be barged out to the pipeline laying locations. Waterfront is needed for the loading and unloading of pipe and concrete materials. 750 feet minimum at dockside would permit the simultaneous handling of two barges. These barges draw only about 10 feet, but aggregate is sometimes shipped in vessels of as much as 30,000 DWT, and these would require 20 to 30 feet water depth.

If pipelaying were going on at one or two locations, 5 to 7 barges would be required to transport the coated pipe, depending on the distance from the yard.

The yard would be in operation from year 8 to year 15 after the lease sale.

9.5.15 Miscellaneous Facilities

Boat repair and maintenance yards would not be established specially for servicing an offshore oilfield. However, those which already exist in the area would experience an increase in business over the period in which boating activity is increased. This would be essentially for the first 15 years after lease sale. Thereafter, service boats would be operating mostly for offshore platforms engaged in production and workover. Comparatively few boats would be involved at that time, and they would represent only a small fraction of the overall demand for repair and maintenance work in the area.

District offices, if any will constitute only a small fraction of the demand for office space in any given area. It is unlikely that office buildings would be constructed specially for this purpose.

10.0 Environmental Impacts

10.1 Construction

Construction activities can cause major disruptions in the environment, potentially affecting the local quality of the air, surface waters and groundwater, as well as the comfort and convenience of the local inhabitants. Clearly, the magnitude of each type of impact will vary from site to site, and of course with the type of facility. However, certain generalizations can be made.

Four phases in the facility construction process have been identified (66). They are:

a. Preconstruction.

   Those activities which follow site selection, namely site inventory, possible environmental monitoring prior to construction (e.g. for power stations), and the implementation of temporary impact controls.

b. Site Work.

   This phase comprises the clearing of the site, and the construction of temporary buildings, access routes (i.e. roads, railroad spurs, dredged channels, and docks) and associated facilities.

c. Permanent Facilities.

   The construction of the actual energy facility.

d. Project Closeout.

   Removal of the temporary buildings, and final landscaping.

Table VIII-14 lists the main pollutants and potential impacts associated with each phase (71).

TABLE VIII-14
POTENTIAL ENVIRONMENTAL IMPACTS RESULTING FROM CONSTRUCTION PRACTICES

Construction Phase	Construction Practice	Primary Pollutants	Potential Environmental Impacts
1. Preconstruction	a. Site Inventory		Short-term and nominal
	(1) Vehicular traffic	Dust, noise, sediment	Dust, sediment and tires injury
	(2) Test Pits		Tree root injury, sediment
	b. Environmental monitoring	Visual	Negligible if properly done
	c. Temporary controls		Short-term and nominal
	(1) Stormwater		Vegetation, water quality
	(2) Erosion & sediment	Sediment spoil, nutrients, solid waste	Vegetation, water quality
	(3) Vegetative		Fertilizers in Excess
	(4) Dust		Negligible if properly done
2. Site Work	a. Clearing and demolition		Short-term
	(1) Clearing	Dust, sediment, noise, solid wastes	Decrease in the area of protective tree, shrub, and ground covers, stripping of topsoil; increased soil erosion, sedimentation, and stormwater runoff; increased stream water temperatures; modification of stream banks and channels, water quality
	(2) Demolition		Increased dust, noise, solid wastes
	b. Temporary facilities		Long-term
	(1) Shops and storage sheds	Gases, odors, fumes, particulates, deicing chemicals, noise petroleum products, waste water, solid wastes, aerosols, pesticides	Increased surface areas impervious to water infiltration, increased water runoff, petroleum products
	(2) Access roads and parking lots		Increased surface areas impervious to water infiltration, increased water runoff, generation of dust on unpaved areas
	(3) Utility trenches and backfills		Increased visual impacts, soil erosion, and sedimentation for short periods
	(4) Sanitary facilities		Increased visual impacts, solid wastes
	(5) Fences		Barriers to animal migration
	(6) Laydown areas		Visual impacts, increased runoff
	(7) Concrete batch plant	Sediment, dust	Increased visual impacts; disposal of wastewater, increased dust and noise
	(8) Temporary and permanent pest control (termites, weeds, insects)		Non-degradable or slowly degradable pesticides are accumulated by plants and animals, then passed up the food chain to man. Degradable pesticides having short biological half-lives are preferred for use

TABLE VIII-14

POTENTIAL ENVIRONMENTAL IMPACTS RESULTING FROM CONTRUCTION PRACTICES

(Continued)

Construction Phase	Construction Practice	Primary Pollutants	Potential Environmental Impacts
	c. Earthwork (1) Excavation (2) Grading (3) Trenching (4) Soil treatment	Dust, noise, sediment, debris, wood wastes, solid wastes, pesticides, particulates, bituminous products, soil conditioner chemicals	Long-term Stripping, soil stockpiling, and site grading; increased erosion, sedimentation, and runoff, soil compaction; increase in soil levels of potentially hazardous materials; side effects on living plants and animals and the incorporation of decomposition products into food chains, water quality
	d. Site drainage (1) Foundation drainage		Long-term Decrease in the volume of underground water for short and long time periods, increased stream flow volumes and velocities, downstream damages, water quality
	(2) Dewatering (3) Well points (4) Stream channel relocation	Sediment	
	e. Landscaping (1) Temporary seeding (2) Permanent seeding and sodding	Nutrients, pesticides	Decreased soil erosion and overland flow of stormwater, stabilization of exposed cut and fill slopes, increased water infiltration and underground storage of water, minimize visual impacts
3. Permanent Facilities	a. Transmission lines & heavy traffic areas	Sediment, dust, noise, particulates	Long-term
	(1) Parking lots		Stormwater runoff, petroleum products
	(2) Switchyard		Visual impacts, sediment, runoff
	(3) Railroad spur line		Stormwater runoff
	b. Buildings		Long-term
	(1) Warehouses		Impervious surfaces, stormwater runoff, solid wastes, spillages
	(2) Sanitary waste treatment	Solid wastes	Odors, discharges, bacteria, viruses
	(3) Cooling towers		Visual impacts

TABLE VIII-14
POTENTIAL ENVIRONMENTAL IMPACTS RESULTING FROM CONSTRUCTION PRACTICES
(Continued)

Construction Phase	Construction Practice	Primary Pollutants	Potential Environmental Impacts
	c. Related facilities		Long-term
	(1) Reactor intake and discharge channel		Shoreline changes, bottom topography changes, fish migration, benthic fauna changes
	(2) Water supply and treatment		Waste discharges, water quality
	(3) Stormwater drainage	Sediment, trace elements,	Sediment, water quality
	(4) Wastewater treatment	noise, caustic chemical	Sediment, water quality, trace elements
	(5) Pams and impoundments	wastes, sediment spoil,	Dredging, shoreline erosion
	(6) Breakwaters, jetties, etc.	flocculants, particulates,	Circulation patterns in the waterway
	(7) Fuel handling equipment	fumes, solid wastes	Spillages, fire and visual impacts
	(8) Oil storage tanks, controls and piping		Visual impacts
	(9) Conveying systems (cranes, hoists, chutes)		Visual impacts
	(10) Waste handling equipment (incinerators, wood chippers, trash compactors)		Noise, and visual impacts
	d. Security fencing		Long-term
	(1) Access road	Sediments, wood wastes	Increased runoff
	(2) Fencing		Barriers to animal movements
4. Project Closeout	a. Removel of temporary offices & shops		Short-term
	(1) Demolition	Noise, dust, solid wastes	Noise, solid waste, dust
	(2) Relocation		Stormwater runoff, traffic blockages, soil compaction
	b. Site Restoration		Short-term
	(1) Finish grading		Sediment, dust soil compaction
	(2) Topsoiling	Sediment, dust	Erosion, sediment
	(3) Fertilizing		Nutrient runoff, water quality
	(4) Sediment controls		Vegetation
	c. Preliminary start-up		Short-term
	(1) Cleaning	Nutrients, petroleum products	Water quality, oils, phosphate and other nutrients
	(2) Flushing		

The distribution and magnitude of the impacts varies with the type of facility being constructed. For example, impacts on the aquatic ecosystem, particularly the benthos, will be greater in the construction of a coal handling facility, for which major channel dredging may be necessary to the depth required for coal barges, than for a shoreside service base requiring bulkheading and only minor dredging. Similarly, water quality impacts arising from erosion of excavated and cleared soil might be greater for a nuclear power plant project than for a fossil-fueled one, because the former has a so much longer construction time.

The impacts associated with a given construction activity must be evaluated in the light of the specific site conditions and the type of facility to be built. Some of the factors to be considered are:

a. Resistance of the surface and subsurface soils to erosion by gravity, water and wind.

b. Chemical and physical properties of the soils.

c. Topography and size of the site.

d. Distribution and frequency of rainfall.

e. Care used in trapping sediments and collecting liquid wastes.

f. Area of the cleared and excavated portions, and the length of time for which they are so exposed.

g. The amount of traffic of personnel and machines, in the course of the project.

One of the problems likely to arise, outside the jobsite itself, is traffic congestion. This will be due to workers commuting to and from the site, and also to the movement of building materials and equipment into the site and waste materials out of the site.

The important considerations of the fiscal benefits and obligations that large facilities of this type can confer on local populations, will not be discussed here.

10.2 Power Plants

Two types of power generation system are discussed here, coal-fired and nuclear. It is believed that oil-fired units are less likely to be licensed than the other two, in the general need to reduce oil imports. Both coal-fired and nuclear plants require to discharge large amounts of heat, and the topic of cooling systems is treated separately (Section 10.2.3). For each type of power plant, impacts are discussed under three headings, namely, air emissions, wastewater, and solid waste.

10.2.1 Coal-fired Plants

10.2.1.1 Air Emissions

These comprise nitrogen oxides, sulfur oxides and particulates.

As mentioned elsewhere in this report, the Federal Government recently issued an order to LILCO to re-convert certain units at the Barrett plant and the Port Jefferson plant to coal firing. It developed that scrubbers were necessary at Barret, but not at Port Jefferson. Because of the proximity of New York City, the permitted emissions at the former location had to be more stringently controlled than at the latter. Consequently, the Barrett plant was deleted from the order, because of adverse economies. The Port Jefferson plant will still require additional precipitators, however, to bring the particulates down to acceptable levels. It therefore appears that a plant site further east than Port Jefferson will have to meet less stringent air quality standards than one further west. The possibility of avoiding the use of scrubbers by employing tall stacks remains to be explored.

10.2.1.2 Wastewater

Wastewater effluents other than those associated with the cooling system arise from several sources: main steam boiler blowdown, demineralizer regeneration wastes, floor drains, sanitary wastes, and ash sluicing water.

Most of these waste streams are relatively small compared to cooling water return flow. (Even a closed-cycle system blowdown flow can be several thousand gallons per minute). Some are subject to standard treatment practices (e.g., sanitary waste treatment and the use of ash settling ponds to significantly reduce suspended solid loads in ash sluicing water).

The impact of these effluents will depend on the volume of flows, treatment received, the discharge structure configuration, the nature of the chemicals, and the assimilative capacities of the receiving waters.

Specific details of potential impacts on the aquatic ecology are difficult to quantify because of the wide variety of variables and the complexity of interactions (most not yet understood) involved.

Leaching of toxic materials from the ash storage pile may represent a serious threat to the quality of the ground-water supply.

10.2.1.3 Solid Waste

A coal-fired power plant requires a considerable acreage for ash disposal over its operational lifetime. The impacts associated with the handling and storage of ash are primarily related to the release of potentially degrading and toxic materials to the environment and the disruption of human and natural systems.

The movement of waste material between the boiler and the disposal site may also have an impact on traffic movement around the facility if the two sites are physically separated.

10.2.2 Nuclear Plants

The principal sources of radioactive materials are the fission products which are produced in the fuel elements as a by-product of normal operation. The quantity formed is small in terms of mass, amounting to a few kilograms per day in a large power plant. Under normal operation, more than 99 percent of fission products remain in the reactor core where they were formed. Small quantities which leak from the fuel elements, however, are ultimately released from the plant radioactive waste processing system to the environment. In addition to the fission products, other sources of radioactivity are leakage of radioactive materials from control rods, activation of impurities in the reactor coolant, activation of corrosion products from structural materials, and tramp uranium which adheres to the outside of the fuel rods during the manufacturing process (71).

There are four types of radioactive waste materials (radwastes) that must be dealt with: gaseous, liquid, ventilation exhaust air, and solids. All four are produced by both reactor types now in use: the boiling water reactor (BWR) and pressurized water reactor (PWR). However, the mix of these wastes varies with reactor type, BWR's producing more gaseous radwaste (radgas) and PWR's producing higher levels of liquid radwaste.

10.2.2.1 Air Emissions

The principal source of radgas in both reactor types is the degassing of the primary coolant. Much of this gas is a result of air inleakage at the condenser. In a BWR, additional gaseous wastes are generated by fission and activation products and radiolytic decomposition products (hydrogen and oxygen). Also, radgas emissions may arise from leakages around the turbine gland seals, especially in older plants (new plants having eliminated this waste source).

Most of these gaseous wastes are removed at the turbine condenser through an air ejector. These effluents contain nigrogen-13 (an activation product), noble gas isotopes, krypton and xenon (fission products), halogens (mostly iodine), and tritium. In addition, there are some radioactive particulates and solid decay products associated with the gaseous wastes.

Treatment consists primarily of delay (30-60 minutes) to allow the short-lived isotopes to decay and filtration through high efficiency particulate filters prior to venting through the station's stack (71). A charcoal absorber system can also be used to provide up to 10 hours of delay to reduce the amount of xenon and krypton, the two principal radioactive species.

10.2.2.2 Liquid Emissions

There are four major types of liquid radwastes from a nuclear power plant facility of either type: high purity wastes, which are radioactive but low in normal chemical impurities (e.g., primary coolant leaks and equipment drains); low purity wastes with varying levels of radioactivity, such as floor drains; chemical wastes; and detergent wastes with low levels of radioactivity (71). These waste streams are segregated according to origin so that liquids of near coolant quality may be treated and reused. Following treatment, the liquid waste discharges are then bled into the cooling water discharge flow at such a rate as to meet government emission standards.

10.2.2.3 Solid Wastes

Solid radwastes are similar for both BWR's and PWR's, consisting of three general types: wet, such as spent resins and evaporator concentrates; dry compressible, such as rags, clothing, and plastic; and dry noncompressible, such as equipment. The wet wastes are solidified and kept on-site for a period to permit the decay of short-lived radionuclides. Ultimate disposal for all forms is burial at an approved site. It is estimated that total solid waste activity from a 1000 MWE reactor amounts to 2,500-5,000 curies per year (71).

10.2.3 Cooling Systems

10.2.3.1 Once-through Cooling

Once-through cooling systems have a minimal impact on the air and local meteorology, as most of the waste heat is carried to the receiving water. Likewise, they have the smallest land requirement and require no major structures that may conflict with the surrounding landscape.

It is the potential impact on the aquatic ecology that has generated the most opposition to the continued use of once-through cooling. These impacts are attributed to (a) the mechanical and thermal shock to small entrained organisms that pass through the cooling system pumps and condensers, (b) the effects of increased water temperature on the biota in the receiving waters, (c) the entrapment and impingement of fish on the intake screens, (d) the toxic effect of chemicals introduced into the cooling water, and (e) the effects of erosion and changing of ambient currents in the receiving water. Because once-through cooling systems utilize large volumes of water from the receiving body (rivers or lakes), they have the potential for producing significant biological impacts (71).

The entrainment and subsequent passage through the condenser system of large numbers of small organisms is considered by some to be the leading environmental hazard of once-through cooling systems (66).

While the importance of entrainment has recently become apparent, the significance of thermal loadings has been discounted by some. However, there is still a large body of evidence that thermal effluents can and do cause significant damage. In general, most effects seem to be sublethal, involving changes in species composition, fish movement through the area, and spawning habits. Other temperature-induced effects include increased incidence of gas bubble disease, synergistic chemical reactions, and oxygen depletion.

Related to the discharge of thermal effluents are the effects of entrainment of fish in the discharge plume. This form of entrainment has been overlooked until recently, but the available information suggests that the number of fish fry that are entrained in this manner may be several times greater than the number entrained at the cooling system intake and passed through the plant. Mortality could occur from heat shock, chlorine intoxication, predation, or from hydraulic mauling received during entrainment. Various investigators have found that one major effect of such sublethal exposure of fish to elevated temperature is a reduction in the ability of exposed fish to avoid predation.

Impingement on the trash rack and mesh screens of the water intake structures also causes fish kills.

Water used in a plant cooling system requires the addition of chemicals to prevent biological fouling and retard corrosion. When released to the aquatic environment, these chemicals and/or their reaction products can have toxic effects, specially on organisms near the outfall.

10.2.3.2 Natural Draft Cooling Towers

The use of a natural draft tower creates potential adverse effects on the local meteorology through increased fogging (and icing during the winter months). However, this is less likely to be a problem than if mechanical draft towers are used.

Related to the problem of fogging is that of drift: water lost in droplet form by means of which salts are deposited over a wide area downwind from the tower. While drift rates are low (0.002 percent of the circulating flow rate for natural draft towers), these deposits may be detrimental to the biota and to agriculture.

One concern related to the use of cooling towers at fossil fuel plants is the possibility of synergistic effects between the vapor plume and the stack emissions. In particular, reactions with SO_2 in the stack gas could produce a sulfuric acid mist. Studies have not indicated that this is a serious problem (71).

Land requirements for a natural draft cooling tower are greater than for a once-through system but are less than that of the other closed-cycle systems.

The most obvious impact of a natural draft cooling tower is its presence in the surrounding landscape. Because they are up to 500 feet tall and 400 feet in diameter, it is difficult to make them unobtrusive.

Finally, natural draft towers could have adverse effects on migratory birds if located in a major flyway (66).

10.2.3.3 Mechanical Draft Cooling Towers

The potential for fogging and icing problems is much greater with mechanical draft towers than with natural draft towers. This is because the mechanical towers are much lower (60 feet versus 500 feet), making inversion penetration less likely. Also, the plume is less concentrated and cools faster than the larger natural draft plume. The potential for drift problems is somewhat higher as 0.005 percent of the circulating flow is lost in this form (71).

Land requirements are somewhat higher than for natural draft towers due to the need for multiple units and spacing between them to prevent recirculation.

Because of their low profiles, mechanical draft towers themselves do not present the aesthetic problems associated with natural draft units. However, the increased propensity for fogging and icing could cause significant visual impacts. Also, noise caused by the fans can be an important problem during operation.

10.2.3.4 Cooling Ponds

Occasional fogging and icing problems may be associated with the use of cooling ponds, although not to the extent of cooling towers. There are no drift problems. The major problem associated with the use of cooling ponds in the large land requirement; greater than 1,000 acres for a 1,000 megawatt plant.

10.2.3.5 Spray Canals

The potential for fogging and icing problems is somewhat higher for spray canals than for cooling ponds, although it may be more localized than that of mechanical draft towers. Also, while there may be some drift produced, it is ejected at such a low altitude (10-15 feet) that it would most likely not be a problem outside of the plant site.

Land area requirements for a spray canal system are larger than that for a cooling tower of either type but much smaller than that for a cooling pond.

10.3 Handling and Storage Facilities for Petroleum Products

10.3.1 Offshore Unloading Facility

Major environmental impacts occur at an oil unloading facility from two basic causes. One is the possible discharges of bilge water and ballast from the vessel activity. The other is the potential for oil spills that any such transfer operation entails.

Bilge water collects in the bottoms of boats, and may contain toxic petroleum products and metallic compounds leaked from the machinery. It is estimated (49), that a 20,000 deadweight ton tanker generates 80 gallons of bilge water per minute. This bilge water must be collected at the unloading facility or at an adjacent port facility for treatment prior to discharge.

Ballast water is taken on by empty tankers after unloading, in order to improve handling at sea. New tankers, above a certain size, are required, by Coast Guard regulations to segregate ballast water in tanks separate from the cargo tanks, to avoid contamination. However, older and smaller vessels use cargo tanks for holding ballast water. When a fresh cargo is to be taken aboard, this ballast water must be treated before discharge, in order to reduce its oil and other pollutant content to acceptable levels. Since, in Long Island, we will presumably be unloading only, ballast water is not "our problem". However, it would be unthinkable to allow a vessel to unload here that was probably going to discharge polluted water elsewhere.

When oil spills occur, the options are either to disperse, or to contain and remove the spillage. Under the terms of the Water Quality Improvement Act of 1970, dispersants may not be used (49):

1. on any distillate fuel
2. on any spill of oil less than 200 barrels
3. on any shoreline
4. in waters less than 100 feet deep
5. in any waters containing major populations or breeding or passage areas for species of fish or marine life which may be damaged or rendered commercially less marketable by exposure to dispersant or dispersed oil.
6. in any waters where winds and/or currents are of such velocity and direction that dispersed oil mixtures would likely, in the judgement of EPA, be carried to shore areas within 24 hours.
7. in any waters where such use may affect surface water supplies.

Skimming and absorbing the oil, and its subsequent removal, are the usual methods of handling oil spills (49). Absorption methods involve the use of material which absorbs the oil, for example, straw, peat or polyurethane foam chips. The main disadvantage is that is a triple operation, requiring first the distribution of the absorbent over the oil and, subsequently, its removal and disposal. Disposal of large quantities of contaminated absorbent can create additional environmental problems. The polyurethane chips have the advantage of both greater absorption properties and the possibility of re-use after the contaminated oil has been wrung out. Due to the slow rate of recovery obtained using this method, its use has been restricted to small slicks. However, its effectiveness is increased by wave action and, thus, it can be used in adverse sea conditions.

10.3.2 Bulk Storage Facility

The magnitude of air emissions, as well as all other environmental impacts, from the operation of a tank farm, will depend upon the volume of delivery, types of storage tanks used, and operating equipment and procedures.

Sources of air emissions at a storage facility (49):

a) evaporation from storage tanks

b) evaporation from transfer of petroleum products

c) combustion products from process machinery

d) accidental small spills and leakage

The magnitude of impacts from these sources will depend on the number of storage tanks and the ambient air conditions. Impacts will be much greater in a rural area than in an industrially developed port.

Emissions from fuel storage tanks fall into three categories. Breathing losses, caused by temperature and pressure changes in the tank, are found only with fixed roof tanks. Working losses from filling and emptying are found with both fixed roof and variable vapor space tanks. Standing storage losses due to improper fits between seal and tank walls are found with floating roof tanks. The transfer of liquids from tankers to storage tanks and from storage tanks to tank trucks results in evaporative emissions. The quantity of the vapor losses depends directly upon the temperature, density, and vapor pressure of the oil and how saturated the vapor space is at the time of loading or unloading of the tanker. Evaporative losses during transit from the tankers may also be substantial. External combustion boilers may be used to heat high-viscosity oil for easier movement from storage tanks to trucks. If natural gas is used as a boiler fuel, the major emissions are nitrogen oxides. Emission quantity will vary according to the size and type of the boilder and the loading. Occasional small accidental spills of fuel and other stored materials, and similar daily operational losses will constitute a relatively minor source of air pollution at a tank farm.

The operation of a marine terminal may generate the following types of wastewater:

a) domestic wastewater;

b) cooling water;

c) boiler water;

d) process water; and

e) stormwater runoff.

Sewage from the oil storage facility can be collected and delivered to a municipal treatment plant or receive the equivalent of secondary treatment at the site. Pumps and other process machinery may require cooling water. The volume of water used will depend on the size of the generating facility, the number of machinery units using cooling water and the type of cooling system employed. Besides the added heat, cooling water may also contain a high degree of dissolved solids and biocides which are added to prevent equipment corrosion and fouling. The chemicals used include sulfuric acid, chromate, zinc and chlorine, and heavy metals such as chromium and zinc are toxic to many marine organisms.

Water used in steam generation, if any, at the facility, is initially preconditioned to remove suspended solids and hardness, and may even be deionized before entering boilers.

Corrosion inhibitors and algicides from cooling water and boiler water blowdown interfere with the metabolism of organisms which oxidize organic compounds.

Stormwater runoff from tank storage areas should be collected and treated before discharge. During periods of heavy rain, large volumes of runoff water must be held before discharge or treatment. In order to prevent overloading and disruption of treatment facilities, the storm runoff from process areas should be retained in holding ponds until it can be treated.

Noise at a storage facility will be produced by such equipment as compressors and boilers. Tank trucks and tank cars used to transport petroleum products from the facility will also generate some noise. A buffer zone around the facility is often used to mitigate sound impacts. The choice of a site at a suitable distance from inhabited areas will also lessen the impact on the surrounding area.

The danger of fire is particularly acute at tank farms, due to the large volumes of petroleum stored. Although a fire may be small and easily contained, the heat generated by combustion may cause adjacent tanks to ignite. Consequently, although fires may be infrequent, extensive precautionary measures are taken. Fire alarms are placed in both the tank area and the main control room. A complete water system for fire fighting, a portable dry powder extinguisher, and a foam fire extinguishing system, which may be used throughout the tank farm, are provided in the storage area.

Storage tanks are also often equipped with individual foam systems, which when triggered will contain a fire by covering an entire tank with foam. In addition, the dike around each tank will help keep fires from spreading.

10.4 Gas Handling and Storage Facilities

It is not anticipated that any new gas facilities will be required, unless new assured long-term supplies become available. Any new gas made available by offshore oil developments in the Middle and North Atlantic is expected to last no more than 30 years (54, 55), and the economics of expanding facilities on Long Island is questionable. However, for the environmental impacts of gas-associated onshore facilities, refer to Sections 10.6.2, 10.6.5 and 10.6.7.

10.5 Coal Handling and Storage Facilities

Coal dust emissions and their associated effects are the most significant negative impacts of coal handling and storage facilities. The two most important impacts of these coal dust emissions relate to the terrestrial and aquatic ecologies. Because of the presence in coal of trace elements such as cadmium, mercury, lead, and arsenic, problems may develop when these heavy metals are taken up from the soils and sediments by terrestrial and aquatic plants (66). Ingestion of these plants by terrestrial and aquatic life introduces these trace elements to the food chain and in some cases, may reach toxic levels through a cumulative process. Coal dust fallout may increase turbidity levels of surrounding water bodies as well. This may result in an overall decrease in the zone of photosynthetic activity and, thus, reduce productivity (66).

Similar impacts result from runoff and leachates associated with coal stockpile drainage. In the case where large stockpiles of coal are maintained, large volumes of coal are exposed to snow and rain and subsequent runoff. In addition, liquid suppressants are sometimes used to wet down the coal piles to control dust, resulting in additional infiltration of the pile by liquids. The result of this drainage is two-fold. First, the surface runoff is capable of washing coal dust from the pile and carrying it into existing drainage canals or storm sewers, eventually introducing the dust to the receiving water body. The effects of this are explained above. Secondly, the water which percolates through the coal pile may take into solution those trace elements mentioned previously and introduce this resulting leachate to the ground-water system. Because of the persistence of these heavy metals, well water quality and even surface water quality may be impacted.

Harbor maintenance, in the form of dredging, and the disposal of dredge spoils, has a potentially significant impact on both water quality and aquatic and terrestrial ecology. Mechanical disruption and displacement of bottom sediments may result in increased turbidity and the release of gases and nutrients to the water column which were previously tied up in the bottom sediments.

Noise from the operation of heavy equipment, such as rail traffic, stackers, conveyors, bulldozers, ship loaders, and ship machinery, may have an impact on the wildlife community within the vicinity of the facility. This may result in both behavioral and physiological changes such as alterations in migratory patterns and sexual function (66).

10.6 Onshore Facilities for OCS Development

10.6.1 Service Bases

These comprise temporary service bases in support of exploratory drilling, offshore platform installation and submarine pipeline laying, as well as permanent service bases supporting development drilling and oil and gas production. The most significant differences between temporary and permanent bases are the land area occupied (5 acres versus 75 acres) and the volume of boat traffic. Boat activity at a permanent base during the development drilling phase is very much greater than at temporary bases. However, the average workboat size is the same, and the materials carried and services performed are comparable.

Storage tankage is miniscule compared to bulk storage facilities, but the source and type of air emissions is the same. (See Section 10.3). Service base operations also result in wastewaters from sewage, bilge water, ballast water and cooling water, although not in the same quantities as from oil unloading and storage facilities. (See Section 10.3).

Because a service base is in operation 24 hours a day, noise is generated continually. Sources of noise from a service base include pneumatic power tools, air compressors, pumps, compressed air machinery for painting and cleaning, industrial trucks, and cranes. In addition, auxiliary generators, if any, can be very noisy. If a service base is located in a relatively quiet inhabited area, the noise which it generates will present a problem. Typically, a noise level increase of 30 decibels or more will result in complaints from local residents.

Because of the large volume of materials moving through service bases, frequent small spills of stored substances will occur. Drainage waters from portions of the yard where hazardous products are stored are often diked and the materials collected for treatment and off-site disposal. Any runoff which does leave the site, and reaches the surface or subsurface waters, will likely be industrial in nature, and will contaminate the waters.

Two types of solid wastes are dealt with at a service base: those generated by offshore oil operations, and those generated by the service base itself. Offshore wastes are the more significant in terms of both quantity and environmental impacts. During drilling operations, approximately six tons per day of solid wastes will be generated per well. This includes drilling wastes, such as mud, mud additives, bit cuttings, sand and sludges collected in separation vessels and tanks; galley garbage; oily sludges; lubrication oils and waxes; rags, cloth, and packaging wastes; drums, spools, cables, and scrap metals; and human wastes. Some of this material is treated and disposed of at sea, but a large quantity is returned to shore through the service bases.

Offshore operators are not permitted to dispose of any oiled drilling mud and drill bit cuttings at the platform. These waste materials come in two forms: oilbase drilling mud (a specialty mud rarely uses), and standard mud and cuttings, which become mixed with oil while drilling. Since these materials cannot be economically reclaimed, they must be returned to shore (usually in barrels) and buried. Some oilbased mud must be transported back to the mainland for centrifuging, if the rig itself does not have this particular equipment on board. The discharge of non-oiled drilling mud and cuttings is permitted in Federal waters (49).

Since drilling wastes often contain hazardous materials, such as oil, acids or heavy metals, they must be disposed of in a special landfill site where there is no danger of penetrating the ground water, running off into surface waters, or evaporating. Less hazardous offshore wastes, such as scrap metal, paper, or wood products, are either recycled or treated at the service base before disposal in an incinerator or sanitary landfill.

Solid wastes generated by service base operation include dunnage (material used to protect cargo), collected during boat unloading, garbage from supply and crew boats, refuse from service base employees. These wastes can be incinerated, disinfected and used as landfill or, in the case of garbage, ground up and disposed of with the sewage. Little adverse environmental impact is anticipated if these materials are disposed of in accordance with existing regulations.

10.6.2 Pipeline and Landfall

Pipelines and landfalls contribute few airborne pollutants compared to other operations involved in OCS development. During the operational phase, air emissions will be generated primarily from two sources, compressors and pumping stations and leakage from valves and seals along the route.

Compresssors are used to maintain proper operation pressures along a gas pipeline. They are fueled by either natural gas or refinery gas and their major emissions are sulfur oxides and hydrocarbons. Hydrocarbon leaks can occur at numerous locations along pipelines, e.g. at pump seals, compressor seals, relief valves and pipeline valves. A study of air emissions for a report on a Southern California OCS lease sale concluded that the major source of leakage was pump seals (49). If a leak of natural gas occurs as a result of pipeline rupture or break, the highly inflammable and asphyxiating gas would be a health and safety hazard.

However, the overall impact of normal pipeline operations on ambient air quality appears to be minimal.

Chronic low level leakages of petroleum, as a result of normal operation, become dissolved in the water surrounding the marine pipeline. The volume emitted is a function of the design of the pipeline (type of joints, etc.) and the number of fittings and valves. Little information is available on the extent of impacts generated by low but continuous concentrations of hydrocarbons in the marine environment. Site-specific physical characteristics such as mixing rates and retention times, and the susceptibility of local organisms to both lethal and sublethal effects of continuous low hydrocarbon concentrations, will determine the severity of impact.

Increased ambient noise levels can be expected in the area of a pipeline corridor, particularly in the vicinity of a booster station where compressors will be located. Compressors generate approximately 92 to 100 dB (A) of noise while operating, which exceeds current federal standards. This uncontrolled level is audible in a 6,000 - 7,000 foot radius from the site on a 24-hour basis (49). Silencers, built into the compressors, can lower the noise level acceptably. Approximately once a year, venting of high pressure gas in a pipeline and at the compression station occurs. Venting lasts approximately 45 minutes on the pipeline and five minutes at the compressor site. Uncontrolled noise levels are audible up to 15 miles away, but stack silencers are available which can reduce the volume of sound considerably.

There is no significant solid waste associated with the normal operation of pipelines. When pipeline spills occur, however, the oil that is spilled is collected and recovered to the extent possible and discarded when it is not practical to recover oil. All such waste must be disposed of at a landfill site suitable for hazardous wastes. Special care must be taken in disposing of the oil wastes so that the hydrocarbons contained in the oil are not released to the atmosphere or to surface or ground waters. The amount of petroleum spilled and its frequency cannot be easily predicted.

10.6.3 Marine Terminal

The type of facility described in Section 10.3 is not intended to handle crude oil from an offshore field. However, everything written there applies to a marine terminal. In addition, the special conditions prevailing in a marine terminal associated with OCS development cause large amounts of hazardous solid waste to be generated.

Oil contaminated solid wastes are a major component of the total volume of solid waste generated by a marine terminal. These include:

a) Sedimented materials either produced with crude oil or precipitated during storage; and

b) Sludge, scums and froth from the treatment of the crude oil or brine.

To maintain terminal storage and throughput, sediment sludges are periodically removed from the bottom of the storage tanks and pipelines, and stored for subsequent treatment and disposal. Iron rust, iron sulfides, sand and oil are major constituents of terminal storage sludges.

In addition, large quantities of chemical waste slurries are produced at the terminal in oil/brine separation (desalting) and wastewater treatment for oil removal. Spent chemicals contain oil, organic and inorganic acids, bases, mercaptans, sulfides and high concentrations of gummy sulfur, oxygen and nitrogen compounds. These chemical wastes are often stored together with the sedimented storage sludge in open pits at the terminal until treatment and disposal. Such pits can allow the toxic chemical wastes to infiltrate to the air, soil, surface and ground waters, especially during periods of strong winds and heavy rainfall. In some states (e.g., Mississippi) (49), the use of earthen salt water storage, evaporation, and burn pits is severely restricted.

No serious environmental consequences will be produced if adequate treatment and disposal facilities exist. If such facilities are not available, however, considerable environmental damage may occur.

10.6.4 Partial Processing Plant

Specific facilities are established at the crude oil terminal and/or at the offshore platform to remove some of the wastes which are present in the oil stream as it leaves the ground. The impurities normally consist of brine, suspended solids, nitrogen, oxygen and sulfur compounds and small amounts of such elements as copper, nickel, iron, and vanadium. The sulfur compounds are converted to hydrogen sulfide which, in turn is converted to either sulfur dioxide through flaring or incinerating, or to elemental sulfur through sulfur recovery processes. The nitrogen oxides are converted to ammonia and the oxygen compounds to water.

Brine water produced with the oil or gas stream has a unique status under the Federal Water Pollution Control Act Amendments of 1972 (P.L. 92-500). The term "pollutant" in the act is defined to exclude "water derived in association with oil or gas production and disposed of in a well, if the well is used either to facilitate production or for disposal purposes, is approved by authority of the State in which the well is located and if such State determines that such injection or disposal will not result in the degradation of ground or surface water resources". Therefore, the disposal of brine from the crude oil stream by injection into a well is regulated at the state level. Disposal into surface water requires a permit under the National Pollution Discharge Elimination System (NPDES).

10.6.5 Gas Treatment Plant

Air emissions at gas plants come from:

a) processing;

b) evaporation;

c) flaring: and

d) combustion from machinery and vehicles.

The magnitude of impacts from these sources will largely be determined by the ambient air conditions. In regions where ambient concentrations approach maximum standard concentrations, a gas plant could add sufficient emissions to limit further industrial growth in the area. In an area where air quality is good and concentrations of pollutants are low, impacts will be less severe. The quantity of emissions in either situation will be determined in large part by the pollution controls at the plant, as well as the extent to which regulations are enforced in the area.

If hydrogen sulfide is present in the natural gas stream in economically valuable concentrations, a sulfur recovery process will be included in the gas processing plant. This process recovers 92-97 percent of the sulfur, originally present in the bas stream as hydrogen sulfide. Tail gases from this recovery operation, containing varying amounts of hydrogen sulfide are burned, converting the hydrogen sulfide to sulfur dioxide. (Fuel is added to ensure complete conversion.) Sulfur dioxide gases are then vented through a stack to the atmosphere. Emissions of sulfur dioxide from tail gases can be lessened by the addition of conversion units which reconvert the sulfur dioxide wastes to elemental sulfur. Such processes, combined with the earlier recovery process can result in a sulfur recovery rate of up to 99.9 percent.

Evaporative losses of hydrocarbons can also be expected during gas processing. These emissions occur at leakage points (such as valves) and increase proportionately with the volume of gas processed. In an emergency situation during sulfur recovery, flaring of tail gas, without the addition of fuel normally used in the incineration process, could take place. In this event, hydrogen sulfide emissions would increase due to less efficient combustion. There is no current federal standard for flaring emissions. External combustion equipment is used for process heating and the regeneration of chemical solutions in the sulfur recovery process. If natural gas is used as a boiler fuel, the major emissions released are nitrogen oxides. Compressors are used in a gas processing plant to help move natural gas as fuel, and sulfur oxides (if other than sweet gas is used), and hydrocarbons are the major emissions. Vehicle emissions from trucks, used to remove products (sulfur and liquid hydrocarbons) from a gas plant, and from employee automobile traffic, can be expected to add carbon monoxide, hydrocarbons, and nitrogen oxides to the air, both at the site and along nearby highways.

Large quantities of oils and hazardous materials are stored at gas plants. These include sulfuric acid, lubricating oil, absorption oil, and sodium hydroxide. In addition, if gas plant products are not delivered by pipeline, storage facilities must be provided on the site for 3 to 5 days of production. Soil and vegetation in the vicinity of the plant may become contaminated with small amounts of these materials. Runoff water removes these contaminants from the soil and vegetation, and will adversely affect the quality of the receiving water.

Wastewater effluents from gas treatment plants include domestic sewage, cooling water, process water, and boilder wastewater. All these categories, except process water, have been discussed in connection with other facility types (see Section 10.3.3). Typically, process wastewater, which usually occurs in small quantities, can include water condensed from the incoming gas stream,steam condensate, spent caustic solutions and other solutions and wash waters.

Formation water (brine) is usually produced with the gas at the offshore platform. If this water is discharged at the platform, it will have no onshore impact. However, some quantity of this brine will be brought ashore with the gas stream. This brine must be eliminated before it reaches the gas plant, because of the corrosive properties of its dissolved salts. This formation water contains no oxygen, and may have concentrations of heavy metals and dissolved hydrocarbons, especially aromatic compounds. Formation water discharges can cause serious environmental impacts, especially in fresh water and estuarine systems. Because of its adverse environmental impact, formation brine waters are not discharged into fresh water systems.

The initial stage of treatment for gas plant discharges includes oil removal. This process uses an oil-water gravity separator and, in some cases, heat treatment may be used to break up emulsions. With treatment, the amount of oil and grease in the plant discharge can be reduced to 10 ppm.

Hazardous wastes can be produced by accidental spills of liquid gas or other hydrocarbons, processed sludge containing chemicals and residuals from brine evaporation. These hazardous substances must be transported to special dumping areas and buried in such a way as to prevent their movement into the atmosphere and surface or ground water. These substances can be treated before disposal by distillation or incineration in a special furnace, to reduce their volume and toxicity (49).

Sources of noise from a gas plant include compressors, boilers, scrubbers, and flare stacks. A buffer zone around the facility is often used to mitigate noise impacts. The choice of a site at a suitable distance from inhabited areas would also lessen the impact on the surrounding area. Noise from a gas plant is not anticipated to have any major impact on the adjacent area.

The materials processed at gas plants are all inflammable. Escaping vapors may reach critical levels of concentration in air (on the order of a few percent) and create the condition for explosion. If there is an ignition source nearby, a fire or explosion could occur.

Gas plants are always designed to minimize the impact of any major accident. Much of the land at a gas processing plant is required to provide buffer areas to separate potential sources of leaks of hydrocarbons from potential ignition sources. Storage tanks are surrounded by dikes designed to contain spills and reduce radiation effects in the event of a fire.

10.6.6 Oil Refinery

Major sources of air emissions at refineries include:

a) processes such as cracking and coking units;

b) process machinery such as boilers and compressors;

c) leaks from valves and seals and floating roof tanks; and

d) mobile sources.

One of the major steps in the processing of petroleum is catalytic cracking, the alteration of the molecular structure of hydrocarbons by heat and catalytic conversion. The major emissions associated with catalytic cracking include carbon monoxide, sulfur oxides, hydrocarbons, and particulates. Spent catalysts from this cracking process are regenerated by passing through a vessel in which coke is burned off. The major emission from these regenrators is particulate matter that can be controlled by electrostatic precipitators.

Coking is a decarbonization process which results in the production of a calcined coke with a carbon-hydrogen ratio of 1,000 and higher. Through this process, the yield of residual fuel oil from crude oil is reduced in favor of an increase in the yield of distillate fuel oils. Average uncontrolled emissions from a fluid coking unit are 523 pounds of particulates per 1000 barrels of fresh fuel. However, fluid coking units are not utilized as frequently as delayed coking units, which generate fewer pollutants (49).

Process machinery used at a refinery includes external combustion boilers and compressors. Major emissions from boilers are sulfur oxides, nitrogen oxides and particulates. Nitrogen oxide emissions can be lowered by using different methods of boiler operation. Compressors used in refinery processes will normally utilize either steam turbines or electric motors, but could be powered by refinery or natural gas. Emissions from the combustion of this fuel are primarily hydrocarbons and sulfur oxides, the volume of which will depend on the sulfur content of the fuel.

Valve and seal leakage can be expected throughout the refinery, particularly in areas where high process pressures are required. The most effective means of controlling these hydrocarbon emissions is through a program of careful maintenance and repair. The combined average emissions of hydrocarbons from various valves and seals is 61 pounds per 1000 barrels refining capacity.

Emissions from mobile sources such as trucks and tankers used to deliver crude oil and remove refinery products, and employee automobile traffic, can be expected to add carbon monoxide, hydrocarbons and nitrogen oxides to the air at and around the facility.

Since the soil at the plant site will be reworked and compacted, its water retention properties may be altered. As a result, less water will seep through the soil to the ground water and more will run off the site as surface water.

Although the actual acreage affected within the refinery limits is small, to the extent that this reduces ground water aquifer replenishment, this can have serious consequences in regions where ground water supply is important.

Wastewater effluents from oil refineries include domestic sewage, cooling water, and boiler blowdown, and these have been discussed in connection with other types of facilities (See Section 10.3.2). However, since economics demands that oil refineries be of large size, the quantities of such effluents are considerably greater.

In addition, refinery process water effluents, although only a small fraction of the total wastewater, will be the most contaminated. The processing pollutants are added during crude oil desalting, steam distillation, steam stripping, water washing of chemicals following treatment, catalyst regeneration, treatment of water (e.g., nitrate addition for caustic embrittlement control), transferring and storing oil, vessel cleaning operations, etc.

Some of the constituents of refinery wastewater are (49):

Floating and dissolved oil

Suspended solids

Dissolved solids

Phenol and other dissolved organics

Cyanide

Chromate

Organic Nitrogen

Phospate

Sulfides and Mercaptans

Caustics and Acids

All new refineries are required to apply for a National Pollutant Discharge Elimination System (NPDES) Permit, under section 402 of the Federal Water Pollution Control Act of 1972. Although regulation of NPDES Permits has, in some instances, been delegated to individual states, it is EPA which actually classifies the proposed refinery according to "New Source" standards, (e.g., type of refinery, volume of crude oil refined). The permit calls for compliance with both EPA and state standards.

Noise impacts from refineries are derived from the operation of air fan coolers, blowers, compressors, cooling towers, motors, furnaces, gas engines, steam boilers turbines, vents and other equipment. Actual noise levels will vary with the size of the plant, plant design and plant location. Meteorological conditions will also influence the noise levels. A modern refinery using the best available technology should be able to keep noise at about 50 decibels or lower at its boundary. The most disruptive noise impacts of refinery operations are those intermittent noises, above the average background level, caused by flaring, pressure relief valves, and other equipment. These noises may, from time to time, be audible to the neighboring population. An adequate buffer area around the plant may significantly decrease noise from the facility.

Solid wastes are produced in the refinery from:

a) oil storage and spillage;

b) oil processing; and

c) wastewater effluent treatment.

Where considerable sediments, suspended solids, and brine are present in the crude oil, gravity separation and chemical and electrostatic desalters are usually employed, resulting in the accumulation of sludge. Wastes containing oil and petroleum products, heavy metals, and process chemicals require special disposal procedures to limit impact on air, ground, or surface water.

In previous years, ocean dumping, deep well injection, and evaporative lagoons were common practices, but recent regulations tend to restrict the use of these disposal techniques. Fluid bed incineration is now being used (49). The sludge is burned, reduced in volume, and the resultant ash, residue, fines and particulate matter collected from the smoke stack are transported to a landfill for burial.

Fire presents a particularly acute danger where large volumes of petroleum are stored, as is the case at a refinery. Although a fire itself may be small and easily contained, the intense heat generated by the combustion of crude oil and petroleum products presents the distinct possiblity of explosion. Consequently, although the frequency of fires may be low, extensive precaution and control is exercised. One proposed storage facility in Scotland (49) includes the following fire prevention equipment. Fire alarms are placed in the tank area and in the main control room. A complete water system for fire fighting is included in the storage area, in addition to portable dry powder extinguishers. A foam fire extinguishing system is also included which may be used throughout the tank farm. Storage tanks are also often equipped with individual foam systems, which, when triggered, can contain a fire by covering an entire tank with foam. In addition, each tank is diked, to prevent a fire from spreading.

In the United States, fire protection systems for tank farms must meet the requirements of the National Fire Prevention Association and the Federal Occupational Safety and Health Act. Individual states may also have specific fire prevention regulations.

10.6.7 Petrochemical Plant

The emissions from a petrochemical plant will resemble those from an oil refinery. In both types of facility, the actual processing scheme used will depend on the volume and character of the raw materials. The detailed pattern of effluent discharges depends on the processing scheme, and, within the limits of this report, only generalizations are possible. Therefore, much of the discussion in the previous section is applicable to petrochemical plants.

10.6.8 Platform Fabrication Yard

Air emissions can result from a number of discrete operations in the fabrication of both steel and concrete platforms. Sources of air pollution in steel platform fabrication include:

a) pipe and metal cleaning by sand blasting;

b) painting and its resultant emissions; and

c) transportation emissions from

cranes and other machinery used to move steel and tubular members throughout the fabrication process;

trains, trucks, tugs and barges used to deliver and remove pipe and other materials; and automobile traffic.

The preparation of metal surfaces for painting by sandblasting will generate particulate matter, i.e. sand and metal dust. These emissions can be controlled through the use of filters, wetscrubbers, or electrostatic precipitators.

The process of painting pipe and other steel members can generate high levels of emissions, during both application and drying. The volume of these losses is determined by the amount of volatile matter in the paint, averaging about 50 percent of the total. Major constituents include aliphatic and aromatic hydrocarbons, alcohols, ketones, esters, alkyl and aryl hydrocarbon solvents and mineral spirits. Approximately 1,120 pounds of vapor will be generated per ton of paint used. If a primer coat is applied, an additional 1,320 pounds of vapor per ton of primer will be generated. Paint particulates are also generated during application and drying. If the painting is done indoors, activated charcoal absorbers can provide up to 90 percent removal of evaporate emissions. Water curtains or filter pads are used to reduce paint particulates but are ineffectual in trapping evaporative emissions (49).

The raw materials and supplies for the platform fabrication yard are delivered by railcars, trucks, supply boats and barges. Heavy duty trucks and machinery are used at the yard to transport the large quantities of steel and other materials required in the assembly of platforms. These pieces of machinery use either diesel fuel or gasoline and release emissions of carbon monoxide, sulfur oxides, hydrocarbons and nitrogen oxides. A considerable increase in automobile traffic can also be expected. Estimates vary, but depending on the type and volume of platforms being fabricated, automobile traffic may range from a few hundred to several thousand vehicles per day.

In those yards where cement platforms will be constructed, additional air emissions will occur from wind blown aggregate and cement dust.

The overall impact of these air emissions will depend on the size and output of the facility, the existing air quality at the site and in adjacent areas, endemic biota, prevailing winds, and local meteorological conditions, and the degree to which available control technology is applied.

Runoff from the site is likely to be contaminated by particulate matter, heavy metals, petroleum products, and process chemicals. Groundwater recharge may be decreased and surface water runoff increased because of soil compaction from the constant movement of heavy equipment within the yard.

Dredging required to maintain the adjacent channel at a depth sufficient for the service boats, work boats, tugs and barges uses to transport and install completed platforms, may cause significant environmental impacts. Continuous changes in circulation and sedimentation patterns may kill or alter the behavior patterns of floating, swimming, or attached organisms, disturb patterns of bird migration and destroy nesting areas, and alter beach erosion and accretion patterns.

Wastewater from a steel platform fabrication yard consists of cooling water, process water, and sewage. Because of the metal fabrication procedures sometimes employed at the yard, e.g. rolling, shot-blasting, welding, and corrosion prevention, process and cooling waters are likely to contain considerable quantities of particulate matter, dissolved heavy metals and anti-fouling chemicals. The dissolved components of the wastewater (e.g., heavy metals and anti-fouling chemicals) can be taken up by plants and animals in the receiving waters with lethal or sublethal effects or concentrated within the tissues of organisms which use these contaminated plants and animals as food sources. Industrial wastewater containing harmful quantities of pollutants will require treatment in accordance with governmental regulations before discharge into coastal waters. It is likely that domestic wastewater will be piped to an existing municipal sewage treatment facility or treated on site.

The principal sources of noise at platform fabrication yards are the heavy machinery used in the processing, movement and fabrication of steel components, and on-site power generation, if required. The utilization of control devices, and the provision of a buffer zone, could significantly reduce the impacts of these noise sources on surrounding communities.

Solid waste will consist of:

a) packaging and shipping materials, e.g. carboard and wooden crates and spools;

b) scrap metals, e.g. strapping cables and fragments of iron or steel; and

c) debris or containers contaminated with oil or hazardous materials, e.g. paint cans, etc.

It appears that much of the volume of solid waste from the platform fabrication yard can be either sold for scrap and reused, or incinerated and disposed of in a standard solid waste management facility or landfill. Solid wastes contaminated with oil or hazardous materials must be shipped, stored, handled, used and disposed of in a manner which will not allow loss of the material to the atmosphere or surface or ground water.

10.6.9 Pipecoating Yard

Several factors help determine the extent to which air quality will be affected by a pipe coating facility. If ambient air quality in the region is close to maximum allowable federal standards, further growth by industries generating high particulate emissions may be limited. In an undeveloped area with low ambient concentrations of pollutants, however, some deterioration of local air quality will result. Adverse impacts resulting from air emissions can be minimized by including appropriate controls (e.g. dust collectors) in the facility design wherever particulate emissions are high.

A pipecoating yard may generate air emissions from three major sources:

a) processing pipe through the yard, chiefly from the cleaning and

b) coating operations;

c) equipment used in the coating process, particularly compressors and boilers, which emit primarily nitrogen oxides; and combustion from machinery used to deliver raw materials, move the pipe in the yard and transport the finished pipe from the yard (trucks, trains, cranes, forklifts and marine vessels).

Particulates of shot and heavy metals from the pipe surface are emitted during pipe cleaning. Dust collectors are normally installed to reclaim the shot and minimize particulate emissions from the operation.

Pneumatic pump transfer systems, employed during the delivery of cement to the site, generate particulate emissions. In such systems, dry cement is blown under pressure to receiving bins. To allow for continuous operation, a two-cycle dust collector gathers excess dust and filters it out into shakers at the bins and the mixing plants. While one collector is in use, the other automatically dumps its dust back into the transfer tube.

External combustion boilers are used for process heating. If natural gas is used as a boiler fuel, the major emissions released are nitrogen oxides. Emission quantity will vary, depending on the size and type of the boiler and the loading. Compressors and other heavy machinery used in the pipe coating process are also possible sources of combustion emissions. The emission composition will vary according to the type of fuel used and the extent of emission controls.

Cranes, forklifts, and trucks used to move the pipe around the yard and the trains, trucks, and barges used to deliver materials and remove the finished pipe, will also contribute to the elevation of combustion emissions, such as carbon monoxide, hydrocarbons, and nitrogen oxides, in the area of the facility. Increases in these emissions may also result from automobile traffic to and from the site.

The shotblasting operation generates high noise levels. Specific noise-reduction design features are available, however. One yard (49), for example, houses its shotblasting operation in a lead-lined building which effectively deadens the noise. The same method may be used for lowering the noise levels of process machinery; appropriate muffling devices can also be installed. The mobile machinery used to move the pipes in the yard may generate noise despite special design features. The overall noise impact for the area must ultimately be determined by analyzing the specifics at the selected site.

A landscaped buffer zone can serve a dual purpose in reducing noise levels. The zone not only extends the actual distance between the source and the nearest residents, but attenuates sounds through its vegetation, resulting in minimal noise infiltration.

The solid wastes which may be generated by a pipe coating yard include:

a) paper, wood, and cardboard packing materials;

b) concrete and mastic fragments;

c) wire mesh, metal drums, cables, metal straps; and

d) soils or debris contaminated with process chemicals or petroleum.

The material used to package or stabilize the cargo delivered in trucks, railroad cars or barges constitutes most of the solid waste which is trucked off the site. Since most of this material is considered non-hazardous, it can be incinerated or buried at a local landfill site. Spilled aggregates, sand and concrete fragments left from trimming finished pipe, and cleaning the concreting plants, are normally utilized to improve existing roadbeds. When the mastic plant is closed down each day for cleaning, significant amounts of mastic are melted down and recycled or used to patch flaws in the mastic coating of previously coated pipe. Wire mesh, metal drums, cables and metal strapping are frequently sold as scrap.

Solid wastes which have been contaminated by oils or spillage of potentially dangerous substances are considered hazardous wastes and must be treated, incinerated or buried in special facilities designed to prevent re-entry into the air or water.

Due to the routine cleaning of vehicles and machinery, in addition to regular spills and leakage of process chemicals, runoff water at the site may contain concentrations of particulate matter, heavy metals and soluble inorganic and organic compounds leached from the soil surface. If material spills are cleaned up quickly and without the use of environmentally sensitive solvents or chemical cleaning agents, contamination from runoff water should not result in major environmental deterioration in the receiving waters.

Wastewater discharges from a pipe coating yard consist of:

a) process water;

b) cooling water; and

c) domestic wastewater.

Process water includes effluent from the whitewash and the sand and gravel washing. This water contains hydrocarbons and alkaline substances, and suspended and dissolved substances. In practice, most of the whitewash which runs off the pipe is collected and reused. Discharges are, therefore, maintained at a minimal level. Suspended and dissolved substances in the sand and aggregate wash water can be minimized by passage through a series of settling basins prior to discharge. The volume of cooling water required to speed up the mastic hardening process depends on the throughput of the plant. The water which cools the pipe also flushes away particulate matter and metal fragments, causing a further reduction in the quality of the cooling water discharge.

11.0 Location of Facilities in the Coastal Zone

11.1 Power Plants

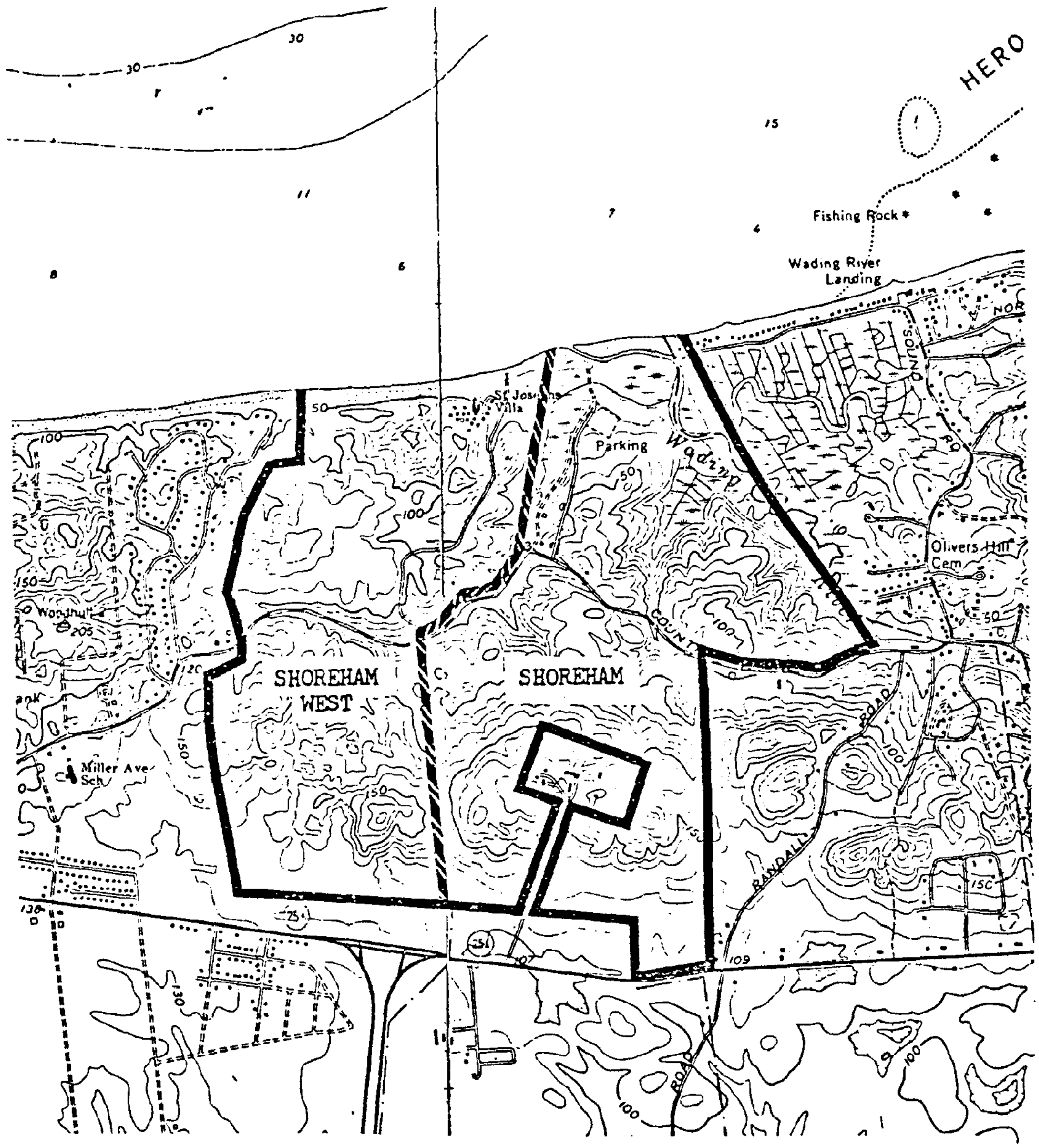
As stated in Section 8.2, approximately 1600 MW of additional generation capacity will be required in the bi-county region by the year 2000. Furthermore, the capacity deficit will manifest itself in about 1992, i.e., some portion of the 1600 MW must be made available by that date.

This generation capacity is roughly equivalent to two additional plants of the same size as the Shoreham nuclear unit. It is also equivalent to the coal-fired alternative submitted by LILCO in their Jamesport application.

In the New York Power Pool's 1977 report to the Public Service Commission (5), LILCO discusses seven possible sites for plant expansion, namely:

Northport
Shoreham
Shoreham West
E. F. Barrett
Holbrook
Glenwood

Northport must be eliminated, because of LILCO's agreement with the Town of Huntington to build no more steam generating facilities on this site. Barrett, Holbrook and Glenwood can be eliminated for lacking sufficient land area. They have 118, 94 and 41 acres respectively, and the same report states that 2400 MW of generating capacity (with cooling towers) requires 250 acres. The remaining three sites, Shoreham, Shoreham West and Jamesport, can all provide this amount of space, ample for the needs of 1600 MW. Shoreham and Shoreham West are conti guous (Figure VIII-5), and can be considered as one.



SHOREHAM SITE AREA - 455 ACRES

SHOREHAM WEST SITE AREA - 425 ACRES

Figure VIII - 5
Shoreham Sites, Town of Brookhaven,
Suffolk County, N.Y.

It has already been established that reconverting Port Jefferson 3 and 4 to coal-firing will require additional precipitators, but no scrubbers, in order to meet all air quality standards. This is in contrast to the Barrett plant, where reconversion would require scrubbers, owing to the nearness of the metropolitan area. It goes without saying, therefore, that Shoreham and Jamesport, since both are further east than Port Jefferson, would also have less stringent air emmission limits. It is probable that cooling towers will be the preferred cooling method in future, and these can cause salt drift, fogging and icing. From this point of view, Jamesport has an advantage over Shoreham, since it is located in an area of sparser population, and fewer homes would be affected.

In the event that the new capacity is coal-fired, a coal storage area of approximately 50 acres would be required. Daily coal consumption would be about 10,000 tons, shipped in by the largest barges. These would require up to 30 feet of water unloading depth, with a dockside length of 500 ft. This depth of water is available about one mile offshore at Shoreham and somewhat less at Jamesport. An offshore unloading terminal would require a pier carrying a conveyor to the shoreside stockpile. Alternatively, a channel of 30 ft. depth would have to be dredged to provide access to a shoreside unloading terminal.

As a power plant site, Shoreham has a number of advantages over Jamesport. First, there is an existing gas turbine installation there, and a nuclear plant is under construction. Additional capacity in this location would therefore probably find readier public acceptance. Second, the sight is wooded, and thus has an excellent buffer against noise and visual impacts. Third, the Jamesport site is located in a prime agricultural area. It is recommended that the Shoreham site be used for all additional generating capacity needed through the year 2000.

11.2 Handling and Storage Facilities for Petroleum Products

Two possible arrangements are described in Section 8.3. Both call for an extension of the existing oil pipeline down the center of the island to link up, by two branches, to the existing bulk storage facility in Northville, and to a new facility at Suffolk County Airport. In addition, two new bulk storage facilities are recommended in the Yaphank-Upton area and at Pilgrim State Hospital.

The two schemes differ, as follows:

a. The first calls for phasing out the onshore unloading terminal in Port Jefferson, and installing an offshore terminal instead off Mount Misery Point. Another offshore terminal would be located off Sands Point, and connect to a bulk storage facility at the head of Hempstead Harbor, to replace all existing shoreside terminals from Manhasset Bay to Huntington Harbor.

b. The second calls for a tunnel from Wading River to New Haven, Connecticut, combined with a mid-Sound unloading terminal with a capacity to supply all the needs of the bi-county area. A pipeline from this tunnel would be run alongside the William Floyd Parkway, and would feed into the pipeline extension referred to previously. The western end of the existing pipeline would then be extended further west to industrial zoned land in the Westbury area, and end in a bulk storage facility that would substitute for the centralized Hempstead Bay installation that the first scheme called for.

None of the pipeline extensions, additional facilities, and alternatives mentioned would have a significant adverse impact on the coastal zone. There would be temporary disruptions during pipeline construction, but good management practices should overcome them.

11.3 Gas Handling and Storage Facilities

The supply of gas to the bi-county region is not expected to change radically, unless a significant quantity of gas is found offshore. The location of gas-related facilities associated with offshore development is treated in Sections 11.5.6, 11.5.8 and 11.5.9.

An increase in gas supply from this, or any source, would require the installation of additional distribution mains, many of them inside the coastal zone. This is not expected to constitute a significant problem.

11.4 Coal Handling and Storage Facilities

It is expected that any such future facilities will be associated with power generating stations. See Section 11.1.

11.5 Onshore Facilities for OCS Development

11.5.1 General

There are six sites in the Nassau-Suffolk area that could accommodate some type of onshore facilities that would be needed for outer continental shelf development. Some could accommodate only one or two types of activities while others could accommodate more. The availability of land, depth of water and surrounding land uses are major limitations.

A site at Fort Pond Bay (Figure VIII-6) in the Montauk area of Suffolk County could accommodate five major activities. They are temporary bases supporting exploratory drilling, platform installation and pipe line installation, a permanent base which requires 50 acres, and a pipe coating yard which would need somewhat more.

At the present time, the land around Fort Pond Bay is partially zoned for industrial purposes and is being used for sand mining, an ocean science laboratory and miscellaneous industrial uses. The sand mining area occupies at least 50 acres and lies between Long Island Railroad and the shore. The three temporary bases could easily be located here, and it is possible to assemble additional land to accommodate the permanent uses. There is over 1,000 acres of land to the west of the site that is not used. Adequate buffering could be built into the site if and when residential development were to occur on the land. Direct access to Montauk Point State Boulevard could be acquired to avoid any additional traffic near the business section of Montauk.

Fort Pond Bay faces roughly north into Block Island Sound, much of which has depths greater than 60 feet. Depths greater than 40 feet are found within 20 yards off the east shore of the bay and within

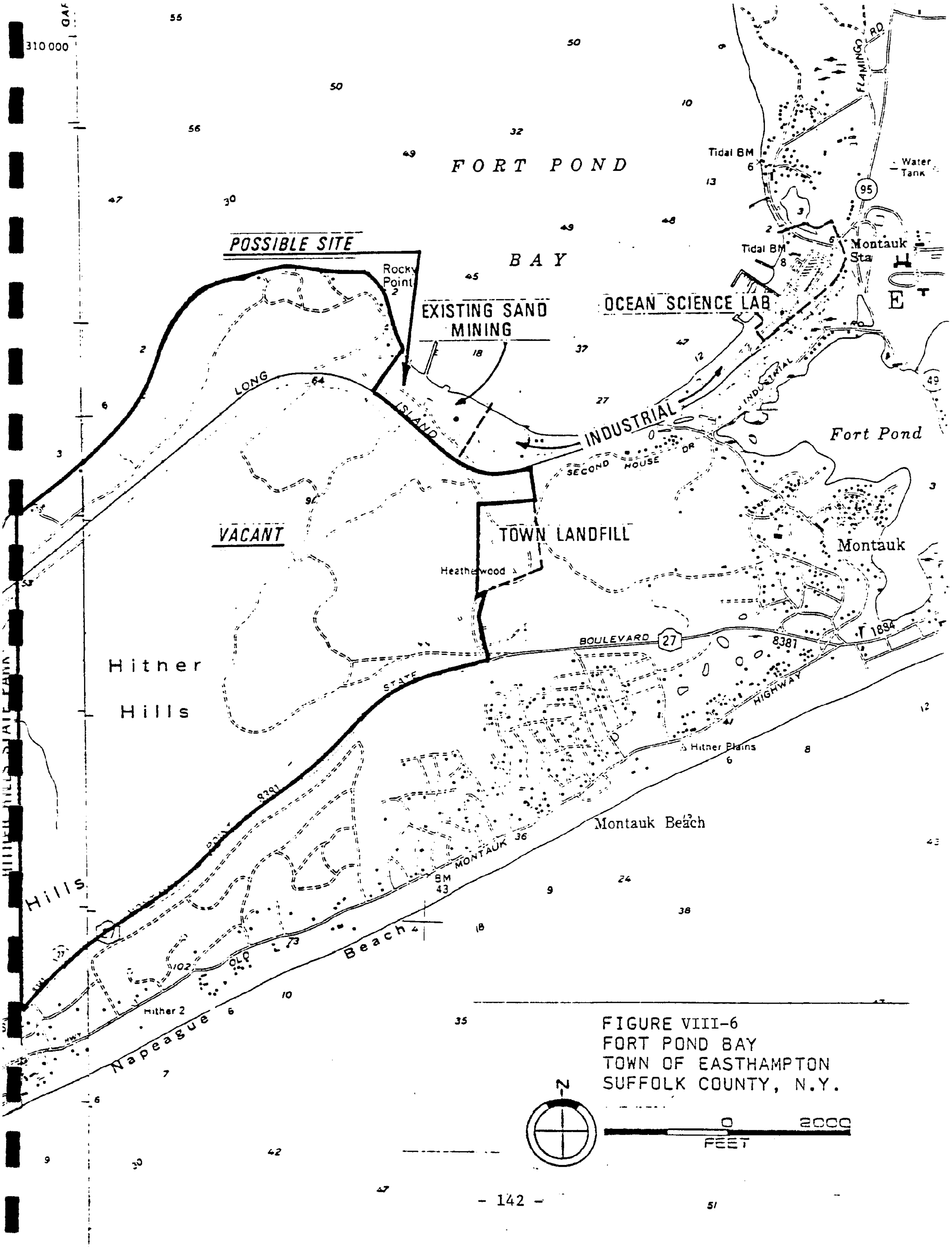


FIGURE VIII-6
FORT POND BAY
TOWN OF EASTHAMPTON
SUFFOLK COUNTY, N.Y.

500 yards off the west and south shores. Ample water depth for service boats and supply barges could be had at dockside for relatively little dredging.

The Village of Greenport (Figure VIII-7) in the Town of Southold, Suffolk County, has two waterfront areas that could accommodate the three temporary uses. Railroad access is a possibility at the southwestern parcel. The drawback of this site is that it is not presently zoned for industrial or commercial use. Unused marine commercial and industrial buildings at the northeastern end of the harbor could be removed or converted to accommodate the uses. Greenport also has boat repair facilities that might accommodate the large boats that would be required for O.C.S. exploration.

The main shipping lane running between Greenport and Shelter Island has a minimum depth of 33 feet, and most of it is deeper than 50 feet. The 20 foot depth contour runs within 220 yards of the southwest site, and within 450 yards of the northeast one. In the boat repair area of the harbor, 20 feet of water is available even closer in. So that, dredging of access channels does not appear to be a problem in this location.

A site on the west side of the harbor in the Village of Port Jefferson (Figure VIII-8) in the Town of Brookhaven, Suffolk County, is usable as a temporary base supporting exploratory drilling. There is an oil terminal site that is being phased out and approximately 5 acres could be obtained in this deep water harbor that has protection from storms and has adequate turning room for large boats. The major drawbacks of Port Jefferson are its distance from the proposed drilling sites and the possible conflict with recreational boating activities in the harbor. However, 35 feet of water depth is already available at

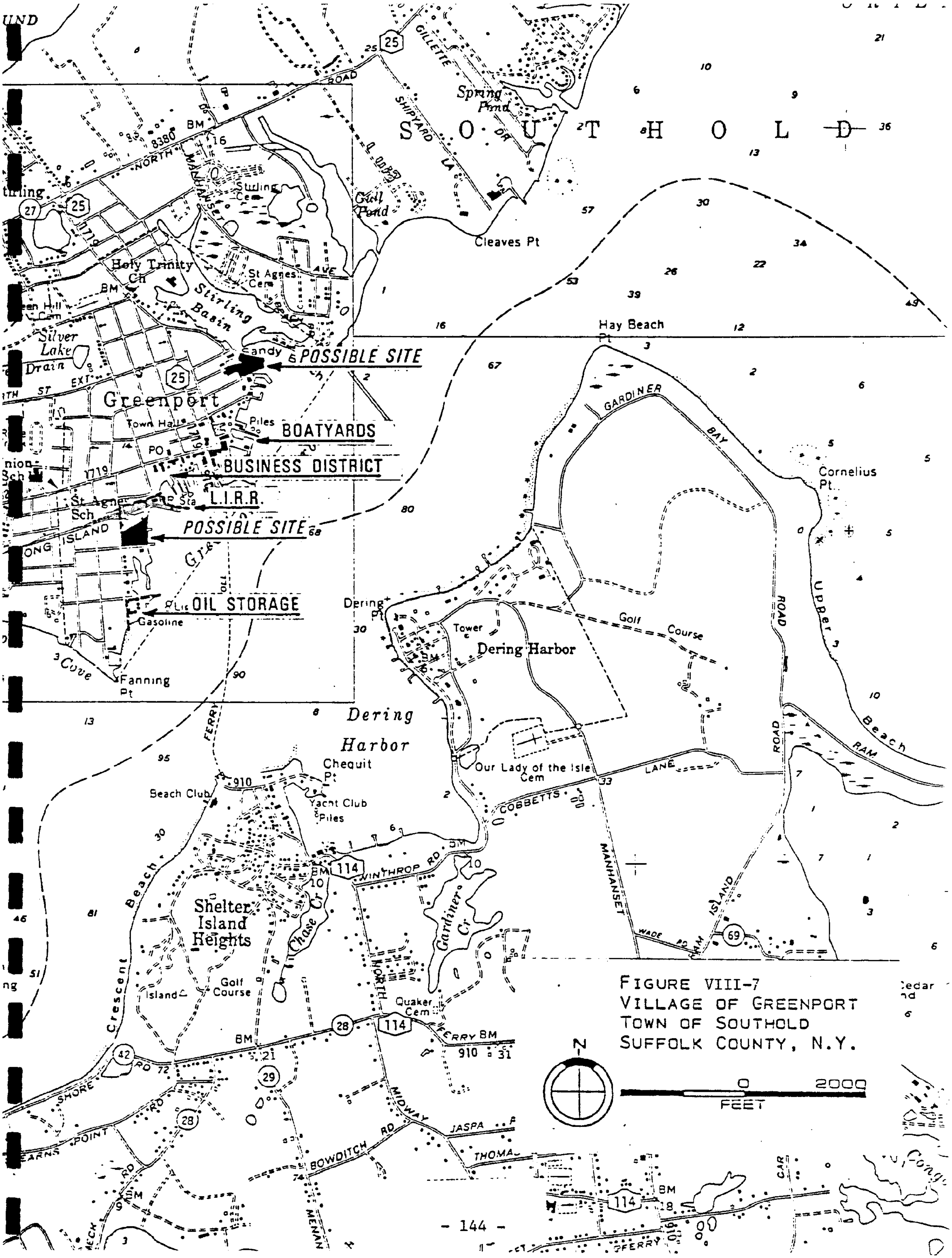


FIGURE VIII-7
VILLAGE OF GREENPORT
TOWN OF SOUTHOLD
SUFFOLK COUNTY, N.Y.

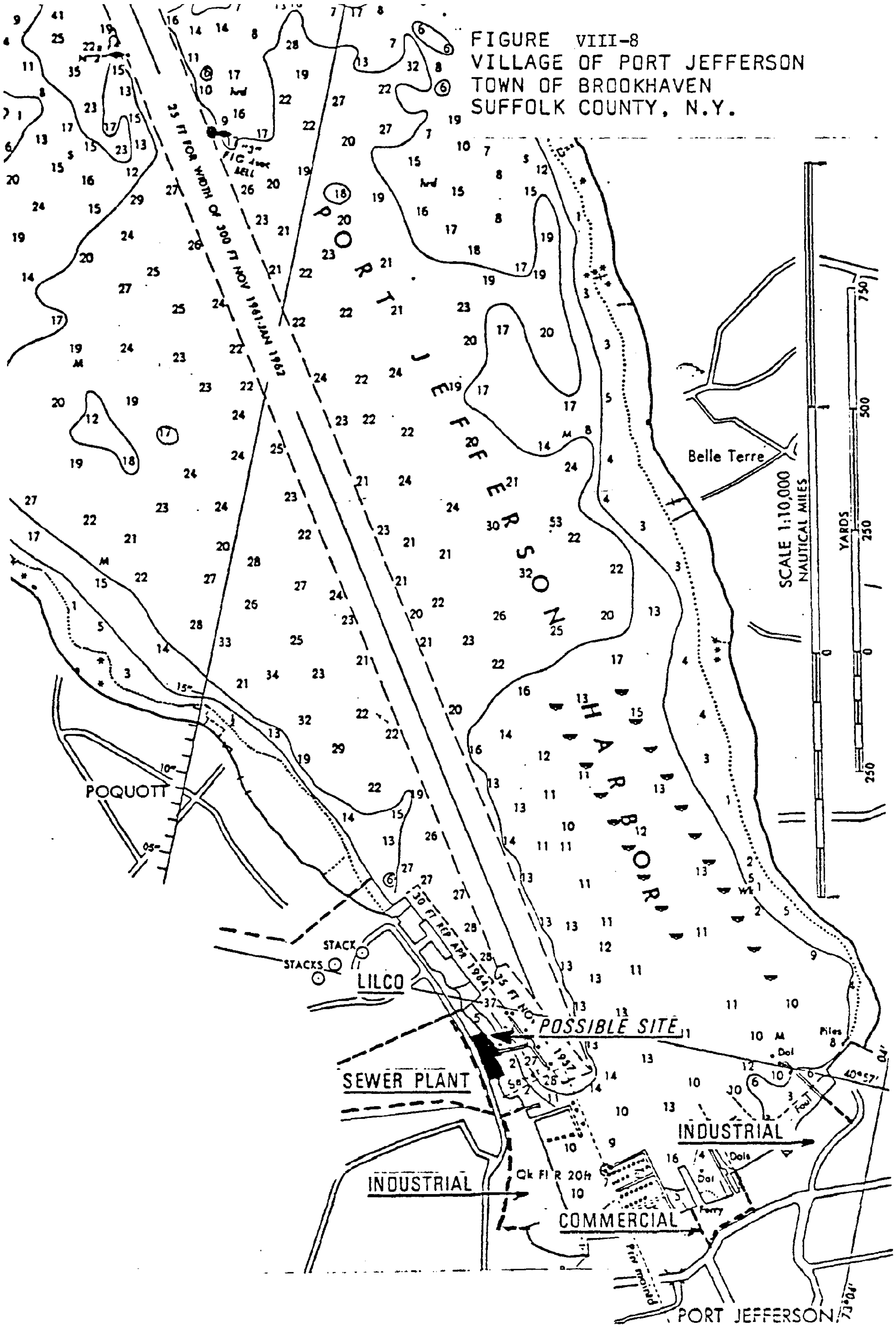


FIGURE VIII-8
VILLAGE OF PORT JEFFERSON
TOWN OF BROOKHAVEN
SUFFOLK COUNTY, N.Y.
PORT JEFFERSON HARBOR
Belle Terre
SCALE 1:10,000
NAUTICAL MILES
YARDS
POQUOTT
STACK
STACKS
LILCO
POSSIBLE SITE
SEWER PLANT
INDUSTRIAL
INDUSTRIAL
COMMERCIAL
PORT JEFFERSON

the existing dock, and a channel 25 feet deep and 300 feet wide extends the full length of the harbor and out into Long Island Sound.

The industrial area in the Village of Freeport (Figure VIII-9) in the Town of Hempstead, Nassau County, could provide a temporary base supporting exploratory drilling. The area could also be used for boat repair since facilities of the type already exist in an area that might have enough depth for large boats. A few of the uses in the industrial area could be phased out in the future so there is an outside possibility of assembling enough land for a permanent base. The village sewer plant, incinerator and public works storage area are the uses that could be replaced by the use of county facilities or could be at a non-waterfront location. The only municipal use that cannot be relocated is the new village power plant.

Sea access is by Jones Inlet, either side of Meadow Island, the Bay of Fundy, the west side of Pettit North, and Freeport Creek, a distance of about 11 miles. Depths along this route are mostly between 10 and 17 feet, with some spots of less than 10 feet. Considerable dredging would be necessary to provide 15 feet minimum throughout. However, the area is highly industrial, and the access that the channel would provide to boat repair yards might make it economical.

A site adjacent to the oil terminals in Oceanside (Figure VIII-10) in the Town of Hempstead, Nassau County, can be used as a temporary base supporting exploratory drilling. A 5 acre site could be assembled by combining the vacant land and abandoned buildings along the channel that leads into East Rockaway. There are two large tracts of industrially zoned land in the Oceanside area that have good highway access and are surrounded almost entirely by non-residential uses. However, they do not

FIGURE VIII-9
VILLAGE OF FREEPORT
TOWN OF HEMPSTEAD
NASSAU COUNTY, N.Y.

- 147 -

FIGURE VIII-10
OCEANSIDE SITE
TOWN OF HEMPSTEAD
NASSAU COUNTY, N.Y.

have direct access to major channels since they are blocked by low bridges on the Long Island Railroad and Long Beach Road.

Sea access is by East Rockaway Inlet, Reynolds Channel, and Hog Island Channel, a total distance of about 16 miles. Most of the route is deeper than 20 feet, in places considerably deeper. However, there are some stretches shallower than 20 feet, and a few places as shallow as 11 or 12 feet. Dredging would probably not be a serious problem if the site itself was considered advantageous, and the distance to the ocean was not a drawback.

A site in the Yaphank-Shirley area (Figure VIII-11) in the Town of Brookhaven, Suffolk County, appears to be the best possibility for locating a gas treatment plant. At the present time, there are two large sites east and west of William Floyd Parway that are between the Long Island Railroad main line and the Long Island Expressway. The westerly site has 118 acres and the easterly site 215 acres. There is an office building on William Floyd Parkway and model homes which are temporarily occupying part of the land, along with an access road for a proposed industrial park on the 215 acre site. The interior of this parcel could accommodate a gas treatment plant on approximately 100 acres. Non-residential uses such as the Brookhaven Laboratory, a race track, and a proposed shopping center, are on the other side of the expressway. Vehicular access to this site is as good as any location on Long Island. In addition, a connection could be made to the gas pipe line system that could serve all parts of Long Island.

In order to connect a pipe line from this site to a site on the continental shelf, a direct line to the south would be necessary. This is possible if the median strip of county-owned William Floyd Parkway is used. The road extends past this site almost to the

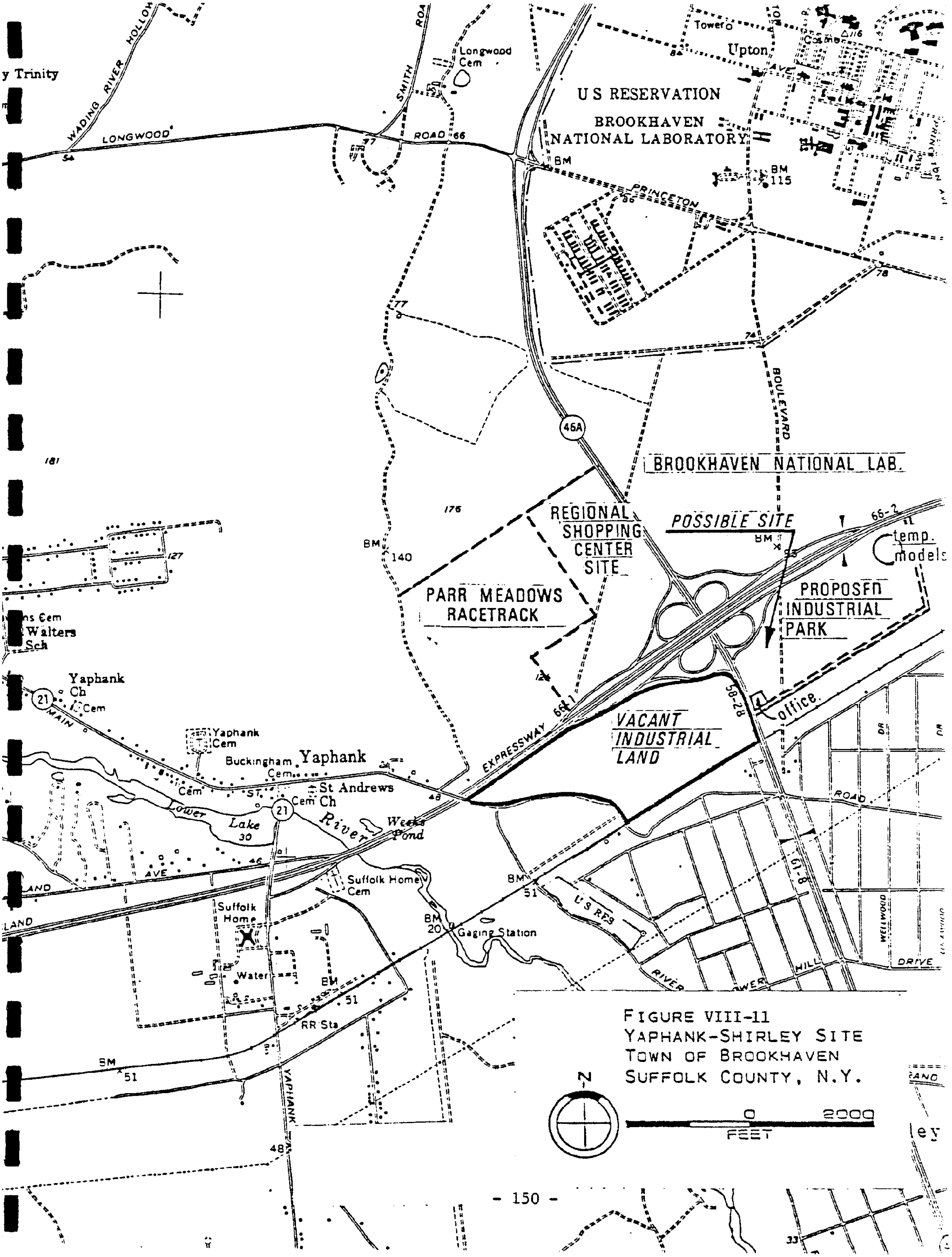


FIGURE VIII-11
YAPHANK-SHIRLEY SITE
TOWN OF BROOKHAVEN
SUFFOLK COUNTY, N.Y.

N
0 2000
FEET

Atlantic Ocean (Figure VIII-12). At the ocean is a parking area that is part of the Smith Point County Park and it would be possible to place a line underneath the parking lot. There are bridges over the Long Island Railroad main line, Sunrise Highway, and Narrow Bay (between the Park and Fire Island). In addition, there is a proposed additional railroad bridge over the Montauk branch. The pipe line could be carried on the bridges or tunneled underneath the roadways and railroad crossings.

The ocean bottom at this point slopes 30 feet in about 1000 yards, the beach itself is gently sloping and the dunes are minimal.

Each type of onshore facility, and its possible locations in Nassau-Suffolk, if any, is discussed below, in further detail.

11.5.2 Temporary Base Supporting Exploratory Drilling

Possible sites can be identified at the following five locations:

Fort Pond Bay	(Figure VIII-6)
Greenport	(Figure VIII-7)
Port Jefferson	(Figure VIII-8)
Freeport	(Figure VIII-9)
Oceanside	(Figure VIII-10)

The sand mine at Fort Pond Bay is still in operation. However, much of it has been mined out, and land could probably be made readily available for a base to service several rigs. In the Village of Greenport, the two possible sites are each only big enough to service one, or possibly two rigs. There would be delays for securing permits, and clearing existing structures. In addition, it might be difficult to provide the length of dockside needed. Port Jefferson offers the potential for a one or two rig service base, with an existing dock and no water depth restrictions. However, their distances from open water, and the need for substantial channel dredging are problems.

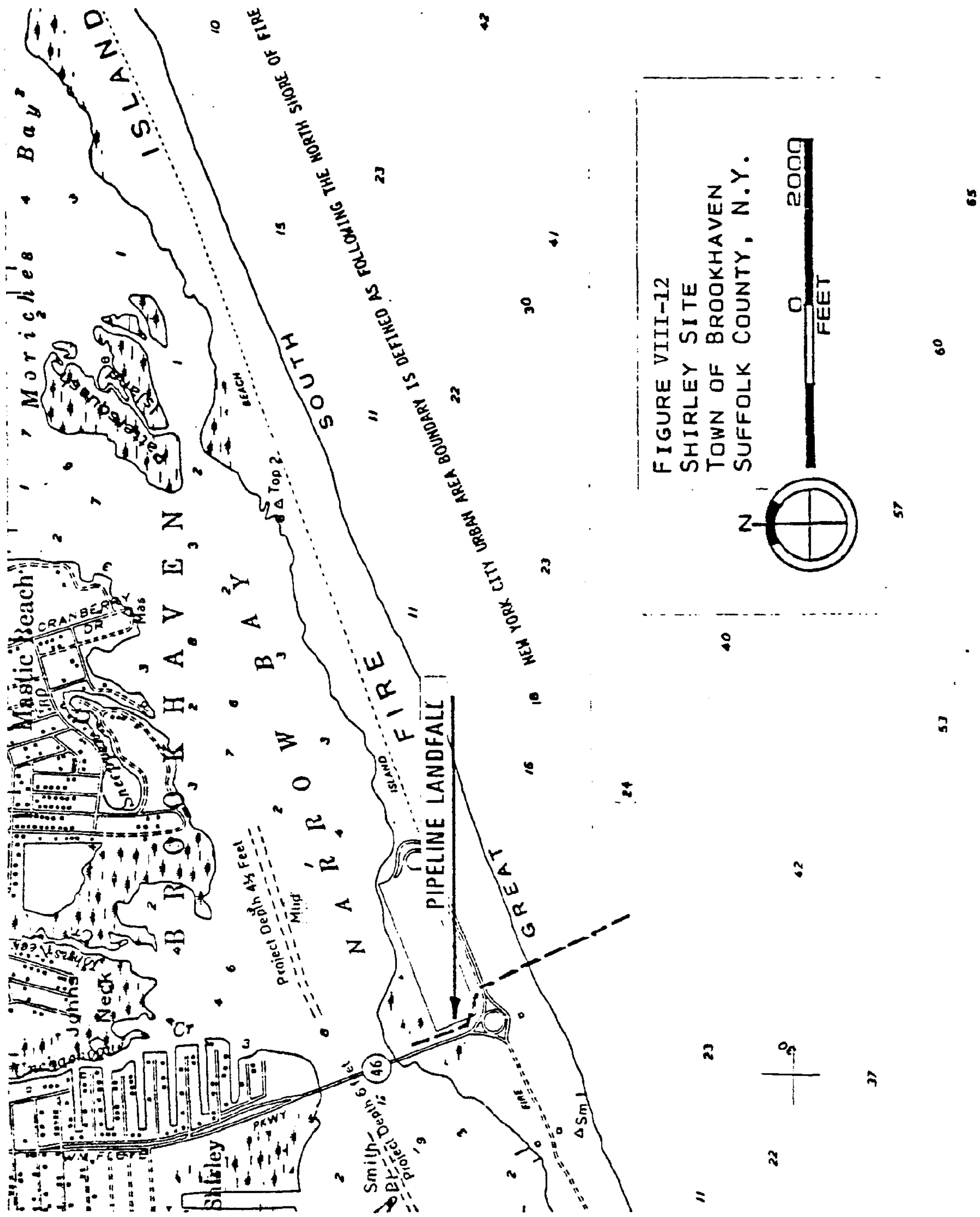


FIGURE VIII-12
SHIRLEY SITE
TOWN OF BROOKHAVEN
SUFFOLK COUNTY, N.Y.

In view of the timing discussed in Section 9.5, the likeliest candidate is Fort Pond Bay.

Freshwater and electricity will have to be supplied locally. The quantity of electricity is difficult to estimate. It would be required only for the normal housekeeping needs of the base, a relatively small amount. However, the water is required for the offshore drilling, and amounts to 4,740,000 gallons per year of non-potable and 460,000 gallons per year of potable water per rig. This would be for drilling four wells, each 15,000 feet deep, per year. Oil fuel and operating materials will be brought in from elsewhere, by rail and truck.

11.5.3 Temporary Base Supporting Platform Installation

The following two sites are possible:

Fort Pond Bay	(Figure VIII-6)
Greenport	(Figure VIII-7)

These are the only sites which provide sufficient open water for maneuvering the large vessels that are employed in platform installation. As mentioned previously, the Greenport sites might not be able to accommodate the necessary length of dockside, although this is no problem at Fort Pond Bay. In any event, bases for platform installation would not be needed until the 5th year after the lease sale, and there would be time to construct the necessary wharfage.

Greenport might present a further complication, because of the possible interference of the additional vessel traffic with regular harbor operations, especially if concrete platforms are involved. This would present no problem at Fort Pond Bay.

Water and electricity will be required, but only in normal base housekeeping amounts.

11.5.4 Temporary Base Supporting Pipeline Laying

The same two locations, Fort Pond Bay and Greenport, could possibly serve for pipeline laying support. Similar reservations can be stated as for platform installation, except that the additional boat traffic would probably not be as heavy as for (concrete) platform installation, and the pipeline base would not be needed until about 7 years after the lease sale.

11.5.5 Permanent Base

The only definite candidate for the location of a service base is Fort Pond Bay (Figure VIII-6), in view of the sand mine acreage available, and the possibility that operations could be phased out in the 3 years after the lease sale. Water depth and sea access are little or no problem. Another possibility is Freeport (Figure VIII-9), if a sufficiently large parcel of land can be accumulated.

As mentioned previously, the Freeport site suffers from its distance from the ocean, and the need to dredge the channel. However, road and rail access into this industrial area is very good. On the other hand, the Fort Pond Bay site could very well be supplied by sea.

Power requirements are for housekeeping purposes only. Freshwater would have to be supplied to the offshore platform(s) in the following amounts:

a. For each platform engaged in development drilling (i.e., approximately from the 6th to the 13th year after the lease sale), having 2 rigs, and drilling 8 wells per year, each 15,000 feet deep.

Non-potable	7,740,000 gal./yr.
Potable	460,000 gal./yr.

b. Production (6th to 31st year after lease sale) - housekeeping requirement only, i.e. about 100 gallons per capita day.

c. Workover (14th to 29th year after lease sale) - 520,000 gallons total for each well worked over.

11.5.6 Pipeline Landfall

Both oil and gas could be pipelined ashore. In the case of oil, there appears to be little justification for bringing a pipeline ashore to Nassau-Suffolk. Such a pipeline would either be run overland to a refinery, or connected to a marine terminal. For reasons presented later, neither of these is a likely possibility. On the other hand, gas is in short supply on Long Island, and a gas pipeline might be justified.

The location of the landfall must be determined by the location of the gas treatment plant it would be connected to. This consideration leads to a landfall site on the Fire Island shore at Smith Point Park, Shirley (Figure VIII-12). As mentioned previously, the local topography is highly favorable, and, if experience elsewhere is repeated here, it should be possible to restore the excavated area to its pristine appearance. The pipeline itself requires minimal maintenance.

11.5.7 Marine Terminal

A marine terminal would be employed either to receive oil from the offshore field by tanker and deliver it by overland pipeline to a refinery, or to receive oil by pipeline, store it, and load it into tankers for shipment elsewhere.

In neither case is a Long Island location reasonable. For one thing, there is no refinery here, nor is there likely to be one (see below). For another, there are existing oil unloading and storage facilitiies in nearby north New Jersey, and an entirely new facility in the area is highly unlikely to receive acceptance.

From the point of view of supplying Nassau-Suffolk with oil products, apart altogether from OCS oil development, refer to Section 11.2.

11.5.8 <u>Partial Processing Plant</u>

The judgment has already been made (Section 11.5.6) that an oil pipeline to Nassau-Suffolk is unlikely to materialize, and consequently, a partial processing plant to treat oil is equally unlikely to be located on shore.

A gas pipeline to shore is much more likely, and, in this case, partial processing is much less complex, and would probably be carried out on the platform. If located on shore, the plant would be integrated into the gas treatment plant.

11.5.9 <u>Gas Treatment Plant</u>

The Yaphank industrial zoned area (Figure VIII-11) appears to be the best location for this facility. Land is available in sufficient amount, in an area set aside for an industrial park. Of the 75 acres estimated to be required for a plant sized to handle 1 billion cubic feet per day, only 20 acres are occupied by processing equipment. The rest, which includes open storage and parking, acts as a buffer around the plant proper.

In addition, the adjacent William Floyd Parkway provides a convenient pipeline route from a good landfall site at Shirley.

However, power and water requirements will be substantial. Power consumption for a plant of this size is 5,400,000 kwh per month, equivalent to an average connected load of 7,500 kw, for 24 hours a day, 30 days a month. Water consumption is 200,000 gpd.

The purified natural gas product from this plant could be fed by overland pipeline into LILCO's distribution facilities, suitably expanded to serve more customers. However, if the plant capacity were larger than local needs, it might warrant running a pipeline back down to the south shore landfall, and continuing it by a submarine pipeline to connect into the New Jersey pipeline off Long Beach. Once installed, and with proper management, such a pipeline system should have no significant adverse impacts.

11.5.10 Oil Refinery

For a capacity of 250,000 bbl/day, an oil refinery would occupy about 1,000 acres. Smaller capacities would still be economical to build (some quite new units are as small as 50,000 bbl/day in capacity), but the savings in acreage would not be commensurate. In addition, the environmental impacts, both in construction and in operation, will be considerable. There is not a large enough piece of land available in the industrially zoned areas of Nassau-Suffolk, and it is highly unlikely that permission would be given for a refinery to be built in a non-industrial area.

11.5.11 Petrochemical Plant

If the flow rate and composition of the crude gas justified the construction of a petrochemical plant, it would be located immediately adjacent to the gas treatment plant. A petrochemical plant is said (49) to require 200 to 350 acres. It is feasible that the gas treatment plant could be combined with it, for no increase in land area. However, this amount of land is not available at the Yaphank site in one piece. Furthermore, the water supply demand of 6.5 million gallons a day (see Section 9.5.10) is too heavy a load to apply to the ground water, and too detrimental environmentally for once-through cooling at an alternative waterfront site. Consequently, a petrochemical plant is not likely to be located on Long Island.

The gases and liquids separated out in the gas treatment plant would have to be shipped elsewhere for further processing. This would require compression and liquifaction facilities to be attached to the gas treatment plant, and the hazardous nature of these operations would be a further constraint on siting even the gas treatment plant here. (However, it should be pointed out that LILCO has operated an LNG plant in Holbrook safely for some time).

11.5.12 Platform Fabrication Yard

There is no waterfront location at which the more than 400 acres are required for steel platform fabrication could be found. Concrete platforms could possibly be built at the Fort Pond Bay site. However, fairly deep water (35 feet minimum) would be required, not in a single channel, but on a fairly wide frontage (200 feet). This would be for building one concerete platform at a time. Two platforms would require deep water on 400 feet frontage, and so on.

It appears infeasible to build platforms in this area.

11.5.13 Pipecoating Yard

So-called "permanent" yards require 100 acres, minimum, whereas "portable" yards occupy only 30 acres. The difference, presumably, is whether the yard is set up for constructing pipelines for just one offshore field, or whether it is conveniently located to serve a wider region.

The Fort Pond Bay site (Figure VIII-6) could accommodate a "portable" yard comfortably, but a "permanent" yard would be a tight squeeze. The water depth and frontage requirements, however, are readily available.

Water and energy requirements would be fairly modest. For a yard coating 300-350 miles of pipe per year, 1 million kwh and 12-13 million cubic feet of natural gas would be consumed per year. Water would be consumed at the rate of 15,000 gpd, which includes 3,800 gpd for mixing concrete and cooling the pipe in the coating process.

11.5.4.14 Miscellaneous Facilities

Boat repair and maintenance facilities exist in Greenport and Freeport (Figures VIII-7 and 9). Water depth is adequate in Greenport with the minimum of dredging, but large sections of the channel to the Freeport location would need to be deepened.

Facilities of this type exist in several of the small harbors in Great South Bay. However, the amount of dredging that would be required to provide 15 to 20 feet of water up to any one of them is prohibitive.

It is considered unlikely that entirely new facilities of this type would be built to meet the demands of offshore development. What is more likely is that existing yards would expand their activities in response to demand. Water, power, and supplies of all kinds will be required, but, at this time, it is not possible to estimate the quantities.

The category of district office is included here, because the literature refers to it. However, with Nassau-Suffolk being so close to New York City, it appears unlikely that an oil company would set up a branch office here. In any event, office space is fairly readily available in the bi-county region.

13.0 Coordination

In addition to a review of the literature listed in the attached Bibliography, the following individuals were contacted for information of a specific and local nature, as noted:

A. Projections of regional and local energy demands, and the analysis of the distributions of these demands between the various fuels.

Dr. Kenneth Hoffmann, Director

Dr. T. Gwen Carroll, Consultant

Dr. Philip F. Palmedo, Head, Energy Policy Analysis Division

Dr. Peter Meier, Manager Regional Studies Program

Mr. Robert Stern, Staff Analyst

all of:

The National Center for Analysis of Energy Systems, Brookhaven National Laboratory, Upton, N. Y. 11973

B. Discussion of the forecasting methods employed by the Long Island Lighting Company (LILCO) in the 1977 issue of the "Report of Member Electric Systems of the New YOrk Power Pool", made pursuant to Article VIII, Section 149-b, of the Public Service Law.

Mr. George Fitzpatrick, Manager

Forecasting Division, LILCO

250 Old Country Road

Mineola, N. Y. 11501

C. Information on the possible re-converstion of certain LILCO power stations to coal-firing.

Mr. Frank Vitale

Generation Section Superintendent

Planning Department, LILCO

175 Old Country Road

Hicksville, N. Y. 11801

E. Information on the size and draft of coal barges.

Mr. Russell McVey

Moran Towing Corp.

1 World Trade Center

New York, N. Y. 10004

F. Information on the current inventory of oil handling facilities in Nassau and Suffolk Counties.

1. Nassau County

   Mr. David Bartow

   Fire Inspector, Commercial and Industrial Division

   Nassau County Fire Marshall's Office

   1 Old Country Road

   Carle Place, N. Y. 11514

2. Suffolk County

   a. Mr. Gilbert W. Hanse

      Senior Fire Inspector, Town of Babylon

      Town Hall

      200 East Sunrise Highway

      North Lindenhurst, N. Y. 11757

   b. Mr. Herbert Davis

      Chief Fire Inspector, Town of Brookhaven

      Town Hall

      205 South Ocean Avenue

      Patchogue, N. Y. 11772

   c. Mr. Joseph T. McDonald, Jr.

      Principal Building Inspector, Town of Huntington

      Department of Engineering, Building and Housing

      191 New York Avenue

      Huntington, N. Y. 11743

d. Mr. Thomas Marquardt
   Planner, Town of Islip
   Town Hall
   655 Main Street
   Islip, N. Y. 11751

e. Mr. John Toomey
   Senior Fire Inspector, Town of Smithtown
   Town Hall
   99 West Main Street
   Smithtown, N. Y. 11787

f. Mr. Kenneth H. Jones
   Chief Fire Inspector, Town of Southampton
   Department of Fire Prevention
   Jackson Avenue
   Hampton Bays, N. Y. 11946

g. Mr. George Fisher
   Building Inspector, Town of Southold
   Town Hall
   Main Road
   Southold, N. Y. 11971

h. Mr. Joseph Cherepowich
   Planning Coordinator, Village of Greenport
   Village Hall
   236 Third Street
   Greenport, N. Y. 11944

3. Private Individuals

a. Mr. Earl Espeland

Manager of Terminals

Northville Industries Corporation

South Shore Road

Riverhead, N. Y. 11901

b. Mr. George Burne

Vice President

Oil Heat Institute of Long Island

132 West Cherry Street

Hicksville, N. Y. 11801

B I B L I O G R A P H Y

1. Federal Register, Vo. 42, No. 83 - Friday, April 29, 1977. 15CFR 920.19

2. Koebel, Charles T., & Donald A. Koneskeberg, 1975. Demographic Pattersn. MESA New York Bright Atlas Monograph 23.

3. Carroll, T. Gwen, Philip F. Palmedo and Robert Stern, 1976. The future Demand for Electricity in the Nassau-Suffolk Region. National Cneter for Analysis of Energy Systems, Brookhaven National Laboratory, Upton, N. Y. 11973. Inst. for Energy Research, SUNY at Stony Brook, Stony Brook, N. Y. 11794.

4. LILCO Population Survey 1976. Current Population Estimates for Nassau and Suffolk Counties.

5. New York Power Pool. Report of Member Electric Systems of the NYPP and the Empire State Elec. Energy Research Corp. Pursuant to Article VIII, Section 149-b of the Public Service Law. April 1, 1977.

6. LILCO Population Survey 1977. Current Population Estimates for Nassau and Suffolk Counties.

7. Nassau-Suffolk Regional Planning Board, 1976 Population Estimates and Projections, 1975 to 1995. Interim Report Series: 1. November 1976. Prepared for 208 study.

8. Kunz, Arthur H., Nassau-Suffolk Regional Planning Board, Private communication, May 1977.

9. Beller, M., ed. 1975. Sourcebook for Energy Assessment. Dec. 1975. National Center for Analysis of Energy Systems. Under Contract No. E(30-1)-16 with USERDA. BNL 50483.

10. Carroll, Palmedo, et. al. 1975. Current & Future Energy Use in the Nassau-Suffolk Region. Phase I Report for "LILCO" study.

11. John Lee, 1976. Future Residential & Commercial Energy Demand in the Northeast. BNL 50552. BNL Energy Perspectives Study.

12. Naresh Bhagert and Mike Jones. 1974. Simulation of Residential Energy Use and its Dependence on Land Use & Economic Parameters. Presented at mtg. of ORSA/Inst. of Mgmt. Sci. Puerto Rico, Oct. 16-18, 1974. Work sponsored by NSF/RANN Program.

13. Carroll, T. Gwen, Robert Nathans, P.F. Palmedo, R. Stern. The Planner's Energy Handbook. A User's Manual for Exploring Land Use and Energy Utilization Relationships. BNL/SUNY Project on Land Use and Energy Utilization. Sponsored by the Office of Conservation and Environment of the F.E.A.

14. John Lee, 1975. Energy Supply & Demand in the Northeast United States, Sept. 1975. BNL 20427. Energy Policy Analysis Group, Dept. of Appl. Sci., Brookhaven Nat'l. Lab., Upton, N. Y. 11973. Prepared for USERDA.

15. Office of Energy Systems. 1976. State Projections of Industrial Fuel Needs. Federal Power Comm.

16. McFarland, Senator James T., 1976. An Overview of the New York State Energy Picture, Aug. 1, 1976. Legislative Commission on Energy Systems.

17. Hausgaard, Glaf. 1976. An Energy Almanac. New York State: 1960-1980. Prepared for Public Service Comm. by Office of Research. OR. A-3.

18. Brainard, Joel, et. al. 1976. A Perspective on the Energy Future of the Northeast United States, June 1976. BNL 50550. Policy Analysis Division, Nat'l. Center for Analysis of Energy Systems, Brookhaven Nat'l. Lab., Upton, N. Y. 11973. Prepd. for USERDA.

19. Richard J. Goettle, IV. 1976. Alternative Patterns of Industrial Energy Consumption in the Northeast. March 1976. BNL 50555. Policy Analysis of Energy Systems, Brookhaven, Nt'l. Lab., Upton, N. Y. 11973. Prepared for USERDA.

20. Tri-State Regional Planning Commission. 1977. Interim Technical Report - Historical Trends in Electric Energy & Fossil Fuels - 1975.

21. Executive Office of the President, The National Energy Plan, April 1977.

22. NSF/NASA Solar Energy Panel. 1972. Solar Energy as a National Energy Resource. December 1972.

23. Williams, Clarke. 1973. The Wind as an Energy Resource. Unpublished report. Large bibliog.

24. Report of the Ad Hoc Comm. on Energy Efficiency in Large Buildings. March 7, 1973. Interdepartmental Fuel & Energy Committee of the State of New York.

25. Report of Ad Hoc Committee on Energy Efficiency in Transportation. Oct. 31, 1973. Interdepartmental Fuel & Energy Committee of The State of New York.

26. CAC on Env. Qual. 1973. Citizen Action Guide to Energy Conservation.

27. Davis, City of, Calif. 1974. A Strategy for Energy Conservation. Proposed Energy Conservation and Solar Utilization Ordinance.

28. Regional Marine Resources Council. 1976. Proceedings of the Seminar on Energy Alternatives for Long Island. May 13, 1974. Hauppauge, N. Y.

29. Dubin-Mindell-Bloome Associates, P.C. 1975. A Study of Existing Energy Usage on Long Island and the Impact of Energy Conservation, Solar Energy, Total Energy, and Wind Systems on Future Requirements. Prep'd. for SCDEC, Oct. 31, 1975.

30. Monroe, James. 1975. Establishing an Energy Policy for New York State - 1975. A Report to the New York State Legislative Commission on Energy Policy.

31. The Science and Public Policy Program, U. of Oklahoma, Norman, Oklahoma, 1975. Energy Alternatives: A Comparative Analysis. Prep'd for CEQ/ERDA/EPA/FEA/FPC/DOI/NSF.

32. Daronstadter, Joel. 1975. Conserving Energy. Prospects & Opportunities in the New York Region. A Resources for the Future Book.

33. FEA, 1976. Buying Solar, FEA/G-76/154.

34. Division of Solar Energy, ERDA. 1976. Ocean Thermal Energy Conversion (OTEC), Program Summary, Oct. 1976.

35. Levins, Amory B. 1976. Energy Strategy: The Road Not Taken? Forein Affairs, October, 1976, pp. 65-96.

36. Suffolk County. 1976. Conference on Energy Conservation & Development. 9/16/76, Colonie Hill, Hauppauge, N. Y.

37. C.E.Q. 1976. Env. & Conserv. in Energy R & D.

38. Meier, P.M., and T.H. McCoy. 1976. Solid Waste as an Energy Source for the Northeast, June 1976. BNL 50559. Policy Analysis Div., Nat'l. Center for Analysis of Energy Systems, Brookhaven Nat'l. Lab., Upton, N. Y. 11973. Prep'd. for USERDA.

39. Baldwin, Pamela L., and Malcolm F. Baldwin. 1975. Onshore planning for offshore oil: lessons from Scotland. The Conservation Foundation, Washington, D. C. 183 pp.

40. Chaudhari, Dev. R. 1973. Analysis of the coastal tank vessel and barge traffic: design and development of system alternatives to identify and locate in ballast tank vessels and barges. U. S. Department of Transportation, Coast Guard, Report DOT-CG-23560-A. Washington D. C. 301 pp.

41. Continental Oil Company. 1976. Offshore oil development on the Georges Bank; symposium on the economics and logistics of offshore oil development. Sebasco Lodge, Phippsburg, Maine, July 1, 1976. Stamford, Conn. 185 pp.

42. Cronin, L. Eugene, and Robert E. Smith, Co-chairmen. 1975. Marine environmental implications of offshore oil and gas development in the Baltimore Canyon region of the Mid-Atlantic coast; proceedings of Estuarine Research Federation OUter Continental Shelf Conference and Workshop, December 2, 3, 4, 1974, University of Maryland, College Park, Md. Estuarine Research Federation, Report ERF 75-1, Wachapreague, Virginia. 504 pp.

43. Field, Barry C. 1976. Secondary Impacts of Coastal Facilities. Tech Update 10, New England River Basins Commission, Boston, Mass. 28 pp.

44. Haan, James. 1976 Comments on the NERBC-RALI "Factbook", Service Base and Repair and Maintenance Yards chapters. Tech Update 8, New England River Basins Commission, Boston, Mass. 11 pp.

45. Jones, J. R., W. W. Doyel, and P. A. Marcus. 1975. Development and Application of a Methodology for Siting Onshore Facilities Associated with Outer Continental Shelf Petroleum Development, U. S. Geological Survey Open File Report 76-78.

46. Lai, N. W., S. J. Campbell, R. F. Dominguez and W. A. Dunlap. 1973. A bibliography of offshore pipeline literature. Texas A & M University, College Station, Texas. 127 pp.

47. National Research Council. 1974. Issues in the assessment of environmental impacts of oil and gas production on the outer continental shelf; a critique of "OCS oil and gas--an environmental assessment", a report to the President prepared by the Council on Environmental Quality. National Academy of Sciences, Washington, D. C. 43 pp.

48. New England River Basins Commission. 1976. Estimates for New England; onshore facilities related to offshore oil and gas development, staff draft. NERBC-RALI Project. Boston, Mass. Loose-leaf publ n.p.

49. New England River Basins Commission. 1976. Factbook: onshore facilities related to offshore oil and gas development, staff draft. NERBC-RALI Project. Boston, Mass. Loose-leaf pub. n.p.

50. New York and New Jersey, Port Authority of. 1976. Service Base Criteria. One World Trade Center, New York, N. Y. 10048.

51. Resource Planning Associates, Inc. 1975. Identification and Analysis of Mid-Atlantic Onshore OCS Impacts, prepared for Middle Atlantic Governors' Coastal Resources Council, Delarware State Planning Office, Dover, Delaware.

52. United States Congress Office of Technology Assessment. 1976. Coastal Effects of Offshore Energy Systems. Washington, D. C. Vols. I and II, 288 and 903 pp.

53. U. S. Department of Commerce, Office of Coastal Zone Management. 1975. Coastal Management Aspects of OCS - Oil and Gas Developments. U. S. Government Printing Office, Washington, D. C. 73 pp.

54. U. S. Department of the Interior, Bureau of Land Management. 1976. Final environmental statement; proposed 1976 Outer Continental Shelf Oil and Gas Lease Sale Offshore the Mid-Atlantic States, OCS sale No. 40. U. S. Government Printing Office, Washington, D. C. 4 Vols.

55. U. S. Department of the Interior, Bureau of Land Management. 1976. Draft Environmental Statement: Proposed 1977 Outer Continental Shelf Oil and Gas Lease Sale Offshore the North Atlantic States, OCS Sale No. 42, U. S. Government Printing Office, Washington, D. C. 4 Vols.

56. U. S. Department of Transportation, U. S. Coast Guard. 1976. Implications of the U. S. Coast Guard Segregated Ballast Retrofit Ruling on Import Alternatives and Pollution of the Marine Environment, Final Report. Office of Research and Development, Washington, D. C. 20590

57. U. S. Environmental Protection Agency. 1977. Public Notices for Pollutant Discharge Permits for Exploratory Drilling in the Baltimore Canyon Trough:

No. NPDES 77-19	Houston Oil and Minerals Corporation
No. NPDES 77-30	Shell Oil Company
No. NPDES 77-38	Union Oil Company of California
No. NPDES 77-39	Mobile Oil Corporation
No. NPDES 77-49	Gulf Oil Corporation
No. NPDES 77-50	Exxon Corporation

58. Woodward-Clyde Consultants, 1975. API Mid-Atlantic Regional Study, American Petroleum Institute, 1801 K Street, N. W., Washington, D. C. 20006.

59. Nassau-Suffolk Regional Planning Board, A Comprehensive Dredging Subplan for Nassau and Suffolk Counties, July 1977.

60. Nassau-Suffolk Regional Planning Board, Nassau-Suffolk Comprehensive Development Plan Summary, July 1970.

61. Parsons, Brincherhof, Quade and Douglas, Inc., "Berths Offshore with Access Tunnel System (BOATS)".

62. Committee on Power Plant Siting, Nat. Acad. of Eng. 1972. Engineering for Resolution of the Energy Environment Dilemna.

63. Grumman Ecosystems Corp. 1973. Base Load Electric Generating Facility. Site Reconnaissance Study for LILCO. Sept. 1973.

64. NYS Public Service Commission. 1974. Generating Station Site Survey. Draft Report on the Hudson River Valley/Long Island Pilot Area Site Survey. July 1, 1974.

65. New York Power Pool. 1976. Statewide Site Selection Guide. Nov. 1976.

66. Great Lakes Basin Commission, Energy Facility Siting in the Great Lakes Coastal Zone: Analysis and Policy Options, January 14, 1977.

67. (U.S.) C.E.Q. 1973. Energy and the Environment - Electric Power.

68. Clark, John, and Willard Brownell, 1973. Electric Power Plants in the Coastal Zone: Environmental Issues. American Littoral Society Special Publication No. 7 October 1973.

69. New York Regional Office, F.P.C., 1974. Power and the Environment. A Planning Report for the NERBC.

70. USEPA, 1976. Proceedings of Nat'l. Conf. on Health, Environmental Effects and Control Technologies of Energy Use. Feb. 9-11, 1976, Sheraton Park Hotel, Washington, D. C. Sponsored by the Office of Energy, Minerals and Industry, within the Office of R & D of the USEPA.

71. State of Illinois, Power Facility Siting in the State of Illinois. Part II - Environmental Impacts of Large Energy Conversion Systems.

72. A.D. Little, Inc., The Potential for Energy Conservation in the Residential and Commercial Sectors, July 1974.