DOE/EV-0075

27
5/9/80
24 NTIS

MASTER

ENVIRONMENTAL DATA ENERGY TECHNOLOGY CHARACTERIZATIONS

Petroleum

U.S. Department of Energy

Assistant Secretary for Environment
Office of Technology Impacts

April 1980

DOE/EV-0075

ENVIRONMENTAL DATA
ENERGY TECHNOLOGY CHARACTERIZATIONS

Petroleum

U.S. Department of Energy

Assistant Secretary for Environment
Office of Technology Impacts
Washington, DC 20545

Program Manager: Nevaire M. Serrajian

April 1980

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

Available from:

National Technical Information Service (NTIS)
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161

Price: **Printed Copy:** $ 6.00
Microfiche: $ 3.00

OVERVIEW

Environmental Data Energy Technology Characterizations are publications which are intended to provide policy analysts and technical analysts with basic environmental data associated with key energy technologies. The first publication, Summary, provides information in tabular form on the eight technology areas examined; subsequent publications provide more detailed information on the technologies. This publication provides documentation on petroleum.

The transformation of the energy in petroleum into a more useful form is described in this document in terms of major activity areas in the petroleum cycle, that is, in terms of activities which produce either an energy product or a fuel leading to the production of an energy product in a different form. The activities discussed in this document are listed in Table 1.

These activities represent both well-documented and less well-documented activity areas. The former activities are characterized in terms of actual operating data with allowance for future modification where appropriate. Emissions are assumed to conform to environmental standards. The less well-documented activity areas examined are those like oil storage in salt domes and exploration for which engineering studies were performed.

The organization of the chapters in this volume is designed to support the tabular presentation in the Summary. Each chapter begins with a brief description of the activity under consideration. The standard characteristics, size, availability, mode of functioning, and place in the fuel cycle are presented. Next, major legislative and/or technological factors influencing the commercial operation of the activity are offered. Discussions of resources consumed, residuals produced, and economics follow. To aid in comparing and linking the different activity areas, data for each area are normalized to 10^{12} Btu of energy output from the activity.

TABLE 1

MAJOR PETROLEUM ACTIVITY AREAS EXAMINED

ACTIVITY AREA
Exploration
Onshore Oil Exploration - Lower 48 States
Offshore Oil Exploration - Lower 48 States
Extraction
Onshore Primary Oil Extraction - Lower 48 States
Offshore Oil Extraction - Lower 48 States
Onshore Enhanced Oil Recovery - Steam Injection - Lower 48 States
Fuel Preparation
Oil Refinery - East Coast
Oil Refinery - Texas Gulf Coast
Power-Plant
Oil-Fired
Fuel Storage
Oil in Salt Domes
Tank Farms
Transportation
Pipeline
Super tanker
Rail
Truck

Note: This list is not intended to be exhaustive at this time. It will be extended in future revisions to this document.

TABLE OF CONTENTS

	Page
OVERVIEW	iii
LIST OF TABLES	ix
LIST OF FIGURES	xii
1.0 OFFSHORE OIL EXPLORATION	1-1
1.1 INTRODUCTION	1-1
1.2 Size of the Facility	1-3
1.3 Resources Requirements	1-5
1.3.1 Energy	1-5
1.3.2 Water Surface Area Land Use	1-6
1.3.3 Water	1-6
1.3.4 Costs	1-7
1.3.5 Personnel	1-7
1.3.6 Occupational Safety	1-8
1.4 Residuals	1-8
1.4.1 Air Pollutants	1-8
1.4.2 Water Pollutants	1-9
1.4.3 Solid Wastes	1-9
1.5 References	1-13
2.0 ON-SHORE ENHANCED OIL RECOVERY - STEAM INJECTION (LOWER 48 STATES)	2-1
2.1 Introduction	2-1
2.2 Characteristics of Enhanced Oil Recovery	2-1
2.3 Technical Constraints	2-4
2.4 Environmental Constraints	2-4
2.5 Resources	2-6
2.5.1 Fuel	2-6
2.5.2 Water	2-6
2.5.3 Land Requirements	2-6
2.5.4 Material	2-6
2.6 Plant Availability	2-6
2.6.1 Costs	2-7
2.7 References	2-7
3.0 OIL-FIRED STEAM ELECTRIC POWER PLANT	3-1
3.1 Process Description	3-1
3.2 Constraints	3-5
3.2.1 Geographical	3-5
3.2.2 Regulatory	3-5
3.2.2.1 Fuel Use Act	3-5
3.2.2.2 Clean Air Act	3-5
3.2.2.3 Clean Water Act	3-6
3.2.2.4 Other Related Legislation	3-8

TABLE OF CONTENTS (Concluded)

		Page
3.3	Resource Consumption	3-12
	3.3.1 Fuel Use	3-12
	3.3.2 Energy Requirement	3-12
	3.3.3 Water Use	3-12
	3.3.4 Land Use	3-12
3.4	Residual Data	3-16
	3.4.1 Water Pollutants	3-16
	3.4.2 Air Pollutants	3-16
	3.4.3 Solid Waste	3-19
	3.4.4 Waste Heat Discharge	3-19
3.5	Occupational Health and Safety	3-22
3.6	Economic Data	3-22
	3.6.1 Power Plant Costs	3-22
	3.6.2 Environmental Control Costs - Waste Water	3-29
	3.6.3 Air Quality Control Costs	3-38
3.7	References	3-41
4.0	CRUDE OIL STORAGE IN SALT DOMES	4-1
4.1	Characteristics of Salt Dome Storage	4-1
4.2	Constraints	4-1
4.3	Resource Requirements	4-4
	4.3.1 Energy Requirement	4-4
	4.3.2 Land Requirements	4-4
	4.3.3 Water Requirement	4-4
4.4	Residuals and Products	4-5
	4.4.1 Residuals in Air	4-5
	4.4.2 Residuals in Water	4-5
	4.4.3 Solid Waste Produced	4-5
	4.4.4 Heat Dissipation	4-5
	4.4.5 Energy Product Stored	4-5
4.5	Economic Data	4-6
	4.5.1 Construction, Operation and Maintenance Cost	4-6
	4.5.2 Environmental Compliance Costs	4-6
	4.5.3 Personnel Requirement	4-6
	4.5.4 Occupational Safety	4-6
4.6	References	4-6

LIST OF TABLES

Table No.		Page
1	Major Petroleum Activity Areas Examined	iv
1-1	Background Drilling Statistics and Success Ratios	1-4
1-2	Estimated Air Emissions for Offshore Oil and Gas Drilling and Production Operations	1-10
1-3	Drilling Mud Components for a 10,000 Foot Seawater-Lignosulfonate System	1-12
3-1	Summary of NSPS for Air Emissions from Oil-Fired Electric Utility Steam Generating Units	3-7
3-2	Summary of Chemical Effluent Limitations for Steam Electric Power Plants	3-9
3-3	Summary of Thermal Discharge Limitations for Steam Electric Power Plants	3-11
3-4	Energy Requirements for the Operation of Pollution Control Equipment on an Oil-Fired Power Plant	3-13
3-5	Water Use Requirements for Fossil-Fired Power Plants	3-14
3-6	Land Use Requirements for Oil-Fired Power Plants	3-15
3-7	Chemical Water Pollutant Data for Oil-Fired Electric Power Plants	3-17
3-8	Air Emissions for Oil-Fired Electric Power Plants	3-18
3-9	Solid Waste Discharges from Oil-Fired Power Plants	3-20
3-10	Heat Emissions from Fossil-Fired Power Plants	3-21

LIST OF TABLES (Continued)

Table No.		Page
3-11	Occupational Health and Safety Coefficients for Oil-Fired Power Plants	3-23
3-12	Capital Costs for Oil-Fired Power Plants	3-24
3-13	Operation and Maintenance Costs for Oil-Fired Power Plants	3-25
3-14	Construction Material for Oil-Fired Power Plants	3-26
3-15	Manpower Operation and Maintenance Requirements for Oil-Fired Power Plants	3-27
3-16	Manpower Construction Requirements for Oil-Fired Power Plants	3-28
3-17	Capital Costs for Central Treatment Plant for Oil-Fired Power Plants	3-30
3-18	Operation and Maintenance Costs for Central Treatment Plant for Oil-Fired Power Plants	3-31
3-19	Capital and Operating Costs for Treatment of Once-Through Cooling Water Discharge for Fossil-Fired Power Plants	3-33
3-20	Capital and Operating Costs for Treatment of Cooling Tower Blowdown for Fossil-Fired Power Plants	3-34
3-21	Capital and Operating Costs for Area Runoff Treatment Facilities for Oil-Fired Power Plants	3-35
3-22	Capital Costs for Cooling Systems for Fossil-Fired Power Plants	3-36
3-23	Operation and Maintenance Costs for Cooling Systems for Fossil-Fired Power Plants	3-37
3-24	Capital and Operating Costs for Flue Gas Desulfurization Processes for Oil-Fired Power Plants	3-39

LIST OF TABLES (Concluded)

Table No.		Page
3-25	Capital Costs for Particulate Precipitators for Oil-Fired Power Plants	3-40

LIST OF FIGURES

Figure No.		Page
2-1	Schematic of Steam Flooding	2-3
3-1	Oil-Fired Steam Electric Power Plant with Flue Gas Clean-up	3-2
3-2	Oil-Fired Steam Electric Power Plant Liquid/Solid Waste Streams	3-4
4-1	Key Elements of a Salt Dome Storage Facility	4-2
4-2	Utilization of Salt Dome Caverns for Storage	4-3

1.0 OFFSHORE OIL EXPLORATION

1.1 INTRODUCTION

Exploring for offshore oil and gas is similar in many respects to exploring onshore; the general procedures are outlined below. An offshore exploratory permit is required from the U.S. Department of the Interior (DOI) by industry to perform geophysical research in Federal waters. The potentials for commercial developments are determined both by the exploratory operations of private industry as well as by the U.S. Geological Survey.

Geophysical research (i.e., exploration) involves regional and local surveys utilizing magnetometers, gravimeters, and seismographs to analyze subsurface geologic strata. Magnetometers, either ship-towed or air-borne, measure changes in the earth's magnetic field; gravimeters measure variations in the gravitational pull of various rock types. Seismographs measure the time required for reflected and refracted sound waves to travel from a high-powered oscillator or propane-oxygen detonation to a subsurface strata and back to a recorder. These forms of information are used to determine the types and thicknesses of geologic strata and their potential for hydrocarbons. Bottom sampling and shallow coring to 1,000 feet are possible with special permits from DOI.

The Federal government holds offshore lease sales. The oil company submitting the highest bid on an offshore block, in a price range the U.S. Department of Interior accepts, reviews the lease, then the oil company is permitted to conduct an exploratory drilling program which will determine the actual potential for subsurface strata to produce oil.

Due to the high cost of offshore drilling and production platforms, movable drilling facilities are used in the exploratory stage.

Operations are conducted from drill barges, drill ships, jack-up rigs, semi-submersible rigs and submersible rigs. Each has advantages and factors such as water depth, climatic conditions, sea floor configuration, cost, and availability dictate which type is appropriate in a specific situation (Kash et al., 1973; U.S. Department of the Interior, 1976; U.S. Department of the Interior, 1977; Clark et al., 1978; and Ranney, 1979). If economically recoverable oil and gas deposits are discovered, then permanent drilling and production facilities are constructed and installed.

Drilling is carried out to the desired depth with a rotary drilling rig and a mud fluid circulation system. As the hole is bored, steel casing is set at intervals to prevent formation cave-ins. Each successive casing is run from the top of the hole to the bottom of the interval, inside the previous steel casings and extending beyond them. The mud fluid circulation system lubricates and cools the bit, brings rock cuttings to the surface, and places a counter pressure on the geologic strata to prevent blowouts.

Subsequent to drilling, the geologic strata are analyzed for their potential hydrocarbon production through a series of geophysical logging tests such as self potential, electrical, and gamma ray logs. If the well proves productive, the remainder of the well hole is cased, the casing is perforated, the well is acidized if necessary, and production tubing and a temporary Christmas tree are installed. Subsea completion apparatuses are becoming more commonplace but as yet are not cost effective. If the well is deemed not economically productive, the potential hydrocarbon zones are plugged with cement and the steel casing crimped 15 feet below the ocean floor to avoid fishing net snags. However, the well may be retained for brine re-injection to maintain reservoir pressure if other oil producing wells are discovered in the vicinity that have salt brines requiring disposal. The sections below describe in greater detail the size of a typical facility and the resource requirements and residuals associated with it.

1.2 Size of the Facility

The size of a typical exploratory offshore oil production facility was estimated by using offshore Louisiana oil production data (International Oil Scouts Association, 1978) and the average platform size in the Gulf of Mexico (Cashman, 1977). Production averages for Louisiana offshore wells were determined from information from 54 offshore blocks which began production between 1965 and 1976; the average production for 659 wells was 77,900 bbls per well per year (International Oil Scouts Association, 1978). In a similar manner, an average platform size calculated from a recent offshore construction report (Cashman, 1977) indicates that while production platforms constructed for the Gulf of Mexico during 1979 ranged from 6 to 62 slots, an 18 slot platform was typical (the arithmetic mean for 54 platforms under construction). An 18-well platform producing oil at the above mentioned rate would produce almost 4000 bbl per platform per day or 1,460,000 bbl per year. The heat content per barrel used for calculations was 5.8×10^6 Btus; thus, a total of 8.47×10^{12} Btus per platform per year ultimate production was used as the normalizing factor.

The national offshore exploratory success ratio is approximately 15% (Table 1-1); however, in order to correlate with the total offshore success ratio seen in the development phase, the small number of wells actually drilled from an offshore platform (compared to an onshore field), and the likelihood that more than one successful well would be necessary to stimulate development, an exploratory project of five wells (two successful and three dry holes) was assumed here.

TABLE 1-1

BACKGROUND DRILLING STATISTICS AND SUCCESS RATIOS
(* indicates that a particular data set was incorporated in the Summary, Volume 1, of this series)

TYPE OF WELL	AREA OF COUNTRY INCLUDED IN STATISTICS	PERIOD OF TIME COVERED	OIL WELLS		GAS WELLS		DRY HOLES		TOTAL NUMBER WELLS DRILLED	PERCENT SUCCESSFUL OIL & GAS	SOURCE
			Number	% Successful	Number	% Successful	Number	%			
All Wells[(1)]	United States	1918 - 1977	1,067,562	55.02	216,032[(2)]	11.13	656,851	33.85	1,940,445	66.15	DeGolyer and MacNaughton, 1978
All Wells	United States	1968 - 1977	136,407	43.37	56,588	17.99	121,491	38.63	314,486	61.36	DeGolyer and MacNaughton, 1978
All Wells	United States	1945 - 1973	579,984	50.90	122,500	10.75	436,916	38.35	1,139,400	61.65	U.S. Federal Power Commission, 1974
All Wells*	United States	1978 - 9/79	26,550	38.57	19,693	28.61	22,588	32.82	68,831[(3)]	67.18	Oil and Gas Journal, 1979
Offshore Wells*	AL/PC/GM[(4)]	All time-1978	10,305	58.09	3,221	18.16	4,214	23.75	17,740[(5)]	76.25	American Petroleum Institute, 1978
Onshore Wells[1]*	Alaska	1967 - 6/79	526	63.93	54	6.66	209	29.41	785	70.59	American Petroleum Institute, 1967-1979
Exploratory[(6)]	United States	1938 - 1977	N/A[(7)]	N/A	N/A	N/A	292,097	80.92	360,950	19.08	DeGolyer and MacNaughton, 1978
Exploratory	United States	1968 - 1977	N/A	N/A	N/A	N/A	67,785	79.53	85,228	20.47	DeGolyer and MacNaughton, 1978
Exploratory	United States	1945 - 1973	37,995	12.65	17,907	6.00	244,408	81.38	300,310	18.61	U.S. Federal Power Commission, 1974
Exploratory*	United States	1978 - 9/79	1,666	11.02	2,452	16.22	10,999	72.76	15,117	27.24	Oil and Gas Journal, 1979
Expl./Off-shore*	AP/PC/GM[(4)]	All time-1978	345	6.18	516	9.25	4,720	84.57	5,581	15.43	American Petroleum Institute, 1978
Expl./On-shore*	Alaska	1967 - 6/79	41	18.0	17	7.5	170	74.5	228	25.5	American Petroleum Institute, 1967-79

(1) All wells - exploratory plus development.
(2) Gas plus condensate wells until 1967 when the condensate wells were then included with the gas wells.
(3) Service wells not included.
(4) Alaska, Pacific Coast and Gulf of Mexico Offshore Wells.
(5) Exploratory wells not included.
(6) Exploratory wells of all types: new-field wildcats, new-pool wells, and extension of existing pool wells.
(7) The number of successful oil and gas wells were not separately reported in this source.

Several additional assumptions were used in the calculations: 1) 9,500 foot average offshore oil and dry hole drilling depth (American Petroleum Institute, 1979); 2) 25 day average drilling time for a 9,500 foot well (Weaver et al., 1972; Matheny, 1979); and 3) an offshore oil reservoir recovery efficiency of approximately 40 percent (University of Oklahoma, 1975).

1.3 Resources Requirements

The resources discussed below are those which could be documented and related to a facility of size listed on the data sheet. The data values are estimations of total exploratory values divided by the expected average annual output normalized to 10^{12} Btu.

1.3.1 Energy

Fuel consumption was determined by assuming the following: 1) five exploratory wells - 25 days drilling time per well or 3000 hours of fuel requirement; 2) an average fuel consumption for large diesel engines of 0.0012354 bbl/hp-hr (6,700 Btu/hp-hr) (Diesel and Gas Turbine Progress, 1977), and 5-6 gallons/100-hp-hr (Salisbury, 1967); and 3) an estimated jack-up exploratory rig horsepower requirement of 7,000 hp. Offshore drilling rigs require power for rotary drilling, drawworks, mud circulation systems, and electricity and other power necessities for 50-100 people to work on the rig. An average horsepower for the major prime movers on ten Gulf Coast jack-up rigs is 5,100 hp (Tubb, 1979); however, since the horsepower ratings for the drawworks, pumps, and other engines were not given, a total estimated horsepower rating of 7000 hp is assumed for the following calculations:

(1) 3000 hrs. x 7000 hp x 0.0012354 bbl/hp-hr =
25,943 bbls of diesel fuel for 5 wells

(2) 25,943 bbls x 5.8 x 10^6 Btu/bbl = 1.5047 x 10^{11} Btu of fuel

(3) 1.5047 x 10^{11} Btu ÷ 8.47 = 17.765 x 10^9 Btus of fuel/10^{12} Btu produced

1.3.2 <u>Water Surface Area Land Use</u>

The amount of water surface area land use could be an important factor if exploratory drilling and subsequent production occurs in productive fishing waters. Jack-up rigs and drillships usually require only 2-5 acres per structure, while semi-submersibles with 1,500 foot anchoring radii would require 162 acres (U.S. Department of Interior, 1977). Additionally, if a fishing avoidance buffer of one mile is necessary, then 2,011 acres of water surface area per platform would be excluded from commercial fishing interests.

1.3.3 <u>Water</u>

Depending on the type of drilling muds used, either fresh or salt water could be used for drilling fluid make-up water; approximately 5,500 bbl of water would be used in a 9,500-10,000 foot well (U.S. Department of Interior, 1973). For five exploratory wells, 27,500 bbl of water (or 3,250 bbl of water per 10^{12} Btu produced) would be required.

Additional fresh water would be needed for domestic living requirements and other work-related needs. Maximum distillation capacity and expected requirements for a modern jack-up rig would be 10,000 gpd (Ocean Industry, 1979) or 1,250,000 gals for 125 exploratory drilling days (5 wells). The maximum fresh water requirement for workers would be 3513.8 bbl of water per 10^{12} Btu produced.

1.3.4 Costs

Three types of costs are shown for exploratory drilling. The first, cantilever jack-up rig example costs (Ocean Industry, 1979), were included to illustrate the large capital outlay for exploratory rig owners, namely, approximately $29.2 million dollars in 1978 dollars or $32.8 million in 1979 dollars. [The 1979 Ocean Industry costs used were deflated for the data sheet (1978 costs) by using the Engineering News-Record Construction Index (U.S Department of Commerce, 1979)].

The second and third types of costs, drilling and rig rental fees, are more appropriate costs for the exploring company, as the cost of exploratory drilling rigs are included in the rig rental rate fee. Shallow and deep water rental rates for 1978 are listed in Ocean Industry [shallow: $16,000-$22,000/day, deep: $25,000-$35,000/day (Ocean Industry, 1979)]. Data sheet values indicate costs for 125 days of drilling (five wells) that have been normalized to 10^{12} Btus. In a similar manner, drilling costs for 1978 were derived by utilizing the 1977 offshore oil and dry hole costs per well (American Petroleum Institute, 1979), inflating them to 1978 costs with the Engineering News-Record Construction Index (U.S. Department of Commerce, 1979), and normalizing to 10^{12} Btus.

1.3.5 Personnel

The number of personnel needed to operate an offshore drilling rig depends on the type of rig. Generally, the employees operate on one or two week shifts. Two estimates indicate that 84-87 men per rig might be expected (U.S. Department of Interior, 1977; Ocean Industry, 1979) or approximately 9.9-10.3 men per 10^{12} Btu.

1.3.6 Occupational Safety

Accident and injury data for offshore operations (1970-1977) were computed by normalizing the number of accidents and injuries in each accident classification to the total Btu content of offshore oil and gas produced between 1970-1977 (U.S Geological Survey, 1978). The data were not segregated into those occurring in the oil and those in the gas industry, or those occurring in the various phases of the technology (i.e., exploration, development, or production). For example, 41 offshore blowouts occurred between 1970-1977; 4.126×10^{16} Btus of offshore oil and gas were produced during the same period. To normalize to 10^{12} Btus, all the accident or injury values are divided by 4.126×10^{4}. Consequently, the normalized number of offshore blowouts would be 0.0010.

1.4 Residuals

The residuals outlined below are those which could be documented and related to this size facility. As in the previous sections, the data values are estimations of total exploratory values divided by the expected average annual output normalized to 10^{12} Btu.

1.4.1 Air Pollutants

During the exploratory stage, air emissions would result from the major prime movers on the exploratory rig. These engines supply power for the rotary drilling rig, the mud circulation system, the drawworks, pumps, and compressors; they also supply electricity and other power requirements for 50-100 workers. An average horsepower rating for the major prime movers for 10 Gulf Coast jack-up rigs is 5,100 hp (Tubb, 1979). Since the horsepower ratings for the draw-works and the pumps were not specified, a total estimated horsepower rating of 7,000 hp is assumed here.

Two assumptions concerning the drilling depth and drilling time were made. The weighted average depth for offshore successful oil wells and dry holes during 1977 was approximately 9500 feet (American Petroleum Institute, 1979). In addition to depth, drilling time varies with the type of formation being drilled. An average drilling time for 12 offshore wells (both vertical and deviated wells to 11,000 feet) in Weaver et al. (1972) was 21.4 days; another average for 8,000-10,000 total vertical depth (TVD) deviated wells was 27 days (Matheny, 1979). Consequently, 25 days per well was assumed here for the drilling time or 125 days for 5 wells (3000 hours).

Air emissions for the exploratory drilling program are derived in Table 1-2 by using U.S. Environmental Protection Agency (1978) emission data for industrial diesel engines. For example, 324.07 tons of nitrogen oxides would be expected from the project or 38.26 tons per 10^{12} Btu.

1.4.2 Water Pollutants

Water pollutants during the exploratory phase would result primarily from the drilling muds; their components are listed under solid wastes. Brines encountered during drilling would be limited since drilling muds would prevent most formation fluids from entering the bore hole; a limited amount of produced brines could be encountered during well testing, depending on the type of oil reservoir contacted. In addition, there is always the possibility of oil pollution from a well blowout. [Forty-one blowouts occurred during offshore oil and gas operations between 1970 and 1977 (U.S Geological Survey, 1978)].

1.4.3 Solid Wastes

During the exploratory stage, solid wastes would be generated from the drill cuttings and the drilling muds. Drilling muds, a

TABLE 1-2

ESTIMATED AIR EMISSIONS FOR OFFSHORE OIL AND GAS DRILLING AND PRODUCTION OPERATIONS

OFFSHORE DRILLING RIGS(1)

	EXPLORATORY DRILLING(2)					DEVELOPMENT DRILLING(3)			
	grams/hp-hr[4]	hp	hrs.	grams	tons	hp	hrs.	grams	tons
CO	3.03	7000	3000	63,630,000	70.14	7000	11,400	241,790,000	266.53
HC	1.12	7000	3000	23,520,000	25.93	7000	11,400	89,376,000	98.52
NO_x	14.0	7000	3000	294,000,000	324.07	7000	11,400	1,117,200,000	1,231.50
SO_x	0.931	7000	3000	19,551,000	21.55	7000	11,400	74,294,000	81.89
Part.	1.00	7000	3000	21,000,000	23.15	7000	11,400	79,800,000	87.96

ESTIMATED ANNUAL AIR EMISSIONS

	DIESEL POWERED OIL PLATFORM(5)					NATURAL GAS TURBINE POWERED GAS PLATFORM(6)				
	grams/hp-hr(7)	hp	hrs.	grams	tons	grams/KW-hr	KW	hrs.	grams	tons
CO	3.03	2000	8760	53,085,600	58.52	0.7	300	8760	1,839,600	2.03
HC	1.12	2000	8760	19,622,400	21.63	0.1	300	8760	262,800	0.29
NO_x	14.0	2000	8760	245,280,000	270.37	1.7	300	8760	4,467,600	4.92
SO_x	0.931	2000	8760	16,311,120	17.98	0.003	300	8760	7,884	0.0087
Part.	1.00	2000	8760	17,520,000	19.31	N/A	N/A	N/A	N/A	N/A

(1) Offshore drilling rig assumptions: a) total hp. requirement - 7000 hp. and b) drilling time for 9,500-10,000 foot wells - 25 days per well (see text for citations).

(2) Five wells x 25 days per well x 24 hrs. per day = 3000 hrs.

(3) Nineteen wells x 25 days per well x 24 hrs. per day = 11,400 hrs.

(4) Values taken from U.S. EPA, 1978 (AP-42 Supplement No. 8 for Compilation of Air Pollutant Emission Factors) for diesel engines listed under section 3.3.3. Gasoline and Diesel Industrial Engines.

(5) Diesel powered generators/motors for electricity, living and other power requirements during normal production are assumed to be 2000 hp for 365 days (8760 hrs). The power requirement is an estimation derived from the average cost of installing large prime movers (approximately $200/hp.) and the total cost for motor generator sets for a medium size Gulf Coast Platform ($350,000-$500,000; Ocean Industry, October 1979).

(6) Natural gas turbine engines are generally used for gas processing, electricity and other power requirements; maximum output of the gas turbines on an 18 slot platform would be 250-300 KW (Funk and Anderson, 1980). For this analysis, 300 KW are assumed for 365 days.

(7) Data for natural gas turbine emissions taken from U.S. Environmental Protection Agency, 1978 (AP-42, Supplement No. 8).

mixture of water, clays, and chemical additives, pass down the drill stem, out the drill bit, and return to the surface outside of the drill string. Concurrently, the mud cools the drill bit, sweeps drill cuttings out of the bore hole, and seals the rock formations pierced.

Drill cuttings were estimated by modifying data for a 15,000-foot offshore well (U.S. Department of Interior, 1977); however, the values are probably over-estimations since bore hole size increments intended to reach 15,000 feet would be somewhat larger than those intended for 9,500 feet. Approximately 1,398 tons per well, or a total of 6,990 tons of rock cuttings for five exploratory wells, could be expected from this project. Normalized to 10^{12} Btu expected average annual production, approximately 825 tons of cuttings per 10^{12} Btu would be produced. Generally, the cuttings are removed from the drilling muds on a shaker, discarded off the platform, and form accumulations on the ocean floor up to three feet thick in the center and tapering rapidly toward the edge (100-150 foot diameter deposit). After a few months, the piles are dispersed by bottom currents (U.S. Department of Interior, 1976).

Drilling muds may be freshwater, saltwater, or oil-based systems. They are altered with depth by addition of clays to increase their weight and other chemical additives to function more effectively at greater temperatures and pressures. A sea water-lignosulfonate system was used to determine typical pollutant discharges (U.S. Department of Interior, 1977). Components for 10,000 foot exploratory wells and their 10^{12} Btu normalized values are detailed in Table 1-3.

Exploratory drilling muds are generally used only once and then discarded due to the microfossils which accumulate during drilling

TABLE 1-3

DRILLING MUD COMPONENTS FOR A 10,000 FOOT
SEAWATER-LIGNOSULFONATE SYSTEM

COMPONENT	POUNDS PER 10,000 ft. well	TONS PER 10,000 ft. well	TONS FOR Five Expl. Wells	TONS FOR FIVE Expl. Wells/10^{12} Btu[1]
Barite (barium sulfate)	535,000	267.5	1337.5	157.9
Bentonitic & Attapulgite Clay	66,000	33.0	165.0	19.5
Caustic Soda (NaOH)	21,000	10.5	52.5	6.2
Aromatic Detergent	3,000	1.5	7.5	0.9
Organic Polymers	4,000	2.0	10.0	1.2
Ferrochrome Lignosulfonate	26,000	13.0	65.0	7.7
Total	655,000	327.5	1637.5	193.3

(1)These are the normalized values for the data sheets; total exploratory values are divided by the expected average annual output, i.e., 1337.5 tons 8.47 (8.47 x 10^{12} Btu expected average annual production) = 157.9 tons of drilling mud/10^{12} Btu produced.

Source: U.S. Department of Interior, 1977. Final Environmental Statement. Proposed 1976 Outer Continental Shelf Oil and Gas Lease Sale Offshore the North Atlantic States. Volume 2 of 5. OCS Sale No. 42. Bureau of Land Management.

operations (U.S. Department of Interior, 1977). These minute fossils are employed to analyze the geologic strata, and after one well hole is drilled the mud becomes useless for this purpose. Therefore, 100% of the mud is considered discarded off-platform. If oil base muds are used, they are processed, usually onshore, prior to disposal.

1.5 References

American Petroleum Institute, 1967-1979. Quarterly Review of Drilling Statistics. Washington, D.C.

American Petroleum Institute, 1978. Basic Petroleum Data Book. Petroleum Industry Statistics. Washington, D.C.

American Petroleum Institute, 1979. 1977 Joint Association Survey on Drilling Costs. Washington, D.C.

Cashman, Margaret D., 1977. Offshore Construction Report. Ocean Industry. Volume 12, Number 7.

Clark, John, Jeffrey Zinn and Charles Terrell, 1978. Environmental Planning for Offshore Oil and Gas. Volume I: Recovery Technology. FWS/OBS-77/12. U.S. Fish and Wildlife Service, Biological Services Program, Washington, D.C.

DeGolyer and MacNaughton, 1978. Twentieth Century Petroleum Statistics. Dallas, Texas.

Diesel and Gas Turbine Progress, 1977. Engine Power Transmission, Generation, Compression and Propulsion System Products. Diesel and Gas Turbine Worldwide Catalog, Volume 42. Milwaukee, Wisconsin.

Funk, V. T. and T. C. Anderson, 1980. Personal Communication, Petroleum Engineers. Department of Energy, Dallas, Texas.

International Oil Scouts Association, 1978. International Oil and Gas Development. Part II, Volume 47. Austin, Texas.

Kash, Don E., I. L. White, K. H. Bergey, M. A. Chartock, M. D. Devine, R. L. Leonard, S. N. Salomon and H. W. Young, 1973. Energy Under the Oceans. A Technology Assessment of Outer Continental Shelf Oil and Gas Operations. University of Oklahoma Press, Norman, Oklahoma.

Matheny, Shannon L., 1979. Shell Group is Rapidly Developing Cognac Field. Oil and Gas Journal. Volume 77.

Ocean Industry, 1979. Facts and Forecasts. Ocean Industry, Volume 14.

Oil and Gas Journal, 1979. U.S. Well Completions - API Data. Oil and Gas Journal. Volume 77.

Ranney, William M., 1979. Offshore Oil Technology Recent Developments. Noyes Data Corporation, Park Ridge, New Jersey.

Salisbury, J. Kenneth (Ed), 1967. Kent's Mechanical Engineers' Handbook - Power Volume. Wiley Engineering Handbook Series. John Wiley & Sons, Inc., London, England.

Tubb, Maretta, 1979. Directory of Marine Drilling Rigs. Ocean Industry. Volume 14.

U.S. Department of Commerce, 1979. Survey of Current Business. Volume 59, Number 11. Bureau of Economic Analysis.

U.S. Department of Interior, 1973. Draft Environmental Statement - Proposed 1974 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Louisiana. OCS Sale No. 33 DES 73-69. Bureau of Land Management.

U.S. Department of Interior, 1976. Final Environmental Statement. Proposed 1976 Outer Continental Shelf Oil and Gas Lease Sale Offshore the Mid-Atlantic States. OCS Sale No. 40. Bureau of Land Management. New York OCS Office.

U.S. Department of Interior, 1977. Final Environmental Statement. Proposed 1976 Outer Continental Shelf Oil and Gas Lease Sale Offshore the North Atlantic States. Volume 2 of 5. OCS Sale No. 42. Bureau of Land Management.

U.S. Environmental Protection Agency, 1978. Compilation of Air Pollutant Emission Factors. AP-42, Supplement No. 8 for Third Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

U.S. Federal Power Commission, 1974. National Gas Survey - Preliminary Draft. Washington, D.C.

U.S. Geological Survey, 1978. Outer Continental Shelf Statistics, 1953-1977. Conservation Division/Geological Survey, Department of Interior, Washington, D.C.

University of Oklahoma, 1975. Energy Alternatives: A Comparative Analysis. U.S. Government Printing Office, Washington, D.C.

Weaver, L. K., H. F. Pierce and C. J. Jirik, 1972. Offshore Petroleum Studies. Composition of the Offshore U.S. Petroleum Industry and Estimated Costs of Producing Petroleum in the Gulf of Mexico. Information Circular 8557. Bureau of Mines, U.S. Department of Interior.

2.0 ON-SHORE ENHANCED OIL RECOVERY - STEAM INJECTION (LOWER 48 STATES)

2.1 Introduction

Primary oil recovery mainly relies on the gas pressure of the reservoir and/or the influx of reservoir water as driving force of the oil flow into the well. Secondary oil recovery involves water flooding and/or recycling, i.e., pumping reservoir gas back into the reservoir forcing oil into the production well. Typically, 40 percent of the OOIP (original oil in place) can be recovered by primary and secondary techniques.

Capillary action, viscosity, gravity, and other forces hold some of the remaining OOIP to the rock surfaces. Another portion of the OOIP is bypassed by the waterflooding due to the particular flow pattern of the reservoir.

Tertiary oil recovery techniques reduce the aforementioned holding forces by thermal methods (reducing viscosity), by miscible methods (reducing interfacial tension resulting in a reduction of the capillary forces) and by chemical methods (reducing adhesion of the oil to rock surface also resulting in a reduction of the capillary forces). Thermal methods either involve steam injection or in-situ combustion.

2.2 Characteristics of Enhanced Oil Recovery

Considering all tertiary recovering methods, steam injection is closest to commercialization. There are continuous and periodic steam injection techniques. Steam soaking ("huff and puff") is a non-continuous method where steam is injected into the reservoir through the production well. After shutting off the steam, water and oil come up through the well. Steam drive is a technique where steam can continuously be injected into the reservoirs through separate wells while oil and water come up through the production wells.

In some cases, tertiary techniques are applied subsequent to primary and secondary oil recovery. Often steam soaking is used first, steam drive later on. In other cases, primary, secondary, and tertiary recoveries are done simultaneously.

For recovery by steam injection, saturated steam (70 to 80 percent quality, i.e., weight fraction of the vapor) is injected into the reservoir. The steam heats the oil with which it comes in contact. The steam condenses during the heat exchange with the oil and the surroundings. The latent vaporization heat causes the main heat release. Since when heated, oil has a lower viscosity and a larger volume it is released from the pores of the rock where it is trapped. A schematic of the steam flooding process is presented in Figure 2-1. When condensed, the (hot) water tends to displace the oil as in waterflooding.

The oil/gas/water mixture flowing out of the production well must be separated, i.e., the emulsion must be broken by chemical treatment, electrical treatment (high voltage alternating current), or gravity settling. Heating the emulsion has an accelerating effect. The water recovered can be recycled to the steam generators. Make-up water and especially recycled water have to be treated and cleaned before being fed into the boiler.

Typically, a number of 20 to 50 million Btu/hr commercial steam boilers are used for redundancy purposes in case of boiler failure. Currently, such boilers are crude oil fired.

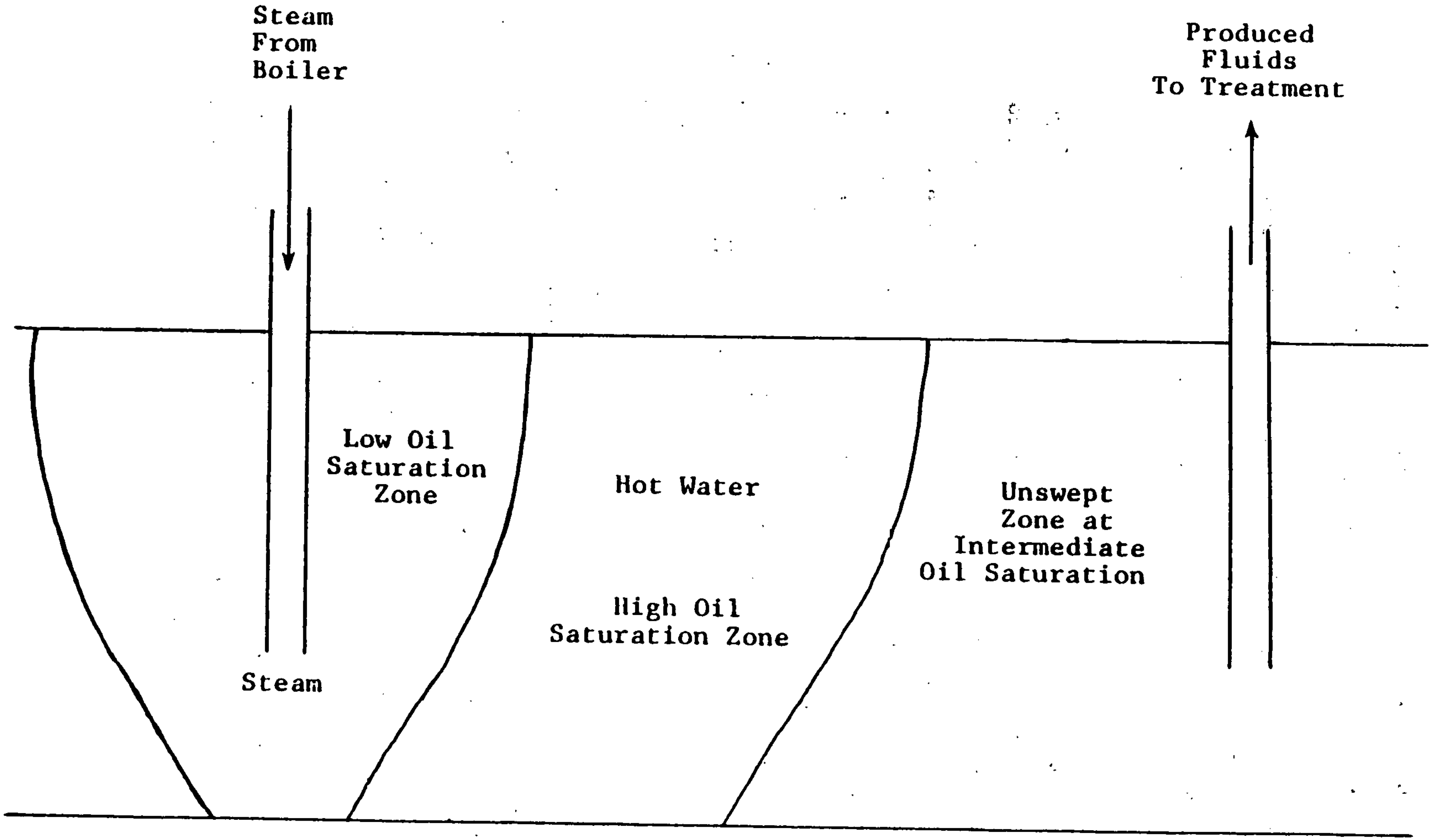


FIGURE 2-1
SCHEMATIC OF STEAM FLOODING

It must be emphasized that all enhanced oil recovery characteristics are very much site specific since natural variations are rather substantial. Furthermore, there is a life cycle dependency of the production rate. The daily production rate, efficiency, etc. decrease with increasing depletion of the OOIP.

2.3 Technical Constraints

The applicability of steam flooding is largely restricted to reservoirs with:

- low gravity crude oil (10-20 API)
- High permeability (>500md)
- Shallow depth (<3000 feet)

Low gravity oils are most viscous. Shallow depth and high permeability reduce heat losses especially to well walls. Most suitable fields are in California, Texas, Louisiana, and Wyoming (U.S. Environmental Protection Agency, 1978).

Wells must be especially equipped to take the higher temperature of the steam. Cement failures are common.

2.4 Environmental Constraints

Air emissions are largely caused by the steam boilers and the separation treatment heaters. There are some fugitive emissions from well caps, pumps, tanks, separators, etc. The fugitive emissions for enhanced oil recovery techniques have not been measured. However, these emissions should be similar to secondary recovery methods since they share the recovery equipment. The data presented by the U.S. Environmental Protection Agency (1978) include such emissions.

The emissions of the boilers can be compared to EPA emissions standards for oil fired burners. Obviously, the amount of steam required for the production of one barrel of oil, which can vary considerably, also changes the emissions per barrel of oil produced. EPA Standards valid in 1977/78 for oil fired boilers for 0.3×10^{12} Btu fuel input are as follows:

NO_x-------------45 tons
Particulates----15 tons
SO_2-------------120 tons

Many boilers used for enhanced oil recovery are below EPA size limits so that the standards do not apply. However, state and local standards do apply, which can force the installation of SO_2 scrubbers. (The data shown in the summary Volume 1 exceed the EPA Standards.)

Estimated specific weight of the crude is .93. Estimated sulfur content is 1.23 percent (U.S. Environmental Protection Agency, 1978). A quantitative conversion of this sulfur to SO_2 amounts to 207 tons per 10^{12} Btu equivalent in produced oil.

There is no information on the nitrogen content of this oil. However, some California oil contains more than one percent nitrogen which might have caused the excessive NO_x formation. It appears that different burner designs (e.g., dual register burners) might be necessary to meet EPA or similar state and local NO_x standards.

The particulate emission must have changed with the introduction of SO_x scrubbers.

Water pollutants for commercial steam flooding have not been measured in a representative way. Brine and other waste water contain some hydrocarbons which can not be economically recovered in the separators. In many cases, these waste waters will be reinjected into the well. The data presented (U.S. Environmental Protection Agency, 1978) assume no reinjection.

2.5 Resources

2.5.1 Fuel

Getty did not report the actual number of barrels of oil needed to produce the steam for each barrel of oil recovered. The U.S. Environmental Protection Agency (1978) states that 0.3 barrels is a representative value.

2.5.2 Water

If the water used for steam injection is not recycled, about five barrels of water are needed for each barrel of oil produced. Again, there are site-dependent variations.

2.5.3 Land Requirements

Typically, two acres are required for each well (U.S. Environmental Protection Agency, 1978). If waste water is discharged in evaporation ponds, additional land is needed. Since all steam injection projects are relatively new and on a trial basis, it is not clear whether this land use is temporary.

2.5.4 Material

Bechtel's model (Bechtel, 1978) appears to represent a nationwide average.

2.6 Plant Availability

No oil production data for single oil fields are published by the oil companies. A 70 percent production rate in 1978 seems to be a good ball park number. It should be emphasized that this rate reflects more the market situation and constraints imposed by the producer than a technically achievable rate.

2.6.1 Costs

Bechtel (1978) presented a nationwide average cost estimate. It should be emphasized that the accuracy of such an estimate is very limited. The main reason in the variation is the natural characteristics of reservoirs. For example, though 0.3 barrels of oil are commonly used per barrel oil production, values down to 0.15 barrels have been reported (U.S. Environmental Protection Agency, 1978). In addition, environmental constraints have had discouraging effects on the industry (Chemical Engineering, 1979). SO_x scrubbers, dual register burners, and baghouses or electrostatic precipitators for particulate removal will have substantial economic impact.

2.7 References

Bechtel Corporation, 1978. Energy Supply Planning Model. San Francisco, CA.

Chemical Engineering, 1979. New Features. Volume 86.

U.S. Environmental Protection Agency, 1978. Energy From the West: Energy Resource Development Systems Report, Volume V: Oil and Natural Gas, EPA-600/7-79-060e. Research Triangle Park, N.C.

3.0 OIL-FIRED STEAM ELECTRIC POWER PLANT

3.1 Process Description

Oil-fired steam electric power plants generate electricity using the same basic unit processes as the other fossil-fueled power stations, i.e., coal and natural gas. The stored chemical energy of the fossil fuel is released as heat in the combustion process. This heat is then converted by means of high-temperature, high-pressure steam into rotating mechanical energy. This mechanical energy is transformed into electrical energy by a generator whose output is distributed across transmission lines to the end users.

Figure 3-1 shows a simplified flow diagram of an oil-fired power plant with flue gas clean-up. The major systems include: fuel oil storage and feeding, water treatment, steam production in the boiler, steam expansion through the turbine, generation of electrical power in the rotating generator, steam condensing and condensate return, water cooling system, flue gas clean-up (if required), and liquid and solid waste treatment and disposal.

Associated with the above systems are various sources of gaseous, liquid, and solid effluents. The principal source of air emissions is the combustion gases exhausted through the stack. Wastewater sources are grouped by EPA into the following seven categories: (1) low volume wastes - including wet scrubber sludge, waste treatment laboratory and sampling streams, floor drainage, cooling water basin cleaning wastes, and service waste systems; (2) ash residues - including fly and bottom ash; (3) metal cleaning wastes - including wastes from boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning; (4) boiler blowdown; (5) once-through cooling; (6) cooling tower blowdown; and (7) area runoff - including material storage runoff. Waste heat is discharged through the

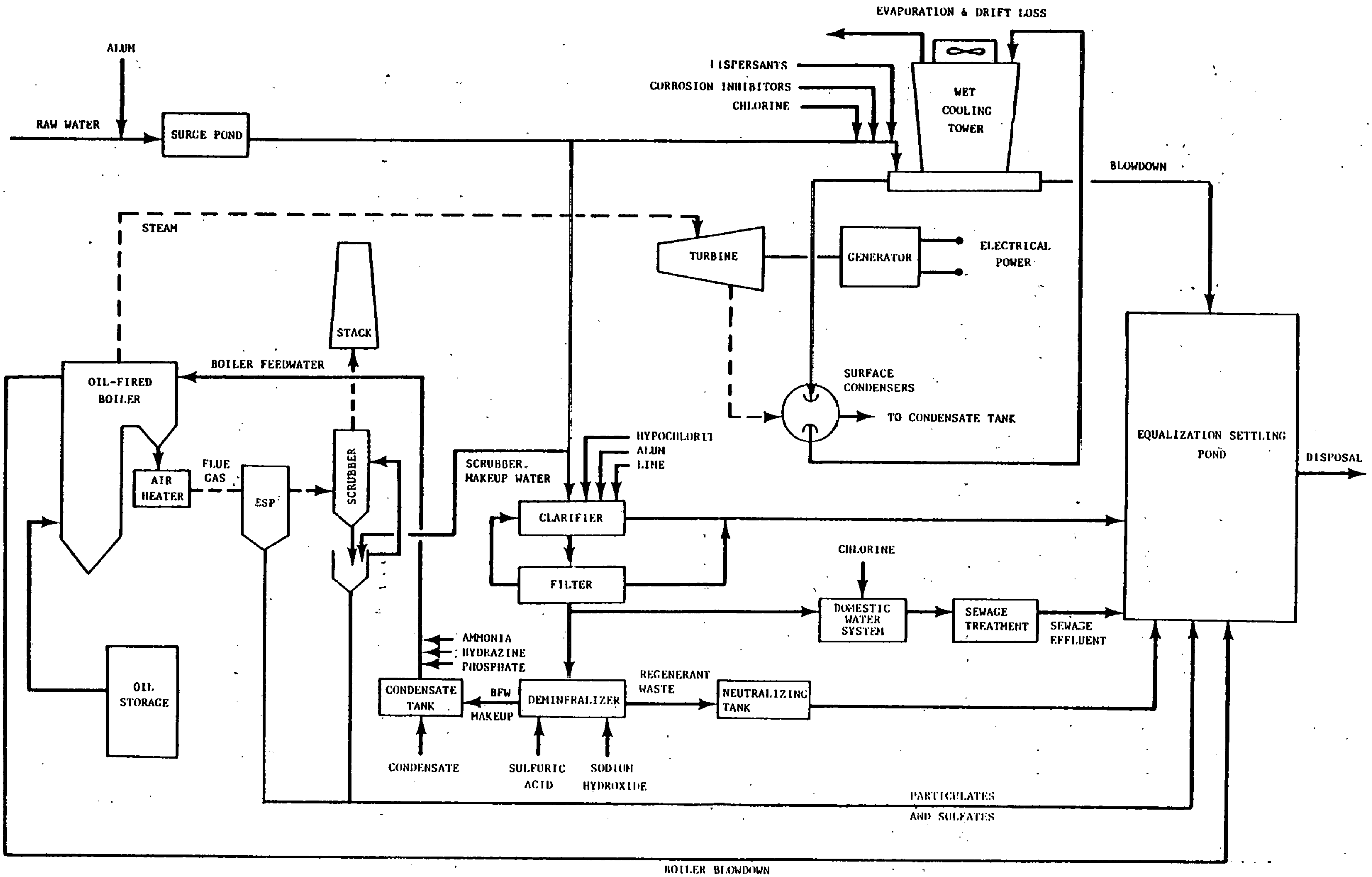


FIGURE 3-1
OIL-FIRED STEAM ELECTRIC POWER PLANT WITH FLUE GAS CLEAN-UP

condenser cooling water system to either a water body (lake, river, etc.) or to the atmosphere. Figure 3-2 schematically identifies these liquid/solid waste streams.

A plant size rating of 800 MW_e is typical for modern oil-fired power stations. Thermal efficiency is the ratio of electrical energy generated to fuel energy input (in similiar units). The average thermal efficiency for oil-fired power plants operating in 1977 was 34.7 percent (Edison Electric Institute, 1978; National Coal Association, 1978).

Heat rate is simply an alternate method of expressing energy conversion efficiency. It indicates the amount of thermal energy input in Btu's required to produce one kilowatt hour of electricity. 9,800 Btu/kWh is the heat rate that corresponds to a 34.7 percent thermal efficiency.

Capacity factor is the ratio of actual energy produced to the potential amount of energy capable of being produced during a given time period (U.S. Environmental Protection Agency, 1974). Plant capacity factors have been steadily increasing over the years. The average annual capacity factor for the year 1977 for oil-fired power plants was 55 percent. Some newly designed base load plants might operate with capacity factors approaching 70 percent (Teknekron, Inc. 1976).

Power plant equipment is a major investment and equipment lifetimes of between 30 and 40 years are expected.

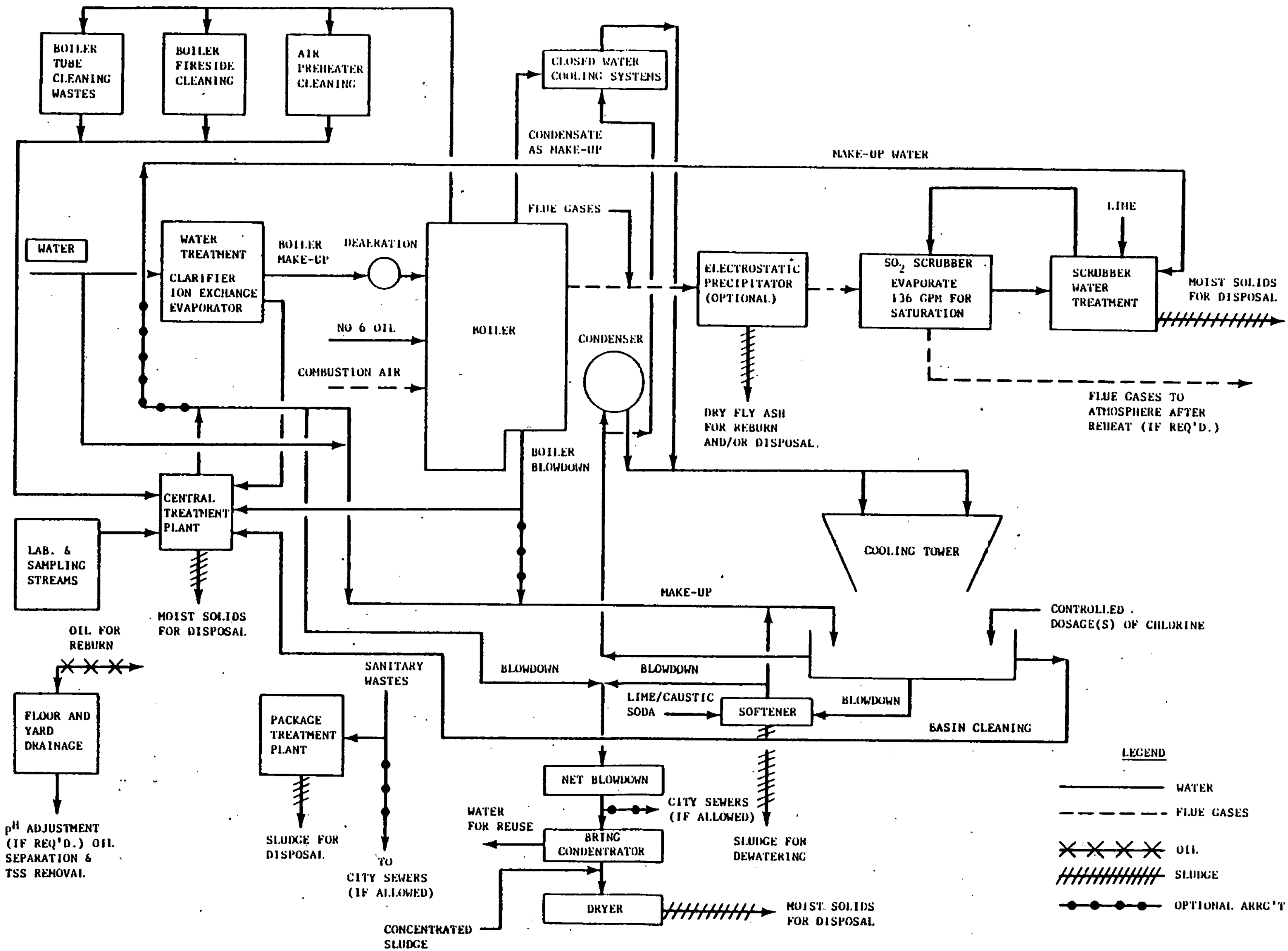


FIGURE 3-2
OIL-FIRED STEAM ELECTRIC POWER PLANT
LIQUID/SOLID WASTE STREAMS

3.2 Constraints

3.2.1 Geographical

A primary geographical consideration in siting oil-fired power plants is the desirability to locate near a navigable water body in order to receive fuel deliveries. Residual fuel oil is too viscous at ambient temperatures to be transported via pipeline; consequently it is usually shipped via oil tanker or barge.

3.2.2 Regulatory

3.2.2.1 Fuel Use Act. The Power Plant and Industrial Fuel Use Act of 1978 places severe constraints on new oil- and gas-fired power plants. The Act's primary purpose is to minimize the use of scarce domestic fuels and expensive imported fuels in industrial and utility boilers. The Act prohibits:

"...use of petroleum or natural gas in new facilities; and ...building new electric power plants that cannot burn coal or other alternative fuels;" (F.R. 43, 54058). (A "new" facility is defined as any facility for which construction or acquisition began, or on which major reconstruction took place, on or after April 20, 1978.)

The burden of proof that an exemption is deserved rests upon the petitioning utility company. The exemptions cover physical, operational, economical, environmental, and legal factors that preclude compliance.

3.2.2.2 Clean Air Act. The Clean Air Act Amendments of 1970 and 1977 provide the legislative basis for environmental air regulations which place constraints on new and existing electric utilities. The Clean Air Act Amendments of 1970 require EPA to promulgate National Ambient Air Quality Standards (NAAQS) and Federal new source performance standards (NSPS). The states are authorized to prepare a

State Implementation Plan (SIP) which provides for the implementation and enforcement of NAAQS.

A summary of the New Stationary Sources Performance Standards for Electric Utility Steam Generating Units is presented in Table 3-1. These standards cover all new, modified, and reconstructed electric utility steam generating units capable of combusting more than 73 MW heat input (250 million Btu/hour) of fossil fuel. The effective date for these standards was June 11, 1979.

3.2.2.3 Clean Water Act. The Federal Water Pollution Control Act (FWPCA), as amended in 1972 and 1977, establishes a regulatory program, administered by EPA and the states, using water quality standards and technology-based standards to meet the national goal of eliminating the discharge of water pollutants by 1985. Standards for the steam electric power plant point-source category, applicable to all fuel types--coal, oil, natural gas, and nuclear--have been set which regulate both the chemical and thermal water discharges.

Chemical Discharges. There are three different technology-based standards which limit the allowable concentration of chemical pollutants from existing steam electric power plants. The BPT standard, derived from "best practicable control technology currently available," is the least stringent standard. The BAT standard, derived from "best available technology economically achievable," requires the highest level of control. The 1977 FWPCS amendments added the "best conventional pollutant control technology" standard (BCT) which lies between the BPT and BAT standards in stringency. The compliance deadline for the various standards is July 1, 1977 - BPTs; July 1, 1984 - BCTs; and July 1, 1984 - BATs. All new plants (construction commenced after March 4, 1974) must comply with new source performance standards (NSPS) at the time of start-up.

TABLE 3-1

SUMMARY OF NSPS FOR AIR EMISSIONS FROM OIL-FIRED
ELECTRIC UTILITY STEAM GENERATING UNITS

SO_2	PARTICULATES	NO_x
0.80 lbs/million Btu heat input and 90% reduction in potential SO_2 emissions. The product reduction does not apply if SO_2 emissions into the atmosphere are less than 0.20 lbs/million Btu heat input. Compliance determined by using a continuous monitor to obtain a 30 day average.	0.03 lbs/million Btu heat input. Opacity limited to 20% (6 minute average)	0.30 lbs/million Btu heat input from combustion of any liquid fuel, except shale oil and liquid fuel derived from coal.

Source: U.S. Environmental Protection Agency, 1979. Development for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C.

A summary of the EPA promulgated chemical effluent limitations is shown in Table 3-2. According to the 1977 FWPCA amendments and the June 1976 National Resources Defense Council (NRDC) Consent Decree, EPA must still promulgate BCT standards for conventional pollutants and must expand the scope of the BAT standard by addressing 129 toxic or priority pollutants.

Thermal Discharges. The thermal discharge limitations established by EPA are designed to reduce the amount of waste heat discharged to receiving water bodies. A summary of the EPA promulgated thermal discharge limitations is shown in Table 3-3. Because of the excessive capital costs and long lead times involved in the installation of closed cycle cooling systems, no thermal limitations were prescribed for existing small (less than 25 MW_e capacity) or old (500 MW_e or greater or operational before January 1, 1970; or 25 to 499 MW_e and operational before January 1, 1974) unit categories. Existing large base-load generating units must achieve a zero heat discharge standard (except for blowdown) by July 1, 1981. (A zero heat discharge requirement effectively means the installation of an off-stream cooling system.)

3.2.2.4 Other Related Legislation. The Toxic Substances Control Act (TSCA) of 1976, although it focuses primarily on the commercial manufacture and use of chemicals, may affect the disposal of hazardous chemical substances from utilities.

The Resource Conservation and Recovery Act (RCRA) of 1976 regulates the generation and ultimate disposal of hazardous wastes. This could affect the waste site selection and disposal operations for utility wastes.

TABLE 3-2

SUMMARY OF CHEMICAL EFFLUENT LIMITATIONS
FOR STEAM ELECTRIC POWER PLANTS

SOURCE	POLLUTANT	EFFLUENT LIMITATIONS* (mg/l)		
		BPT (1977)[a]	BAT (1984)[b]	NSPS[c]
• All Sources	pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
	Polychlorinated biphenols	No discharge	No discharge	No discharge
• Low Volume Wastes	Total suspended solids	30 (100 max)	30 (100 max)	30 (100 max)
	Oil and grease	15 (20 max)	15 (20 max)	15 (20 max)
• Bottom Ash Transport Water	Total suspended solids	30 (100 max)	30 (100 max)	30 (100 max)
	Oil and grease	15 (20 max)	15 (20 max)	15 (20 max)
• Fly Ash Transport Water	Total suspended solids	30 (100 max)	30 (100 max)	No discharge
	Oil and grease	15 (20 max)	15 (20 max)	No discharge
• Metal Cleaning Wastes	Total suspended solids	30 (100 max)	30 (100 max)	30 (100 max)
	Oil and Grease	15 (20 max)	15 (20 max)	15 (20 max)
	Copper	1.0 (1.0 max)	1.0 (1.0 max)	1.0 (1.0 max)
	Iron	1.0 (1.0 max)	1.0 (1.0 max)	1.0 (1.0 max)
• Boiler Blowdown	Total suspended solids	30 (100 max)	30 (100 max)	30 (100 max)
	Oil and grease	15 (20 max)	15 (20 max)	15 (20 max)
	Copper	1.0 (1.0 max)	1.0 (1.0 max)	1.0 (1.0 max)
	Iron	1.0 (1.0 max)	1.0 (1.0 max)	1.0 (1.0 max)

TABLE 3-2 (Concluded)

SUMMARY OF CHEMICAL EFFLUENT LIMITATIONS
FOR STEAM ELECTRIC POWER PLANTS

SOURCE	POLLUTANT	EFFLUENT LIMITATIONS* (mg/l)		
		BPT (1977)(a)	BAT (1984)(b)	NSPS(c)
• Once-Through Cooling	Chlorine-free available	0.2 (0.5 max)	0.2 (0.5 max)	0.2 (0.5 max)
• Cooling Tower Blowdown	Chlorine-free available	0.2 (0.5 max)	0.2 (0.5 max)	0.2 (0.5 max)
	Zinc	No limitation	1.0 (1.0 max)	None detectable
	Chromate	No limitation	0.2 (0.2 max)	None detectable
	Phosphorous	No limitation	5.0 (5.0 max)	None detectable
	Other corrosion inhibitors	No limitation	Case by Case	None detectable
• Area Runoff	Total suspended solids	50***	50	50

Notes: *Limitations are expressed as concentrations, mg/l, except for pH. Quantity discharge is limited to concentration limit x flow. For BAT, bottom ash limit is x flow/12.5 and for NSPS limit for bottom ash x flow/20. In some cases limits are given for the maximum allowable daily discharge for any one day.

**Applicable to all sources except once-through cooling.

***Area runoff limits are concentration limits only.

(a)BPT - best practicable control technology currently available, July 1, 1977.

(b)BAT - best available technology economically achievable, July 1, 1984.

(c)NSPS - new source performance standards. Applicable to any plant constructed after March 4, 1977.

Source: Code of Federal Regulations, Title 40, Part (400 to End).

TABLE 3-3

SUMMARY OF THERMAL DISCHARGE LIMITATIONS FOR STEAM ELECTRIC POWER PLANTS

The compliance deadline for existing plants is July 1, 1981. Extensions may be granted to no later than July 1, 1983. Plants whose construction began on or after March 4, 1974 must comply with the new source standards at the time of the start-up.

Existing Generating Units	
$500\ Mw_e$ and greater	
Operation commenced before January 1, 1970	No Limitation
Operation commenced on or after January 1, 1970	No Discharge*
$25\ Mw_e$ to $499\ Mw_e$	
Operation commenced before January 1, 1974	No Limitation
Operation commenced on or after January 1, 1974	No Discharge*
Less than $25\ Mw_e$	No Limitation
New Sources	
(all unit categories)	No Discharge**

Notes: Zero discharge limitations allow for blowdown from the cold-side of the system.

*Exceptions may be granted on a case-by-case basis for units in systems for less than $150\ MW_e$ capacity, units with cooling ponds or cooling lakes, units without sufficient land available, units with blowdown TDS 30,000 mg/l or greater, and neighboring land within 500 ft. of cooling tower(s), and units where a potential hazard to commercial aviation would exist.

**Waivers may be granted based upon a demonstration of excessive stringency according to Sec. 316 (a).

Source: Code of Federal Regulations, Title 40, Part (400 to End).

The Safe Drinking Water Act, the Coastal Zone Management Act, Noise Control Act, and the Endangered Species Act also have potential implications to the siting and operation of steam electric power plants.

3.3 Resource Consumption

3.3.1 Fuel Use

A typical 800 MWe plant burning #6 fuel oil, operating with a thermal efficiency of 34.7 percent and with a capacity factor of 55 percent, would consume about 6.18 x 10^6 barrels of fuel oil per year.

3.3.2 Energy Requirement

Table 3-4 gives the energy requirements in terms of a percentage of the total plant energy output for the various air, water, and noise pollution control devices which might be installed on an oil power plant.

3.3.3 Water Use

Water withdrawal and consumption estimates for open and closed cycle cooling systems are given in Table 3-5. Water withdrawal requirements are important environmental factors that affect site selection. Note that withdrawal requirements for open cycle cooling systems are inversely proportional to the rise in condenser cooling water temperature--this is typically 15°F (Teknekron, 1976). Withdrawal requirements for closed cycle cooling are primarily dependent upon the system design.

3.3.4 Land Use

Fixed and incremental land use requirements for the siting and operation of a typical 800 MWe oil fired power plant are given in Table 3-6. The fixed area consists of land that is permanently

TABLE 3-4

ENERGY REQUIREMENTS FOR THE OPERATION
OF POLLUTION CONTROL EQUIPMENT ON AN OIL-FIRED POWER PLANT

PROCESS	PERCENT ENERGY GENERATED
Air	
SO_2 Control	
Flue Gas desulfurization	
lime wet scrubbers	3.5
limestone wet scrubbers	4.0
Particulate Control	
Mechanical Collectors	
multiple cyclones	0.2-0.9
electrostatic precipitators	0.3
NO_x Control	
combustion modifications	0-0.6
Water	
Chemical Pollution Control	
wastewater treatment plant	0.01
evaporative ponds	0.04
complete treatment and reuse	0.2
Thermal Pollution Control	
Open Cycle	0
Closed cycle	
cooling ponds	1.0
mechanical draft towers	2.5
Noise	
Noise Control	<0.1

Source: U.S. Department of Commerce/U.S. Environmental Protection Agency. 1977. Energy Consumption of Environmental Controls: Fossil Fuel, Steam Electric Generating Industry.

TABLE 3-5

WATER USE REQUIREMENTS FOR FOSSIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

COOLING SYSTEM	WITHDRAWAL[a] (Acre-Ft Per Year)	CONSUMPTION[b] (Acre-Ft Per Year)
Once-through	65,000	250
Cooling pond or lake	1,300	<550
Spray pond		<550
Evaporative cooling tower		
mechanical draft	2,000	<550
natural draft	2,000	<550
Dry cooling tower		
mechanical draft	20[c]	0

Notes: [a]Data based upon a 1,000 MWe plant; University of Oklahoma, Energy Alternatives.
[b]Based upon scaled up data for a 680 MWe plant; EPA, Development Document.
[c]Make-up water for circulation.

Sources: Cootner, P.H. and G.O.G. Lof, 1974. Water Demand for Steam Electric Generation, 1965. An Economic Projection Model. Washington, D.C.

University of Oklahoma, 1975. Energy Alternatives: A Comparative Analysis. Norman, Oklahoma.

TABLE 3-6

LAND USE REQUIREMENTS FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btus Produced)

LAND COMMITTED	ACRES (Per 10^{12} Btus Output)
FIXED AREA	
Plant area	6-12
Cooling pond or lake	75-150
Spray pond	3-25
Evaporative cooling tower	
mechanical draft	0.6-1.4
natural draft	0.1-0.4
Dry cooling tower	
mechanical draft	0.5
INCREMENTAL AREA	**Acres/Year****
Waste disposal methods	
surface storage piles	.03
landfill	highly variable
evaporation ponds	NA*
conveyance to off-site disposal	NA

Notes: *Not available
**Annualized

Sources: U.S. Environmental Protection Agency, 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C.

Teknekron, Inc., 1975a. Water Pollution Control for the Steam Electric Power Industry. The National Committee on Water Quality. Volume I and II. Berkeley, California.

committed to the plant and cooling structures. The plant area consists of the fuel delivery terminals, fuel storage area, powerhouse, service bay, access roads and parking areas, and air pollution equipment. The range for fixed plant area in the literature is from 6 to 12 acres per trillion Btus output. However, the more reliable sources cite six acres per trillion Btus output.

Land requirements for closed cycle cooling systems vary depending upon the particular system design, the plant size, the heat rate, and climatic factors. Cooling ponds or lakes require large areas, generally one to two acres per MW_e (Teknekron, 1975a; University of Oklahoma, 1975). Evaporative and dry cooling towers are relatively compact units by comparison, requiring from 0.1 to 1.4 acres per trillion Btus output.

3.4 Residual Data

3.4.1 Water Pollutants

Table 3-7 lists the expected water pollutant discharge data from oil-fired electric power plants on a trillion Btu equivalent electrical output basis. These data are based on actual field monitoring and sampling surveys.

Because the gross residual discharges for the restricted pollutants are in compliance with all existing regulations, no removal is presently required. Standards do not yet exist for the other pollutants, including toxic pollutants, and therefore a zero percent removal efficiency was also assumed for these pollutants.

3.4.2 Air Pollutants

Table 3-8 shows both the gross and net air emissions from a typical oil-fired electric power plant burning two percent sulfur fuel oil containing 0.5 percent ash. The net air emissions are

TABLE 3-7

CHEMICAL WATER POLLUTANT DATA FOR OIL-FIRED ELECTRIC POWER PLANTS
(Tons Per 10^{12} Equivalent Btu Output)

POLLUTANT	OPEN CYCLE (Tons)	CLOSED CYCLE (Tons)
alkalinity (as $CaCO_3$)	26.9	27.3
acidity (as $CaCO_3$)	52.4	0.0
BOD (biochemical oxygen demand)	0.397	5.16
COB (chemical oxygen demand)	34.6	38.7
TDS (total dissolved solids)	109.	386.
TSS (total suspended solids)	69.2	69.2
ammonia (as N)	0.0743	0.0743
nitrate (as N)	0.605	0.605
phosphorus (as P)	0.0445	0.0445
aluminum	9.88	1.14
chloride	31.6	58.7
chromium	0.0313	0.0313
copper	0.0470	0.0470
iron	27.0	0.734
magnesium	6.19	69.9
nickel	4.37	4.37
sodium	83.1	83.1
sulfate	284.	268.
zinc	0.486	0.0426
oil and grease	0.00382	0.00382
	Gross*	
antimony	0.00334-0.0216	
arsenic	0.00723-0.00134	
benzene	0.0000174-0.000836	
beryllium		
cadium	0.000522-0.0139	
chloroform	<0.0000346	
cyanogens	<0.201	
lead	0.00948-0.000209	
mercury	0.00000677-0.000507	
phenol	0.0228	
selenium	0.0156-0.0128	
toluene	0.0640-0.000122	

*Data range is based upon plant samplings of a domestic residual oil-fired plant and a Venezuelan residual oil-fired plant. These values represent a minimum range, excluding Middle Eastern and African oils and excluding the minor effluent sources; Hittman, Trace Toxic Pollutant Coefficients for Energy Supply and Conversion.

Sources: Hittman Associates, Inc., 1977. Trace Toxic Pollutant Coefficients for Energy Supply and Conversion, Draft Final Report. Columbia, Maryland.

TABLE 3-8

AIR EMISSIONS FOR OIL-FIRED ELECTRIC POWER PLANTS
(Tons per 10^{12} Equivalent Btu Output)

POLLUTANT	GROSS	NET (Revised NSPS)
TSP (total suspended particulates)	410	43.2
particulates/arsenic	0.00963	0.001
particulates/beryllium	0.00769	0.0008
particulates/cadium	0.288	0.03
particulates/lead	0.00154	0.0002
particulates/mercury	0.00963	0.001
particulates/nickel	2.88	0.3
particulates/manganese	0.00963	0.001
particulates/chromium	0.0226	0.002
particulates/copper	0.0226	0.002
particulates/vanadium	0.0455	0.005
SO2	3,270	327
NO_x	432	432
H	9.8	9.8
CO	49.3	49.3

Sources: U.S. Environmental Protection Agency, 1977. Compilation of Air Pollutant Emission Factors. Third Edition. Office of Air and Waste Management. Research Triangle Park, North Carolina.

Daumeister, T., 1977. Standard Handbook for Mechanical Engineers. McGraw-Hill Book Company, New York.

consistent with the revised NSPS outlined in Table 3-1. In all cases, the derived removal efficiency for total suspended particulates (TSP) is applied to each of the trace metal particulates. Because standards do not exist for the other potential pollutants (hydrocarbons and CO), a zero percent removal efficiency is assumed.

3.4.3 Solid Waste

The primary sources of solid waste in fossil-fired power plants are scrubber sludge and ash. Therefore, the amount of solid waste captured is directly related to the fuel characteristics and the degree of air pollution emission control required.

The amount of scrubber sludge produced is dependent upon the size of the plant, fuel composition, type of FGD device installed (i.e., regenerative or non-regenerative), and the removal efficiency of the scrubber. The solid waste values shown in Table 3-9 are for a typical 800 MWe plant burning a 2.0 percent sulfur content fuel with an installed limestone scrubber operating at 90 percent efficiency. The sludge composition, before dewatering, is as follows: 60 percent water, 34 percent $CaSO_4$, five percent $CaSO_3$, and one percent other.

It is assumed that 100 percent of the ash in the fuel oil will be converted to fly ash. To meet the revised NSPS, an 89.5 percent particulate collection efficiency is required. The quantity of fly ash collected for disposal is only a small fraction of the total wet solid waste, i.e., slightly more than two percent.

3.4.4 Waste Heat Discharge

The thermal releases shown in Table 3-10 were computed based upon a plant efficiency of 34.7 percent, a waste heat discharge of 51.4 percent of the input energy into the cooling water system (also

TABLE 3-9

SOLID WASTE DISCHARGES FROM OIL-FIRED POWER PLANTS
(Tons Per 10^{12} Equivalent Btu Output)

SOURCE	WITHOUT SCRUBBERS	WITH NON-REGENERATIVE LIMESTONE SCRUBBERS[(a)]
Scrubber sludge	0	16,000
(60 percent water) (40 percent dry solids)		
Fly ash (100 percent dry solids)	370	370
Total solid waste	370	16,370

[(a)]Assumptions: 800 MW_e; S=2.0 percent; S removal efficiency = 90 percent.

TABLE 3-10

HEAT EMISSIONS FROM FOSSIL-FIRED POWER PLANTS

SOURCE	BTU/YEAR[a]	PER 10^{12} BTU (equivalent electrical output)
Stack loss	5.27×10^{12}	0.40×10^{12} Btu
Cooling water loss and miscellaneous station losses	19.48×10^{12}	1.48×10^{12} Btu
Totals	24.75×10^{12}	1.88×10^{12} Btu

[a] Assuming a thermal efficiency of 34.7 percent.

Source: Teknekron, Inc., 1975a. Water Pollution Control for the Steam Electric Power Industry. The National Committee on Water Quality. Volumes I and II. Berkeley, California.

including miscellaneous station losses), and a waste heat discharge of 13.9 percent of the input energy up the stacks (Teknekron, 1975a).

3.5 Occupational Health and Safety

The occupational health and safety coefficients shown in Table 3-11 are based upon the findings of Hittman (1974) based upon historical data. The accuracy of these coefficients is classified as "fair" - having an error probability of less than or equal to 50 percent. Permanent total disabilities are considered to represent 6000 days lost while other disabilities are estimated as 100 days lost; man-days lost are for injuries only (Hittman, 1974).

3.6 Economic Data

3.6.1 Power Plant Costs

The cost data and the materials and manpower requirements for building and operating an oil-fired power plant (exclusive of pollution abatement equipment and fuel costs) were derived from the Bechtel Corporation's "Energy Supply Planning Model." This data base used an 800 MWe rated model oil-fired power plant operating at 55 percent of full capacity, producing 13.15×10^{12} Btus of electrical output energy annually. All cost, materials, and manpower data were normalized on a trillion Btus output basis.*

Tables 3-12, 3-13, 3-14, 3-15, and 3-16 show the capital costs, annual operation and maintenance costs, cost of construction materials, manpower operational and maintenance (O&M) requirements, and

*Example: The cost of non-manual technical labor for building the model 800 MWe oil-fired power plant ($616,000 per trillion Btus annual output) was derived by dividing the absolute cost, $8.10 million, by the annual output, which is 13.15×10^{12} Btus per year.

TABLE 3-11

OCCUPATIONAL HEALTH AND SAFETY COEFFICIENTS FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btu Equivalent Electrical Output)

DEATHS	INJURIES	MAN-DAYS LOST*
0.00181	0.173	7.20

*For injuries only.

Source: Hittman Associates, Inc., 1974. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use. Volume I. Columbia, Maryland.

TABLE 3-12

CAPITAL COSTS FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

ITEMS	DOLLARS (1978)
Construction Labor	
non-manual technical labor	616,000
non-manual non-technical labor	174,000
manual labor	4,570,000
Labor total	5,360,000
Materials	
Wood products	74,600
chemicals & allied products	8,300
petroleum products	282,000
glass, clay & stone products	200,000
primary iron & steel products	194,000
primary non-ferrous metals	97,300
fabricated structural products	371,000
other fabricated products	340,000
Materials total	1,570,000
Equipment	
HVAC heating and cooling units	22,900
HVAC ductwork and accessories	11,000
turbines	2,270,000
electric welding sets	26,200
construction, mining & oil field equipment	706,000
materials handling equipment	74,400
general industry equipment	288,000
instrumentation & controls	118,000
electrical equipment	270,000
fabricated plate products	2,630,000
miscellaneous equipment	112,000
Equipment total	6,530,000
Other construction	3,970,000
Land & land rights	90,100
General plant	480,000
(Escalation during construction)	(3,940,000)
(Interest during construction)	(4,330,000)
(Working capital)	(2,090,000)
Capital cost total	18,000,000

Notes: Values in parentheses were not included in the total. Values have been rounded so they will not sum to the total.

Source: Bechtel Corporation, 1975. Energy Supply Planning Model, San Franciso, California.

TABLE 3-13

OPERATION & MAINTENANCE COSTS FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

ITEM	DOLLARS (1978)
Operation & Maintenance	
non-manual technical labor	76,700
non-manual non-technical labor	35,500
manual labor	127,000
Labor total	240,000
chemicals & allied products	6,390
glass, clay & stone products	2,590
primary iron & steel products	31,600
primary non-ferrous metals	1,750
fabricated structural products	25,000
other fabricated products	29,700
Materials total	97,000
turbines	19,200
construction, mining & oil field equipment	6,000
materials handling equipment	837
general industry equipment	1,220
instrumentation & controls	7,530
electrical equipment	29,000
miscellaneous equipment	8,440
Equipment total	72,200
natural gas	837
water	72,500
Utilities total	73,400
(Rent, royalties, etc.)	(6,160)
(All taxes)	(307,000)
(Services & miscellaneous)	(84,900)
Annual Operating Cost (excluding fuel)	482,000

Notes: Values in parentheses were not included in the total.
Values have been rounded so they will not sum to the total.

Source: Bechtel Corporation, 1975. Energy Supply Planning Model. San Francisco, California.

TABLE 3-14

CONSTRUCTION MATERIAL FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

MATERIALS	TONS*
concrete	6,555.13
total steel & castings	3,497.46
copper, brass & bronze	47.63
aluminum & castings	15.49
manganese	15.28
chromium	10.67
nickel	1.74
cast iron	28.28
steam turbogenerator (MWe)	60.84
steam turbine (1000 HP)	1.83
pumps & drivers (1000 HP)	1.83
heat exchangers (1000 ft^2)	12.17
boilers (10^6 lbs. steam per hr.)	.40

*Selected materials and equipment items.

Source: Bechtel Corporation, 1975. Energy Supply and Planning Model. San Francisco, CA.

TABLE 3-15

MANPOWER OPERATION & MAINTENANCE REQUIREMENTS
FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

PERSONNEL	WORKERS/YEAR
Operation & Maintenance	
electrical engineers	0.4
mechanical engineers	0.1
designers & draftsmen	0.1
supervisors & managers	1.3
other technical	0.5
Non-manual technical total	2.4
Non-manual, non-technical total	2.8
pipefitters	0.6
welders	0.6
electricians	1.2
mechanics	0.8
machinists	0.2
operators	1.5
teamsters & laborers	1.0
Manual total	5.8
Manpower total	11.0

Note: Values may not sum to totals due to rounding.

Source: Bechtel Corporation, 1975. Energy Supply and Planning Model. San Francisco, California.

TABLE 3-16

MANPOWER CONSTRUCTION REQUIREMENTS FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btu Equivalent Electrical Output)

PERSONNEL	WORKERS/YEAR				
	First Year	Second Year	Third Year	Fourth Year	Fifth Year
Construction (5 years)					
civil engineers	0.4	1.3	1.9	1.3	0.7
electrical engineers	0.3	1.0	1.4	0.9	0.5
mechanical engineers	0.3	0.8	1.1	0.7	0.4
designers & draftsmen	0.4	1.2	1.7	1.2	0.6
supervisors & managers	0.2	0.6	0.8	0.6	0.3
Non-manual technical total	1.6	4.9	6.8	4.7	2.5
Non-manual non-technical total	0.8	2.4	3.3	2.3	1.2
pipefitters	0	4.1	9.6	9.6	4.1
pipefitters/welders	0	1.8	4.3	4.3	1.8
electricians	0	2.9	6.7	6.7	2.9
boilermakers	0	3.1	7.2	7.2	3.1
boilermakers/welders	0	1.0	2.4	2.4	1.0
iron workers	0	1.4	3.4	3.4	1.4
carpenters	0	1.4	3.4	3.4	1.4
equipment operators	0	1.0	2.4	2.4	1.0
teamsters & laborers	0	2.5	5.7	5.7	2.5
other	0	1.2	2.9	2.9	1.2
Manual total	0	20.5	47.9	47.9	20.5
Construction Manpower Total	2.4	27.8	58.0	54.9	24.2

*Values may not sum to totals due to rounding.

Source: Bechtel Corporation, 1975. Energy Supply and Planning Model. San Francisco, California.

construction manpower requirements, respectively. Expenditures for pollution abatement equipment are not included in these tables. In Table 3-12, estimates for escalation and interest during construction and working capital are provided (shown within parentheses) but are not included in the capital cost total. In Table 3-13, the cost of fuel is excluded from the annual operation and maintenance cost. For the labor force requirements (Table 3-16), a construction period of five years is assumed. The non-manual technical and the non-manual non-technical labor costs were phased in according to the following scheme: 8 percent - first year, 24 percent - second year, 33 percent - third year, 23 percent - fourth year, and 12 percent - fifth year. The manual manpower costs were phased as follows: 0 percent - first year, 15 percent - second year, 35 percent - third year, 35 percent - fourth year, and 15 percent - fifth year.

3.6.2 Environmental Control Costs - Wastewater

Wastewater environmental control cost estimates were derived from EPA and Teknekron reports. These estimates are based upon a model plant size of 1000 MWe. Although plant size does have a direct bearing on abatement costs, no attempt was made to adjust these data to 800 MWe because the extrapolation error is considered to be minor in comparison with the overall uncertainty in the available abatement cost data. All abatement cost data were standardized to 1978 dollars.

Tables 3-17 and 3-18 give capital and O&M cost for the wastewater treatment facility, respectively. All compatible wastewater streams, including low volume wastes, equipment cleaning wastes, and boiler blowdown are presently combined and treated in a central treatment plant. Contingency and fixed charges against capital costs for escalation and interest during construction and operation are provided (shown in parentheses) but are not included in the engineering cost totals.

TABLE 3-17

CAPITAL COSTS FOR CENTRAL TREATMENT PLANT
FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

ITEMS	DOLLARS (1978) Retrofit	New Source
Equipment Cost		
equalization tank no. 1	9,930*	9,930
equalization tank no. 2	5,810	5,810
equalization tank no. 3	519	519
oil removal tank no. 1	850	850
oil removal tank no. 2	769	769
reactor system	403	403
clarifier	1,870	1,870
filters	894	894
pumps and piping	1,810	1,810
• Equipment subtotal	22,800	22,800
• Installation Cost		
50% new sources		11,400
100% retrofit	22,800	
• Instrumentation Cost - 20%	4,570	4,570
• Total Equipment Cost	50,300	38,800
Construction Cost	50,300	38,800
• labor cost - 15%	7,540	5,840
• (contingency costs - 15%)	(7,540)	(5,840)
Total capital cost	57,800	44,700

Note: Values may not sum in totals due to rounding. Values in parentheses were not included in the total.

Source: U.S. Environmental Protection Agency, 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C.

TABLE 3-18

OPERATION AND MAINTENANCE COSTS FOR CENTRAL TREATMENT PLANT FOR OIL-FIRED POWER PLANTS (Per 10^{12} Btus Equivalent Electrical Output)

ITEMS	DOLLARS (1978)	
	Retrofit	New Source
Construction Cost (CC)	51,000*	39,400
Total Capital Cost (TCC)	58,600	45,300
Operation		
chemicals and power	3,130	3,130
labor	16,100	16,100
maintenance @ 3% of CC	1,470	1,130
(fixed charges @ 15% of TCC)	(9,540)	(7,380)
Total annual cost	20,700	20,400

Notes: Flow basis is 205 GPD/MW.
Values have been rounded so they will not sum to the total.

Tables 3-19 and 3-20 give capital and operating costs for alternative open and closed cooling wastewater treatment system options, respectively. (The chlorine minimization program option costs were used in the summary sheet in Volume 1, of this series.)

Area runoff, consisting of rainfall drainage from materials storage and construction sites, is primarily a function of local meteorological conditions and the amount of affected area. In the case of an oil-fueled plant, negligible amounts of runoff occur from the on-site fuel storage tank area. Temporary facilities are needed to treat construction runoff during the five-year construction period. Retrofit construction operations may also require treatment facilities.

Table 3-21 gives the capital and annual operating expenses for area runoff treatment facilities. These cost estimates were derived from Teknekron (1975a).

The cost estimates pertaining to cooling water systems were derived from the EPA Development Document, a Teknekron study, and a University of Oklahoma report (U.S. Environmental Protection Agency, 1974; Teknekron, 1975b; and University of Oklahoma, 1975). Cost estimates are highly site dependent, depending upon system design, local meteorological conditions, and regional construction costs. In general, the costs for cooling systems averaged less than ten percent of the plant cost (U.S. Environmental Protection Agency, 1974).

Table 3-22 lists the capital costs for various cooling modes. Table 3-23 estimates the annual operating and maintenance costs, excluding the additional fuel costs and blowdown treatment, for various cooling modes of fossil-fueled power plants. These estimates are based primarily upon cost data (for the 800 MW_e range) presented in

TABLE 3-19

CAPITAL AND OPERATING COSTS FOR TREATMENT OF ONCE-THROUGH COOLING WATER DISCHARGE FOR FOSSIL-FIRED POWER PLANTS (Per 10^{12} Btus Equivalent Electrical Output)

TREATMENT TECHNOLOGY	DOLLARS (1978)	
	Capital Costs	Annual Operating Costs
Chlorine minimization program	8,520	985
Mechanical system	46,800	3,950
Dechlorination system	12,200	973
Lime precipitation	724,000	18,400
Activated carbon	7,300,000	367,000

Source: U.S. Environmental Protection Agency, 1978. Technical Report for Revision for Steam Electric Effluent Limitations Guidelines. Washington, D.C.

TABLE 3-20

CAPITAL AND OPERATING COSTS FOR TREATMENT OF COOLING TOWER BLOWDOWN FOR FOSSIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

TREATMENT TECHNOLOGY	DOLLARS (1978)	
	Capital Costs	Annual Operating Costs
Chlorine minimization program	6,080	985
Mechanical system	46,800	3,950
Dechlorination system	8,520	2,430
Lime precipitation	115,000	166,000
Activated carbon	115,000	29,800

Source: U.S. Environmental Protection Agency, 1978. Technical Report for Revision for Steam Electric Effluent Limitations Guidelines. Washington, D.C.

TABLE 3-21

CAPITAL AND OPERATING COSTS FOR AREA RUNOFF TREATMENT FACILITIES FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

COST ITEMS	DOLLARS (1978)
CAPITAL COSTS	
Materials Storage Area Runoff	-
Construction Area Runoff (5 years)	
excavation costs	5,300
chemical treatment facility costs	12,000
trenching costs	280
Total Capital Costs	18,000
ANNUAL OPERATING COSTS	
Materials Storage Area Runoff	-
Construction Area Runoff (5 years)	
operation (labor, power, chemicals)	negligible
maintenance	
labor	700
Total Annual Operating Costs	700

Source: Teknekron, Inc., 1975a. Water Pollution Control for the Steam Electric Power Industry. The National Committee on Water Quality. Volumes I and II. Berkeley, California.

TABLE 3-22

CAPITAL COSTS FOR COOLING SYSTEMS FOR FOSSIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

COOLING SYSTEM	DOLLARS (1978)*
Once-through	391,000
Cooling Pond	782,000
Evaporative Cooling	
mechanical draft	753,000
natural draft	1,190,000
Dry Cooling Towers	
mechanical draft	2,360,000
natural draft	2,630,000

Note: Exclusive of escalation and indirect costs during construction.

Source: U.S. Environmental Protection Agency, 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C.

TABLE 3-23

OPERATION AND MAINTENANCE COSTS FOR COOLING SYSTEMS
FOR FOSSIL-FIRED POWER PLANTS
(Per 10^{12} Btus Equivalent Electrical Output)

COOLING SYSTEM	DOLLARS (1978)
Once-through	1,000[a]
Cooling pond	1,400[b]
Evaporative Cooling Towers	
mechanical draft	4,000[c]
natural draft	2,000[d]

Notes: [a]Based upon an EPA sampling of one 820 MWe plant.
[b]Based upon an EPA sampling of one 792 MWe plant.
[c]Based upon a Teknekron ratio applied to EPA data (820 MWe plant).
[d]Based upon an EPA sampling of one 820 MWe plant.

Sources: Teknekron, 1975a. Water Pollution Control for the Steam Electric Power Industry. The National Committee on Water Quality. Volume I and II. Berkeley, California.

U.S. Environmental Protection Agency, 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C.

the EPA Development Document (1974). The operation and maintenance cost estimate for the mechanical draft tower was derived by applying a proportional cost estimate from a Teknekron report to the EPA data (Teknekron, 1976).

3.6.3 Air Quality Control Costs

Capital and operating cost estimates shown in Table 3-24 for FGD systems were obtained from Teknekron (1975b). Costs are specified for five different FGD systems operating with a 90 percent removal efficiency installed on a new 1000 MWe plant burning 2.5 percent sulfur fuel oil (Teknekron, 1976). The lime/limestone nonregenerative systems are currently the most popular types of scrubbers. The reason a 2.5 percent sulfur fuel is used in this case, when most oil-fired power plants today are burning a 1.0 percent sulfur fuel, is because more of today's residual oil undergoes some degree of desulfurization at the refinery. If a scrubber system is installed on a plant, they will no longer need to pay the price for desulfurized fuel oil. To date, only a few oil-fired plants have installed FGD systems. If any new plants are built, they will most likely have to install some type of FGD system in order to meet the NSPS standards.

Approximate capital cost ranges shown in Table 3-25 for particulate removal were derived from an annual Federal Energy Regulatory Commission (FERC) survey report 1979. Costs ranges are specified for three common types of particulate control-mechanical collectors, electrostatic precipitators (ESPs), and combination units. Annual inventory survey data of the steam electric power industry compiled by FERC were used because they contained plant-by plant precipitator cost data for every oil-fired plant existing in 1975 (Federal Energy Regulatory Commission, 1979). Cost estimates vary widely because of economies of scale differences in removal efficiences, unique equipment and system designs, different fuel and ash characteristics,

TABLE 3-24

CAPITAL AND OPERATING COSTS FOR FLUE GAS DESULFURIZATION PROCESSES FOR OIL-FIRED POWER PLANTS (per 10^{12} Btu Equivalent Electrical Output)

FGD PROCESS	DOLLARS (1978) Capital Costs	DOLLARS (1978) Annual Operating Costs (Equipment Lifetime 30 Years)
Limestone Wet-Scrubbing	1,900,000	632,000
Lime Wet-Scrubbing	2,130,000	760,000
Magnesium Oxide Scrubbing - regeneration	1,900,000	690,000
Sodium Scrubbing - regeneration	1,750,000	968,000
Catalytic Oxidation	3,750,000	627,000

Source: Teknekron, Inc., 1975b. An Integrated Technology Assessment of Electric Utility Energy Systems. Berkeley, California.

TABLE 3-25

CAPITAL COSTS FOR PARTICULATE PRECIPITATORS
FOR OIL-FIRED POWER PLANTS
(Per 10^{12} Btu Equivalent Electrical Output)

PRECIPITATOR	DOLLARS (1978) CAPITAL COSTS
Mechanical Collector	37,100 - 234,000
Electrostatic Precipitator	123,000 - 701,000
Combination Units	220,000 - 689,000

Source: Federal Energy Regulatory Commission, 1979. Steam Electric Plant Air and Water Quality Control Data.

and regional economic differences. Presently, the most popular type of fly ash control device installed on oil-fired boilers is the mechanical collector. If any new plants are built, it is expected that they will install ESPs in order to meet the revised NSPS standards.

3.7 References

Bechtel Corporation, 1975. Energy Supply and Planning Model. San Francisco, California.

Code of Federal Regulations, Title 40, Part (400 to End).

Cootner, P.H. and G.O.G. Lof, 1974. Water Demand for Steam Electric Generation, 1965. An Economic Projection Model. Washington, D.C.

Daumeister, T., 1977. Standard Handbook for Mechanical Engineers. McGraw-Hill Book Company, New York.

Edison Electric Institute, 1978. Statistical Year Book for 1977. No. 45, Washington, D.C.

Federal Energy Regulatory Commission, 1979. Steam Electric Power Plant Air and Water Quality Control Data.

Hittman Associates, Inc., 1974. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I. Columbia, Maryland.

Hittman Associates, Inc., 1977. Trace Toxic Pollutant Coefficients for Energy Supply and Conversion, Draft Final Report. Columbia, Maryland

National Coal Association, 1978. Steam Electric Plant Factors.

Teknekron, Inc. 1975a. Water Pollution Control for the Steam Electric Power Industry. The National Committee on Water Quality. Volume I and II. Berkeley, California.

Teknekron, Inc., 1975b. An Integrated Technology Assessment of Electric Utility Energy Systems. Berkeley, California.

Teknekron, Inc. 1976. An Integrated Technology Assessment of Electric Utility Energy Systems. Berkeley, California.

University of Oklahoma, 1975. Energy Alternatives: A Comparative Analysis. Norman, Oklahoma.

U.S. Department of Commerce/U.S. Environmental Protection Agency, 1977. Energy Consumption of Environmental Controls: Fossil Fuel, Steam Electric Generating Industry.

U.S. Environmental Protection Agency, 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. Washington, D.C.

U.S. Environmental Protection Agency, 1975. Water Pollution Control for the Steam Electric Power Industry. Volume 1.

U.S. Environmental Protection Agency, 1977. Compilation of Air Pollutant Emission Factors. Third Edition. Office of Air and Waste Management. Research Triangle Park, North Carolina.

U.S. Environmental Protection Agency, 1978. Technical Report for Revision for Steam Electric Effluent Limitations Guidelines. Washington, D.C.

U.S. Environmental Protection Agency, 1979. Development for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category, Washington, D.C.

4.0 CRUDE OIL STORAGE IN SALT DOMES

Uncertainty in petroleum supply has resulted in the development of salt dome caverns for the storage of crude oil. Salt domes exist in various regions of the United States. Some salt domes have been excavated for salt leaving sizable caverns. Some of these caverns have been used as crude oil storge reservoirs.

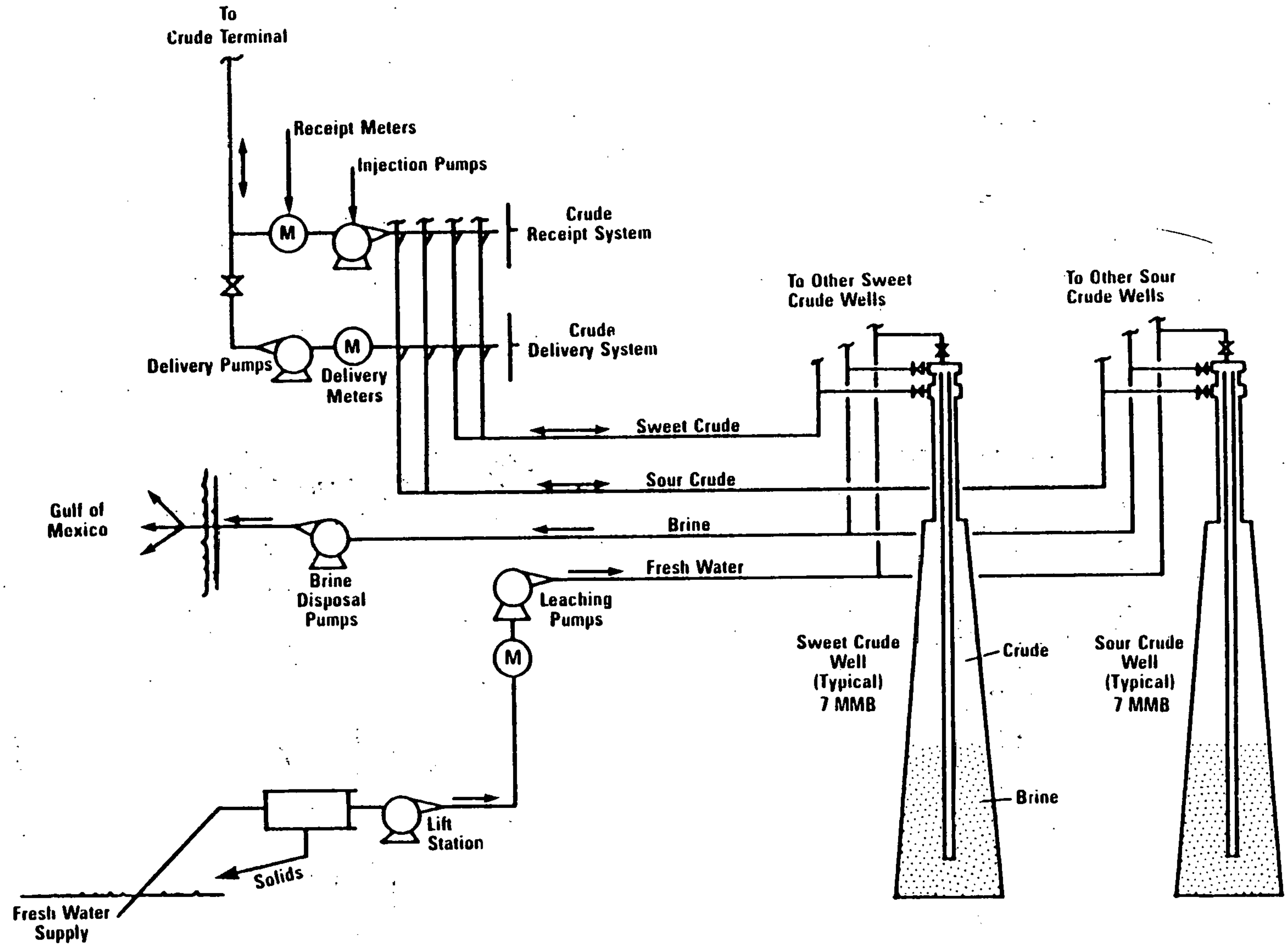
4.1 Characteristics of Salt Dome Storage

As shown in Figure 4-1, a salt dome storage facility consists of salt dome caverns, pipelines to carry water and brine and to deliver and discharge crude, a large body of water nearby, and crude oil delivery facilities (Strategic Petroleum Reserve, 1977). The salt dome caverns, schematically shown in Figure 4-2, are made by leaching the salt domes with water and discharging the resulting brine in an environmentally acceptable manner (Strategic Petroleum Reserve, 1977). Usually, the caverns are provided with a cement casing to protect the subterranean water quality.

The salt dome caverns are filled with domestic and/or imported oil that has been delivered to the crude terminal. During the cavern fill-up, brine is displaced and discharged into a large nearby body of water, for example, the Gulf of Mexico. When the need for oil arises, water is pumped into the caverns to force the oil out and back through the distribuiton system to the crude oil terminal for redistribution. The fill-up and withdrawal processes are illustrated in Figure 4-2.

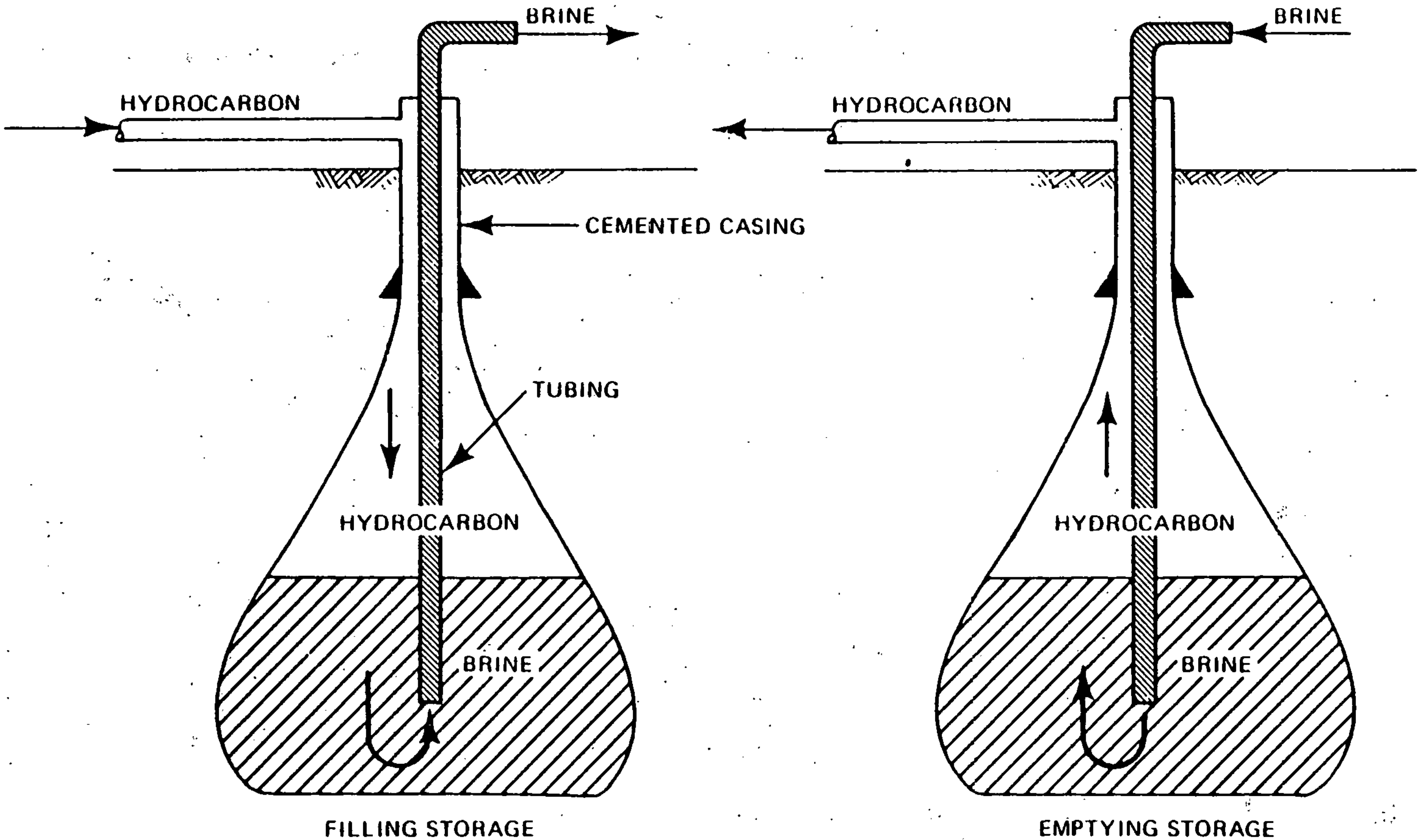
4.2 Constraints

The major constraint is the need for a large body of water as a source for water as the displacement medium and as a sink for discharging brine in an environmentally acceptable manner. The crude oil handling, transportation, and storage facility present some concerns in terms of fugitive emissions and risk of oil spills; these



Source: Strategic Petroleum Reserve, 1977. Supplement Final Environmental Impact Statement. West Hackberry Salt Domes. NTIS PB 265 796.

FIGURE 4-1
KEY ELEMENTS OF A SALT DOME STORAGE FACILITY



Source: Strategic Petroleum Reserve, 1977. Supplement Final Environmental Impact Statement. West Hackberry Salt Domes. NTIS PB 265 796.

FIGURE 4-2
UTILIZATION OF SALT DOME CAVERNS FOR STORAGE

concerns, common to all crude oil handling and storage operations, can be minimized by adequate design and equipment selection.

4.3 Resource Requirements

4.3.1 Energy Requirement

Electrical power is needed to operate the oil distribution system, the fill-up and withdrawal system, and miscellaneous other purposes. The energy requirement for these operations is considered to be a relatively small fraction of the energy stored in the caverns and is thus ignored.

4.3.2 Land Requirements

The pipelines required for water, oil, and brine transport and the above-ground salt dome site facilities involve the permanent commitment of land; this requirement is highly site-specific since it depends on the proximity of an appropriate water body to the salt dome facility as well as the distance to the oil terminal and the reaction time requirements designed into the fill-up/withdrawal system. For the West Hackberry salt dome site (Strategic Petroleum Reserve, 1977), the fixed plant land requirement is estimated to be about 1.6 acres per trillion Btu of crude oil stored; the pipeline right-of-way requires about 0.8 acres per trillion Btu of oil stored.

4.3.3 Water Requirements

The water required for leaching salt dome caverns to store a trillion Btu crude oil is estimated (Strategic Petroleum Reserve, 1977) to be 56,250,000 gallons or 173 acre-feet. Each pumping operation for withdrawal of crude oil requires about 24 acre-feet per trillion Btu of crude oil withdrawn.

4.4 Residuals and Products

4.4.1 Residuals in Air

The residuals in air mainly consist of hydrocarbons from evaporation and leakage i.e., fugitive emissions. In the event of oil spillage, these hydrocarbon concentrations will increase by several fold locally. The total quantity of annual hydrocarbon fugitive emissions is estimated to be 2.27 tons per trillion Btu energy stored.

4.4.2 Residuals in Water

The leaching operation produces a large quantity of brine estimated to be about 196 acre-feet per trillion Btu crude oil storage capacity. This brine must be either discharged in an environmentally and ecologically acceptable manner or used to make salt as a by-product. In addition, it is estimated that each crude oil fill-up operation produces about 24 acre-feet of brine.

4.4.3 Solid Waste Produced

The solid waste produced in operating a salt dome cavern crude oil storage is negligible. However, during the construction phase, some earth needs to be excavated to lay the pipelines. The quantity of this excavated solid depends on the length of the pipelines and the terrain; this solid waste can be disposed of in an environmentally acceptable manner.

4.4.4 Heat Dissipation

Heat generated during the crude oil storage and withdrawal operations associated with salt dome caverns is considered to be minimal and can be neglected for all practical purposes.

4.4.5 Energy Product Stored

The quantity of crude oil stored is estimated to be 178,572 bbl per trillion Btu capacity storage.

4.5 Economic Data

4.5.1 Construction, Operation and Maintenance Costs

These costs are not firmly established; the projected cost for construction of the salt dome facilities and equipment is about $230,000 per trillion Btu of crude oil storage capacity; operation and maintenance (O&M) costs are not available but are expected to be negligible (Petroleum Storage for National Security, 1975).

4.5.2 Environmental Compliance Costs

The costs for constructing environmental safeguards are not currently available since they are highly site-specific. The costs associated with the operation and maintenance of such safeguards are assumed to be negligible.

4.5.3 Personnel Requirement

The personnel required to construct a salt dome facility is estimated to be 0.6 man years per trillion Btu crude oil storage capacity (Strategic Petroleum Reserve, 1977). The data for operation and maintenance manpower requirements are not available.

4.5.4 Occupational Safety

This data for petroleum storage in salt dome caverns is not available; it is assumed that the risks of fire or explosions in salt dome cavern operations are less than those associated with conventional tank storage systems. Thus the occupational hazards as well as losses from the potential fires and explosions in underground crude oil storage systems are expected to be less than those associated with conventional storage systems.

4.6 References

Petroleum Storage for National Security, 1975. National Petroleum Council, Washington, D.C.

Strategic Petroleum Reserve, 1977. Supplement Final Environmental Impact Statement. West Hackberry Salt Dome. NTIS PB265796.