Energy Alternatives: A Comparative Analysis

Prepared for CEQ • ERDA • EPA • FEA • FPC • DOI • NSF

Energy Alternatives: A Comparative Analysis

Prepared for

Council on Environmental Quality
Energy Research and Development Administration
Office of the Assistant Administrator for Planning and Analysis
Environmental Protection Agency
Division of Policy Planning
Office of Energy Research
Federal Energy Administration
Office for Environmental Programs
Federal Power Commission
Office of Energy Systems
Department of the Interior
Bureau of Land Management
Office of Research and Development
National Science Foundation
Office of Energy R & D Policy

by The Science and Public Policy Program, University of Oklahoma, Norman, Oklahoma

May 1975

PREFACE AND ACKNOWLEDGMENTS

The descriptions and analysis of energy resource systems in this report were prepared by an interdisciplinary research team working under the Science and Public Policy Program at the University of Oklahoma. The study, conducted under Contract Number EQ4ACØ34 with the Council on Environmental Quality, was funded by the Atomic Energy Commission (now a part of the Energy Research and Development Administration), Council on Environmental Quality, Department of Interior, Bureau of Land Management, Environmental Protection Agency, Federal Energy Administration, and Federal Power Commission.

The Science and Public Policy Program was able to develop this report in a relatively short time because the first part of the report parallels and draws heavily on research being carried out under phase one of a complementary project supported by National Science Foundation Grant Number SIA74-17866, "An Energy Systems Analysis of Alternative Resource Options." This volume will serve as a publicly available data base for the National Science Foundation study.

The team which prepared this report included: Don E. Kash, Director of the Science and Public Policy Program and Professor of Political Science; Irvin L. (Jack) White, Assistant Director of the Science and Public Policy Program and Professor of Political Science; Karl H. Bergey, Research Fellow in Science and Public Policy and Professor of Aerospace, Mechanical, and Nuclear Engineering; Michael A. Chartock, Research Fellow in Science and Public Policy and Assistant Professor of Zoology; Michael D. Devine, Research Fellow in Science and Public Policy and Associate Professor of Industrial Engineering; James B. Freim, Research Fellow in Science and Public Policy and Assistant Professor of Aerospace, Mechanical, and Nuclear Engineering; Martha W. Gilliland, Research Fellow in Science and Public Policy; Timothy A. Hall, Research Assistant in Science and Public Policy; David A. Huettner, Research Fellow in Science and Public Policy and Associate Professor of Economics; R. Leon Leonard, Research Fellow in Science and Public Policy and Assistant Professor in Aerospace, Mechanical, and Nuclear Engineering; Paul J. Root, Research Fellow in Science and Public Policy and Professor of Petroleum and Geological Engineering; Thomas J. Wilbanks, Research Fellow in Science and Public Policy and Associate Professor and Chairman of Geography; and David Willcox, Research Fellow in Science and Public Policy and Visiting Assistant Professor of Philosophy. The team's research was supported by Hee Man Bae, Cary Bloyd, Robert W. Rycroft, and Cheryl Swanson, all Research Assistants in Science and Public Policy. Mark Elder, Co-Director of Program Development, Office of Research Administration, was technical editor of the report.

A number of people served as consultants on the study, and we wish to express our appreciation to them for their assistance and expert advice. They include: Marlan Blissett, Associate Professor, the LBJ School of Public Affairs, University of Texas-Austin; James Christensen, Associate Professor of Chemical Engineering and

Materials Science, University of Oklahoma; Donald E. Menzie, Professor of Petroleum and Geological Engineering, University of Oklahoma, and Paul G. Risser, Director of the Oklahoma Biological Survey. Pong N. Lem of the Denver National Environmental Research Center, Environmental Protection Agency, provided particularly useful critiques of the preliminary report.

The staff of the Science and Public Policy Program was indispensable in the preparation of this study. Janice K. Whinery directed the logistics as Project Specialist. Peggy L. Neff directed the preparation of the manuscript as Clerical Supervisor and, with Pamela J. Dickey, Carol B. Friar, Linda Edzards, and Pamela K. Hignite, typed the numerous research papers and drafts of this report. Martha T. Jordan and Nancy J. Creighton served as research assistants and were essential in handling the data and references for the report. Ginna A. Davidson was scientific illustrator and prepared most of the figures. Sheila Mulvihill was the Technical Editor for the Council on Environmental Quality.

Sole responsibility for the contents of this report rests with the Science and Public Policy Program of the University of Oklahoma. Any factual or interpretative errors are those of the research team which conducted the research and prepared this report.

We also wish to express appreciation for the advice and suggestions of members of the Interagency Committee: Steven Jellinek, Barrett Riordan, and Malcolm Baldwin, Council on Environmental Quality; Carolita Kallaur, Flora Milans, Rima Cohen, Matthew J. Reilly, and Nicolai Timenes, Jr., Department of the Interior; Richard Livingston, Environmental Protection Agency; Richard H. Williamson, Energy Research and Development Administration; Kenneth Woodcock and Ernest Sligh, Federal Energy Administration; Richard Hill, Federal Power Commission. In addition, Stephen Gage, now at the Environmental Protection Agency, played a major conceptual role while he was at the Council on Environmental Quality during the early period of the study. We want to express particular appreciation to Marvin Singer, Chairman of the Interagency Committee, who provided invaluable assistance and support. Finally, we wish to thank Charles Johnson and William Wetmore of the Office of Systems Integration and Analysis, Research Applied to National Needs Division of National Science Foundation, for assistance in coordinating the National Science Foundation-funded research with this study.

TABLE OF CONTENTS

PAGE

PART I: DESCRIPTIONS OF ENERGY RESOURCE SYSTEMS

CHAPTER 1: THE COAL RESOURCE SYSTEM

PAGE

PAGE

PAGE

CHAPTER 2: THE OIL SHALE RESOURCE SYSTEM

CHAPTER 3: THE CRUDE OIL RESOURCE SYSTEM

CHAPTER 4: THE NATURAL GAS RESOURCE SYSTEM

PAGE

CHAPTER 5: THE TAR SANDS RESOURCE SYSTEM

CHAPTER 6: THE NUCLEAR ENERGY--FISSION RESOURCE SYSTEM

PAGE

PAGE

CHAPTER 7: THE NUCLEAR ENERGY--FUSION RESOURCE SYSTEM

CHAPTER 8: THE GEOTHERMAL ENERGY RESOURCE SYSTEM

PAGE

PAGE

CHAPTER 9: THE HYDROELECTRIC RESOURCE SYSTEM

CHAPTER 10: THE ORGANIC WASTE RESOURCE SYSTEM

CHAPTER 11: THE SOLAR RESOURCE SYSTEM

PAGE

CHAPTER 12: ELECTRIC POWER GENERATION

PAGE

CHAPTER 13: ENERGY CONSUMPTION

PART II: PROCEDURES FOR EVALUATING AND COMPARING ENERGY ALTERNATIVES

CHAPTER 14: PROCEDURES FOR COMPARING THE RESIDUALS OF ENERGY ALTERNATIVES

CHAPTER 15: PROCEDURES FOR COMPARING THE ENERGY EFFICIENCIES OF ENERGY ALTERNATIVES

APPENDIX TO CHAPTER 15: SUGGESTIONS CONCERNING IMPACT ANALYSIS

PAGE

CHAPTER 16: COMPARING THE ECONOMIC COSTS OF ENERGY ALTERNATIVES

LIST OF TABLES

TABLE		PAGE
	8-23

TABLE		PAGE
8-8	Cooling Tower Discharge Plant Reinjected at the Geysers	8-24
8-9	Capital Costs of Geothermal Power Plants, 1973	8-25
8-10	System Efficiency; Wellhead Through Electric Power Generation	8-25
8-11	Environmental Residuals for Geothermal Development at the Geysers	8-26
8-12	1972 Costs for Geothermal Power	8-27
8-13	Costs of Geothermal Power Generation Systems	8-28
9-1	U.S. Hydroelectric Power Resources by Region	9-5
9-2	Relationship of Operating Head and Water Flow to Power Output	9-10
9-3	1972 U.S. Hydroelectric Power Costs by Region	9-15
9-4	Relationship of 1967 Capital Cost to Operating Head	9-15
10-1	Composition of Municipal Refuse Materials and Chemicals	10-3
10-2	Quantities of Organic Wastes by Source	10-4
10-3	Percent of Various Fuels Potentially Represented by Organic Wastes	10-5
10-4	Products from Garrett Pyrolysis	10-12
10-5	Products from BuMines Pyrolysis	10-13
10-6	Pyrolysis Costs and Revenue	10-15
10-7	1972 Costs for Direct Burning of Organic Waste	10-17
10-8	Energy Efficiencies for Utilization of Organic Wastes	10-18
11-1	Solar Radiation at Selected Locations in the United States During 1970	11-5
11-2	Annual Energy Output for Various Windmill Diameters in Central United States	11-17
12-1	Energy Sources for 1972 U.S. Electricity Generation	12-1
12-2	Technological Status of Some Stack-Gas Sulfur Dioxide-Removal Processes	12-14
12-3	Cooling Water Requirements for 1,000-Mwe Plant	12-16
12-4	Residuals for Boiler-Fired Power Plants	12-18
12-5	Generation Costs (1971) For Steam Power Plants With No Stack Gas Cleaning	12-22
12-6	Sulfur Dioxide and Particulate Control System Cost	12-23
12-7	Costs of Cooling Systems for Steam-Electric Plants	12-25
12-8	Residuals for Environmentally Controlled Combined-Cycle Electricity Generation	12-29
12-9	Costs for Westinghouse Combined Cycle Fluidized-Bed System	12-30
12-10	Major Residuals for 1,000-Mwe Plants at 75 Percent Load Factor	12-40
12-11	Average Costs of U.S. Electricity, 1968	12-44
12-12	Example of Residential Electricity Rate Structure	12-44
12-13	Average 1968 Generation Costs	12-46
12-14	Example of Fixed Charge Rate for Conventional Steam Plant	12-46
13-1	Total and Per Capita U.S. Energy Consumption	13-2
13-2	Energy Consumption in the U.S. by End Use, 1960-1968	13-3
13-3	Fuel Consumption for Major End Uses in the Residential and Commercial Sector, 1970	13-6
13-4	Space Heating Efficiencies by Fuel for the Residential and Commercial Sector	13-8
13-5	Coefficients of Performance for Electrically Driven Heat Pumps With Various Sources and Sinks	13-8
13-6	Residuals for Space Heating Energy Use	13-10
13-7	Annual Fuel Cost and Consumption for Space Heating	13-11
13-8	Variations in Performance of Selected Air Conditioners	13-12
13-9	Residuals for Air Conditioning Energy Use	13-13
13-10	Water Heating Efficiencies by Fuel for the Residential and Commercial Sector	13-14
13-11	Residuals for Water Heating Energy Use	13-15
13-12	Residuals for Cooking Energy Use	13-18
13-13	Annual Fuel Consumption for Six Major Industrial Uses	13-24
13-14	Energy Intensiveness of Major Industrial Groups	13-24
13-15	Residuals for Industrial Energy Use	13-28
13-16	Fuel Sources for Transportation, 1970	13-33
13-17	Categories of Transportation Use	13-33

TABLE		PAGE
13-18	End Use of Energy Within the Transportation Sector, 1970	13-34
13-19	Methods of Inter-City Freight Traffic	13-35
13-20	Energy Intensiveness of Freight Traffic	13-36
13-21	Residuals for Freight Transportation Energy Use	13-37
13-22	Inter-City Freight Transportation Price Data	13-38
13-23	Methods of Inter-City Passenger Traffic	13-39
13-24	Energy Intensiveness of Inter-City and Urban Passenger Travel	13-42
13-25	Residuals for Passenger Transportation Energy Use	13-43
13-26	Passenger Transportation Prices	13-44
13-27	Residuals for Military and Government and Feedstocks Transportation Energy Use	13-46
13-28	Effect of Auto Design on Fuel Economy	13-47
14-1	Residuals of the Proposed Action: Synthane High-Btu Gasification	14-6
14-2	Residuals of a Technological Alternative: Lurgi High-Btu Gasification	14-7
14-3	Residuals of a Locational Alternative: Synthane Facility Moved to Demand Center	14-8
14-4	Residuals of a Source Alternative: Alaskan Natural Gas via Canadian Pipeline	14-10
14-5	Residuals of a Source Alternative: Alaskan Natural Gas via Alaskan Pipeline and LNG Tanker	14-11
14-6	Residuals of a Source Alternative: Offshore Natural Gas	14-13
14-7	Residuals of a Source Alternative: Imported LNG	14-14
14-8	Totals by Trajectory for Categories of Residuals	14-15
14-9	Totals by Location for Categories of Residuals	14-18
14-10	Comparison of Environmental Protection Agency Source Standards and Expected Emissions	14-33
14-11	Potential Impacts of Air Pollutants and Ambient Data Required to Evaluate Them	14-33
14-12	Ground Level Ambient Air Concentrations of Particulates for Worst Cases	14-34
14-13	Ground Level Ambient Air Concentrations of Particulates for Two Meteorological Conditions	14-35
14-14	Frequency of High Air Pollution Potential of Colstrip, Montana	14-36
14-15	Mid-Afternoon Mixing Depths at Colstrip	14-37
14-16	Potential Impacts of Water Demand and Data Required for Its Evaluation	14-38
14-17	Ambient Data Needed to Evaluate Impact of Water Requirement on Water Quantity	14-39
14-18	Percent of River Flow and Consumptive Use in Montana Represented by Gasification Water Demand	14-39
15-1	Efficiencies of the Proposed Action: Synthane High-Btu Gasification	15-6
15-2	Efficiencies of a Technological Alternative: Lurgi High-Btu Gasification	15-6
15-3	Efficiencies of a Locational Alternative: Synthane Facility Moved to Demand Center	15-7
15-4	Efficiencies of a Source Alternative: Alaskan Natural Gas Via Canadian Pipeline	15-8
15-5	Efficiencies of a Source Alternative: Alaskan Natural Gas Via Alaskan Pipeline and LNG Tanker	15-8
15-6	Efficiencies of a Source Alternative: Offshore Natural Gas	15-9
15-7	Efficiencies of a Source Alternative: Imported LNG	15-9
15-8	Energy Cost of Delivering 2.62×10^{12} Btu's of Natural Gas Using Seven Alternative Trajectories	15-11
A-1	Examples of Energy Content of Materials	A-15-13
A-2	Energy Value of a Dollar in 1973 for Several Categories of Materials	A-15-13
A-3	External Inputs to Lurgi High-Btu Gasification	A-15-16

TABLE		PAGE

LIST OF FIGURES

FIGURE		PAGE
2-1	Oil Shale Resource Development	2-2
2-2	Distribution of U.S. Oil Shale Resources	2-5
2-3	Oil Shale Areas in Colorado, Utah, and Wyoming	2-6
2-4	Diagrammatic Cross Section of Green River Formation	2-8
2-5	Hypothetical Oil Shale Surface Mine	2-12
2-6	Small Room and Pillar Oil Shale Mine	2-14
2-7	Primary Crusher Dust Control	2-22
2-8	Gas Combustion Process	2-27
2-9	Union Oil Process	2-28
2-10	TOSCO II Process	2-30
2-11	*In Situ* Retorting Operation	2-32
2-12	Oil Shale Processing Sequence	2-34
3-1	Crude Oil Resource Development	3-2
3-2	Sulfur Content and API Gravity of Crude Oils	3-4
3-3	Alaskan Oil Provinces	3-7
3-4	Drilling and Mud System	3-10
3-5	Oil Well Casing	3-12
3-6	Blowout Preventer Stack	3-13
3-7	Jack-up Offshore Drilling Rig	3-14
3-8	Drill Ship	3-15
3-9	Semi-Submersible Offshore Drilling Rig	3-16
3-10	Wellhead "Christmas Tree" of Control Valves	3-18
3-11	Waterflood Secondary Recovery System	3-20
3-12	Oil Refinery	3-26
3-13	Refinery Crude Oil Distillation Column	3-28
3-14	Refinery Hydrodesulfurization Process	3-29
3-15	Amine Solvent H_2S Removal Column	3-30
3-16	Catalytic Cracking Process	3-32
3-17	Offshore Pipelaying Barge	3-38
3-18	Single Buoy Mooring Facility	3-44
3-19	Sea Island Mooring Facility	3-45
3-20	Artifical Island Mooring Facility	3-47
3-21	Costs of Tanker Transport	3-50
4-1	Natural Gas Resource Development	4-2
4-2	Selected Samples of Unprocessed Natural Gas	4-4
4-3	U.S. Natural Gas Proved Reserves and Reserves-to-Production Ratio	4-6
4-4	Interstate Natural Gas Movements	4-8
4-5	Proposed Canadian Natural Gas Pipeline Routes and Oil and Gas Discoveries	4-10
4-6	Three-Stage Wellhead Separation Unit	4-14
4-7	Cycling Operation	4-16
4-8	Amine Treating Process for CO_2 and H_2S Removal	4-18
4-9	Location of Underground Gas Storage Reservoirs	4-25
4-10	Major Pipeline Costs	4-30
4-11	Integrated Liquid Natural Gas Operation	4-32
4-12	Cascade Cycle Liquefaction Plant	4-33
4-13	Potential Receiving Ports	4-36
4-14	Liquid Natural Gas Receiving Terminal	4-37
5-1	Tar Sands Resource Development	5-2
5-2	Distribution of U.S. Tar Sands Resources	5-5
5-3	Hot Water Extraction Process	5-9
5-4	Solvent Extraction Process	5-10
5-5	Pyrolysis "Coking" Extraction Process	5-11
5-6	Steps Involved in Upgrading Bitumen to Synthetic Crude Oil	5-13
6-1	Light Water Reactor Fuel Cycle	6-4
6-2	Uranium Exploration	6-7
6-3	Milling Plant	6-14
6-4	UF_6 Production--Dry Hydrofluor Process	6-17
6-5	UF_6 Production--Wet Solvent Extraction-Fluorination	6-18
6-6	Gaseous Diffusion Stage	6-22
6-7	Mode of Operation for Gaseous Diffusion Plant	6-22
6-8	Fuel Fabrication--ADU Process	6-26
6-9	Boiling Water Reactor	6-29

FIGURE		PAGE
6-10	Pressurized Water Reactor	6-31
6-11	High Temperature Gas Reactor Fuel Cycle	6-43
6-12	HTGR Fuel Components	6-52
6-13	High Temperature Gas-Cooled Reactor	6-54
6-14	Liquid Metal Fast Breeder Reactor Fuel Cycle	6-60
6-15	Plutonium Availabilities and Requirements	6-62
6-16	LMFBR Fuel-Fabrication Plant	6-64
6-17	Liquid Metal Fast Breeder Reactor	6-68
8-1	Geothermal Resource Development	8-2
8-2	Distribution of U.S. Geothermal Resources	8-7
8-3	Typical Well Configuration at the Geysers	8-11
8-4	Dry Rock Geothermal Energy System by Hydraulic Fracturing	8-15
8-5	Plowshare Concept of Geothermal Heat Extraction	8-16
8-6	Geothermal Power Plant Types	8-20
8-7	Geothermal Power Plant	8-22
9-1	Hydroelectric Resource Development	9-2
9-2	Distribution of Developed U.S. Hydroelectric Resources	9-4
9-3	Components of a Hydropower System	9-6
9-4	Impulse Turbine	9-8
9-5	Reaction Turbine	9-9
9-6	Turbine-Generator Unit	9-11
9-7	Pumped-Storage Operation	9-12
10-1	Organic Waste Resource Development	10-2
10-2	LANDGARD Solid Waste Disposal System	10-10
10-3	Garrett Pyrolysis System	10-12
11-1	Solar Energy Resource Development	11-2
11-2	Distribution of U.S. Solar Energy	11-4
11-3	Residential Heating and Cooling with Solar Energy	11-7
11-4	Solar Thermal-Conversion Power System	11-8
11-5	Silicon Solar Cell Cost Projections	11-10
11-6	Satellite Solar Power Station	11-11
11-7	Comparison of Land Disturbed from Surface-Mined Coal and Solar Electric 1,000-Mwe Plant	11-13
11-8	Typical Wind Rotor System	11-16
11-9	Farm Output Per Man Hour	11-21
11-10	Land Area Required for 1,000 Mwe Equivalent Output as a Function of Solar Conversion Efficiency	11-26
12-1	Electrical Generation System	12-2
12-2	Boiler-Fired Power Plant	12-4
12-3	Simplified Schematic of a Steam Power Plant	12-5
12-4	Boiler Air and Flue Gas Circulation Patterns	12-8
12-5	Pope, Evans, and Robbins Fluidized Bed Boiler Power Plant	12-9
12-6	Lime and Limestone Stack Gas Scrubbing Methods	12-13
12-7	Regenerative Cycle Gas Turbine	12-24
12-8	Combined Cycle Gas Turbine	12-27
12-9	Westinghouse Pressurized Fluidized Bed Boiler Power Plant	12-28
12-10	Hydrogen-Oxygen Fuel Cell	12-31
12-11	MHD Generator Electrical System	12-35
12-12	The Electric Power Industry	12-43
13-1	Total U.S. Energy Production and Consumption, 1947-1973	13-4
13-2	Growth in Vehicle Miles, 1940-1972	13-40
13-3	Comparison of Fuel Economy for Four Engines	13-49
14-1	Totals by Trajectory for Categories of Residuals	14-16
14-2	Totals by Trajectory for Categories of Residuals	14-17
14-3	Totals by Location for Air Pollutants	14-20
14-4	Totals by Trajectory for Specific Air Pollutants	14-21
14-5	Totals by Trajectory for Specific Air Pollutants	14-22
14-6	Totals by Trajectory for Specific Air Pollutants	14-23
14-7	Totals by Location for Specific Air Pollutants	14-24
14-8	Impact Analysis for Energy Alternatives, Phase I	14-29
14-9	Impact Analysis for Energy Alternatives, Phase II	14-30
15-1	Energy Efficiency Measures	15-2
15-2	Comparison of Energy Efficiencies	15-10
A-1	Dependence of Energy Development on External Inputs and Evaluation of Net Energy	A-15-15
16-1	Fixed and Operating Costs by Alternative	16-11
16-2	Cost-Plus Price by Alternative	16-22

LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

AC	alternating current
ACS	American Chemical Society
ADU	ammonium diuranate
AEC	Atomic Energy Commission
AGA	American Gas Association
ANFO	ammonium nitrate and fuel oil
API	American Petroleum Institute
BART	San Francisco Bay Area Rapid Transit
bbl	barrel(s)
bcf	billion cubic feet
BLM	Bureau of Land Management
BOD	biochemical oxygen demand
BOP	blowout preventer
Btu	British thermal unit
BuMines	Bureau of Mines
BWR	boiling water reactor
C	Centigrade
CAB	Civil Aeronautics Board
CEQ	Council on Environmental Quality
cf	cubic foot (feet)
cfs	cubic feet per second
CO	carbon monoxide
CO_2	carbon dioxide
COD	chemical oxygen demand
C.O.P.	coefficient of performance
CSF	consol synthetic fuel
dB	decibel
DC	direct current
DCF	discounted cash flow (analysis)
DOI	Department of the Interior
DOT	Department of Transportation
ECCS	emergency core cooling system
e.g.	for example
EIS	environmental impact statement(s)
EMDB	Energy Model Data Base
EPA	Environmental Protection Agency
_et al_.	and others
F	Fahrenheit
FCR	fixed change rate
FCST	Federal Council for Science and Technology
FEA	Federal Energy Administration
FFTF	fast flux test facility
FHA	Federal Housing Administration
f.o.b.	free-on-board
FPC	Federal Power Commission
FWKO	free water knock out
GNP	gross national product
gpd	gallon(s) per day
gpm	gallon(s) per minute
HAPP	high air pollution potential
HCDA	hypothetical core disruptive accidents
HTGR	high temperature gas reactor
HYGAS	hydrogasification
ICC	Interstate Commerce Commission
i.e.	that is

KGRA	known geothermal resource area
kv	kilovolt
kw	kilowatt(s)
kwe	kilowatt(s)-electric
kwh	kilowatt-hour(s)
LACT	lease automatic custody transfer
LMFBR	liquid metal fast breeder reactor
LNG	liquefied natural gas
LOCA	loss of cooling accident
LP	liquefied petroleum
LPG	liquid petroleum gas
LWR	light water reactor
mcf	thousand cubic feet
MERES	Matrix of Environmental Residuals for Energy Systems
mmcf	million cubic feet
MHD	magnetohydrodynamic
mpg	miles per gallon
mph	miles per hour
mrem	millirem
Mw	megawatt(s)
Mwe	megawatt(s)-electric
Mwh	megawatt-hour(s)
NAE	National Academy of Engineering
NASA	National Aeronautics and Space Administration
NEB	Canadian National Energy Board
NEPA	National Environmental Policy Act
NGRS	National Gas Reserves Study
NGSF	noble gas storage facility
NO_x	oxides of nitrogen
NPC	National Petroleum Council
NPV	net present value
NSF	National Science Foundation
OCR	Office of Coal Research
OCS	outer continental shelf
OEP	Office of Emergency Preparedness
OPEC	Organization of Petroleum Exporting Countries
OSHA	Occupational Safety and Health Administration
OST	Office of Science and Technology
OU	University of Oklahoma
PCRV	prestressed concrete reactor vessel
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch atmosphere
psig	pounds per square inch guage
PWR	pressurized water reactor
R&D	research and development
r/p	reserve-to-production
rpm	rotations per minute
RSSF	retrievable surface storage facility
SBM	single buoy mooring
SIC	standard industrial classification
SO_x	sulfur oxides
SRC	solvent refined coal
SRI	Stanford Research Institute
TAPS	trans-Alaska pipeline system
tcf	trillion cubic feet
TOSCO	The Oil Shale Corporation
USGS	United States Geological Survey
USSR	Union of Soviet Socialist Republics (Russia)
VLCC	very large crude carrier

GENERAL INTRODUCTION

This report is intended to contribute to the development of a methodology for systematically identifying, assessing, and comparing energy alternatives in environmental impact statements (EIS). As a step toward the achievement of this goal, this report provides descriptions and data on the major energy resource systems in the United States and suggests procedures for using these descriptions and data.

The report is divided into two major parts. Part I (Chapters 1 through 13) contains descriptions of the coal, oil shale, crude oil, natural gas, tar sands, nuclear fission, nuclear fusion, geothermal, hydroelectric, organic wastes, and solar energy resource systems plus descriptions of electric power generation and energy consumption. In addition to discussing the resource and development technologies, each resource system description contains data on energy efficiencies, environmental residuals, and economic costs.

Part II (Chapters 14 through 16) describes procedures for using the descriptions and data contained in Part I in systematically evaluating and comparing the residuals, efficiencies, and economic costs of a proposed energy action and its alternatives. This part also suggests procedures for impact analyses. Both Parts I and II are preceded by introductions that explain the organization of each part.

The resource descriptions in Part I rely heavily on reports prepared for the Council on Environmental Quality (CEQ), Environmental Protection Agency (EPA), Bureau of Land Management (BLM), Atomic Energy Commission (AEC), and National Science Foundation (NSF). For the most part, quantitative data on energy efficiencies, environmental consequences, and economic costs are taken from CEQ's Matrix of Environmental Residuals for Energy Systems (MERES). At present, MERES contains data only on fossil fuel systems (coal, crude oil, natural gas, and oil shale) prepared by Hittman Associates for CEQ, EPA, and NSF and reported in <u>Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use</u> (1974, Vol. I: 1975, Vol. 2).* MERES data have been incorporated into a computerized data system by Brookhaven National Laboratory (BNL, 1975). Part I descriptions include MERES data plus additional information and data on tar sands, nuclear fission, nuclear fusion, geothermal, hydroelectric, organic wastes, solar, electric power generation, and energy consumption.

In addition to MERES data, this report includes data from Teknekron, Incorporated's <u>Fuel Cycles for Electric Power Generation</u> (1973) (prepared for EPA), Battelle Columbus and Pacific Northwest Laboratories' <u>Environmental Considerations in Future Energy Growth</u> (1973) (prepared for EPA), and miscellaneous other sources. Each chapter of the report cites references (by author and date) in the text and lists those references alphabetically at the chapter's end. Throughout the report, data are presented in tabular form, where feasible, to facilitate comparisons by users.

There are several reasons why the data in this report and MERES should be used

*Data on other energy resources will be added to MERES in the near future.

cautiously. First, the data are basically limited to what can be quantified. Some qualitative information is included, especially for energy efficiencies and environmental residuals, but in many areas the data in this report must be considered incomplete.

Second, data on energy efficiencies, environmental residuals, and economic costs are not available for all the technological alternatives described in this report. Because of this, specific abbreviations were developed for the data tables to avoid misleading or ambiguous entries. Thus, the term "not applicable" (NA) refers to entries that would not apply to a particular process or category. "Not considered" (NC) refers to potential data that were not available from a particular problem area or process. "Unknown" (U) refers to values that should exist for the particular process or category but that members of the study team were unable to find.

Third, many of the estimates are based on a limited number of cases and, at times, on scaled-up pilot projects; thus, they may not accurately represent cases in different locations, at other scales, or under other conditions. When known, these types of factors are noted in this report.

Fourth, most of the individual data estimates are based on specific assumptions that may differ from the assumptions of other individual estimates. For example, MERES data distinguish between environmentally "uncontrolled" and "controlled" activities. "Uncontrolled" means that the data represent processes permitted under current environmental management regulations. "Controlled" refers to a more restrictive set of regulations that might apply 5 to 10 years in the future. As an illustration, an uncontrolled strip mine involves the kind of land restoration now being practiced but a controlled strip mine presumes complete reclamation, including revegetation. In addition to these types of assumptions, the assumptions about the particular characterisitcs of an activity (e.g., energy content of coal or oil well depth) vary widely between estimates. Thus, indiscriminate comparisons of data could produce invalid results.

In the MERES data, all estimates are based on an energy input to a process of one trillion British thermal units (10^{12} Btu's). For consistency and comparisons, the Battelle, Teknekron, and other data were converted to this unit of measure. Linearity is assumed in all scaling and, in many cases, this is a poor assumption. For example, the total land required for a 3,000-Mwe (megawatts-electric) power plant is not three times that required for a 1,000-Mwe power plant.

The MERES data have been assigned "hardness" numbers to indicate their reliability. Reliability ranges from very good (an error probability of 10 percent or less) to very poor (an error probability as high as an order of magnitude). These data hardness estimates are included in the text as a caution to users.

Wherever possible, the report identifies the assumptions incorporated in the estimates, but all the current data tend to be for specific sites, technologies, and fuels. Therefore, users should regard data estimates in this report with a healthy skepticism. As MERES evolves, its data will be modified frequently, reflecting increased sources of information and further experience with technologies.

PART I: DESCRIPTIONS OF ENERGY RESOURCE SYSTEMS

INTRODUCTION

The energy resource descriptions in Part I of this report (Chapters 1 through 11) contain available information and data on residuals, energy efficiencies, and economic costs for 11 major U.S. energy resource systems: coal, oil shale, crude oil, natural gas, tar sands, nuclear fission, nuclear fusion, geothermal, hydroelectric, organic, and solar. Similar descriptions were prepared for phase one of NSF Grant No. SIA74-17866. These 11 chapters, plus a description of electric power generation (Chapter 12) and a discussion of U.S. energy consumption (Chapter 13), comprise Part I of this report.

Excepting the chapter on nuclear fusion, the energy resource descriptions are broken into major sections which begin with a general resource description then delineate the steps or activities involved in developing the resource. The nuclear fusion chapter is limited to a brief discussion of present and near future technology which clearly shows that fusion cannot be a viable energy resource before the year 2000.

In addition to the 11 energy resource descriptions, Chapter 12 is a description of the technological alternatives for the use of solid, liquid, and gaseous fuels in central station electric power plants. Since this chapter covers the conversion of a produced fuel to electricity, the activities described are in addition to one or more of the resource development activities described in Chapters 1 through 11.

Chapter 13 summarizes available information about energy end uses in the U.S. This chapter is divided into three major consumption sectors: transportation, industrial, and residential/commercial. Each sector includes a description of options for conserving energy at the point of use. This makes it possible to associate a product of a resource system with levels of demand for particular energy end uses.

The first section of each general resource system description describes the characteristics of the resource and gives the best current estimates of total "resources" and "reserves". The "resource" estimate is the total amount of the energy source within the United States (except where otherwise noted), including amounts that have not been identified but are surmised to exist on the basis of broad knowledge or theory. The "reserve" estimate is the amount of the energy source both known to exist and economically recoverable using currently available technologies. For mineral resources such as coal and oil shale, these estimates are fixed quantities. For renewable resources such as organic wastes and solar radiation, these estimates are production rates. For example, solar energy "resources" are daily radiation rates for selected locations throughout the U.S. Likewise, organic waste "resources" are production rates from major sources per year. In addition to the resource characteristics, resource estimates, and reserve estimates, this section also discusses the resource in terms of location and ownership.

The resource development technologies sections describe each resource system in terms of a basic sequence of "activities". In the coal resource system, for example, the activities are exploration, mining and reclamation, beneficiation, processing/conversion, and transportation. These activities are shown graphically in Figure 1, which is a duplicate of Figure 1-1 in Chapter 1. For each activity, "technological alternatives" are discussed which represent one set of policy and/or potential research and development options. These alternatives are listed within the activity blocks in Figure 1. (The number within each block refers to the text section where the activity is discussed.) Obviously, where technological alternatives exist for each activity, different combinations might be selected to achieve the proposed resource development action. Any particular combination of these alternatives is referred to as a "trajectory". Each trajectory represents a second set of policy and/or research and development options. An example of a particular coal trajectory from Figure 1 would be to select area surface mining, beneficiation by breaking and sizing Synthane high-Btu gasification, and pipeline transportation.* For the proposed action, the descriptions in Part I allow users to plot a number of possible trajectories and provide basic data on the effects of those trajectories.

Categories of Data

For each technological alternative, the descriptions contain three broad categories of data: energy efficiencies, environmental considerations, and economic considerations. These data categories are described below.

Throughout Part I, energy efficiencies of technological alternatives are assessed in two ways: primary energy efficiency and ancillary energy. Primary energy efficiency (expressed as a percent) is the ratio between the energy value of the output fuel and the energy value of the input fuel. In other words, it is a measure of energy consumed or physically lost in a process. Ancillary energy is the amount of energy required from external sources* to accomplish the activity, such as fuel for process heat, electricity for motors, and diesel fuel for truck transport. This energy is expressed as Btu's required per 10^{12} Btu's input to the process. By dividing the output energy by the sum of the ancillary energy and energy input, an overall efficiency (percent) can be calculated for each activity. The overall efficiency provides a basis for comparing the energy requirements of activities and technological alternatives.

The environmental considerations sections identify and discuss "residuals" that may pose environmental problems for each activity or technological alternative. "Residuals" are defined as the byproducts that an activity, technological alternative, or process produces in addition to its primary product. Using this broad definition, residuals include such effects as air and water pollutants, solid wastes, and impact-producing inputs (e.g., the materials requirements of a particular process). For each process and technological alternative, the quantified environmental residuals are reported in tabular form. These measures, which were taken from MERES, include air residuals (particulates, sulfur oxides, nitrous oxides, aldehydes, carbon monoxide, and hydrocarbons), water residuals (thermal, acids, bases, phosphates, nitrates, total dissolved solids, suspended solids, non-degradable organics, biochemical oxygen demand, and chemical oxygen demand), solids, land, deaths, injuries, and man-days lost.

*Some activities are not broken into technological alternatives and processes. For example, exploration is generally so standard that it has not been broken down. However, exploration, including the equipment used, is described in the text.

*Where the energy for process heat is taken from the resource (coal in a gasifier or oil in a refinery), it is evaluated as part of the primary efficiency.

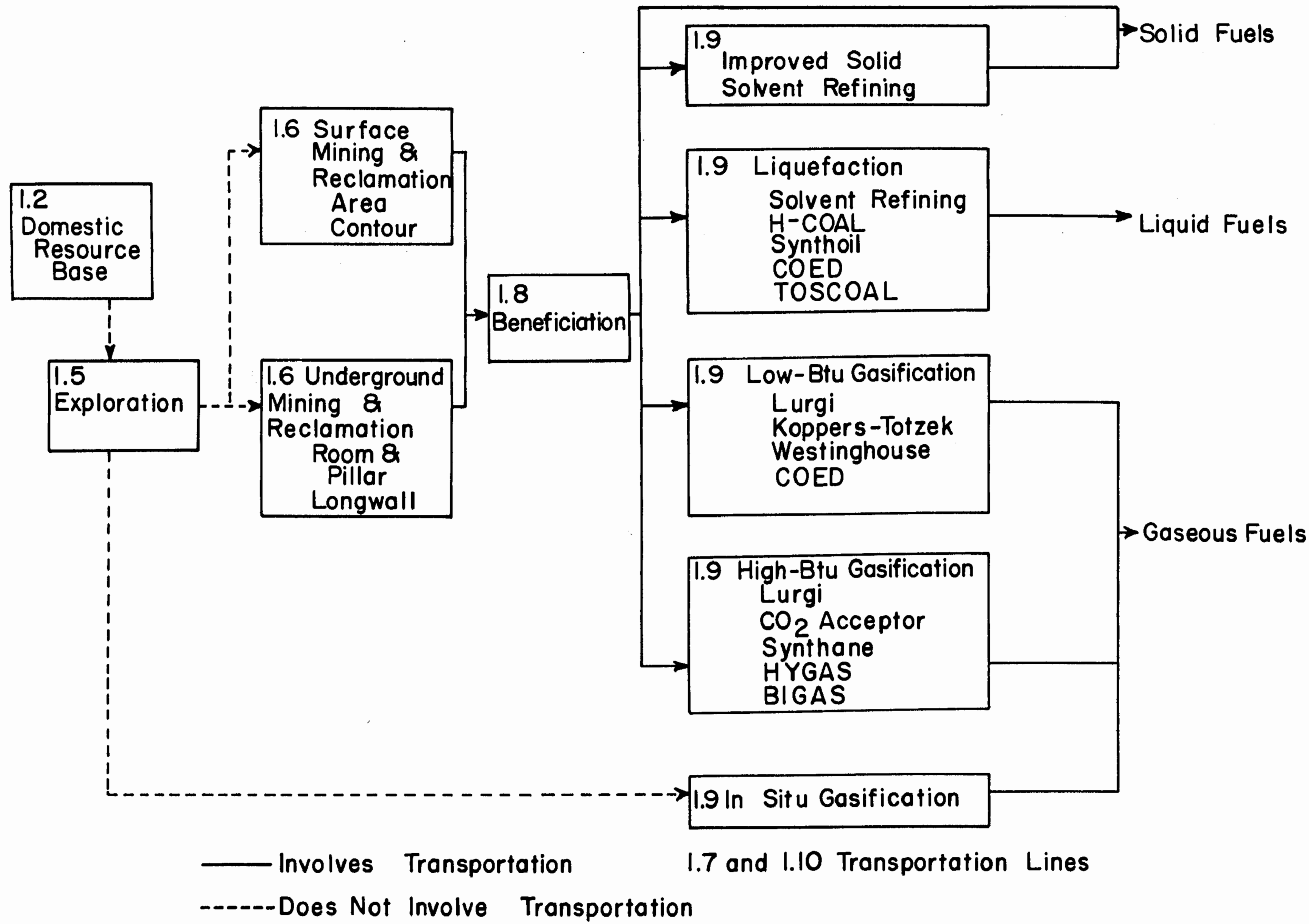


Figure 1. Coal Resource Development

Residuals are expressed in tons per 10^{12} Btu's input to the process (acre-year for land, Btu's for thermal, and days for man-days lost) in the first 12 chapters (the resource descriptions plus the description of electric power generation in Chapter 12). The units of residuals in Chapter 12, Energy Consumption, are expressed in tons per measure, where the measure is the unit appropriate for each particular end use. Examples of these measures are passenger-miles, tons, and dwelling-years. A value referred to as "the multiplier" is also included. The multiplier is the amount of each end use measure which is used in the U.S. each year. Thus, the product of the multiplier and the measure is the yearly consumption for a specific end use. The product of the measure and any one residual yields tons of emissions per measure. Where numerical values are missing from tables, abbreviations have been entered to indicate the reasons, as explained in the General Introduction. "NA" means the residual is not applicable to the activity, "NC" means the data were not considered (not given) by the information sources, and "U" means that the residual exists but the quantity is unknown.

Economic considerations sections are limited to fixed, operating, and total costs for an activity. As used here, total costs are simply the sum of fixed and operating costs. Cost data are given in either dollars per 10^{12} Btu's energy input or dollars per kilowatt-hour output. These data are necessarily based on market situations which are now out-of-date; thus, reference dates (e.g., "1972 dollars") are cited wherever possible. Although a user can convert these figures into current values, their principal value is in comparing costs of alternatives rather than evaluating the economic feasibility of a particular alternative in today's economy.

REFERENCES

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc. (NTIS numbers: Vol. I, PB-238 784; Vol. II, PB-239 158).

Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif.: Teknekron.

CHAPTER 1

THE COAL RESOURCE SYSTEM

1.1 INTRODUCTION

Coal was the U.S.'s principal energy source from the 1880's until shortly after World War II (Senate Interior Committee, 1971: 94-102) but declined dramatically thereafter. In 1947, coal met approximately 48 percent of the total U.S. energy demand; by 1971, it accounted for only about 18 percent (Interior, 1972: 40, 43). The decreased demand for coal resulted primarily from several major consumers switching to other fuels. Railroads converted to diesel fuel and households, commercial consumers, and (more recently) electric utilities converted to natural gas or fuel oil. Most of these conversions were made because the newer fuels are cleaner, easier to handle, and more environmentally acceptable than coal.

Recent events (especially the decreasing availability of natural gas and the oil embargo) emphasize the need to increase the proportion of our total energy demand met by coal, a relatively abundant domestic resource. However, any increased use of coal must be reconciled with our national policy of promoting environmental quality. This has emphasized the need to make coal less environmentally threatening as an energy source through the development of technologies to improve its direct combustion properties or to convert it to a liquid or gas.

The development of coal for use as either a solid, gaseous, or liquid fuel involves five major sequential activities: exploration, mining and reclamation, beneficiation, processing/conversion, and transportation. These activities are diagrammed in Figure 1-1 and described in Sections 1.5 through 1.10.

As shown in the figure, the coal development system can be configured in various ways, depending on the technological alternative chosen to achieve each of the five major activities. Both decision points within the system and technological alternatives are identified in the description of coal development technologies in this chapter.

1.2 A NATIONAL OVERVIEW

Coal is a combustible natural solid formed from fossilized plants. It is dark brown to black in color and consists primarily of carbon (more than 50 percent by weight) in the form of numerous complex organic compounds. The composition of coal varies considerably from region to region and within given fields.

Coal is generally found as a layer in sedimentary rock. These layers, called seams or beds, differ greatly in thickness, depth below the surface, and areal extent. In this section, U.S. coal resources are described in terms of amount, characteristics, location, and ownership.

1.2.1 Total Resource Endowment

The U.S. Geological Survey (USGS) estimates the total remaining coal resources of the U.S. to be more than three trillion

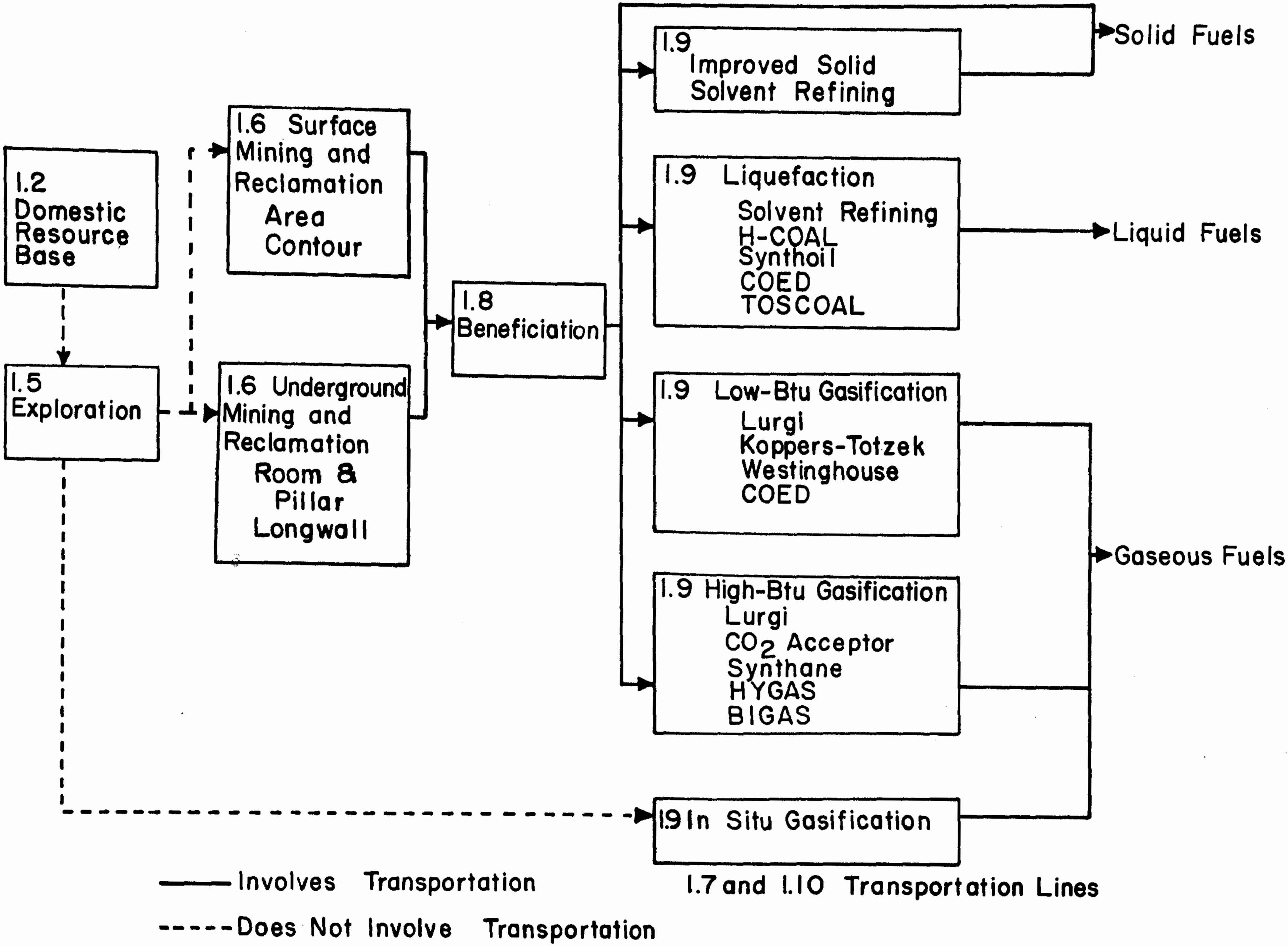


Figure 1-1. Coal Resource Development

tons;* however, as indicated in Table 1-1, the proportion of this estimate classified as identified and recoverable is substantially less than the total.** In fact, only about 195 billion tons are classified as reserves, meaning they are (1) known in location, quantity, and quality from geologic evidence supported by engineering measurements and (2) economically recoverable using currently available technologies.*** Almost 1.2 trillion tons of identified coal resources cannot be economically mined at present, and an additional 1.6 trillion tons have not actually been identified but are surmised to exist on the basis of broad geologic knowledge and theory.

Assuming an average heating value of 10,000 Btu's per pound, U.S. coal resources have an energy value equivalent to 850 times the total U.S. energy input in 1970.**** The 195 billion tons of coal reserves are equivalent to 55 times the total U.S. energy input for that year.

U.S. coal resources account for approximately 20 percent of world coal resources (Averitt, 1973: 140). The Union of Soviet Socialist Republics (USSR) possesses a large share of the remaining 80 percent.

In 1972, about nine percent of the bituminous and lignite mined in the U.S. was exported, mostly for metallurgical processing. A small amount of coal was imported into the U.S. from Canada.

*The estimates are 2.9 trillion tons within 3,000 feet and 3.2 trillion tons within 6,000 feet of the surface. All estimates are in short (2,000-pound) tons.

**The estimates for identified resources are subject to a 20-percent margin of error. Both identified and undiscovered estimates should be treated with caution. USGS considers its estimates to be conservative; however, some other observers disagree.

***"Economically recoverable" estimates are dependent on the market value of the resource. These estimates are based on the latest available USGS data.

****Total U.S. energy input in 1970 was 69×10^{15} Btu's.

1.2.2 Characteristics of the Resources

Coals are classified on the basis of specific compositional characteristics such as carbon content, heating value, and impurities. Anthracite and bituminous coals are primarily ranked on the basis of fixed carbon content (Figure 1-2).* Subbituminous coals and lignite, which contain less fixed carbon, are ranked on the basis of heating value (Figure 1-3). As indicated in Table 1-2, approximately 70 percent of all U.S. coal is bituminous or subbituminous, while only about one percent is anthracite.

In addition to being ranked, coals are graded on the basis of the impurities that they contain. Certain impurities (including moisture, ash, and sulfur) present problems when coal is processed and utilized. Moisture content is related to rank; the higher the rank, the lower the moisture content. Moisture ranges from one percent in some anthracites to more than 40 percent in some lignites (BLM, 1974: Vol. 1, p. I-57).

The ash content of coal (the amount of non-combustible inorganic materials the coal contains) varies considerably even within a single seam, making proportional generalizations difficult. For example, in a 1942 study of 642 typical U.S. coals, investigators found that ash content ranged from 2.5 to 32.6 percent (BLM, 1974: Vol. 1, p. I-57).

One impurity that causes great difficulty is sulfur. The sulfur content of U.S. coals ranges from 0.2 to 7.0 percent,

*Fixed carbon is the solid, nonvolatile portion of coal that is combustible. Rank is one method of categorizing coals. Higher rank coals are considered to have undergone the greatest chemical transformation from ancient plant deposits.

TABLE 1-1

COAL RESOURCES OF THE U.S.[a]
(BILLIONS OF SHORT TONS)

Feasibility of Recovery	Knowledge of Resource		
	Discovered	Undiscovered Resources[b]	
	0-3,000 feet overburden	0-3,000 feet overburden	3,000-6,000 feet overburden
Recoverable[c]	100[d] 95[e]	0	0
Submarginal[f]	1,285[g]	1,300	340

Sources: Averitt, 1973: 137; Theobald and others, 1972: 3.

[a]Reliability of estimates decreases downward and to the right.

[b]Unspecified bodies of mineral-bearing material surmised to exist on the basis of broad geologic knowledge and theory.

[c]Resources which are both identified and recoverable are termed "reserves."

[d]Coal in beds 42 inches or more thick for bituminous coal and anthracite and 10 feet or more thick for subbituminous coal and lignite; overburden not more than 1,000 feet.

[e]Additional coal recoverable in beds 28 to 42 inches thick for bituminous coal and anthracite and 3 to 5 feet thick for subbituminous coal and lignite; overburden not more than 1,000 feet.

[f]Resources which are technically possible but not economic to mine; a substantially higher price (more than 1.5 times the price at the time of the estimate) or a major cost-reducing advance in technology would be required for these resources to become reserves.

[g]Additional coal recoverable in beds at least 14 inches thick for bituminous coal and anthracite and 2-1/2 feet thick for subbituminous coal and lignite; overburden not more than 3,000 feet.

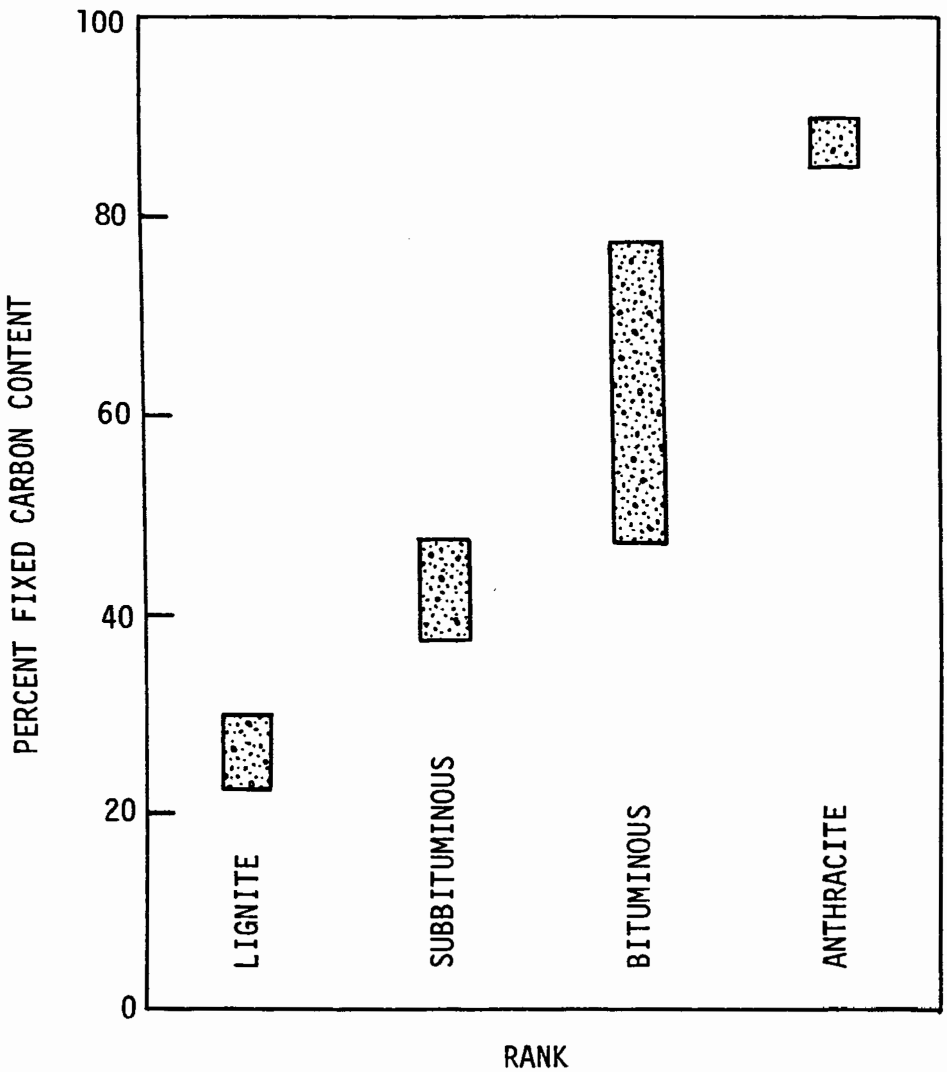


Figure 1-2. Fixed Carbon Content of Major Coal Ranks

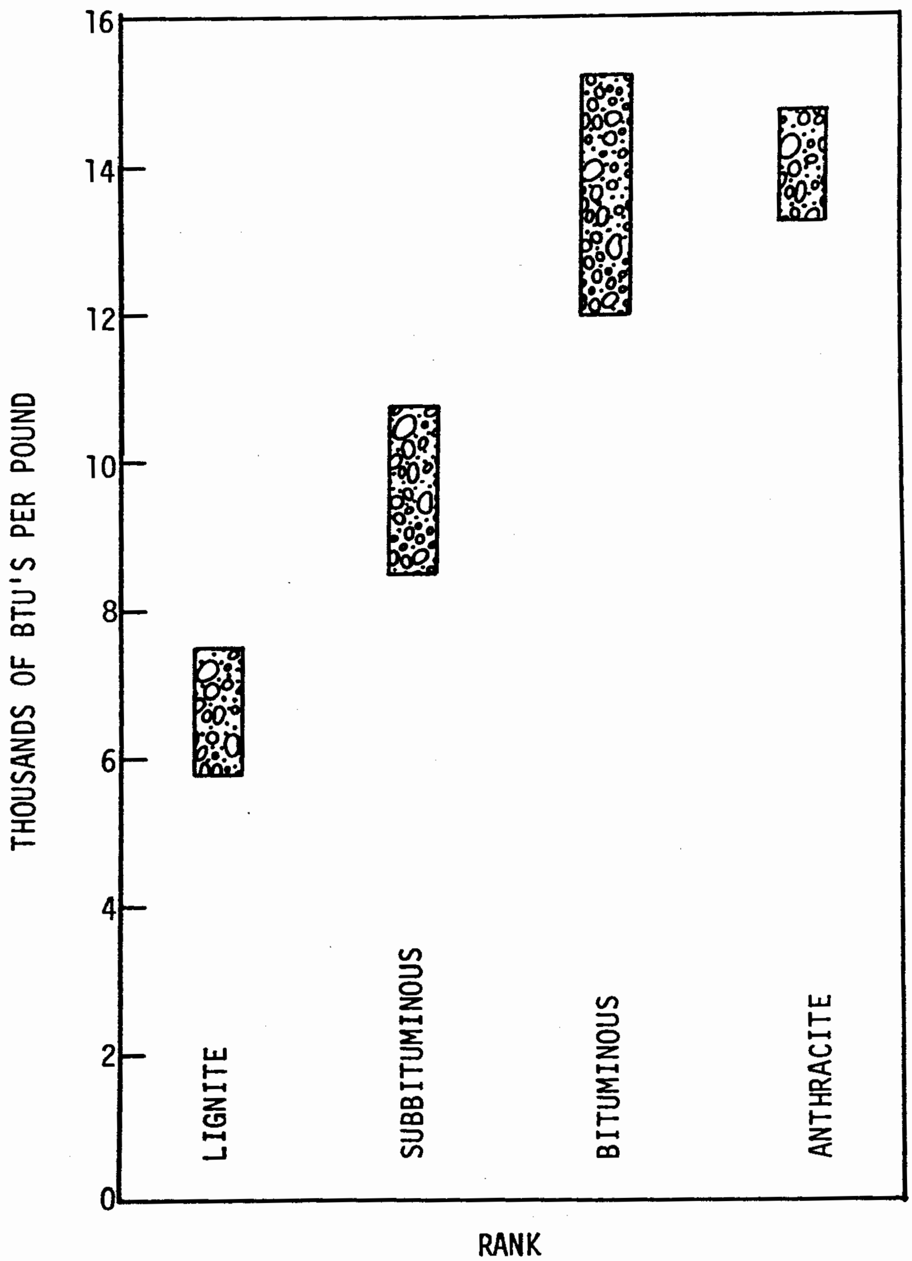


Figure 1-3. Heat Content of Major Coal Ranks

TABLE 1-2

RANK OF IDENTIFIED U.S. COAL RESOURCES

Rank	Identified Resources (billions of tons)[a]
Anthracite	21
Bituminous	686
Subbituminous	424
Lignite	449
TOTAL	1,580

Source: Averitt, 1973: 137.

[a]In short tons (2,000 pounds).

varying considerably between geographic regions. Most of the low-sulfur coal (coal with a sulfur content of one percent or less) is located in the western U.S. (BLM, 1974: Vol. 1, p. I-57). On an equivalent Btu basis, however, the contrast between western and eastern coals is often diminished because western coals generally have a lower heating value than do eastern coals.

1.2.3 Location of the Resources

Coal occurs in many parts of the U.S.: bituminous in Appalachia and the drainage basin of the Mississippi River; a mixture of ranks in the Northern Great Plains and Rocky Mountains; and scattered deposits elsewhere (Figure 1-4). However, almost 90 percent of all coal resources in the contiguous 48 states are located in just four USGS coal provinces: the Eastern, Interior, Northern Great Plains, and Rocky Mountain (Table 1-3). These provinces are described in the following regional overview.

1.2.4 Recoverability of the Resources

Two of the most important factors in the recoverability of coal are bed depth and seam thickness. Although both are major economic factors, bed depth is often the more important because of the lower

TABLE 1-3

COAL RESOURCES IN U.S. GEOLOGICAL SURVEY PROVINCES[a]
(BILLIONS OF TONS)

Province	Identified	Undiscovered	Total
Eastern	276	45	321
Interior	277	259	536
Northern Great Plains	695	763	1,458
Rocky Mountains	187	395	582
Other	146	181	327
TOTAL	1,581	1,643	3,224

Source: Averitt, 1973: 137.

[a]Because available estimates are by state and USGS Provinces cross state boundaries, the figures for these provinces are only approximate.

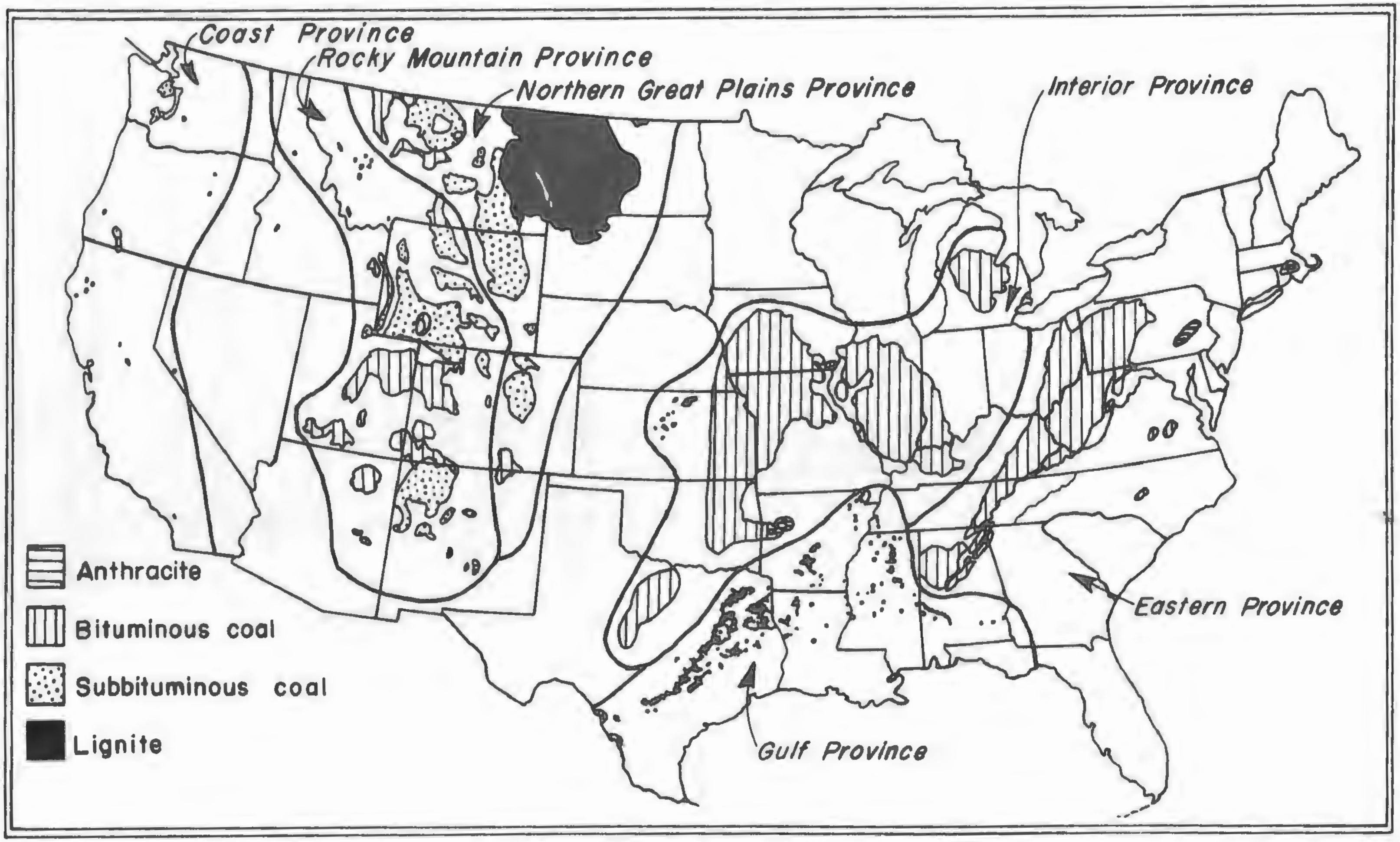


Figure 1-4. Distribution of United States Coal Resources

Source: BLM, 1974: I-47

cost and relatively greater safety of surface mining. In 1965, the average depth of coal being mined from the surface was 55 feet and the average seam thickness was 5.2 feet, giving a ratio of overburden-to-seam thickness of roughly 10:1 (Young, 1967: 18).* This ratio has been increasing as mining technologies have advanced, and a 30:1 ratio is now suggested as reasonable for the mid-1970's (Averitt, 1970: 6).** Whether or not a 30:1 ratio is generally reached, approximately 45 billion tons of coal are now considered economically recoverable using available surface mining technologies (BuMines, 1971: 23).

1.2.5 Ownership of the Resources

The development of a coal--regardless of its compositional characteristics, depth, and seam thickness--depends in large part on the ownership of the lands and/or mineral rights. The federal government owns approximately 48 percent of all coal lands located in Alaska, Colorado, Montana, North Dakota, Oklahoma, Utah, and Wyoming (BLM, 1974: Vol. 1, p. V-208). Federal ownership in these states ranges from four percent in Oklahoma to 97 percent in Alaska (BLM, 1974: Vol. 1, p. V-208). Although overall data are not available, apparently the federal government does not own as much as four percent of the coal lands in any other state. In any case, the major coal lands in the eastern and midwestern U.S. are privately owned.

Most U.S. coal is mined from privately owned lands. In 1971, only about three percent of the coal produced in the U.S. was mined from lands owned by the federal government or Indians (BLM, 1974: Vol. 1, p. I-64). In part, this is because only about 800,000 acres of federal coal lands (one percent of the more than 85 million acres of coal lands that are federally owned) have been leased for development. This pattern will change as more mines are opened in the Northern Great Plains and Rocky Mountain provinces.*

*Industry frequently uses a ratio of cubic yards of overburden per ton of coal.

**Selected thin seams of coal for metallurgical use are presently mined at a 40:1 ratio in Oklahoma (Johnson, 1974).

1.3 A REGIONAL OVERVIEW

1.3.1 The Eastern Province

The Eastern Province is comprised of three regions: Appalachian, Pennsylvania Anthracite, and Atlantic Coast. As shown in Figure 1-5, the Appalachian Region is far larger than the other two combined. Most of the coal lands in the province are privately owned.

Although this province has been mined for many years, considerable quantities of coal (mostly anthracite and bituminous) are still in place (Table 1-4). Only approximately 21 billion of the Eastern Province's 276 billion tons of identified resources are anthracite; however, this province has more than 80 percent of the U.S.'s remaining identified high-rank bituminous.

As indicated by their high rank, eastern coals have a high fixed carbon content and contain relatively low amounts of moisture and volatile matter. The sulfur content of eastern coals varies considerably. Approximately 65 percent of the province's identified resources have a sulfur content of more than one percent.

Coal deposits in this province are sometimes exposed on the side of a hill or

*A province, the largest unit used by USGS to define the areal extent of coal resources, is made up of regions on the basis of similarity in the physical features of coal fields, coal quality, and contiguity. Regions are made up of fields which are made up of districts. A field is a recognizable single coal-bearing territory; a district is an identifiable center of coal mining operations. These four terms provide a convenient means for aggregating and disaggregating data on coal resources and production.

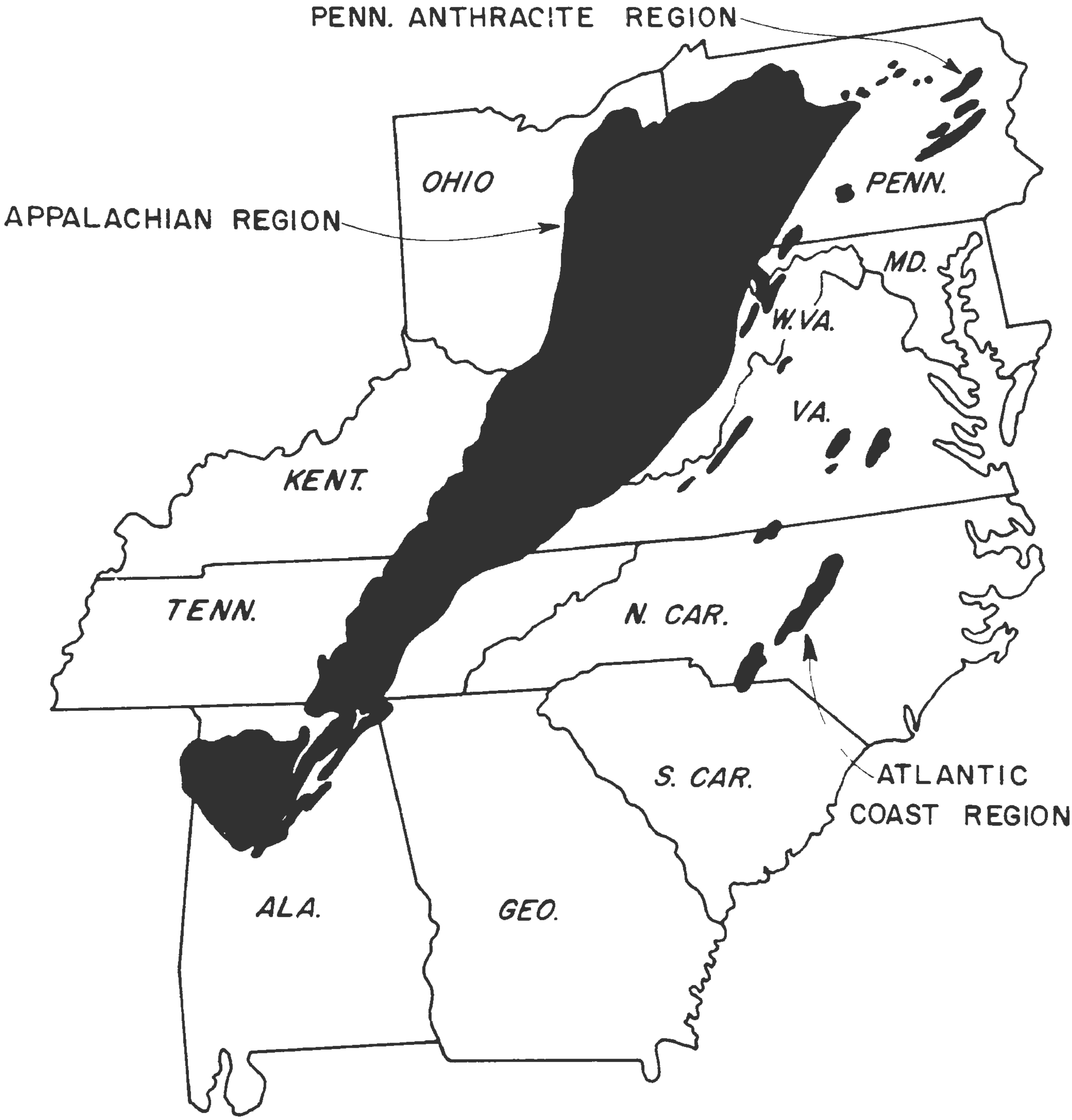


Figure 1-5. Distribution of Coal in the Eastern Province

Source: BLM, 1974: II-213.

TABLE 1-4

COAL RESOURCES IN THE EASTERN PROVINCE

Depth (feet)	Status	Amount (billions of short tons)
0-1,000	Recoverable	122[a]
0-3,000	Thin bed and identified	154
0-3,000	Undiscovered	39
3,000-6,000	Undiscovered	6
TOTAL		321

Sources: BLM, 1974: I-69; Averitt, 1973: 137.

[a]Does not include mining losses. Coal out-of-the-ground would be approximately 50 percent of this value.

TABLE 1-5

COAL RESOURCES IN THE INTERIOR PROVINCE

Depth (feet)	Status	Amount (billions of short tons)
0-1,000	Recoverable	102[a]
0-3,000	Thin bed and identified	175
0-3,000	Undiscovered	249
3,000-6,000	Undiscovered	10
TOTAL		536

Sources: BLM, 1974: I-69; Averitt, 1973: 137.

[a]Does not include mining losses. Coal out-of-the-ground would be approximately 50 percent of this value.

mountain; at other times, they are buried deep below the surface. Seam thickness rarely exceeds six feet.

Croplands, pasture, and forestry are the other major land uses in the province. Most farming is of a subsistence type. The economic mainstay outside the major urban-industrial centers, such as Pittsburgh and Charleston, is minerals extraction.

Surface water supplies are abundant, and precipitation averages between 35 and 50 inches a year.

1.3.2 The Interior Province

Four regions comprise the Interior Province: Northern, Eastern, Western, and Southwestern (Figure 1-6). Except for a portion of the Western Region, most coal lands in the province are privately owned.

The coal resources of the province are 536 billion tons; some 102 billion tons in the ground could be economically mined (Table 1-5). Most of this coal is bituminous, a small amount of anthracite in Arkansas being an exception. Except for low-volatile coal found in Arkansas and eastern Oklahoma, the bituminous is highly volatile.* The moisture content is generally low, except for coals in the northern part of the province, and sulfur content tends to be high, generally in excess of three percent.

As in the Eastern Province, seams are generally six feet or less in thickness. Many of the deposits are close to the surface, making them candidates for surface mining.

The major land use in the province is farming and livestock feeding. In fact, the province is intensely agricultural and one of the most productive agricultural areas in the U.S.

Although most of the province is well supplied with water, competition for its use is generally keen. The annual rainfall ranges from about 32 to 48 inches.

*Volatile matter is the portion of coal that turns into a vapor when heated. Volatile coals burn easily.

Figure 1-6. Distribution of Coal in the Interior Province

Source: BLM, 1974: II-192.

1.3.3 The Northern Great Plains Province

As illustrated in Figure 1-7, the Northern Great Plains Province, which contains 45 percent of the remaining coal resources in the U.S., is made up of six regions. The two largest regions, Fort Union and Powder River, contain almost 1.5 trillion tons of coal (Table 1-6), most of which is owned by the federal government. Indian tribes and railroads are also large owners.

Most of the coal within the province is relatively low in rank, lignite in the Fort Union Region and thick deposits of subbituminous in the Powder River Region. Near the edge of the Rocky Mountains, the coal is somewhat higher in rank. The moisture and volatile matter content of both Fort Union and Powder River coals are relatively high and, as indicated by their low rank, both tend to be low in energy value. However, more than 657 billion tons or about 44 percent of the province's coal is low sulfur.

Although seam depth and thickness in the province vary considerably, some beds are quite thick and sufficiently near the surface to allow surface mining.

Much of the surface area of the province is still covered by native vegetation. Some parts of the province, particularly the areas along the Missouri River, are farmed intensively.

Water supplies are not abundant, and most of the surface water is found in the Northern Missouri River drainage basin. Much of this water comes from runoff from the mountains to the west. The average annual runoff ranges from less than 1 inch to 10 inches.

1.3.4 The Rocky Mountain Province

The largest of the Rocky Mountain Province's eight regions (Figure 1-8) are the Green River, Uinta, and San Juan River. As shown in Table 1-7, estimated remaining resources in the province are more than 580 billion tons, 187 billion of which have been identified. Resource ownership in the province is largely shared by the federal government, Indian tribes, and railroads.

TABLE 1-6

COAL RESOURCES IN THE NORTHERN GREAT PLAINS PROVINCE

Depth (feet)	Status	Amount (billions of short tons)
0-1,000	Recoverable	106[a]
0-3,000	Thin bed and identified	589
0-3,000	Undiscovered	663
3,000-6,000	Undiscovered	100
TOTAL		1,458

Sources: BLM, 1974: I-69; Averitt, 1973: 137.

[a]Does not include mining losses. Coal out-of-the-ground would be approximately 50 percent of this value.

TABLE 1-7

COAL RESOURCES IN THE ROCKY MOUNTAIN PROVINCE

Depth (feet)	Status	Amount (billions of short tons)
0-1,000	Recoverable	37[a]
0-3,000	Thin bed and identified	150
0-3,000	Undiscovered	194
3,000-6,000	Undiscovered	201
TOTAL		582

Sources: BLM, 1974: I-69; Averitt, 1973: 137.

[a]Does not include mining losses. Coal out-of-the-ground would be approximately 50 percent of this value.

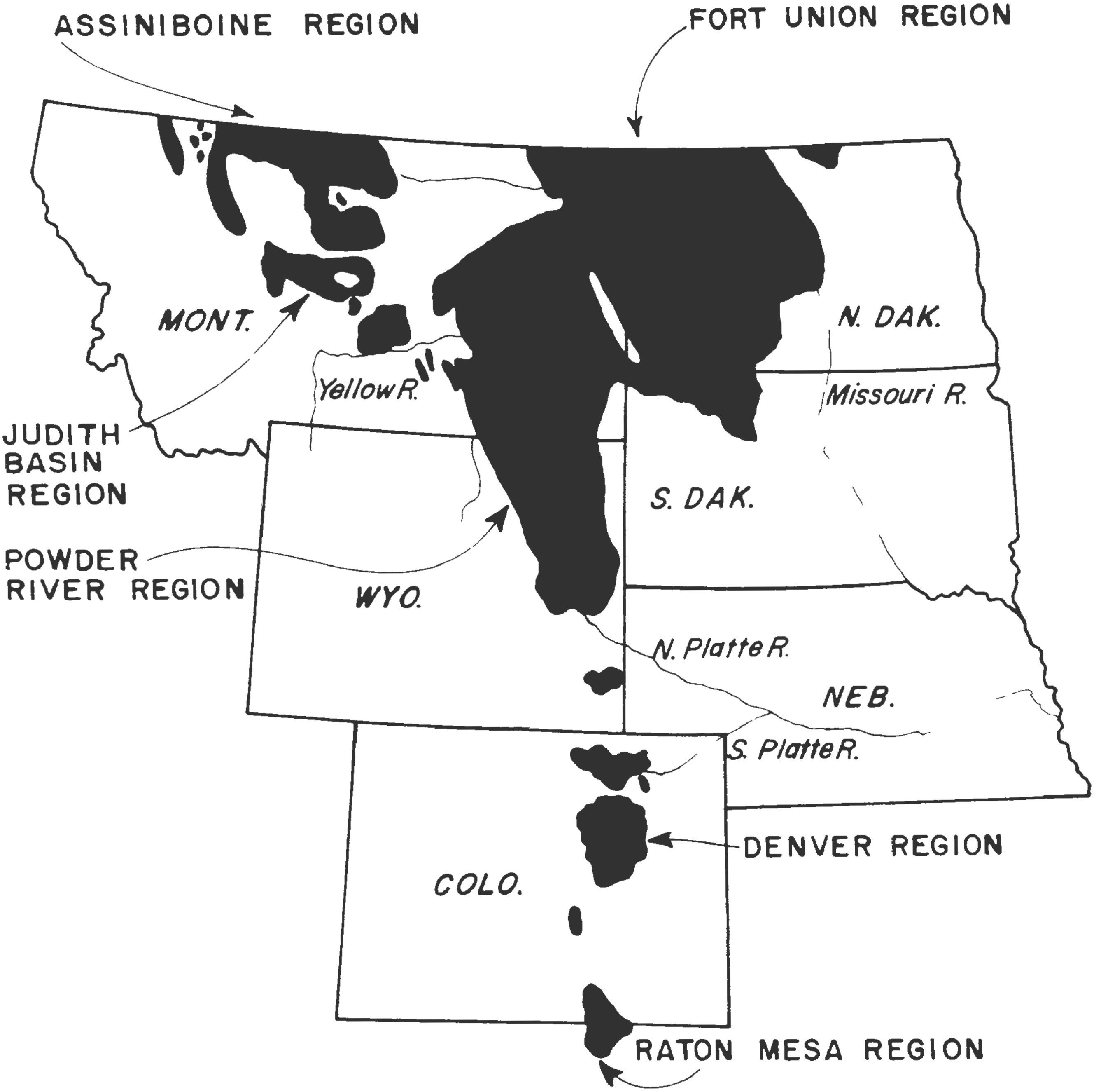


Figure 1-7. Distribution of Coal in the Northern Great Plains Province*

Source: BLM, 1974: II-132.

*See Figure 1-10, for other coal deposits in these states.

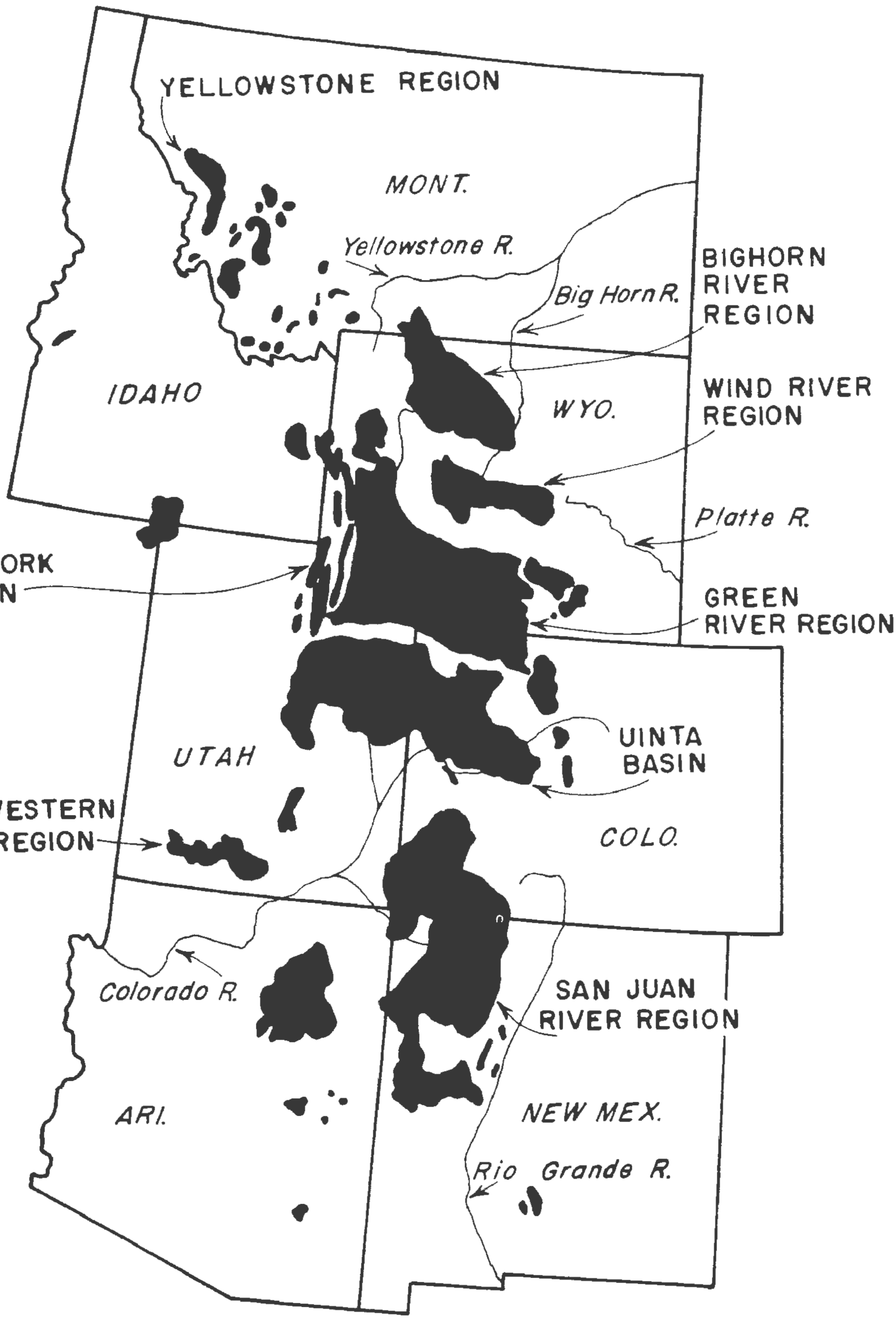


Figure 1-8. Distribution of Coal in the Rocky Mountain Province*

Source: BLM, 1974: II-132.

*See Figure 1-9 for other coal deposits in these states.

The province has the greatest variety in ranks and geologic setting of any province in the U.S. Coals of greatest current interest are subbituminous and low-grade bituminous, found mainly in the southern part of the province and in the Green River and Uinta Regions. Moisture content tends to be low and volatile matter content relatively high. Heating values range from 5,000 to more than 14,000 Btu's per pound (BLM, 1974: Vol. 1, p. I-57). Sulfur content is generally low, with almost 90 percent of identified resources having a sulfur content of one percent or less.

The depth and thickness of coal seams in the province vary greatly. A number of thick seams are being surface mined at the present time; other, deeper seams are not.

Much of the province is still covered by natural vegetation, and grazing is a major land use. Mining, logging, ranching, and farming are other land uses.

Except for the high mountains, precipitation averages less than 16 inches a year, and large, semidesert areas receive less than eight inches. As a consequence, water is almost universally scarce in the province.

1.4 SUMMARY

A number of important points emerge from this brief description of U.S. coal resources. Four major provinces--Rocky Mountain, Northern Great Plains, Interior, and Eastern--contain more than 90 percent of all coal resources in the contiguous 48 states. There are major differences between these provinces in terms of the quantity and quality of their coal, ownership, bed depth, seam thickness, and availability of water resources, as well as competition for surface area usage. Further, these differences will become increasingly important as technologies are developed to make coal a more acceptable, less environmentally threatening source of energy.

The Northern Great Plains and Rocky Mountain Provinces contain approximately 70 percent of the coal resources in the four major provinces and most of the nation's low-sulfur coal. Other characteristics of these two provinces are:

1. Much of the coal likely to be developed in the near future can be surface mined.
2. Competition for surface area usage is relatively low.
3. The federal government controls the majority of the coal lands.
4. Coals are lowest in energy value per unit weight.
5. Water resources are least plentiful.

These points should be kept in mind when reading the remaining sections in this chapter.

1.5 EXPLORATION

As mentioned in Section 1.1 and illustrated in Figure 1-9, coal resource development entails a sequence of activities beginning with exploration and ending with the transportation of solid, gaseous, or liquid fuels. There are a number of points in this sequence at which technological choices have to be made. In the following sections, the technological alternatives associated with each of these decision points will be identified and described.

1.5.1 Technologies

The general locations of major U.S. coal deposits are well-known, and data on these resources are more extensive than for such resources as oil and natural gas. Consequently, there has been little motivation for promoting the development of better coal exploration technologies.

Knowledge about coal resources is usually obtained in stages. First, available geological and geophysical data for a large area are reviewed and evaluated. If these data are sufficiently promising, a check is undertaken to identify the owner

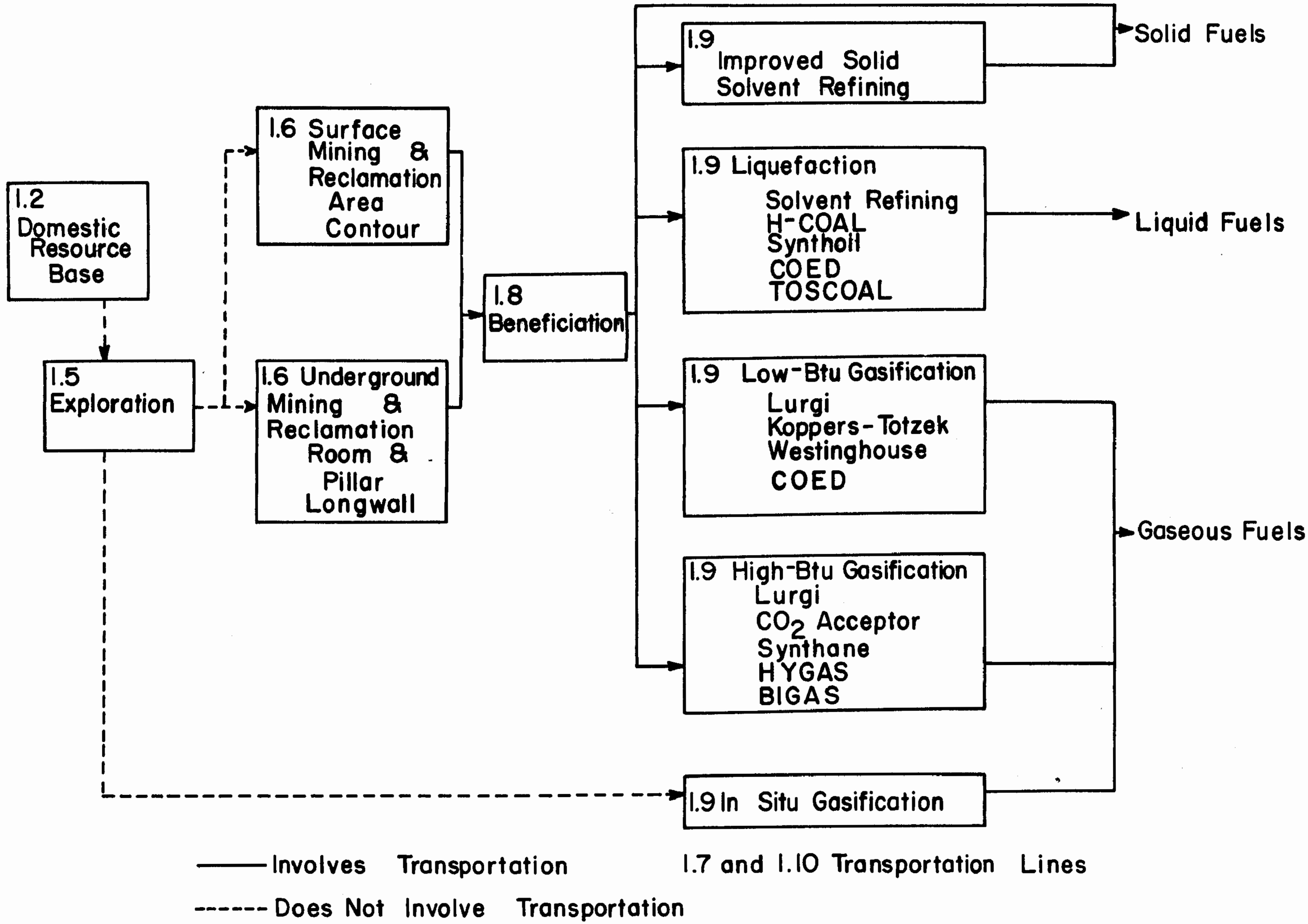


Figure 1-9. Coal Resource Development

of the surface and mineral rights. Additional data may also be gathered, usually by examining the surface to detect coal outcrops and by collecting samples.

If warranted, this regional appraisal is followed by a detailed study of identified or suspected deposits. Although drilling into deposits to determine seam depth, thickness, and areal extent is the primary exploratory technique at this stage, other techniques may also be used to supplement cuttings and core sample data. For example, surface and areal photographic surveys and magnetic and gravimetric measurements may be made to detect variations in the geologic structure, and tunnels may be dug to obtain additional subsurface samples. Seismic devices that distinguish geologic strata by recording reflected sound waves may also be employed, as might down-hole well-logging instruments (including cameras and acoustical devices) to distinguish geophysical characteristics. Despite the availability of this array of exploratory tools, the drill remains the primary tool used for finding and then mapping coal deposits. Mapping is essential for planning an effective mine operation (Grim and Hill, 1974: 26).

1.5.2 Energy Efficiencies

All exploration energy inputs are ancillary. While not calculated, they appear small.

1.5.3 Environmental Considerations

Environmental residuals from exploration are limited to surface and subsurface physical disturbances and noise associated with work crews, drilling, tunneling, etc. These are usually limited to small areas and the overall residuals are small.

1.5.4 Economic Considerations

Data on exploration costs are limited and generally out of date. However, a Bureau of Mines (BuMines) cost analysis of hypothetical mines does provide an indication of the relative magnitude of exploration costs in 1969 as a component of coal resource development (BuMines, 1972: 2). Data for three surface mines and two underground mines are summarized in Tables 1-8 and 1-9. The data for surface mines combine capital costs for exploration, roads, and buildings. These data seem to show that the proportionate cost of exploration is less for the higher rank coals.

In the case of underground mining, the data seem to indicate that the thicker the seam, the less the proportionate cost of exploration. Also, the cost of exploration appears to be proportionately less for underground mines, although a direct comparison is impossible given the failure to break out exploration costs as a single category for surface mining. The proportionate total cost of exploration for surface mining is apparently comparable to that for underground mining.

1.6 MINING AND RECLAMATION

1.6.1 Technologies

The principal coal mining methods are underground and surface. A third type, auger mining, is occasionally identified as a distinct method.

1.6.1.1 Surface Mining

Until recently, most U.S. coal was mined underground. However, as indicated in Figure 1-10, surface mining has been increasing for several decades, and slightly more than 50 percent of the coal mined in the U.S. now comes from surface mines (Gouse and Rubin, 1973: III-1). Most surface coal is produced by a relatively few large mines; 50 of the largest mines produced about one-fourth of the 552 million tons of bituminous coal produced in 1971.

The choice of mining method depends on a number of considerations, including seam depth and thickness, deposit size, and local geology. As discussed in Section 1.2.4,

TABLE 1-8

EXPLORATION COSTS IN SURFACE MINES[a]
(1969 DATA)

Rank	Location	Direct Capital Requirement[b]		Percentage Exploration[d]	Total Capital Requirement	Percentage Exploration[e]
		Exploration[c]	Total			
Bituminous	Northern West Virginia	$698,000	$9,648,000	7.2	$12,725,500	4.5
Subbituminous	Southwestern U.S.	797,000	5,888,900	13.5	7,898,100	10.1
Lignite	North Dakota or Montana	698,000	4,763,900	14.6	6,381,800	10.9

Source: BuMines, 1972: 8, 70, 101.

[a]Mine size capable of producing one million tons of coal per year.

[b]Direct capital costs are for equipment or items that can be assigned to particular activities, such as buildings. In contrast, indirect capital costs are a general expenditure such as overhead, engineering, etc.

[c]Includes direct capital requirement for roads and buildings.

[d]Exploration as a percentage of total direct capital requirement for all mining activities.

[e]Exploration as a percentage of total capital requirement, both indirect and direct as defined in footnote b.

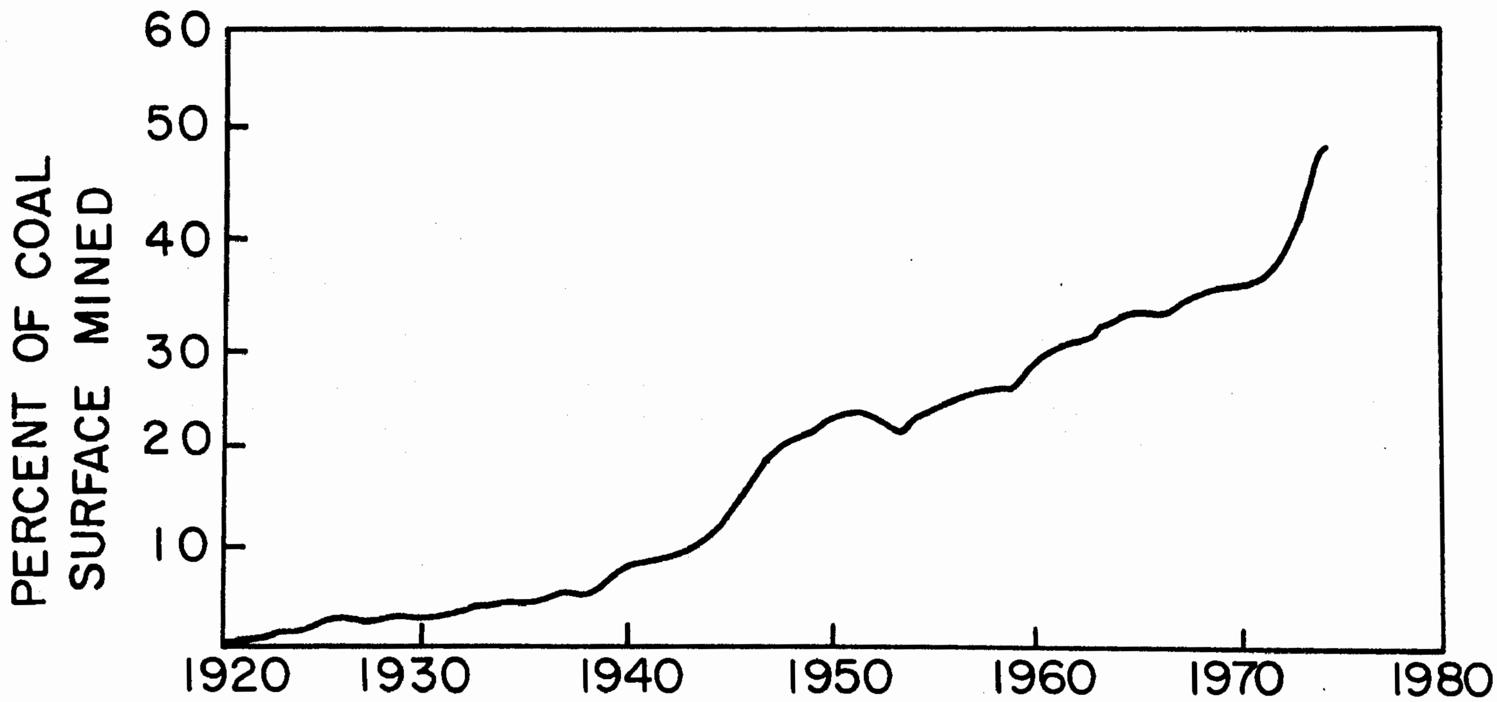


Figure 1-10. Increase in Coal Production by Surface Mining

Source: Adapted from Gouse and Rubin, 1973: III-5.

TABLE 1-9

EXPLORATION COSTS IN UNDERGROUND BITUMINOUS MINES[a]
(1969 DATA)

Annual Production (millions of tons)	Seam Thickness (inches)	Direct Capital Requirement	Percentage Exploration[b]	Total Capital Requirement	Percentage Exploration[c]
1.06	72	$7,264,600	0.7	$10,801,600	0.5
1.03	48	6,626,900	0.8	11,189,400	0.5

Sources: Katell and Hemingway, 1974a: 6, 7; Katell and Hemingway, 1974b: 5, 6.

[a]Fixed exploration cost of $50,000.

[b]Exploration as a percentage of total direct capital requirement.

[c]Exploration as a percentage of total capital requirement.

until about 1965 surface mining of coal was not considered feasible unless the overburden-to-seam thickness ratio was 10:1 or less. Thus, to justify removing 50 feet of overburden, the coal seam would have to be five or more feet thick. Since 1965, this ratio has been increasing and most coal within 150 feet of the surface is not considered economically recoverable, even when the overburden-to-seam thickness ratio is as much as 30:1.*

There are two major types of surface mines, contour and area. Contour mining is generally used in hilly or mountainous terrain. In this mining method, the overburden is removed from the slope to create a flat excavation, or bench, which is flanked by a vertical highwall on one side and a downslope pile of spoils on the other (Figure 1-11) (Senate Interior Committee, 1973: 14). The exposed surface layer of coal is then mined. Coal exposed in the highwall may also be mined by large drills or augers which pull the coal horizontally from the seam.

*As mentioned in Section 1.2.4, selected thin seams of coal for metallurgical use are being mined at a 40:1 ratio in Oklahoma.

Area mines, used in flat terrain, are opened by excavating a trench to expose the coal deposit (Senate Interior Committee, 1973: 12). As succeeding cuts are made to expose the coal, the overburden is piled into the cut from which the coal has already been mined (Figure 1-12). The operations involved in surface mining include surface preparation, fracturing, excavation, and transportation.

1.6.1.1.1 Surface Preparation

The initial phase of mine development requires construction of access roads and maintenance and personnel facilities. Also, utilities must be brought to the site and, in most regions, vegetation removed from the area to be mined. Even after the mine is established, additional vegetation removal may be required as the overburden stripping operation advances. When the vegetation is sparse and a dragline is used for excavation, vegetation is removed with the overburden.

The equipment used in surface preparation consists primarily of bulldozers, scrapers, and loaders. If the topsoil is to be replaced during reclamation, trucks are required to transport it to a stockpile or to an area being reclaimed.

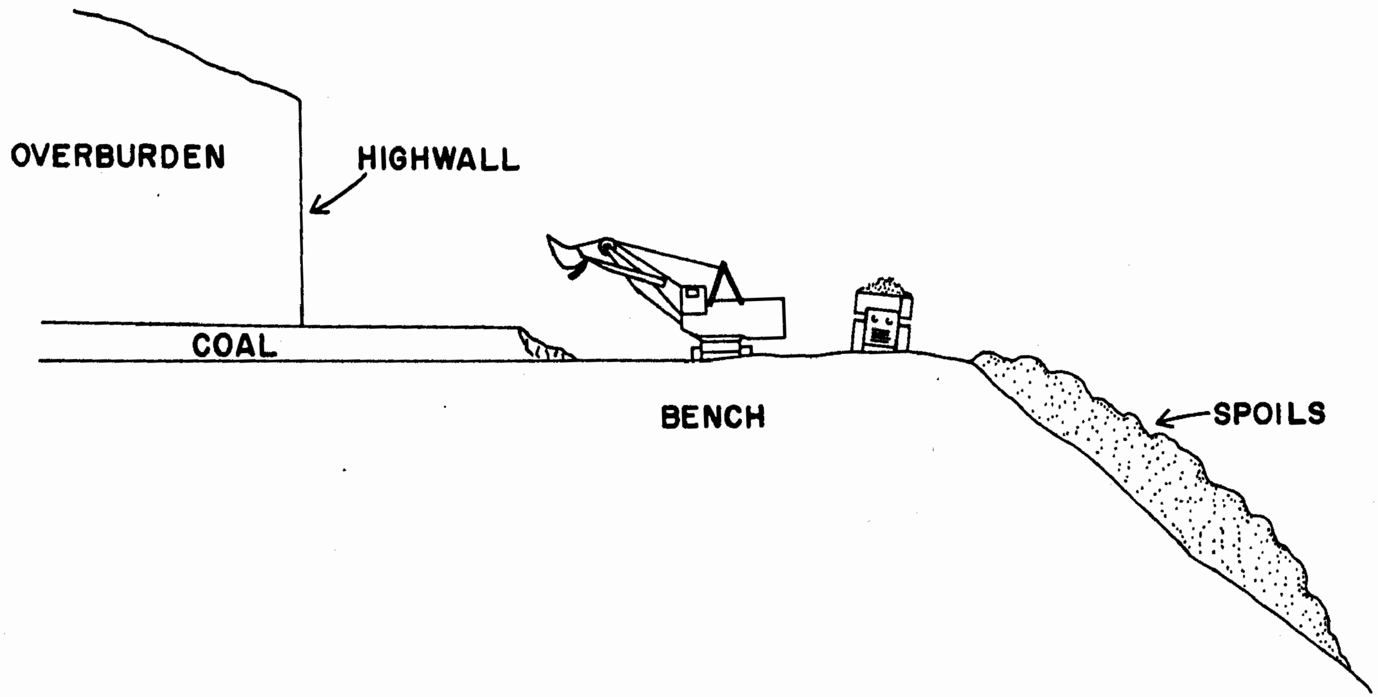


Figure 1-11. Contour Mine

Source: Adapted from NPC, 1972: 51.

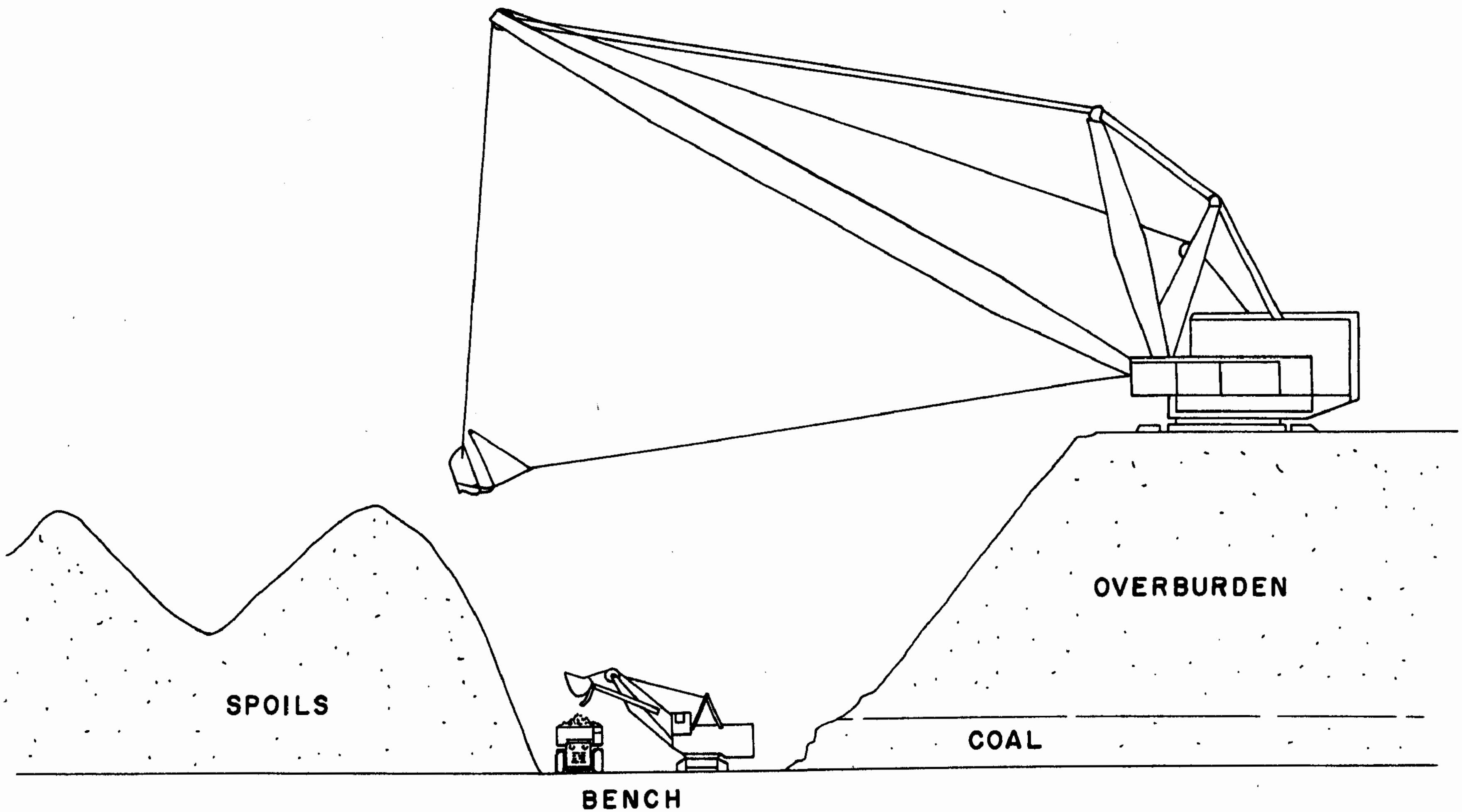


Figure 1-12. Area Mine

Source: Adapted from NPC, 1972: 51.

1.6.1.1.2 Fracturing

Fracturing consists of two steps, drilling blastholes and blasting. Blastholes extending from the surface to the coal seam are usually drilled by an electrically-powered rotary drill of 4 to 15 inches in diameter. Larger holes are drilled for fracturing the overburden than for the coal. When the formation to be penetrated is particularly hard, a pneumatic drill may be used. Both types of drills are usually mounted on a truck or tractor.

The most frequently used explosive is a mixture of ammonium nitrate (a commercial fertilizer) and fuel oil termed "ANFO." Either dynamite or metalized mixtures, such as ammonium nitrate and aluminum, can be used when a more powerful explosive is required. In populated areas, noise control is attempted by covering the explosive cord used in detonating and by introducing millisecond delays in explosion sequences (Grim and Hill, 1974: 93). For safety, blast areas may be covered by mats to minimize the scattering of rock fragments (Grim and Hill, 1974: 94).

1.6.1.1.3 Excavation

A number of technological alternatives are available for excavating overburden and coal after fragmentation. Four kinds of equipment are used in typical surface mining operations:

1. Small, mobile tractors, including bulldozers, scrapers, and front-end loaders.
2. Shovels.
3. Draglines.
4. Wheel excavators.

Most mining operations will use several of these equipment items in varying combinations, although one or two usually dominate the operation. Item selection and combination are generally based on the nature and quantity of the material to be moved, distance and transport surface conditions, and flexibility of the equipment for other applications (Killebrew, 1968: 463). Descriptions of the major mining equipment items follow:

1. Tractors. Tractors are typically used either in small mines or in conjunction with larger, more specialized equipment in large mines. The principal advantages of tractors are their maneuverability, ability to negotiate steep grades, and capability to dig and transport their own loads (Killebrew, 1968: 463, 464). Tractors are used for a variety of tasks, including clearing, preparing benches, leveling spoil piles, and constructing roads.
2. Shovels. Large diesel or electrically powered stripping shovels have been used in surface mines for a number of years and are often designed for a particular mine application. These machines progress along a bench scooping up the fragmented overburden or coal in buckets with capacities of up to 130 cubic yards. In the largest surface mines, shovels are often used in conjunction with draglines, primarily to load coal.
3. Draglines. Electrically powered draglines, such as the one shown in Figure 1-13 are capable of moving larger amounts of materials in a single bite than any other equipment item currently being used in surface mines. Bucket capacity of these machines ranges from 30 to 220 cubic yards. The dragline moves along the bench, positions its bucket on the overburden to be removed, and loads it by dragging it toward the machine. The loaded bucket is then lifted, the machine rotated, and the bucket dumped in an area that has already been mined.
4. Bucket Wheel Excavators. Another type of excavator, although seldom used in the U.S., has a rotating bucket wheel mounted at the end of the boom. This bucket wheel can be 50 or more feet in diameter and the boom up to 400 feet long (Aiken and Wohlbier, 1968: 479). As shown in Figure 1-14, rotating the wheel loads the buckets from the cut and empties the material onto a conveyor which then transports it to whatever in-mine transportation system is being used. Only the largest mines with suitably soft materials justify the expense associated with this type of excavator.

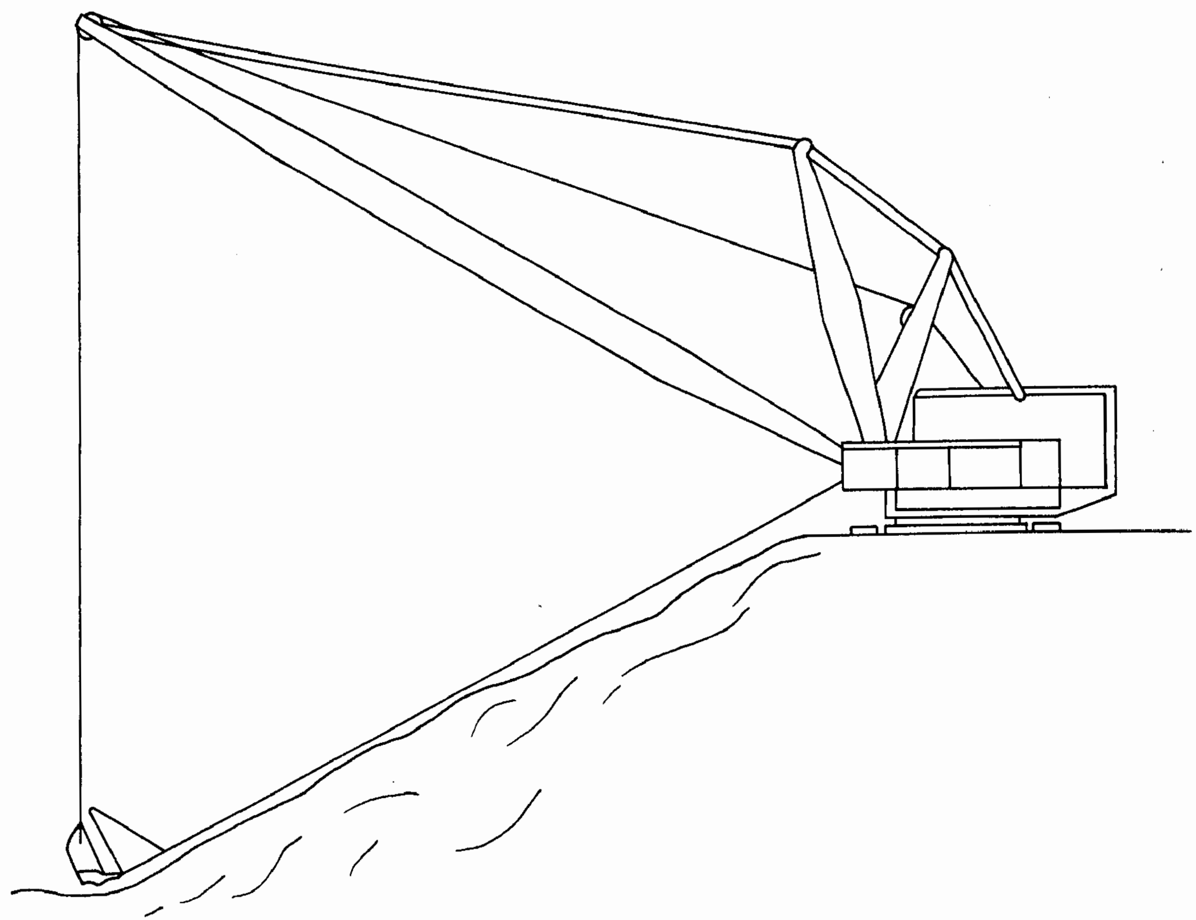


Figure 1-13. Dragline

Source: Adapted from NPC, 1972: 51.

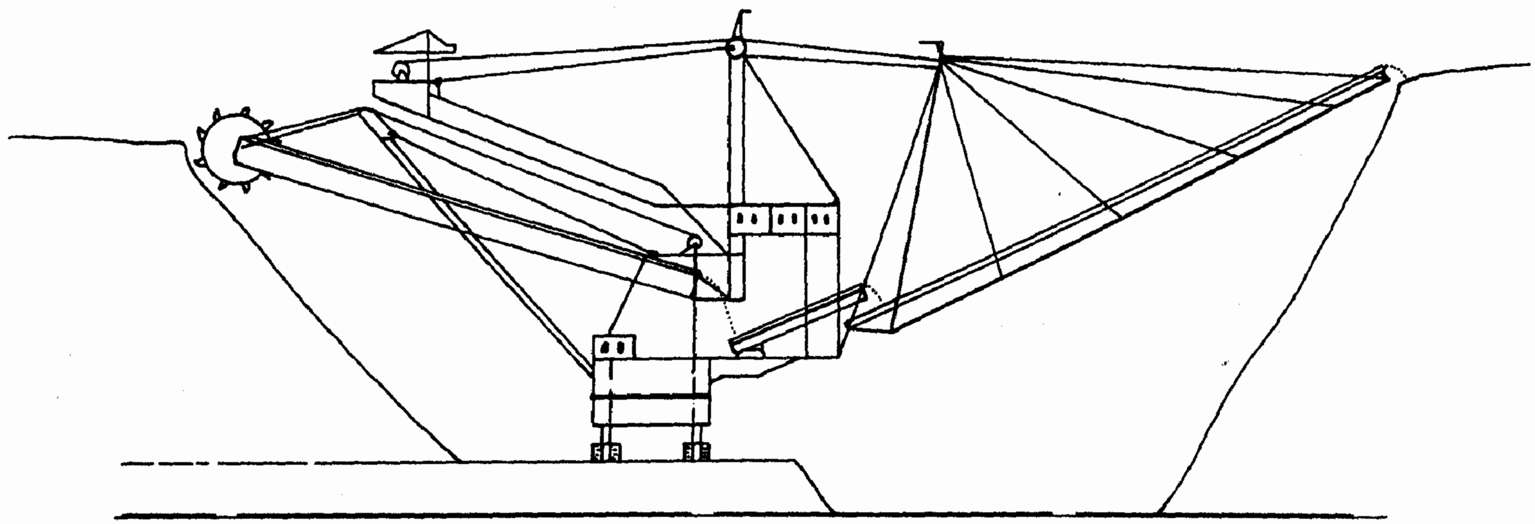


Figure 1-14. Bucket Wheel Excavator

Source: Adapted from Weimer and Weimer, 1973: Figure 17-79, p. 17-136.

The bucket wheel excavator has been used fairly extensively in Europe, generally in deep surface mines where the overburden is several hundred feet thick (Gartner, 1969: 26). In this type of mine, the excavator can operate for an extended time in a relatively fixed position. Bucket wheel excavators can make high cuts, thus requiring fewer levels in the mine, and can cut seams that have a high slope angle (Gartner, 1969: 26).

Whatever the method used, area and contour mines require large energy inputs and have high materials outputs. The materials balance for surface mining methods is listed in Tables 1-10 and 1-11.

1.6.1.2 Underground Mining

The two basic methods used in underground mining in the U.S. are: (1) room and pillar, and (2) longwall. In both types of mines, the initial step is to prepare the surface by constructing access roads and facilities, bringing the necessary utilities to the site, and clearing vegetation from the construction site and the location of tunnels or shafts. The equipment used for these tasks is the same as that used for surface mines.

The coal deposit is reached by digging or boring a vertical shaft or a horizontal (or slanting) tunnel. Only after the deposit is reached do differences in the mining methods occur.

TABLE 1-10

MATERIALS BALANCE FOR AREA SURFACE MINING[a]

Inputs	Quantity	Outputs	Quantity
Electricity	76,741 kwhd[b]	Coal	5,490 tpd[c]
Fuel (diesel)	1,121 gpd[d]	Solid waste	46.49 tpd
Water	0	Liquid waste	6.14 tpd
Chemicals and explosives	U	Air emissions	0.32 tpd

U = unknown.

Source: Adapted from Hittman, 1974: Vol. I., Table 1.

[a]National average for coal mine of two million tons production per year; assumes an average depth of 48 feet and an average seam thickness of 5.2 feet; equivalent to 48.9×10^{12} Btu's per year.

[b]kilowatt-hours per day.

[c]tons per day.

[d]gallons per day.

[e]Coal mining water demands are usually minor and are primarily for dust control, fire protection, coal washing, and revegetation. However, if the mine is in an arid region (less than 10 inches of rainfall per year), a supplemental source of water (other than local or mine-produced supplies) may be needed, especially for revegetation. In the revegetation program for an arid region, 0.5 to 0.75 acre-feet of water per acre mined should be sufficient to establish seedlings (Davis and Wood, 1974: 1).

TABLE 1-11

MATERIALS BALANCE FOR CONTOUR MINING[a]

Inputs	Quantity	Outputs	Quantity
Electricity[b]	76,183 kwhd[c]	Coal	5,490 tpd[d]
Fuel[b] (diesel)	1,101 gpd[e]	Solid waste	53.3 tpd
Water	0	Liquid waste	1.22 tpd
Chemicals and explosives	U	Air emissions	0.48 tpd

U = unknown.

Source: Adapted from Hittman, 1974: Vol. I., Table 10.

[a]Based on a two-million-tons-per-year Central Appalachian mine under controlled conditions (equivalent to 48.9×10^{12} Btu's per year).

[b]Complete energy consumption information by the modified block cut method is not available.

[c]kilowatt-hours per day.

[d]tons per day.

[e]gallons per day.

1.6.1.2.1 Room and Pillar

In room and pillar mining, a passageway is excavated through the coal seam. From this passageway, rooms are formed by mining the coal, leaving portions in place to act as support pillars for the strata overlying the rooms. The pattern of this excavation is diagrammed in Figure 1-15.

Room size depends on the geology of the strata being mined, the two governing factors being seam thickness and the strength of the coal and the materials immediately above and below it. In typical U.S. underground mines (which are mostly in the Eastern Province), coal and surrounding material strengths are low, and coal seams range from two to six feet thick. As a consequence, the rooms are long and narrow, typically 10 to 20 feet wide and several hundred feet long. The rooms are kept this small even though mechanical supports are used to increase the load-bearing capacity of the mine roof.

In room and pillar mining, the coal is cut off the face of the seam and loaded onto some type of transportation equipment. This is accomplished by any of four methods:

1. Hand cutting and loading.
2. Machine cutting and hand loading.
3. "Conventional mining," which uses machine cutting and mechanical loading.
4. "Continuous mining," in which one machine performs the cutting and loading operations.

Most U.S. room and pillar mines now employ either conventional or continuous mining methods.

In conventional mining, a cutting machine, operating somewhat like a large chain saw, cuts a slice under the seam (Figure 1-16). A mobile drilling rig then drills blastholes, the coal is fragmented

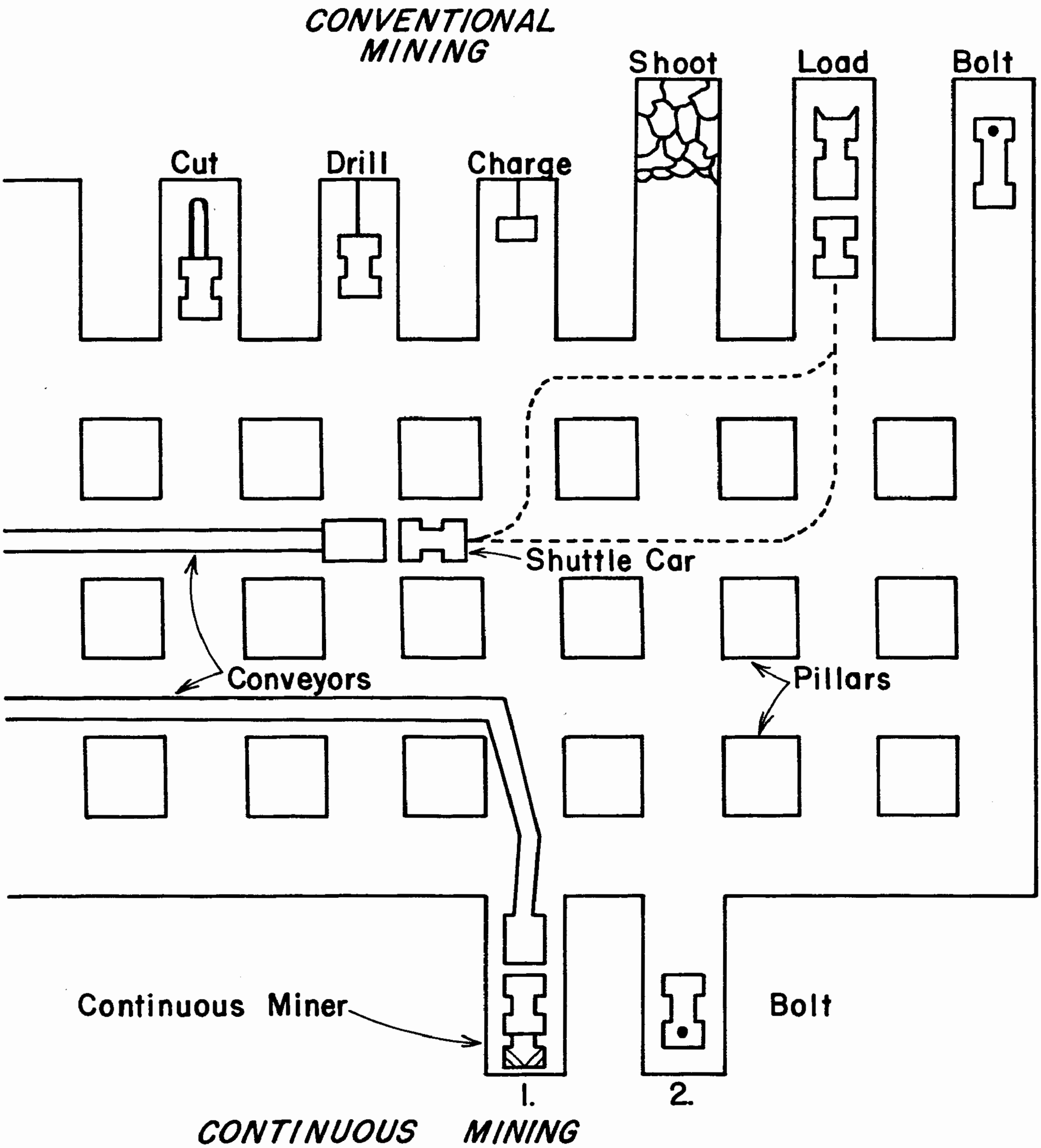


Figure 1-15. Alternative Methods for Room and Pillar Mining

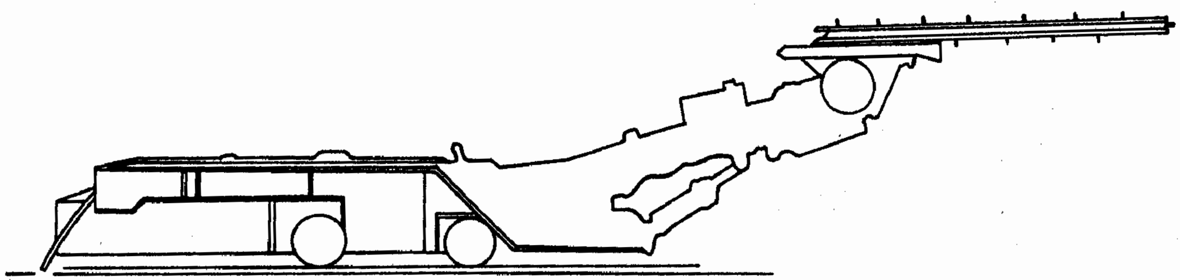


Figure 1-16. Cutting Machine

by blasting (Gouse and Rubin, 1973: III-19), and the fragments are picked up by a mechanical loader (Figure 1-17). Because of the low clearances in most underground mines, the blasthole drills (both rotary and percussion types are used) are mounted on low-profile vehicles and the holes drilled horizontally. As in surface mining, the most commonly used explosive is ANFO.

In continuous mining, a single machine (the continuous miner) performs the cutting, loading, and initial transportation operations (Gouse and Rubin, 1973: III-21). This machine cuts the coal off the face of the seam by rotating a drum-shaped cutter. The cutter is mounted above a loading device that pulls the mined coal onto a conveyor belt which then moves it to the transportation system being used to carry the coal to the surface.

As indicated in Figure 1-18, the current trend in U.S. underground mining is toward increased use of both the conventional and continuous mining method, although the latter method has shown the greatest increase. One reason for this is that continuous mining is considerably less labor intensive than is conventional mining.

Roof support must be provided for the rooms excavated by either mining method. The system most frequently used involves drilling holes in the roof and inserting bolts equipped with either expansion heads or another fastening system (Gouse and Rubin, 1973: III-21). Roof bolts generate compressive stresses to strengthen the roof and, as indicated earlier, permit excavating larger rooms than would otherwise be possible. Recently, epoxy has been used to cement either bolts or rods into place.

Leaving pillars in place to support the roof significantly decreases the portion of the coal that can be mined. On the average, about 45 to 50 percent of the coal in place is recovered in U.S. room and pillar mines. This percentage can be increased by removing additional coal when the mine is being closed down and roof support is no longer a problem. Possibly as much as 80 percent of the coal in place can eventually be recovered by the room and pillar method (Gouse and Rubin, 1973: III-36). The materials balance for a hypothetical room and pillar mine is indicated in Table 1-12.

1.6.1.2.2 Longwall

Although used extensively in Europe, longwall mining accounts for only about three percent of U.S. coal production (Gouse and Rubin, 1973: III-23). This type of operation is illustrated in Figure 1-19. A shearing drum moves back and forth across the working face of the seam between two access passageways or galleries (Laird, 1973: Vol. 1, p. 12-176). Sheared coal drops onto a conveyor which moves it to the transportation system being used to remove the coal from the mine. The roof in the area immediately behind the mining machine is held up by hydraulic jacks that are moved forward as the mining operation advances (Figure 1-20). As the jacks are moved, the roof in the area from which the coal has been mined is allowed to collapse.

The major advantage offered by longwall mining is recovery of a higher percentage of the coal in place than is possible with the room and pillar method. It is also less labor intensive than some of the other techniques. On the other hand, capital costs for longwall mining systems are generally much higher than for either conventional or continuous room and pillar mining (Gouse and Rubin, 1973: III-23). The relative advantage of longwall over room and pillar mining is indicated in the materials balance shown in Table 1-13. Longwall mining consumes less electricity than does room and pillar mining.

Shortwall mining, a variation of the longwall method is sometimes used in U.S. mines. In shortwall mining, the face is

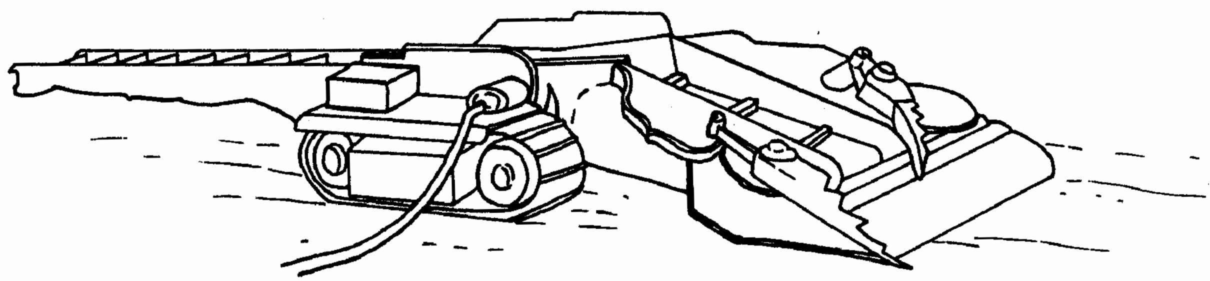


Figure 1-17. Mechanical Loader

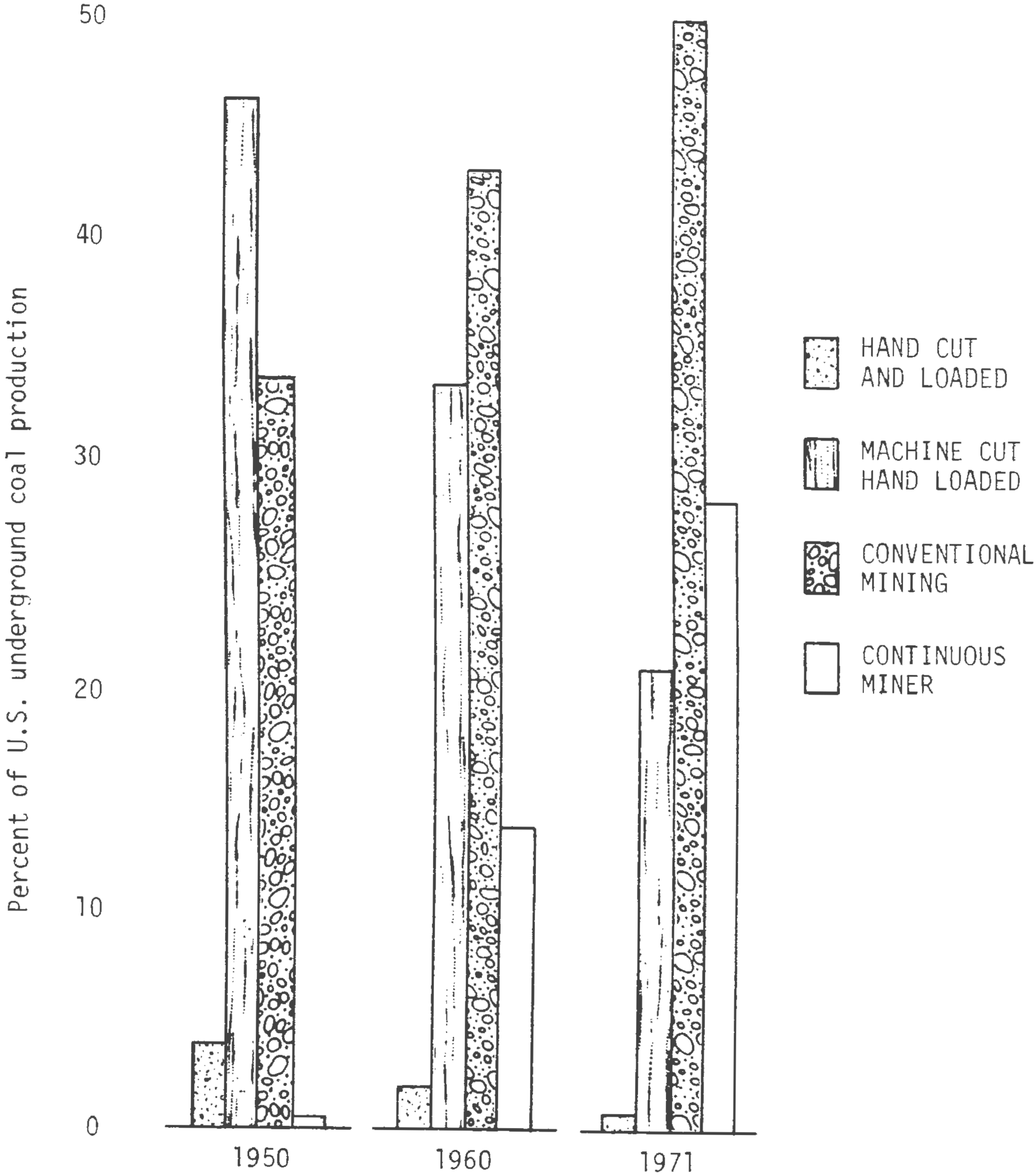


Figure 1-18. Underground Mining Methods

Source: Adapted from Gouse and Rubin, 1973: III-9.

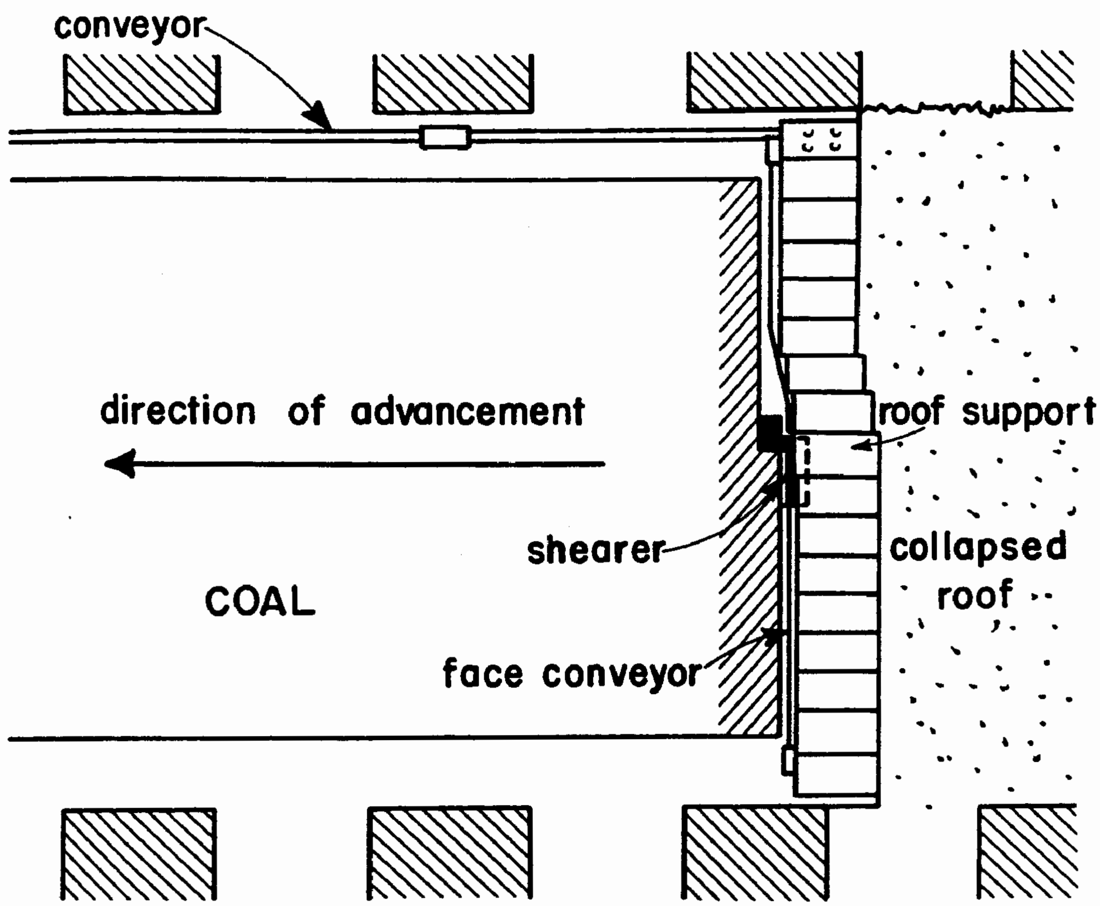


Figure 1-19. Plan View of Longwall Mining

Source: Adapted from Gouse and Rubin, 1973: III-24.

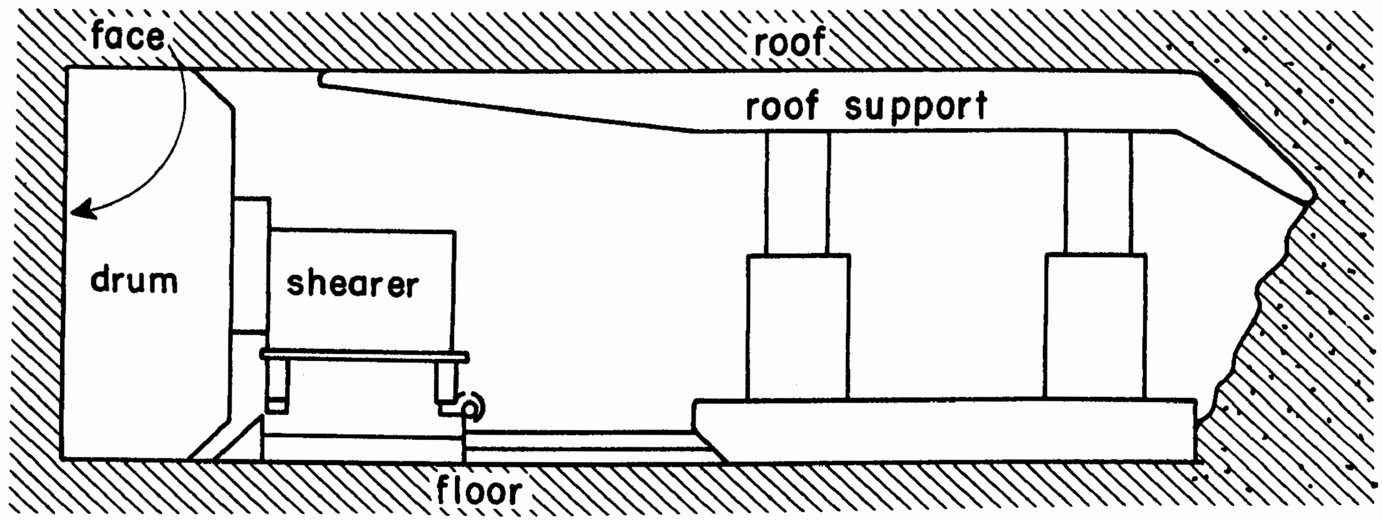


Figure 1-20. Section View of Longwall Mining

Source: Adapted from Gouse and Rubin, 1973: III-24.

TABLE 1-12

MATERIALS BALANCE FOR ROOM AND PILLAR MINING[a]

Inputs	Quantity	Outputs	Quantity
Electricity	98,672 kwhd[b]	Coal	5,490 tpd[c]
Fuel (diesel)	0	Solid waste	154 tpd
Lime	Approximately 230 tpd	Liquid waste	5.23 tpd
Water	U	Air emissions	0.00 tpd
Chemicals and explosives	U	Water	1.61 mmgpd[d]

U = unknown.

Source: Hittman, 1974: Vol. I., Table 8.

[a]Based on a two-million ton-per-year Northern Appalachian mine (equivalent to 47.17×10^{12} Btu's per year). Under controlled conditions.

[b]kilowatt-hours per day.

[c]tons per day.

[d]millions of gallons per day.

TABLE 1-13

MATERIALS BALANCE FOR LONGWALL MINING[a]

Inputs	Quantity	Outputs	Quantity
Electricity	89,346 kwhd[b]	Coal	5,490 tpd[c]
Fuel (diesel)	0	Solid waste	230 tpd
Water	U	Liquid waste	7.79 tpd
Chemicals	U	Air emissions	0.00 tpd
		Water discharge	1.61 mmgpd[d]

U = unknown.

Source: Hittman, 1974, Vol. I, Table 8.

[a]Based on a two-million-ton-per-year Northern Appalachian mine under controlled conditions.

[b]kilowatt-hours per day.

[c]tons per day.

[d]millions of gallons per day.

roughly 150 feet long as compared to 600 feet for longwall, and a continuous miner is used instead of a shearer (BLM, 1974: Vol. 1, p. I-96).

1.6.1.3 Mine Safety

Mine safety, a continuing problem, is more critical in underground than in surface mining. In surface mines, safety problems are much the same as those associated with any activity involving heavy equipment and the use of explosives. In underground mines, ventilation, methane control, general fire and explosion control, and roof support are additional problems. Despite these formidable safety problems, underground mine safety has been improving since BuMines began keeping records in 1910 and, as Figure 1-21 indicates, fatalities have decreased since then.

Mines are usually ventilated by positively managing airflow patterns throughout the mine. This may include erecting temporary partitions, establishing airwall barriers, and installing fans to circulate air. Temporary partitions are being used to control ventilation in the mine diagrammed in Figure 1-22. Ventilation systems typically include several techniques, together with dust collectors and monitoring equipment.

Methane has always been a problem in underground mines. Most current attempts to deal with this problem use conventional ventilation methods. However, degasification (including drilling holes to drain methane pockets or introduce gases which have a higher affinity for methane than does coal) is now receiving R&D attention (Gouse and Rubin, 1973: III-37). Although at least one large coal company is using seismic technologies to locate methane pockets, it is not clear whether this is an operational procedure in all of the company's underground mines (Interview with industry engineer, June 1974).

In addition to methane drainage, fire and explosion control includes installing fire quenching systems, dust suppressors, explosion and fire barriers, inflatable seals, and monitoring systems. All these technologies have been under development for considerable periods of time. In addition, rigid inspection, testing, and approval procedures have helped make mine equipment safer. Mine safety has improved during the last 50 years, and, as shown in Figure 1-23, this improvement is apparently linked very closely to the introduction of new technologies.

1.6.1.4 Reclamation

Although the large areal disturbances of surface mining are generally more visible, both underground and surface mining techniques produce significant physical impacts. Both methods disturb the surface, produce wastes that require disposal, can affect water resources, and expose materials that produce acids when dissolved in water. Using a broad definition, these are all reclamation problems.

1.6.1.4.1 Surface Mine Reclamation

In surface mining, the major reclamation problem is dealing with the surface disruption. This normally involves smoothing out piles of overburden and making some attempt to revegetate the area. Comprehensive reclamation programs include restoring the surface topography, replacing the topsoil, fertilizing and revegetating, and returning the land to some productive use, whether agricultural, commercial, residential, or recreational.

Replacement topsoil may be the original topsoil, which has been removed and stockpiled, or may be topsoil brought from some other area. In any case, plant receptive material is replaced after the overburden is graded and shaped. Seeding and fertilization is then undertaken, using either

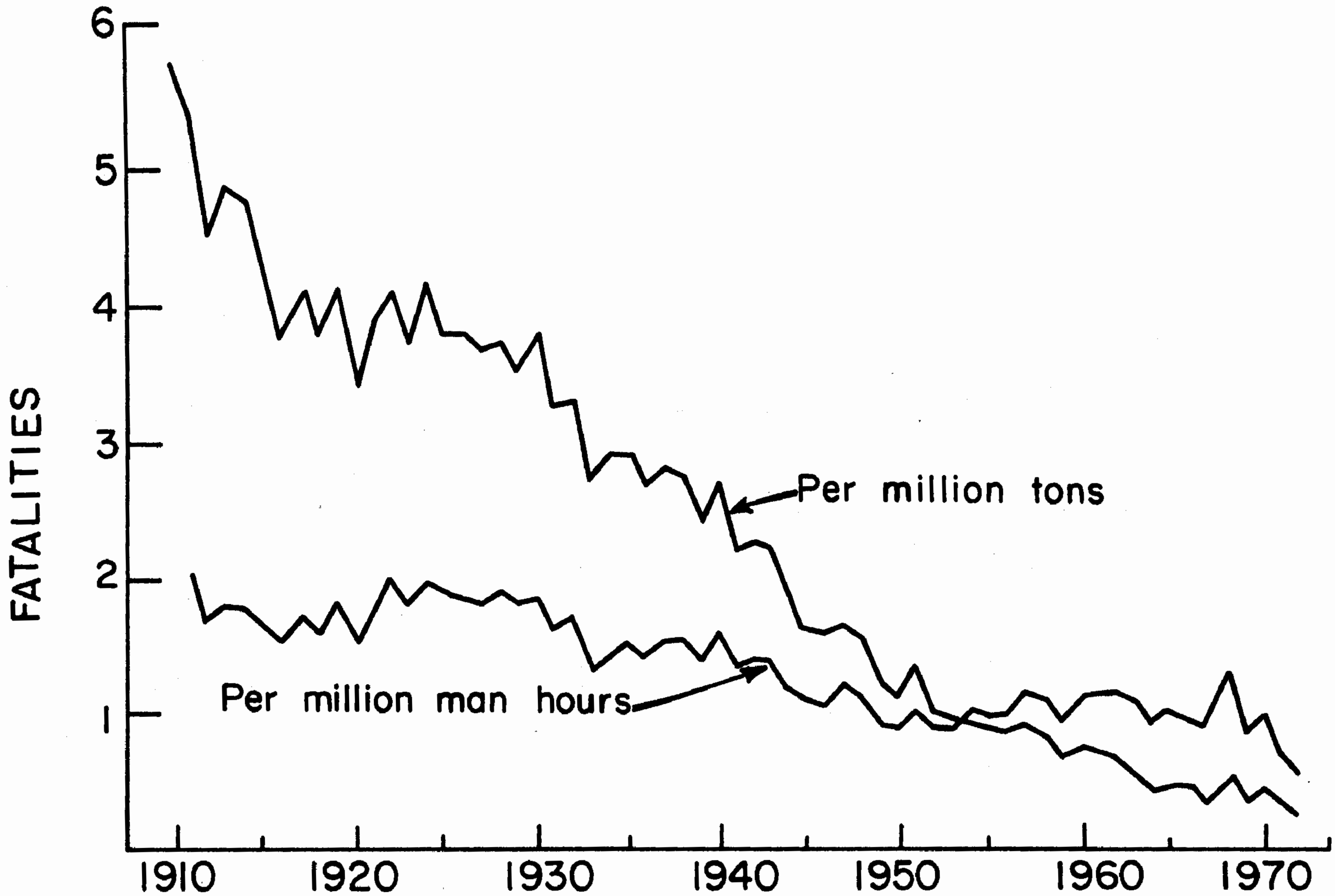


Figure 1-21. Underground Mine Fatalities

Source: Adapted from Gouse and Rubin, 1973: III-13.

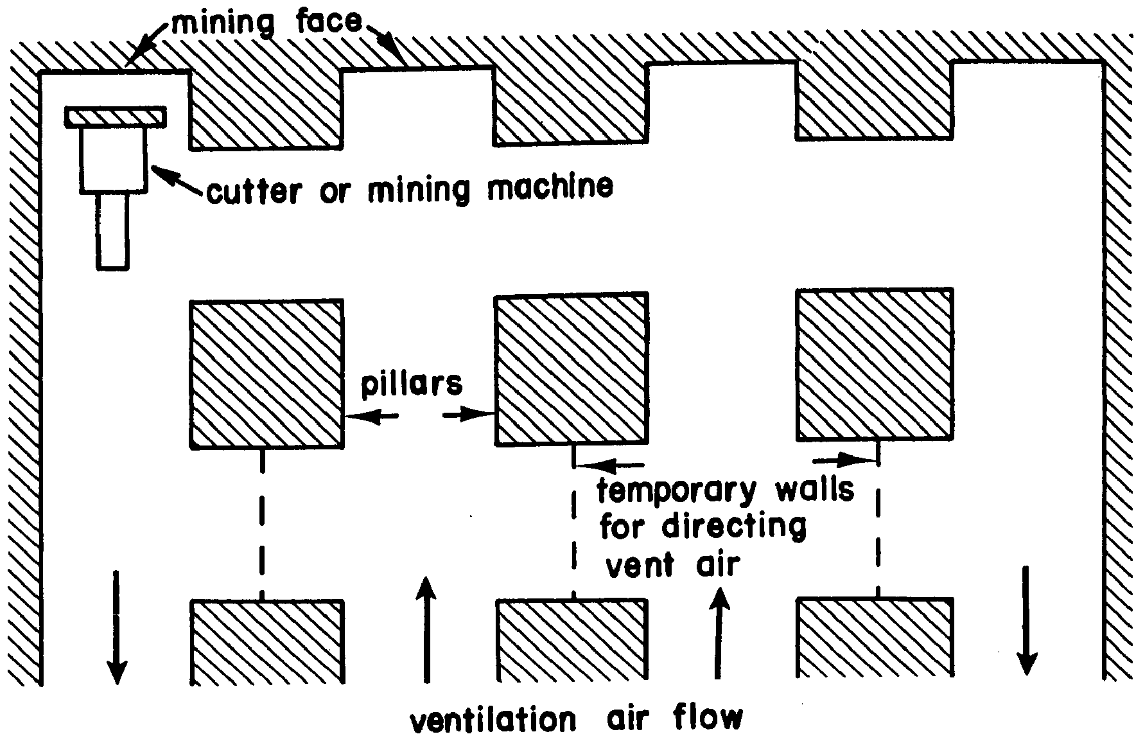


Figure 1-22. Ventilation in a Room and Pillar Mine

Source: Adapted from Gouse and Rubin, 1973: III-20.

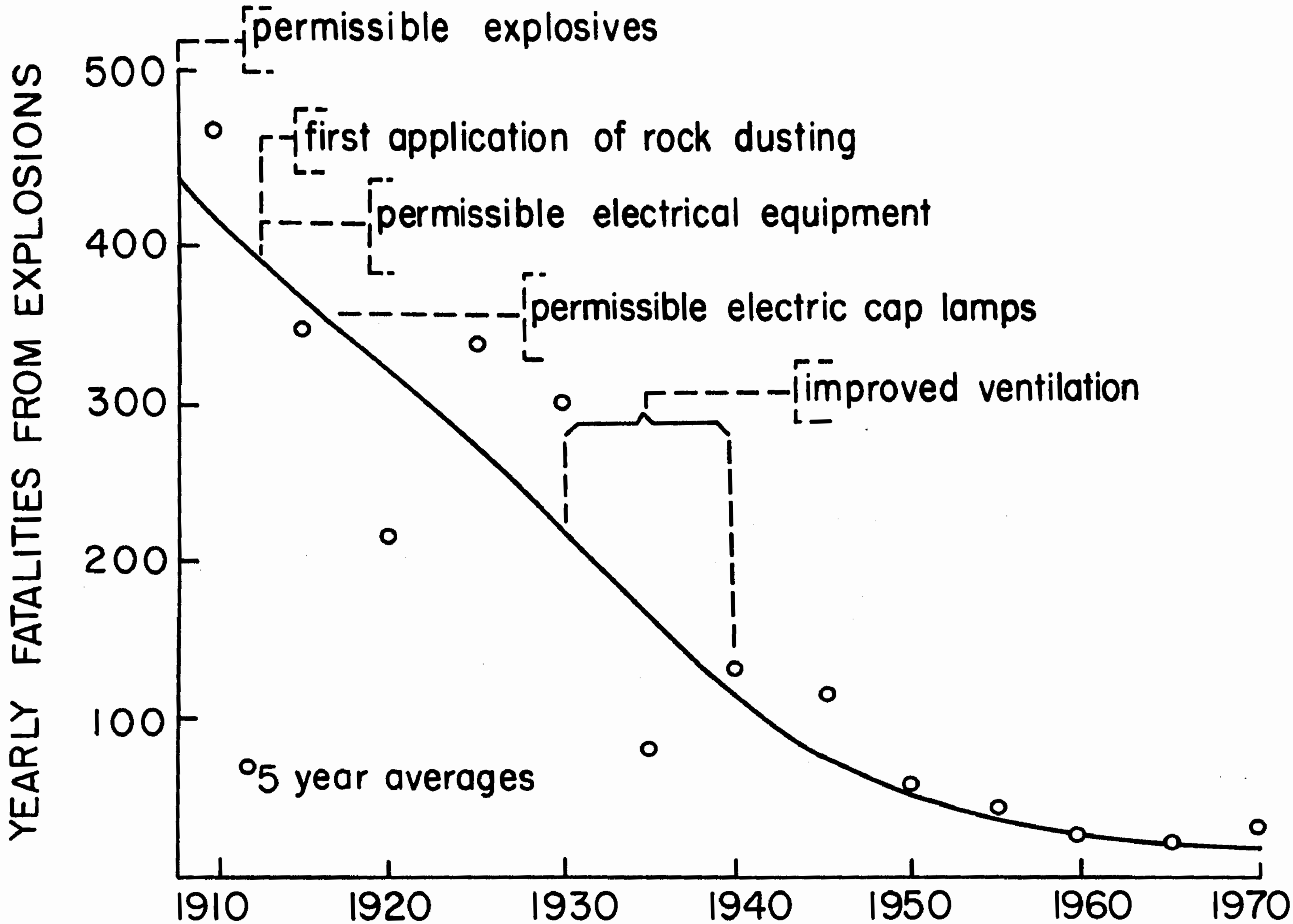


Figure 1-23. Fatalities from Explosions in Underground Coal Mines

Source: Adapted from House and Rubin, 1973: III-12.

conventional methods or such combination techniques as air-dropping pelletized seeds (EPA, 1973: 175). However, successful revegetation apparently depends more heavily on adequate rainfall than on seeding and fertilizing methods.*

1.6.1.4.2 Contour Mine Reclamation

As noted in the earlier description of contour mining, the overburden is piled on the downslope behind the mining operation. Although this slope presents a reclamation problem, a number of techniques are available for minimizing undesirable impacts (Senate Interior Committee, 1973: 11). Some of these include:

1. Shaping the Spoil Bank. In this technique, the spoil bank is reshaped by a bulldozer as indicated in Figure 1-24. This involves knocking down all vegetation and compacting the spoil in layers to reduce erosion. A revegetation program then follows. Although this technique reduces damage, the exposed highwall remains (Senate Interior Committee, 1973: 16-18).
2. Backfilling the Bench. In this technique, the spoil bank is moved back over the bench to fill in the original cut and cover the highwall. This leaves the land in a configuration similar to the original form (Figure 1-25). Terraces or diversion ditches can be used to minimize erosion. Although several approaches can be used in backfilling, substantial portions of the downslope areas are damaged by the spoils, and all the spoils cannot be returned to the bench (Senate Interior Committee, 1973: 18-20).
3. Modified Block Cut. This technique modifies the sequence of mining operations in conventional contour mining. Instead of continuously mining a slope by pushing the spoils over the downslope, successive cuts excavate the spoils into a previously cut bench. Thus, only an initial bench cut must push overburden into a downslope pile. This technique has the advantage of allowing the topsoil to be set aside, and only the bench topography is modified (Senate Interior Committee, 1973: 20-23).

1.6.1.4.3 Area Mine Reclamation

Area mines pose fewer reclamation problems than contour mines. The mined areas are frequently returned to their original topography, but restoration requirements and capabilities vary with location. For example, when thick Montana and Wyoming coal beds are mined, restoring the land to its original form is almost impossible. Further, revegetation in arid and semiarid areas such as these is also a major problem.

1.6.1.4.4 Underground Mine Reclamation

The reclamation problems associated with underground mines vary somewhat from those of surface mines. Although some surface clean-up may be required and the materials removed to gain access to underground coal seams require disposal, both problems are comparatively small. A larger problem is the disposal of materials mined with the coal. Often the coal is cleaned at the surface to remove these materials. However, the materials cannot be simply piled up and left uncovered because they may produce acid water runoff when dissolved by rain. Clean-up of acid mine waste by lime treatment is assumed in the materials balance previously tabulated (Tables 1-12 and 1-13).

Waste piles (composed of access materials, coal-separated materials, and/or refuse, such as tailings and slag) also present reclamation problems. The water impounded by such a pile, and released when it gave way, produced a disastrous flood at Buffalo Creek, West Virginia a few years ago. That pile was not designed to be a dam but was used as one. The water

---

*This has been assumed to be the case. However, the actual shaping and restoration program depends largely on the type of mine and where it is located. Contour mine reclamation problems are more difficult than those associated with area mines, primarily because of topography.

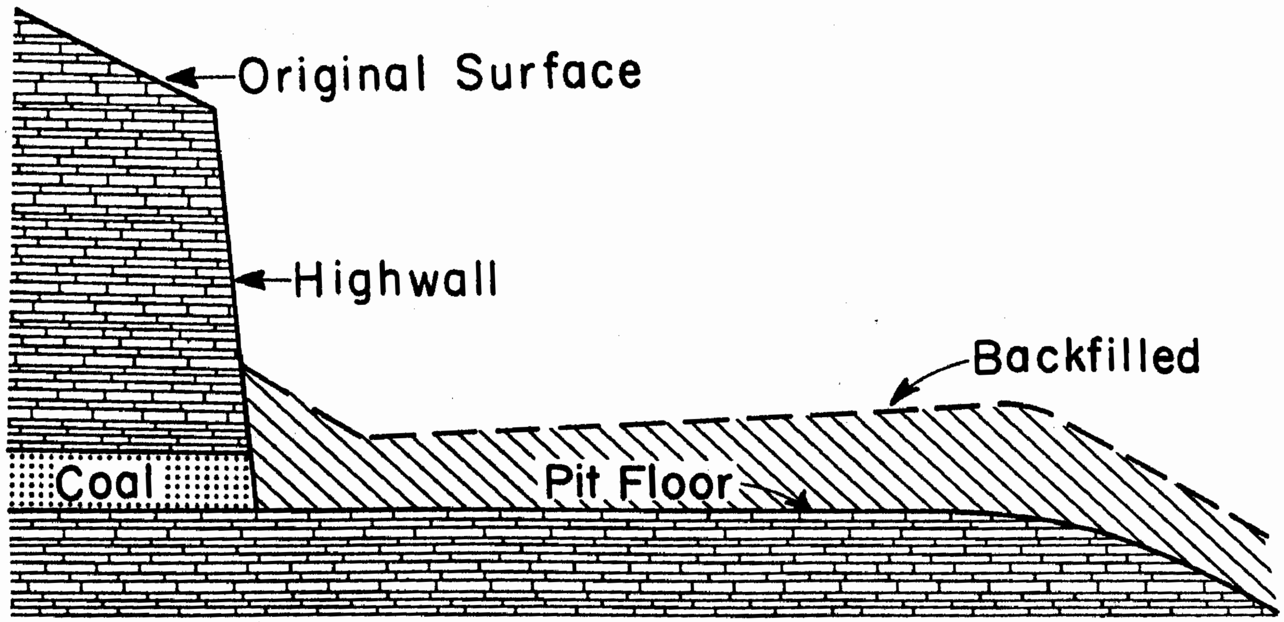


Figure 1-24. Reclamation by Reshaping the Spoil Bank and Partial Backfilling

Source: Adapted from EPA, 1973: 116.

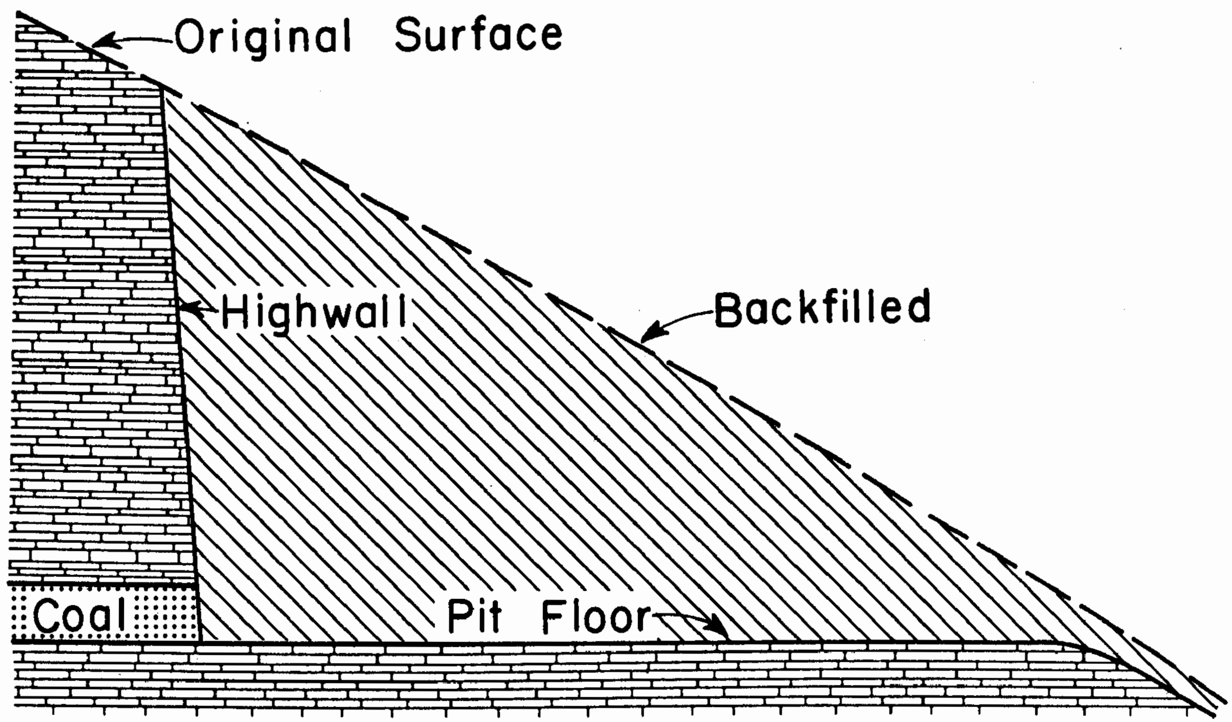


Figure 1-25. Reclamation by Full Backfilling of the Bench

Source: Adapted from EPA, 1973: 112.

impounded in the narrow hollow was also used as a settling pond and a source of process treatment water.*

Subsidence of the surface area overlying underground mines also constitutes a reclamation problem. Generally, the surface will subside, limiting subsequent surface usage.

1.6.2 Energy Efficiencies

Energy efficiency and environmental data are from Hittman, Battelle, and Teknekron. The Battelle data are based on hypothetical mines located in the eastern and western U.S. The characteristics of the resource used in the Battelle calculations are listed in Table 1-14. Teknekron data are representative of eastern coal in general. Specific coal characteristics and assumptions used by Teknekron are not available. Differences in the efficiencies and environmental residuals reported in several of the tables can be partially explained by assumptions stated in the text. The assumptions cannot account for many of the differences, however, and these may represent variation in technologies or methods of calculation. Hittman's mining and reclamation data are for respective mines located in five areas which can be related to USGS provinces and regions as follows:

Hittman Area	USGS Province/Region
Northern Appalachian	Eastern/Appalachian
Central Appalachian	Eastern/Appalachian
Central	Interior/Illinois Eastern
Northwest	Northern Great Plains/Powder River
Southwest	Rocky Mountain/ San Juan River

The coal characteristics for each of the five Hittman areas are given in Table 1-14. Since coal composition and the conditions under which coal resource development takes place can vary significantly even within a single area, Hittman's data for these five areas apply only to a mine at a specific location. These data are not applicable, even as averages, to the region within which the mine is located.

Data on mining and reclamation are reported for area, contour, auger, longwall, and room and pillar mines under either controlled or uncontrolled conditions. Under controlled conditions, land reclamation and water treatment are included as a part of the mining operation; under uncontrolled conditions, they are not.

Two yardsticks are used in assessing the efficiency of various mining methods: the percentage of in-place coal recovered and the amount of ancillary energy required. Ancillary energy requirements are the diesel fuel and electricity required to operate all mining equipment (including drills, draglines, tractors, and trucks) and, under controlled conditions, to reclaim the land.

1.6.2.1 Surface Mining and Reclamation

Recovery efficiencies and ancillary energy requirements per 10^{12} Btu's for various types of surface mines are presented in Table 1-15. Recovery efficiencies range from a low of 46 percent for Central Appalachian auger mining to a high of 98 percent for Northwest strip mining. Area strip mining in other regions is about 80-percent efficient. No variation occurs between the uncontrolled and controlled cases, and the data are known for all of the recovery efficiencies to within 10 percent.

Ancillary energies are not well known, and the data are only valid to within an order of magnitude. Of the total ancillary requirement, approximately 85 percent is electric and 15 percent is diesel. An exception is the Northwest Region, where

---

*Processing of coal for cleaning and sizing is discussed in Section 1.8.

TABLE 1-14

COAL CHARACTERISTICS USED IN ENVIRONMENTAL RESIDUALS CALCULATIONS

	Hittman[a]					Battelle[b]	
	Northwest	Central	Northern Appalachia	Central Appalachia	Southwest	Eastern	Western
Heat content (Btu's per pound)	8,780	10,600	11,800	12,100	9,820	12,000	9,235
Ash (percentage)	6.77	8.9	14.7	11.2	15.7	NC	NC
Sulfur (percentage)	0.85	2.92	3.07	0.93	0.6	NC	NC
Density (pounds per cubic foot)	81	81	85	85	81	82	82
Tons coal equal to 10^{12} Btu's	57,000	47,200	42,400	41,000	51,000	41,500	54,000
Average seam thickness-underground mine (feet)	U	6.8	5.1	4.7	U	NC	NC
Average seam thickness-strip mine (feet)	39	4.8	3.9	U	11.8	2	5
Average overburden thickness-strip mine (feet)	60	52	47	U	47.9	33[c]	13[c]

NC = not considered, U = unknown.

Sources: [a]Hittman, 1974: Vol. I, Tables 3-12 and footnotes.

[b]Battelle, 1973: 69.

[c]Tons overburden per ton of coal.

TABLE 1-15

SURFACE MINING EFFICIENCIES

	Northwest	Central	Northern Appalachia	Central Appalachia	Southwest
Area mining				NA	
Recovery efficiency (percentage)	98	81	81		81
Ancillary energy (10^9 Btu's per 10^{12} Btu's)					
Uncontrolled	1.92	6.48	5.82		5.09
Controlled	1.93	6.62	5.94		5.11
Contour mining	NA	NA			NA
Recovery efficiency (percentage)			80	80	
Ancillary energy (10^9 Btu's per 10^{12} Btu's)					
Uncontrolled			10.9	10.6	
Controlled (modified block cut)			U	10.7	
Auger	NA	NA	NA		NA
Recovery efficiency (percentage)				46	
Ancillary energy (10^9 Btu's per 10^{12} Btu's)					
Uncontrolled				0.86	
Controlled				0.93	

NA = not applicable, U = unknown.

Source: Hittman, 1974: Vol. I, Tables 3-12 and footnotes.

diesel fuel accounts for 50 percent of the total ancillary energy required.*

Ancillary energy needs for area mining are small, averaging 5×10^9 (five billion) Btu's for every 10^{12} (trillion) Btu's mined; this means that only 0.5 percent of the energy mined is used in mining. The ancillary energy requirement for contour mining is higher than for either of the other types, averaging about 1.4 percent. The ancillary energy needed under controlled conditions increases slightly for all types of mines.

*The electric energy was calculated as three times the Btu equivalent of a kilowatt hour (kwh) to obtain the petroleum equivalent.

1.6.2.2 Underground Mining

Recovery efficiencies and ancillary energy requirements (per 10^{12} Btu's) for longwall and room and pillar mines are reported in Table 1-16. The recovery efficiencies are valid to within 10 percent, but ancillary energies are only known to within an order of magnitude. In room and pillar mines, recovery efficiency is 57 percent regardless of region and whether controlled or uncontrolled. The recovery efficiency

TABLE 1-16

MINING AND RECLAMATION EFFICIENCIES

	Central	Northern Appalachia	Central Appalachia
Room and Pillar			
Recovery efficiency (percentage)			
Uncontrolled	57	57	57
Ancillary energy requirement[a] (10^9 Btu's per 10^{12} Btu's)			
Uncontrolled	4.75	4.21	4.07
Controlled	4.84	4.47	4.18
Longwall			
Recovery efficiency (percentage)	U		U
Uncontrolled		85	
Ancillary energy requirement (per 10^{12} Btu's)	U		U
Uncontrolled		5.64	
Controlled		6.02	

U = unknown.

Source: Hittman, 1974: Vol. I, Tables 3-10 and footnotes.

[a]Calculated as three times the Btu equivalent of the kilowatt hour requirement.

of longwall mining is 85 percent. The difference is primarily the coal left in the pillars of room and pillar mines.

In underground mines, the principal ancillary energy requirement is for the electrically powered continuous miner. The higher energy requirement in the Central Region is a result of the lower heat content of the region's coal. To produce the same number of Btu's, more coal must be mined (and thus more energy expended) in the Central Region than in the Appalachian Region. Controlled conditions also increase energy requirements (by some two to six percent) because of the addition of water treatment facilities (Table 1-16).

In all cases, the ancillary energy needed to extract the coal is only a small portion of the energy contained in the coal (on the order of 0.4 to 0.6 percent); thus, the large data uncertainty is not serious.

1.6.3 Environmental Considerations

1.6.3.1 Surface Mining and Reclamation

Basic environmental data for surface mining are presented in Table 1-17, including the amount of air and water pollutants, solids, and land consumption associated with each type of surface mine. Although they may be matters of great concern, residuals of a qualitative nature, such as esthetics and noise, are not included.

Table 1-17. Residuals for Surface Coal Mining and Reclamation

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year/10^{12} Btu's	Deaths	Injuries	Man-Days Lost
NORTHWEST-AREA STRIP																					
Uncontrolled	NA	U	NA	NA	.894	23.2	NA	NA	0	NA	2.27	1.03	.075	.103	.628	.017	730.	.3/.8 10.7	.0025	.057	1.41
Controlled[b]	NA	0	NA	NA	0	0	NA	NA	NA	NA	.839	1.03	.075	.103	.628	.017	730.	3.87/0 3.87	.0025	.057	1.41
CENTRAL-AREA STRIP																					
Uncontrolled	3.82	U	NA	NA	43.	4.22	NA	NA	0	NA	.05	1.42	.103	.142	.861	.023	433.	.16/5.6 69.9	.003	.16	3.99
Controlled[c]	0	3.98	NA	NA	13.4	.198	NA	NA	0	NA	.05	1.42	.103	.142	.861	.023	563.	15.9/0 15.9	.003	.16	3.99
NORTHERN APPALACHIAN-AREA STRIP																					
Uncontrolled	6.9	U	NA	NA	45.5	6.86	NA	NA	0	NA	.045	1.27	.093	.127	.775	.021	352.	0.1/5.9 73.5	.005	.12	2.49
Controlled	0	.446	NA	NA	15.	.223	NA	NA	0	NA	.045	1.27	.093	.127	.775	.021	668.	6.9/0 6.9	.005	.12	2.49
NORTHERN APPALACHIAN CONTOUR																					
Uncontrolled	6.8	U	NA	NA	45.	265.	NA	NA	0	NA	.07	2.	.146	.2	1.22	.032	3.68 $\times 10^5$	0/12 150.	.005	.12	2.49
Controlled[c]	0	.441	NA	NA	14.8	.22	NA	NA	0	NA	.07	2.	.146	.2	1.22	.032	412.	27.9/0 27.9	.005	.12	2.49
CENTRAL APPALACHIAN AUGER																					
Uncontrolled	1.89	U	NA	NA	21.2	859.	NA	NA	0	NA	.04	1.15	.084	.115	.7	.019	3.93 $\times 10^4$	0/3.9 48.8	.0001	.094	1.9
Controlled[c]	0	.34	NA	NA	5.12	.115	NA	NA	0	NA	.04	1.15	.084	.115	.7	.019	3.93 $\times 10^4$	23.8/0 23.8	.0001	.094	1.9

Table 1-17. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
CENTRAL APPALACHIAN CONTOUR																					
Uncontrolled	3.28	U	NA	NA	36.9	545.	NA	NA	0	NA	.068	1.94	.142	.194	1.18	.032	5.04 $\times 10^5$	0/15.6 195.	.0018	.164	3.30
Controlled[c]	0	.589	NA	NA	8.92	.2	NA	NA	0	NA	.068	1.94	.142	.194	1.18	.032	398.	24.9/0 24.9	.0018	.164	3.30
SOUTHWEST-AREA STRIP																					
Uncontrolled	0	0	NA	NA	0	0	NA	NA	0	NA	6.59	1.05	.077	.105	.639	.017	414.	.2/2.45 30.8	0	.059	.678
Controlled[b]	0	0	NA	NA	0	0	NA	NA	0	NA	2.39	1.05	.077	.105	.639	.017	414.	11.0/0 11.0	0	.059	.678
EASTERN COAL-AREA STRIP																					
Uncontrolled[e]	286.1	NC	NC	NC	273.2	514.6	NC	NC	NC	0	NC	NC	NC	NC	NC	NC	39.65[f]	U/14.49 NC	NC	NC	NC
Controlled[d,c]	0	NC	NC	NC	90.4	276.	NC	NC	NC	0	70.3	.1	0	0	0	0	120.5[f]	U/11.49 NC	.005	.25	74.
WESTERN COAL-AREA STRIP																					
Controlled[d,c]	0	NC	NC	NC	U	140.3	NC	NC	NC	0	35.	.04	0	0	0	0	0	6.06/0 NC	.0065	.31	96.

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement $\left(\frac{\text{Acre year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

[b]Five years are assumed for land reclamation.

[c]Three years are assumed for land reclamation.

[d]Battelle, 1973: Tables A-1 and A-2.

[e]Teknekron, 1973: 63.

[f]Includes overburden as solid waste.

1.6.3.1.1 Water

Table 1-18 is a summary of residuals by area, and the data are good to within a factor of two in most cases. The principal water pollutant in surface mining is suspended solids. These solids are a product of runoff from solid waste piles and are assumed to occur at a rate of 2.54 tons per acre mined for each inch of runoff water. (Runoff is 20 inches per year in the Appalachian area and 10 inches per year in the Central area. Acreage mined also varies in different regions.)

The higher values for residuals in Battelle's Eastern and Western Strip Mine (Table 1-17) in part are explained by their assumption of a two-foot coal seam in the East and five-foot coal seam in the West. Both amounts are quite small. Suspended solids can occur in concentrations at least as high as 1,600 parts per million (ppm). As indicated in Table 1-18, discharges are particularly high in Appalachian contour mining due primarily to the large areas of downslope overburden.

Total dissolved solids are concentrated at about 850 ppm. For comparison, the Public Health Service's recommended upper limit on effluent from secondary treatment of municipal wastewater is 700 ppm.

All water pollutants in Hittman's Southwest area are assumed to be zero because, to date, mines in that area have not intersected groundwater and the limited rainfall creates very little runoff. In addition, the overburden is alkaline. However, even a small amount of runoff could possibly leach sulfates and salts from these soils.

Under controlled conditions, drainage and runoff water is collected, allowed to settle, and treated at either a lime or soda ash facility. Suspended solids are reduced to a 30-ppm concentration and a zero acid content. In the Northwest and Southwest where water is especially valuable, groundwater seepage and runoff are collected and used for dust suppression and irrigation.

1.6.3.1.2 Air

Air pollutants in a surface mining operation originate from two sources: diesel-fueled support equipment and wind erosion. The particulates, caused principally by wind erosion and total emissions from diesel equipment, are summarized in Table 1-18 but are only known to within an order of magnitude. Wind erosion is highest in the Northwest and Southwest areas, averaging 428 pounds per acre each year; therefore, particulate pollutants also are highest in these areas (Hittman, 1974: Vol. I, footnote 1207). Particulate emissions for the Eastern and Western strip mines described by Battelle (included in Table 1-17) are three orders of magnitude higher than those described by Hittman. The former is based on an emission factor of 0.1 pound of particulates per ton of overburden removed. (Thirty-three tons of overburden are removed per ton of coal recovered in the east; in the west, the ratio is 13:1.)

Regional variations for diesel emissions depend primarily on the percent of equipment that is diesel rather than electrically powered. A majority of equipment in the Northwest and Southwest is electric; thus, the total diesel emissions are small in those areas. (Using electrical equipment does not mean that air pollutants are not generated; they are simply transferred from the mining site to the electric power station site.) The highest diesel emissions are from contour mining in Northern Appalachia and both contour mining and augering in Central Appalachia (Table 1-18).

Hittman's data indicate no difference in air pollutant emissions under controlled and uncontrolled conditions. However, this may not be correct. Reclamation would reduce particulates resulting from erosion

TABLE 1-18

SUMMARY OF SURFACE MINING RESIDUALS[a]

Residual	Northwest		Central		Northern Appalachia[b]		Central Appalachia[c]		Southwest	
	Unc.[d]	Con.[e]	Unc.	Con.	Unc.	Con.	Unc.	Con.	Unc.	Con.
Water (tons per 10^{12} Btu's)										
Total dissolved solids	1	0	43	13	45	15	21-37	5-9	0	0
Acidity	0	0	4	0	7	0	2-3	0	0	0
Suspended solids	23	0	4.22	.2	7-265	.22	859-545	.1-.2	0	0
Air (tons per 10^{12} Btu's)										
Particulates	2.27	.839	.05	.05	.05-.07	.05-.07	.04-.07	.04-.07	6.6	2.4
Total of others[f]	1.85	1.85	2.55	2.55	2.3-3.6	2.3-3.6	2.1-3.5	2.1-3.5	1.9	1.9
Solids (waste) (tons per 10^{12} Btu's)	730	730	433	563	352 to 368,000	668-412	39,300 to 504,000	39,300 to 398	414	414
Land										
Stripping (acres per 10^{12} Btu's)	.8	0	5.6	0	5.9-12.0	0	3.9-15.6	0	2.45	0
Fixed[g] (total acres for mine life)	10.0	5.0	8.7	10.0	7.2-0	14.8	0	6.1	39.2	U

Source: Hittman, 1974: Vol. I, Tables 3-12 and footnotes.

[a]Area strip and contour mining in Northern Appalachia; contour and augering in Central Appalachia. All others are area strip.

[b]First value is for area stripping; second value is for contour. When only one value is given, it applies to both.

[c]First value is for augering; second value is for contour. When only one value is given, it applies to both.

[d]Uncontrolled case.

[e]Controlled case.

[f]Includes sulfur oxides, nitrogen oxides, carbon monoxide, hydrocarbons, aldehydes.

[g]For the uncontrolled case, this is total area needed for refuse storage; for the controlled case, it is a water treatment facility; spoils are assumed reclaimed in the controlled case.

but would increase other pollutants by requiring more diesel-powered trucks, tractors, etc.

1.6.3.1.3 Solids

As indicated in Table 1-18, solid wastes from mining vary as a function of surface mining technique, and these variations are considerable. These data are considered to be accurate to within 50 percent.

In area strip mining, solid wastes are produced only during the box cut (five acres) made to open the mine. The amount of wastes produced by this initial excavation is on the order of 500,000 to 1,000,000 tons of overburden or about 500 tons per 10^{12} Btu's. Under controlled conditions, an area mine's water treatment facility contributes an additional 50 to 150 tons per 10^{12} Btu's of sludge to the total mine wastes. The effect is to convert water pollutants into solid wastes.

Teknekron's estimate for solid wastes from an Eastern area mine (Table 1-17) is 100 times larger than the Hittman estimates. The reason for this difference is the Teknekron data includes all overburden while the Hittman data includes only that produced during the initial cut.

In the "uncontrolled" contour mines of Northern and Central Appalachia, solid wastes and overburden are continually dumped downslope, except for four feet of material above the height of the coal which is used to backfill the bench. When the modified box cut mining technique is used in the controlled technology, the solids problem is greatly diminished.

To put the quantities of solid wastes into perspective, a typical area strip mine excavating 10,000 tons of coal per day would produce 100 tons of solid waste per day, an amount approximately equal to the daily municipal refuse from a town of 40,000 people. The same coal production from a contour mine would result in 120,000 tons per day, which is approximately equal to the quantity of municipal refuse of 48 million people.

1.6.3.1.4 Land

Two land impact categories are included in Table 1-18: the incremental land uses required by stripping the overburden, and the fixed land requirement for the life of the mine (including the land needed to store the initial box cut refuse and, under controlled conditions, the water treatment facility and settling pond). The land impact data are considered accurate to within 50 percent.

Land use for area strip mining varies from 0.8 to 5.9 acres per 10^{12} Btu's extracted. The smallest value is in the Northwest location where seam thickness is 39 feet. The largest amount of land on a Btu basis is needed in Northern Appalachia, where seam thickness is 3.9 feet. For perspective, a Northwest mine producing 10,000 tons of lower Btu coal per day would strip 2.5 square miles in 30 years, while a similar mine in Northern Appalachia would strip 27 square miles in 30 years.

Augering and contour mining have more severe land impacts than does area mining. Contour mining requires 12.0 acres per 10^{12} Btu's in Northern Appalachia and 15.6 acres per 10^{12} Btu's in Central Appalachia. Augering requires 3.9 acres per 10^{12} Btu's in both areas. Four categories of land despoilment are involved in contour mining: acreage stripped, acreage covered by the spoil pile reaching downslope from the outcrop, drainage ditch above the highwall, and acreage affected by landslides. Of the acreage affected in contour mining, stripping and downslope spoils each account for between 5.3 and 5.8 acres respectively, while the drainage ditch and landslides consume about 2.5 acres per 10^{12} Btu's mined. For augering, the breakdown is 1.3 acres for subsidence, while the bench and spoils from downslope deposits each account for

1.2 acres. Landslides are negligible in auger mining. In all cases, the fixed acreage required is very small relative to the acreage involved in stripping.

Controlled conditions assume that contour mines use a modified box cut and that all land is reclaimed through backfilling, topsoil replacement, and revegetation. The revegetation (establishment of grass cover) period is estimated at five years for the Northwest and Southwest areas and three years for the Central and Appalachian areas.

1.6.3.1.5 Summary

In all four environmental categories--water, air, solids, and land--area strip mining produces fewer residuals than either contour mining or augering. Also, the Hittman sites indicate that the Northwest area is least affected by all types of surface mining, controlled or uncontrolled. In the Northwest, the major concern is particulates generated by wind erosion. Presumably, particulate air pollution would be controlled in time by revegetation, although this is not indicated in the tabulated data. Environmentally, the Appalachian mine location appears to be the worst for surface mining. This also seems to be the area where esthetic and noise residuals are most significant, although these are difficult to quantify.

1.6.3.2 Underground Mining

Hittman does not discuss underground mining for the Northwest and Southwest regions, where surface mining is primarily used at the present time. Basic environmental data for the other regions are presented in Table 1-19.

Controlled conditions for underground mining mean that surface runoff and mine drainage waters are treated. Prevention of land subsidence is not addressed, and the control of spoils is discussed with beneficiation technologies.

Room and pillar mining is used in the Central and Central Appalachian areas, while both room and pillar and longwall mining are used in Northern Appalachia. In Northern Appalachia, both underground techniques produce the same residuals (Table 1-19) except for land use, which is higher for longwall mining.

1.6.3.2.1 Water

Underground mining residual data are summarized in Table 1-20 and are generally accurate to within 50 percent. The principal water pollutant in Appalachia is acid drainage. In Northern Appalachia, acid drainage from mines is about 1,700 ppm. The other dissolved solids are principally sulfates and minerals contributing to hardness (calcium and magnesium ions). Suspended solids are primarily runoff from the solid waste pile at a rate of 2.54 tons per acre per inch of runoff per year (Hittman, 1974: Vol. I, footnotes 1305, 1404, 1503). Under controlled conditions, lime treatment is used to reduce acidity to zero, and the resultant effluent meets the Environmental Protection Agency's (EPA) guidelines.

In the Central area, acid drainage (140 ppm) is not a serious problem because most mines are located below drainage levels and, in some cases, the overburden is alkaline. When treated with lime, the effluent has no acid waste as in Appalachia. As a result, one-third less water is required, and the total effluent amount is one-third less.

1.6.3.2.2 Air

Since electrically powered equipment is generally used underground, air emissions are not a problem. However, dust within the mine can be hazardous to the miners' health.

Table 1-19. Underground Coal Mining and Reclamation Residuals

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
CENTRAL																					
Room and Pillar																					
Uncontrolled	2.02	U	NA	NA	341.	.016	NA	NA	0	NA	0	0	0	0	0	0	1.61	.0006/9.6 120.	.01	1.01	37.8
Controlled	0	.42	NA	NA	14.1	.21	NA	NA	0	NA	0	0	0	0	0	0	64.	.106/9.6 120.	.01	1.01	37.8
NORTHERN APPALACHIA																					
Room and Pillar																					
Uncontrolled	67.7	U	NA	NA	438.	.028	NA	NA	0	NA	0	0	0	0	0	0	1.45	.0005/10.32 129.	U	U	U
Controlled	0	1.19	NA	NA	39.9	.6	NA	NA	0	NA	0	0	0	0	0	0	1190.	.782/10.32 130.	U	U	U
Longwall																					
Uncontrolled	101.	U	NA	NA	654.	.042	NA	NA	0	NA	0	0	0	0	0	0	2.16	.0008/22.8 285.	U	U	U
Controlled	0	1.77	NA	NA	59.4	.89	NA	NA	0	NA	0	0	0	0	0	0	1780.	1.16/22.8 286.	U	U	U
CENTRAL APPALACHIA																					
Room and Pillar																					
Uncontrolled	9.35	U	NA	NA	331.	.027	NA	NA	0	NA	0	0	0	0	0	0	1.40	.0005/10.6 132.	.022	.955	3.42
Controlled	0	.49	NA	NA	16.3	.243	NA	NA	0	NA	0	0	0	0	0	0	249.	.182/10.6 132.	.022	.955	3.42

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement (Acre - year / 10^{12} Btu's) / Incremental Land Requirement (Acres / 10^{12} Btu's).

TABLE 1-20

SUMMARY OF UNDERGROUND MINING RESIDUALS

Residual	Uncontrolled Case			Controlled Case		
	Central	Northern Appalachia	Central Appalachia	Central	Northern Appalachia	Central Appalachia
Water (tons per 10^{12} Btu's)						
Total dissolved solids	341	438	331	14[a]	39.9[a]	16
Acidity	2.0[b]	68[c]	9.4	0	0	0
Suspended solids	.02	.03	.03	.21	.60	.24
Air	0	0	0	0	0	0
Solids (tons per 10^{12} Btu's)	2	1	1	64	1,190	249
Land						
Incremental (acres affected per 10^{12} Btu's)	9.6[d]	10.3 to 22.8[e]	10.6[f]	9.6	10.3 to 22.8	10.6
Fixed (total acres for mine life)	0	0	0	7.8	64.6	15.5

Source: Hittman, 1974: Vol. I, Tables 3-12 and footnotes.

[a]Hardness at 2,000 parts per million (ppm), Al = 1 ppm, Mn = 4 ppm, Fe = 4 ppm, alkalinity = 60 ppm.

[b]142 ppm.

[c]1,714 ppm.

[d]6.8-foot seam thickness and 57-percent recovery efficiency.

[e]Higher value is for longwall mining.

[f]4.7-foot seam thickness and 57-percent recovery efficiency.

1.6.3.2.3 Solids

In underground mines, the amount of solids produced by sinking the initial shaft is not large (about 3,000 tons). However, as indicated in Table 1-20, the solids produced when mine water is treated amount to 56,000 tons per year for a typical mine in Northern Appalachia (1,190 tons per 10^{12} Btu's), 21,200 tons per year in Central Appalachia (249 tons per 10^{12} Btu's), and 449 tons per year in the Central area (64 tons per 10^{12} Btu's) (Hittman, 1974: Vol. I, footnotes 1350, 1461, 1550). These data have an error of 50 percent or less.

1.6.3.2.4 Land

Land impacts include subsidence and refuse storage sites, as well as a site for a water treatment facility under controlled conditions.

Greater subsidence results from the longwall method than from the room and pillar method because the roof is allowed to collapse as mining progresses (Table 1-20).*

*Data for both mining types assume subsidence from single seams and are accurate to within 50 percent. The combined effects of mining multiple seams are not considered.

For room and pillar mining, an average of 25 percent of the undermined acreage subsides, and this subsiding area then affects a larger surface area. Hittman calculates that 10.3 acres are affected for every 10^{12} Btu's of coal mined by room and pillar methods in Northern Appalachia (660 acres per year for a typical mine) (Hittman, 1974: Vol. I, footnotes, 1304, 1402, 1403, 1502). The comparable land impact for longwall mining is 23 acres. In Central Appalachia, a total of 10.6 surface acres are affected by the subsidence of two acres. In the Central area, 9.6 surface acres are affected for every 10^{12} Btu's mined.

The decision to treat mine drainage and runoff water converts water pollutants to solid wastes which require disposal and thus land for settling ponds and a treatment facility.

In all pollutant categories summarized in Table 1-20, underground mining in the Central Region produces fewer environmental residuals than in Appalachia.

1.6.4 Economic Considerations

1.6.4.1 Surface Mining and Reclamation

Surface mining cost estimates for each mining method are presented in Table 1-21 and have a probable error of less than 50 percent. Estimated 1972 national average costs range from \$0.81 per ton for augering to \$2.73 per ton for contour mining with reclamation (Table 1-21). For both area and contour mining, operating costs are 70 percent of the total cost.

The variations in regional production cost estimates (for hypothetical mines) given in Table 1-22 are due primarily to differences in overburden thickness and characteristics and coal seam thickness and slope. BuMines 1969 per ton operating cost estimates range between \$3.06 and \$4.15 for Eastern Province bituminous coal, \$2.85 and \$5.27 for Interior Province bituminous, \$1.39 and \$3.03 for Rocky Mountain and Northern Great Plains subbituminous coal, and \$1.68 and \$2.37 for Northern Great Plains lignite. Within provinces, these cost variations reflect the size of the operation, as measured in tons of production per year, and whether single or multiple coal seams are being mined. Larger scale operations require a heavier initial capital outlay but permit lower per-ton recovery costs. This indicates that there are considerable economies of scale in strip mining.

As an example of cost variation within a province, note that the cost of mining coal in Oklahoma is considerably higher than in Kentucky. The overburden of the Oklahoma Iron Post deposit, on which these estimates are based, has been described as hard and unyielding and, therefore, expensive to remove. In addition, the coal seam averages only about 16 inches thick. For these reasons, the per-ton-of-resource cost of overburden removal is high.

Another example is the cost differential between subbituminous mining in Montana and in Wyoming. This difference results primarily from varying license fees,

TABLE 1-21

SURFACE MINING COSTS[a]
(DATA FOR 1972)

Technique	Total Cost (dollars per ton)	
	No Reclamation	With Reclamation
Area strip	2.51	2.68
Contour	2.73	3.61[b]
Auger	0.81	0.88

Source: Hittman, 1974: Vol. I, Tables 3-12 and footnotes.

[a]Estimated national averages for 1972.

[b]Modified block cut.

TABLE 1-22

SURFACE COAL MINING PRODUCTION COSTS[a]
(DATA FOR 1969)

Province	Mine Type and Location	Production (10^6 tons per year)	Estimated Capital Investment (millions of dollars)	Per Ton Operating Cost Excluding Return on Capital (dollars)	Energy Cost (cents per million Btu's)
Eastern (bituminous)	Contour strip Northern West Virginia	1	12.7	4.15	15.7
		3	28.0	3.06	11.6
Interior (bituminous)	Strip mine single seam Western Kentucky	1	13.7	3.90	16.3
		3	24.9	2.85	10.8
	Strip mine double seam Western Kentucky	1	8.3	2.98	12.4
	Strip mine single seam Oklahoma	1	16.0	5.27	21.1
Rocky Mountain and Northern Great Plains (subbituminous)	Strip mine Southwest	1	7.9	3.03	14.3
		5	28.7	2.40	11.4
	Strip mine Powder River Basin Montana	5	13.9	1.39	8.2
	Strip mine Powder River Basin Wyoming	5	13.9	1.58	9.3
Northern Great Plains (lignite)	Strip mine Dakota or Montana	1	6.4	2.37	16.5
		5	20.7	1.68	11.7

Source: BuMines, 1972: 3.

[a]Estimated 1969 costs for 12 hypothetical mines (reclamation costs included).

taxes, wages, and payments to the United Mine Workers' Welfare Fund.

Table 1-22 also indicates that per-Btu costs are high for mining lignite, despite generally low per-ton mining costs. This, of course, is due to the relatively low Btu content of lignite.

Everything considered, strip mining in the Powder River Basin yields the most Btu's of energy for the least amount of money. Oklahoma coal is the most expensive.

A study by Continental Oil Company has estimated that present costs of reclamation run between $3,000 and $5,000 per acre for eastern surface mines. This averages between $1.00 and $3.00 per ton. For western coal, the per-acre reclamation cost estimates range between $1,000 and $4,000 or $0.02 to $0.20 per ton. The wide variance on a per-ton basis results from large variations in seam thickness.

1.6.4.2 Underground Mining and Reclamation

The hypothetical cost estimates listed in Table 1-23, based on a room and pillar mine with 57-percent recovery and a 20-year expected mine life, have a probable error of less than 100 percent. The estimated 1973 range of costs is from $6.45 to $7.60 per ton (1973 dollars). Economies of scale are evident, and coal costs are higher for thinner seams.

Hittman's estimate for a room and pillar mine is $282,000 per 10^{12} Btu's or $6.87 per ton (1972 dollars)(Hittman, 1974: Vol. I, Table 1). This agrees with the BuMines estimate. Both estimates include the cost of rail transportation within the mine.

According to Hittman, the water treatment facility would add an additional $20,200 per 10^{12} Btu's or $0.50 per ton (Hittman, 1974: Vol. I, Table 2).

Economic data on longwall mining are not available.

1.7 WITHIN AND NEAR MINE TRANSPORTATION

1.7.1 Technologies

1.7.1.1 Surface Mine Transportation

The major alternatives for transporting coal within or near surface mines are

TABLE 1-23

1973 UNDERGROUND COAL MINING PRODUCTION COSTS[a]

Seam Thickness	Mine Output (million tons per year)	Capital Investment (tons per year of mining output)	Total Production Costs (dollars per ton)
72-inch coal seam	1.06	20.62	7.35
	2.04	17.47	6.77
	3.18	15.87	6.50
	4.99	15.15	6.45
48-inch coal seam	1.03	20.09	7.60
	2.06	17.61	6.97
	3.09	16.83	6.81

Sources: Katell and Hemingway, 1974a: 5; Katell and Hemingway, 1974b: 4.

[a]Estimated 1973 costs for hypothetical mines.

conveyors and diesel-engine trucks.* The major factors influencing the choice are capacity, distance, ramp angles, mobility, and maneuverability.

The trucks used in mines range from multiple purpose conventional designs to very large, special purpose, off-the-road vehicles capable of carrying as much as 250 tons. The latter vehicles are used extensively in surface mining but normally only haul materials for short distances.

Trucks require haul roads with appropriate contours and drainage provisions. Dust control can be provided through the application of calcium chloride or sodium chloride, although the most common procedure is to keep the roads wet with water trucks (Grim and Hill, 1974: 116).

Conveyor systems are efficient for moving large quantities over short-to-moderate distances. They require little space, can negotiate tight turns, and move materials up steeper slopes than a rail or truck system can accommodate (Gartner, 1969: 21, 34). Some conveyors (not currently being used) are several miles long, more than seven feet wide, and can attain speeds of 17 feet per second or more.

1.7.1.2 Underground Mine Transportation

Most underground mines still use conveyors and rail shuttle cars (or some combination of the two) to move coal to a collection point within the mine. From there, coal is normally moved to the surface by rail or by a larger conveyor. However, at least one eastern mine is now using a slurry pipeline, linked to a continuous miner, for more rapid extraction and continuous transportation to the surface. Since in-mine transportation has generally not kept pace with excavation machinery, this type of innovation is needed.

---

*Diesel engines are discussed in Chapter 13.

1.7.2 Energy Efficiencies

Since data on actual coal losses during transportation are not available, primary efficiencies are assumed to be 100 percent. As discussed previously, ancillary energy requirements are the diesel fuel and electricity needed for vehicles and conveyors. Table 1-24 gives these requirements, by area, for truck transportation in surface mines and for conveyors in underground mines. These data are estimated to have an error of 100 percent or less.

1.7.2.1 Surface Mine Transportation

Transporting coal by truck consumes 0.2 to 0.8×10^9 Btu's for each 10^{12} Btu's hauled. In Table 1-24, the lowest energy expenditure rating for trucked coal is at Hittman's hypothetical Northwest mine, which has the shortest average haul distance. Conversely, the mine with the longest average haul distance (Hittman's Northern Appalachian) also has the highest energy expenditure ratio. However, all values are small, ranging from 0.02 to 0.08 percent of the energy being hauled; thus, the data inaccuracies are not serious. No data for conveyors used in surface mines are available.

1.7.2.2 Underground Mine Transportation

Transporting coal by conveyors in underground mines consumes about 0.2×10^9 Btu's for each 10^{12} Btu's hauled (within a factor of two) regardless of the region (Table 1-24). Apparently, haul distances are approximately the same among regions. This is a very small value (0.02 percent) relative to the amount of energy being hauled.

Energy consumption data for rail transportation in underground mines are not available.

TABLE 1-24

ANCILLARY ENERGY REQUIREMENTS OF IN-MINE TRANSPORTATION SYSTEMS

Region	Trucking (surface mines)			Conveyors (underground mines)	
	Average Haul Distance Assumed	Diesel Oil Gallons per 10^{12} Btu's	10^8 Btu's per 10^{12} Btu's Hauled	10^8 Btu's per 10^{12} Btu's Hauled	Kilowatt Hours per 10^{12} Btu's
Northwest	1.5	1,400	1.94	U	U
Central	3.8	2,920	4.05	2.48	24,300
Northern Appalachia	7.3	5,600	7.02	2.23	21,800
Central Appalachia	4.7	3,160	4.38	2.18	21,300
Southwest	3.2	2,710	3,76	U	U

U = unknown.

Source: Hittman, 1974: Vol. I, Tables 3-12 and footnotes.

1.7.3 Environmental Considerations

1.7.3.1 Surface Mine Transportation

Environmental residuals for truck transportation in surface mines are given in Table 1-25 and can be presumed to have an error of 50 percent or less. Controlled and uncontrolled conditions are the same except for suspended solids in runoff water. Under controlled conditions, suspended solids are collected in settling ponds along the haul roads. Consequently, controlled conditions increase land residuals. About one acre of settling ponds per mile of haul distance is required. Suspended solids are assumed to be 35 tons per acre per year in the Central and Northern Appalachian examples and 78 tons per acre per year in the Northwest.

Coal haul roads usually constitute about 10 percent of the area of a mine (Grim and Hill, 1974: 116). Haul distances are longest in the Northern Appalachian Region (7.3-mile average) and shortest in the Northwest Region (1.5-mile average); thus, land residuals for trucking are highest in Northern Appalachia (Hittman, 1974: Vol. I). Values for particulates range from 0.009 to 0.036 ton per 10^{12} Btu's of coal hauled; for nitrogen oxides, the range is 0.259 to 1.04 tons; and for sulfur oxides, the range is 0.019 to 0.075 ton (Table 1-25). Half of these values would be emitted on a daily basis for a typical mining operation excavating about 20,000 tons of coal per day. Noise generation would be greatest from truck and rail transport.

1.7.3.2 Underground Mine Transportation

According to Table 1-25, all residuals are zero when conveyors or rail transportation is used. Thus, conveyors are assumed to be covered or operated at speeds that do not produce dust.

1.7.4 Economic Considerations

1.7.4.1 Surface Mine Transportation

Within and near-mine transportation was included in the BuMines cost data discussed above in mining and reclamation.

Table 1-25. Residuals for In-Mine Coal Transportation

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	$^{F}/_{I}$[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land $\frac{\text{Acre-year}}{10^{12}\text{ Btu's}}$	Deaths	Injuries	Man-Days Lost
NORTHWEST COAL																					
Trucking																					
Uncontrolled	NA	NA	NA	NA	NA	21.1	NA	NA	NA	NA	.009	.259	.019	.026	.175	.002	NA	.274/0 .274	0	.027	.674
Controlled	NA	NA	NA	NA	NA	0	NA	NA	NA	NA	.009	.259	.019	.026	.175	.002	NA	.303/0 .303	0	.027	.674
CENTRAL COAL																					
Trucking																					
Uncontrolled	NA	NA	NA	NA	NA	20.2	NA	NA	NA	NA	.019	.54	.039	.054	.365	.009	NA	.584/0 .584	U	U	U
Controlled	NA	NA	NA	NA	NA	0	NA	NA	NA	NA	.019	.54	.039	.054	.365	.009	NA	.679/0 .679	U	U	U
Conveyor																					
Uncontrolled	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	0	0	0	0	0	NA	0	U	U	U
Controlled	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	0	0	0	0	0	NA	0	U	U	U
Mine Rail																					
Uncontrolled	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	0	0	0	0	0	NA	0	U	U	U
Controlled	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	0	0	0	0	0	NA	0	U	U	U

Table 1-25. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
SOUTHWEST COAL																					
Trucking																					
Uncontrolled	NA	NA	NA	NA	U	U	NA	NA	NA	NA	.018	.5	.036	.05	.34	.008	NA	.53/0 .53	0	.015	.171
Controlled	NA	NA	NA	NA	U	0	NA	NA	NA	NA	.018	.5	.036	.05	.34	.008	NA	.58/0 .58	0	.014	.171

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

BuMines also has separate 1969 cost estimates for the trucks used to transport coal in its hypothetical surface mines. A vehicle capable of hauling 100 tons in a northern West Virginia bituminous contour mine would have an estimated capital cost of $175,000. If this vehicle is operated two shifts (16 hours) per day, 240 days per year, driver costs would be about $15,300 (1969 dollars) per truck per year. Estimates for both equipment and operating costs are out of date and would be much higher now than when calculated by BuMines (BuMines, 1972: 5, 7).

According to Hittman data, the 1972 estimate of truck transportation costs within a surface mine is $6,850 for each 10^{12} Btu's of coal hauled or $0.16 per ton within an error of less than 50 percent (Hittman, 1974: Vol. I, Table 1 and footnote 1046). Operating costs account for 96 percent of this amount.

1.7.4.2 Underground Mine Transportation

The BuMines 1973 estimate of the cost of a shuttle car for within and near-mine transportation in underground mines is $49,000. In a 48-inch seam room and pillar mine, 12 shuttle cars would be required to produce 1.03 million tons per year. Total operating costs for three shifts per day, 220 days per year are estimated to be almost $290,000.

A comparable capacity conveyor system would cost $1,471,200 or approximately $53 per foot. Additionally, the cost for conveyor operators would be almost $86,000 per year (Katell and Hemingway, 1974b: 6-8).

Costs are approximately the same for a 72-inch coal seam. Hittman estimates 1972 conveyor costs at $1,750 for each 10^{12} Btu's of coal hauled or $0.04 per ton, 78 percent of which are operating costs (Hittman, 1974: Vol. I, Table 1 and footnote 1049). These estimates have a probable error of less than 50 percent.

1.8 BENEFICIATION

1.8.1 Technologies

Coal is often prepared, or beneficiated, before being used. Beneficiation, which may be done at (or near) the mine or at the point of use, consists of any or all of the following steps:

1. Crushing and screening to a desired maximum size.
2. Cleaning to remove dust and noncoal materials.
3. Drying to prepare the coal for shipping or use.

Large rotary mills are used to reduce the coal to a desired maximum size which is dictated by intended usage. The sized coal is then cleaned using either air or water.

Air washing--blowing air over the coal--is the simplest cleaning technique for removing small particles. In wet washing, the coal is floated on a water/magnetite (pulverized iron ore) slurry and impurities are allowed to sink. An alternative method is to entrain the coal in an upward flow of water. Both wet washing methods are avoided wherever possible because they add moisture to the coal, thereby reducing its available energy.

A third wet washing technique is froth flotation. In this process, chemicals are added to cause the coal to repel water and attach to air bubbles. The coal is then skimmed off the top as a froth. Impurities do not attach to the bubbles and are allowed to sink. Slurries containing the impurities recovered by all three types of wet washing techniques are usually retained in settling ponds.

Coal is normally dried by hot air streams. Several different configurations are used, including fluidized beds* and

---

*A fluidized bed is a body of finely crushed particles with a gas blown up through them. The gas separates the particles so that the mixture behaves like a turbulent liquid.

TABLE 1-26

COAL BENEFICIATION EFFICIENCIES

Technique	Northwest	Central	Northern Appalachia	Central Appalachia	Southwest
Breaking and sizing					
Primary efficiency (percent)	100	100	100	100	100
Ancillary energy (10^9 Btu's per 10^{12} Btu's input)	2.19	1.81	1.72	1.68	2.07
Washing					
Primary efficiency (percent)	U	97.3	96.4	U	U
Ancillary energy (10^9 Btu's per 10^{12} Btu's input)					
Uncontrolled	U	2.42	2.17	U	U
Controlled	U	2.55	2.29	U	U

U = unknown.

Source: Hittman, 1974: Vol. I, Tables 3-12 and footnotes.

rotary kilns.* One drying technique uses oxygen instead of air to promote the oxidation of any sulfur in the coal. According to Kennecott, this system removes all inorganic sulfur and up to 30 percent of the organic sulfur. This method of removing sulfur is reported to be competitive with stack gas cleaning technologies achieving comparable clean-up (Soo, 1972: 187).

1.8.2 Energy Efficiencies

Table 1-26 summarizes efficiencies and ancillary energy requirements for breaking and sizing, and washing coal. Since the amount of feed removed as tramp iron is miniscule (0.006 percent), breaking and sizing is considered 100-percent efficient. Ancillary energy requirements have been estimated, within a factor of two, to average 2.0×10^9 Btu's for each 10^{12} Btu's processed, 80 to 85 percent of which is provided by electricity and the remainder by oil.

Washing is 96- to 97-percent efficient, depending on the percentage of the feet that requires washing (56 percent in the Central area and 72 percent in Northern Appalachia). The ancillary energy requirement, within a factor of two, is estimated to be 0.22 percent of the processed energy (2.2 to 2.4×10^9 Btu's for each 10^{12} Btu's processed). This requirement is slightly greater under controlled conditions, 0.25 percent. Electricity provides 80 percent of the total ancillary energy requirement.

For both processes, regional differences are small and are due to variability in heat content of coals. Central Appalachian coal has the highest heat content and, therefore, requires the lowest ancillary energy on a per-Btu basis.

1.8.3 Environmental Considerations

Table 1-27 includes all Hittman data by areas for breaking and sizing, and

*A rotary kiln is a heated rotating horizontal cylinder.

Table 1-27. Residuals for Coal Beneficiation

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)							$^F/_I{}^a$	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (Tons/10^{12} Btu's)	Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
BREAKING AND SIZING																					
Northwest																					
Uncontrolled	0	0	0	0	0	0	0	NA	0	NA	0	NA	NA	NA	NA	NA	3.42	.997/0 .997	0	.003	.148
Controlled	0	0	0	0	0	0	0	NA	0	NA	0	NA	NA	NA	NA	NA	3.42	.997/0 .997	0	.003	.148
Central																					
Uncontrolled	NA	NA	NA	NA	0	0	NA	NA	0	NA	0	NA	NA	NA	NA	NA	2.83	.826/0 .826	U	U	U
Controlled	NA	NA	NA	NA	0	0	NA	NA	0	NA	0	NA	NA	NA	NA	NA	2.83	.826/0 .826	U	U	U
Northern Appalachia																					
Uncontrolled	NA	NA	NA	NA	0	0	NA	NA	0	NA	0	NA	NA	NA	NA	NA	2.54	.74/0 .74	U	U	U
Controlled	NA	NA	NA	NA	0	0	NA	NA	0	NA	0	NA	NA	NA	NA	NA	2.54	.74/0 .74	U	U	U
Central Appalachia																					
Uncontrolled	NA	NA	NA	NA	0	0	NA	NA	0	NA	0	NA	NA	NA	NA	NA	2.46	.724/0 .724	U	U	U
Controlled	NA	NA	NA	NA	0	0	NA	NA	0	NA	0	NA	NA	NA	NA	NA	2.46	.724/0 .724	U	U	U
Southwest																					
Uncontrolled	NA	NA	NA	NA	0	0	NA	NA	0	NA	0	NA	NA	NA	NA	NA	3.06	.893/0 .893	0	0	0
Controlled	NA	NA	NA	NA	0	0	NA	NA	0	NA	0	NA	NA	NA	NA	NA	3.06	.893/0 .893	0	0	0

Table 1-27. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
CLEANING INCLUDING WASHING[b]																					
Uncontrolled	4.4	NC	NC	NC	66.	937.	NC	NC	NC	NC	440.	2.6	16.	NC	NC	NC	4180.	U/U .30	.0026	.0053	22.9
Controlled	0	NC	NC	NC	0	0	NC	NC	NC	NC	4.4	2.6	1.8	NC	NC	NC	130.	U/U .30	.0026	.0053	22.9
CLEANING INCLUDING WASHING[c]																					
Uncontrolled	70.7	NC	NC	NC	42.8	82.4	NC	NC	NC	NC	2.7	NC	NC	NC	NC	NC	9000.	NC	NC	NC	NC

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

[b]Battelle, 1973: Vol. I.

[c]Teknekron, 1973.

washing. Coals from the Northwest, Southwest, and Central Appalachian areas are assumed to be relatively clean, thus requiring only breaking and sizing. Central and Northern Appalachian coals require washing as well as breaking and sizing.

1.8.3.1 Breaking and Sizing

As stated earlier, residuals from breaking and sizing are negligible. Although small quantities of water are used for dust control, potential environmental impact from this source is also negligible.

Thirty-five acres of land are required for the preparation plant and loading facility.

1.8.3.2 Washing

Washing coal creates more residuals than breaking and sizing, thus has more serious environmental impacts.

1.8.3.2.1 Water

Battelle estimates that washing requires an estimated 1,500 to 2,000 gallons of water per ton of coal processed; Teknekron estimates only 524 gallons, 18 of which are consumed in the process.

According to Hittman, refuse pile runoff is a problem. This water (which contains acids, sulfates, iron, and manganese) seeps from refuse piles at a rate of 1,670 gallons per acre per day; acidity concentration is as high as 11,000 ppm. The refuse pile runoff also contains suspended solids as does the water used to wash the crushed coal. These data are considered to be accurate to within 10 percent.

Under controlled conditions, water pollutants can be reduced to zero because seepage from the refuse pile is eliminated by land reclamation and settling ponds retain suspended solids and other pollutants.

1.8.3.2.2 Air

Air pollutants emanate in small quantities from smoldering refuse piles. These can be controlled by covering the pile with soil and revegetating the area during land reclamation. Thermal and air drying are a major source of airborne particulates according to Battelle (1973: 75) and average 20 to 25 pounds per ton of coal washed in uncontrolled situations.

1.8.3.2.3 Solids

Solids generated during washing amount to about 4,000 tons for every 10^{12} Btu's of coal processed with an error of less than 100 percent. For a typical washing plant processing 500 tons of coal per hour, about 1,000 tons of refuse must be disposed of daily.* This is roughly equal to the weight of refuse generated daily by a city of 400,000 people.

1.8.3.2.4 Land

Under controlled conditions, and to within 50-percent error, five acres are required for the washing plant, 40 acres for the loading facility, and 50 acres for the settling pond. However, Teknekron (1973: 67) estimates that a coal cleaning facility may require 200 to 400 acres, including mine equipment storage and settling ponds.

1.8.4 Economic Considerations

The total estimated 1972 cost for breaking and sizing is $2,250 per 10^{12} Btu's processed. Of this total, operating costs make up 87 percent and fixed costs are 13 percent. This total converts to $0.002 per million Btu's or $0.055 per ton.

Total estimated 1972 cost for washing is $11,900 per 10^{12} Btu's processed. Of this amount, operating costs account for 76 percent and fixed costs are 24 percent. Washing costs, therefore, are $0.012 per million Btu's or $0.31 per ton of coal

*In some circumstances, up to 40 percent of the mined material may be dumped as solid waste.

output assuming an energy content of 26x106 Btu's per ton (Hittman, 1974: Vol. I). Battelle's (1973: 330) total beneficiation cost estimate of $0.066 per million Btu's is in close agreement with Hittman.

1.9 PROCESSING

1.9.1 Technologies

Once coal has been mined it can be used raw, processed to improve its qualities as a solid fuel, or converted into either gas or oil. The technologies for producing gaseous, liquid, and improved solid fuels from coal are described in this section. Information on some of these technologies is limited because they are either at an early stage of development or, in some cases, are proprietary.

1.9.1.1 Gaseous Fuels

Gaseous fuels with low, intermediate, or high energy content can be produced from coal.* Low and intermediate gases are produced in a two-stage process involving preparation and gasification; a third stage, upgrading, is required if high-Btu gas is to be produced. These three stages, illustrated in Figure 1-26, are described below. Following the generalized description, specific gasification processes are identified and described.

1.9.1.1.1 Preparation

All gasification processes require some preparation of the coal feedstock. In addition to handling and storage, a particular gasification process may require further reduction of the coal particle size. Also, depending on coal type and kind of gasifier, the coal may require additional pretreatment--most commonly to prevent the coal from agglomerating into a plastic mass at the bottom of the gasifier.

1.9.1.1.2 Gasification

The three primary ingredients needed to chemically synthesize gas from coal are carbon, hydrogen, and oxygen. Coal provides the carbon; steam is the most commonly used source of hydrogen, although hydrogen is sometimes introduced directly from an external source; and oxygen is usually supplied as either air or pure oxygen. Heat can be supplied either directly by combusting coal and oxygen inside the gasifier or indirectly by hot pebbles or ceramic balls from an external source.

Three combustible gases produced by coal gasification processes are carbon monoxide (CO), methane (CH_4) and hydrogen (H_2). Methane, the primary component of natural gas, is similar to natural gas in heating value. Carbon monoxide and hydrogen heating values are approximately equal, being about one-third the methane/natural gas value. Several noncombustible gases are also produced, including carbon dioxide, hydrogen sulfide, and nitrogen.

A major goal for most coal gasification processes is to produce a high quality gas during the initial gasification stage. The product from each process is determined primarily by the methods used to introduce hydrogen, oxygen, and heat into the gasifier. Each method involves trade-offs. For example, if air is used to provide the oxygen, nitrogen is produced as an undesirable by-product and the heating value of the gas is reduced. Although pure oxygen is more expensive than air, it eliminates the nitrogen problem and produces intermediate- rather than low-Btu gas.

The use of steam to introduce hydrogen into the process produces primarily carbon monoxide and hydrogen, while the direct

*No fixed energy values are associated with these gases; however, 100 to 200 Btu's per cubic foot (cf) is generally considered low, 300 to 650 Btu's intermediate, and 900 to 1,050 Btu's high.

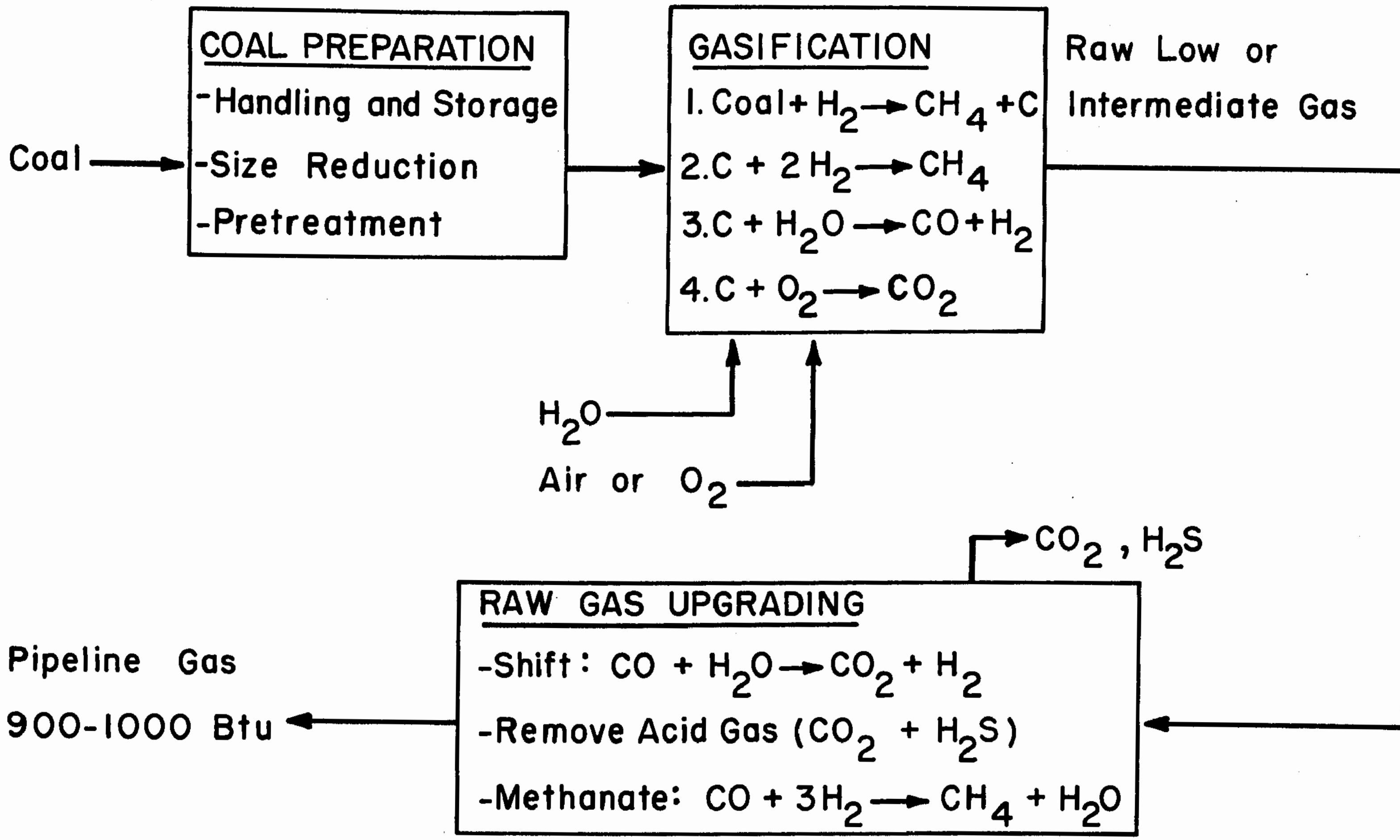


Figure 1-26. General Process Scheme for Producing Gas from Coal

Source: Adapted from Gouse and Rubin, 1973:IV-3.

introduction of hydrogen produces methane and carbon. Since reacting hydrogen directly with coal also produces heat (an exothermic reaction), hydrogen would seem preferable to steam, but the amount of methane produced is usually quite small (a large amount of the carbon is left in the gasifier as char). As a consequence, this devolatilization reaction (coal + $H_2 \longrightarrow CH_4$ + C + heat) is normally placed in a pretreatment stage rather than in the stage where most of the gasification occurs, which also conserves hydrogen. The other method of introducing hydrogen, the steam-carbon reaction (heat + C + $H_2 \longrightarrow CO + H_2$) is used more frequently, both to produce final-product low and intermediate gases and to produce feedstocks for high-Btu gasification.

For coal gasification processes, direct heat is more thermally efficient than indirect heat. However, most direct heat processes use either air or oxygen as an oxidizer, producing the products and problems identified above. One alternative direct heating method feeds lime (CaO) into the gasifier where its exothermic reaction with carbon dioxide produces heat. The gaseous products are carbon monoxide and hydrogen, and the carbon dioxide is removed by the lime. Indirect heating using molten salts, dolomite solids, molten slag, pebbles, etc. introduces additional materials requirements and makes the gasification more complicated.

The types and proportions of gases produced are determined by the design of the specific gasification process. As indicated above, the basic chemical choices are whether to use hydrogen or steam, air or oxygen, and direct or indirect heat. On the basis of the options selected and specific conditions such as temperature and pressure, reactor vessels can be divided into three general categories: gasifier, hydrogasifier, and devolatilizer (Figure 1-27). Gasification systems employ one or more of these reactor types.

As shown in Figure 1-27, the gasifier reactor produces some gas through the steam-carbon reaction (heat + C + $H_2O \longrightarrow CO + H_2$) and some through the water-gas shift reaction ($CO + H_2O \longrightarrow CO_2 + H_2$ + heat). The major differences in gasifier reactor systems are in the method (direct or indirect) of providing heat.

In the hydrogasifier reactor, methane is produced by reacting hydrogen with coal or char under pressure ($C + 2H_2 \longrightarrow CH_4$ + heat). Although systems of this type differ in the method of supplying hydrogen, all hydrogasifiers produce up to twice as much methane as gasifiers or devolatilizers of comparable capacity.

The devolatilizer reactor decomposes large coal compounds. In this system, hydrogen reacts with the coal to produce methane and heat (coal + $H_2 \longrightarrow CH_4$ + C + heat).

Gasification systems can also be categorized on the basis of engineering features, two significant ones being whether the system is pressurized and the type of bed used. Gasification systems may be operated either at high pressure or at atmospheric pressure. The main advantages gained from pressurizing are improving the quality of product gas, maximization of the hydrogasification reaction, reduction of equipment size, and elimination of the need to separately pressurize gas before introducing it into a pipeline (Interagency Synthetic Fuels Task Force, 1974: 22).

In terms of beds, there are three basic types of gasification systems: fixed-bed, fluidized-bed, and entrainment (Corey, 1974: 44). In the fixed-bed system, a grate supports lumps of coal through which the steam or hydrogen is passed. Conventional fixed-bed systems are incompatible with caking coals (coals which, when heated, pass through a plastic stage and cake or

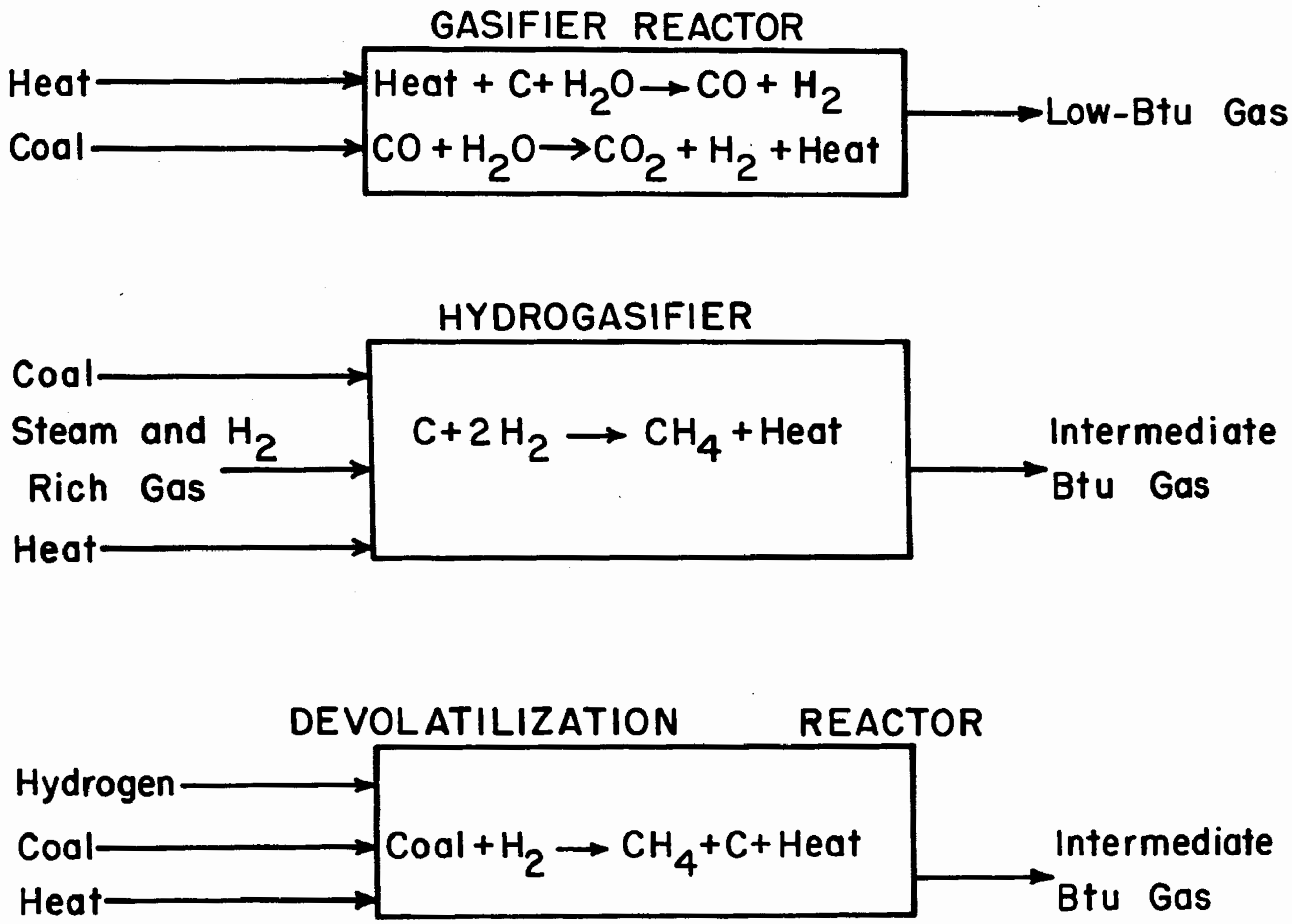


Figure 1-27. Principal Coal Gasification Reactions and Reactor Types

agglomerate into a mass). To expand the range of coals that can be used, some fixed-bed systems are modified to incorporate a rotating grate or stirrer to prevent caking.

The fluidized-bed system uses finely sized coal. Gas is flowed through the coal, producing a lifting and "boiling" effect. The result is an expanded bed with more coal surface area to promote the chemical reactions. Fluidized-bed systems also have a limited capacity for operating with caking coals; consequently, these types of coals are often pretreated to destroy caking characteristics when the fluidized-bed system is used.

Finely sized coal is also used in entrainment systems. In this type of system, the coal particles are transported in the gas (for example, steam and oxygen) prior to introduction into the reactor. The chemical reactions occur, and the product gases and ash are taken out separately. There are no limitations on the types of coal that can be used with the entrainment system.

1.9.1.1.3 Upgrading

Three steps are involved in upgrading raw gases produced during the gasification stage just described: shift conversion, purification, and methanation. Shift conversion combines carbon monoxide and water to produce carbon dioxide and hydrogen ($CO + H_2O \longrightarrow CO_2 + H_2$ + heat). This shift is necessary to adjust the hydrogen and carbon monoxide to the 3:1 ratio required for methanation. A catalyst, usually an iron-chromium oxide compound, is used in this reaction.

After shift conversion, the gas is purified to less than 1.5-percent carbon dioxide by volume and less than one ppm of hydrogen sulfide. Methanation follows, reacting carbon with hydrogen to produce methane ($C + 2H_2 \longrightarrow CH_4$ + heat). Nickel compounds are the most frequently used catalysts for this reaction. The basic upgrading process is fairly standardized, and the major choices involve engineering details rather than alternative processes.

1.9.1.1.4 Specific Low-Btu Gasification Processes

The major characteristics of four processes designed to produce either low- or intermediate-Btu gas from coal are summarized in Table 1-28. Two of these, Lurgi and Koppers-Totzek, are used commercially at present; the others are in the pilot plant stage. A large number of other processes (with, for example, different combinations of bed types, pressure levels, and oxygen sources) have been proposed or are in early stages of development. The four technologies described below illustrate the current state of the art.

1.9.1.1.4.1 Lurgi

There is no pretreatment in the Lurgi process and only noncaking coals can be used. As shown in Figure 1-28, pulverized coal is introduced into a pressurized reactor vessel through a lock hopper. The coal passes downward and is distributed onto a rotating grate. Steam and oxygen are introduced below the grate. All the coal is combusted, leaving only ash which is allowed to fall through the grate. Product gas from the combustion zone above the grate leaves the reactor at 800 to 1,000 $^{\circ}$F. To produce 250 billion Btu's per day, 27 to 33 gasifiers of 13-foot inside diameter would be required. Materials balance for the Lurgi process is shown in Table 1-29.

1.9.1.1.4.2 Koppers-Totzek

In the Koppers-Totzek process, finely ground coal is mixed with oxygen and steam, then pumped into an atmospheric-pressure vessel (Figure 1-29). Because of the low pressures used and the entrained flow of the materials injected, a complex and troublesome system of hoppers is avoided.

TABLE 1-28

SELECTED DESIGN FEATURES OF FOUR
LOW- AND INTERMEDIATE-BTU GASIFICATION PROCESSES

Name	Reactor Type	Bed Type	Pressure	Hydrogen Sources	Oxygen Sources	Heat	Pretreatment	Coal Input
Lurgi	Gasifier	Modified fixed	300-450 pounds per square inch	Steam	Air/ oxygen	Direct burning	Sizing	Noncaking 1/4x2 inch, no fines
Koppers-Totzek	Gasifier	Extrained suspension	Atmospheric	Steam	Oxygen	Direct burning	Pulverizing	Caking or noncaking, pulverized[a]
BuMines[b]	Gasifier	Modified fixed	Atmospheric to 300 pounds per square inch	Steam	Air	Direct burning	Pulverizing	Caking or noncaking, coarse or fine
Westinghouse	Gasifier	Fluidized	200-300 pounds per square inch	Steam	Air	Direct and internal exothermic reactions in desulfurizer	Pulverizing drying, integrated devolatiles/ desulfurizers	Caking or noncaking, pulverized
Ash agglomerating	Gasifier	Fluidized	Pressurized	Steam	Air	Direct burning	Pulverizing	Caking or noncaking, pulverized

[a]Pulverized means crushed so that 70 to 80 percent of the coal passes a 200-mesh screen (0.003 inch).

[b]The BuMines process listed here is often identified as two processes. The only difference between the two is that one is pressurized.

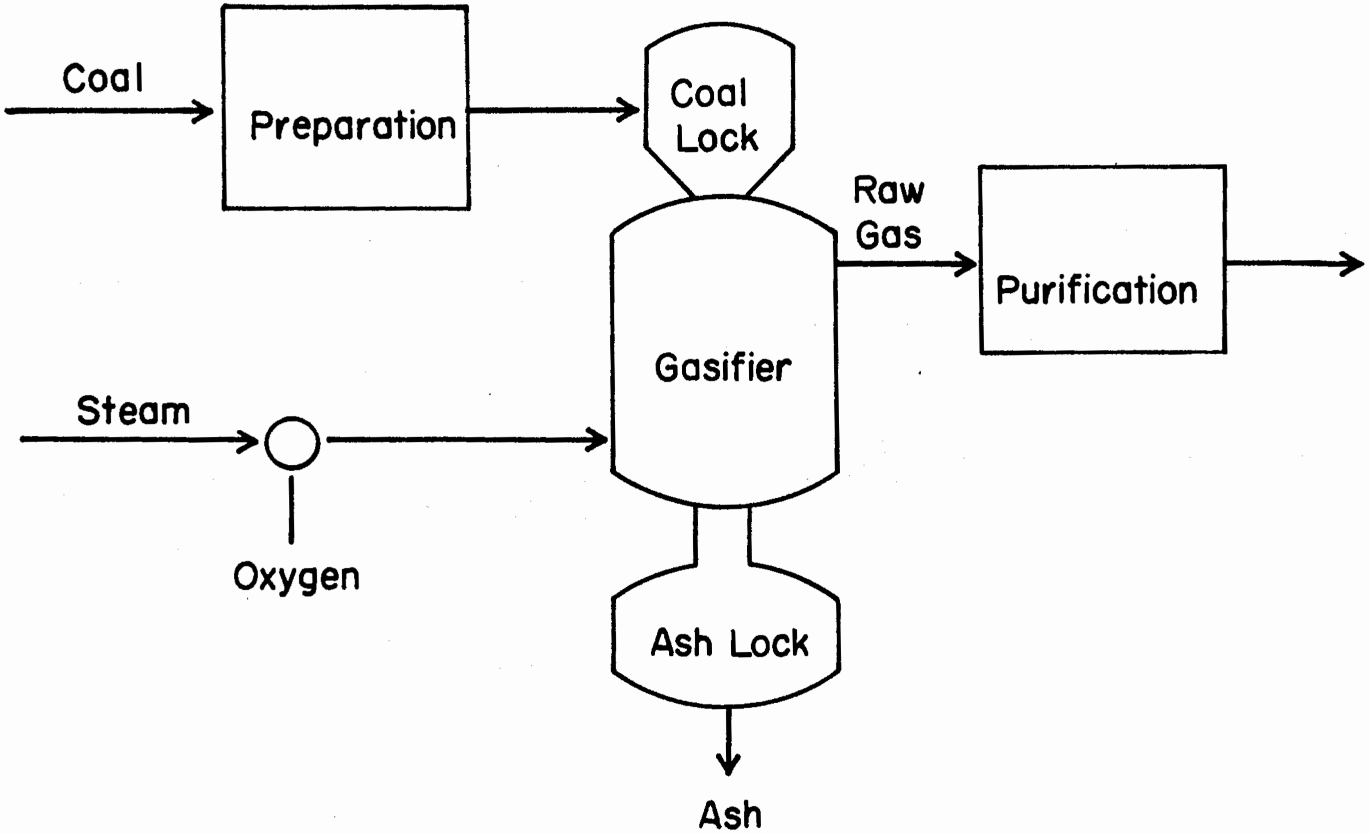


Figure 1-28. Lurgi Low-Btu Coal Gasification Process

Source: Adapted from Bodle and Vyas, 1973: 53.

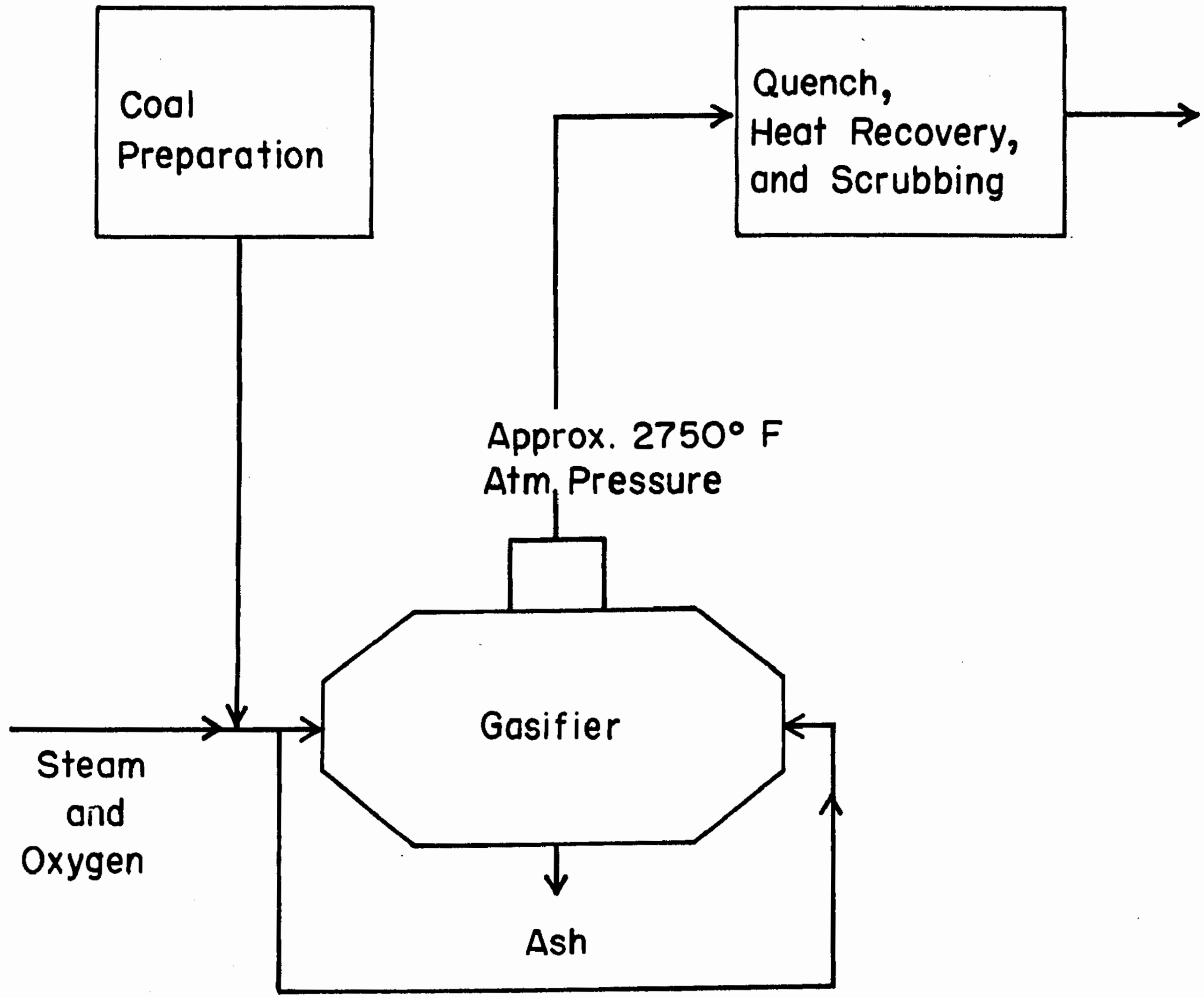


Figure 1-29. Koppers-Totzek Coal Gasification Process

Source: Adapted from Bodle and Vyas, 1973: 68.

TABLE 1-29

MATERIALS BALANCE FOR LURGI PROCESS

Input	Quantity	Output	Quantity
Coal[a]	10,770 tpd[b]	Intermediate-Btu gas	250×10^9 Btu's per day
Water	U	Solid waste	865 tpd
		Sulfur dioxide[c]	0.83 tpd

U = unknown.

Source: Hittman, 1975: Vol. II, p. III-29.

[a]Using Northwest coal of 8,780 Btu's per pound, 6.77-percent ash, and 0.85-percent sulfur.

[b]tons per day.

[c]controlled emission.

TABLE 1-30

MATERIALS BALANCE FOR KOPPERS-TOTZEK PROCESS[a]

Input	Quantity	Output	Quantity
Coal[b]	10,570 tpd[c]	Intermediate-Btu gas	250×10^9 Btu's per day
Water	463,000 gpd[d]	Solid waste	865 tpd
		Sulfur dioxide[e]	4.4 tpd

Source: Hittman, 1974: Vol. II, p. III-34.

[a]Based on a facility with a 250-billion-Btu output per day.

[b]Using Northwest coal of 8,780 Btu's per pound, 6.77 percent ash, and 0.85 percent sulfur.

[c]tons per day.

[d]gallons per day

[e]controlled emission.

Two or four injection or burner heads may be used. Combustion occurs at high temperatures (about 3,000 ^{o}F) in the center of the reactor vessel, and the product gas exits upwards through a central verticle outlet. Molten slag exits at the bottom. A typical large gasifier is about 10 feet in diameter and 25 feet long.

A Koppers-Totzek reactor will produce about twice the gas of a Lurgi reactor because of its higher throughput capabilities (NAE/NRC, 1973: 34). Materials balance for the Koppers-Totzek process is indicated in Table 1-30.

TABLE 1-31

MATERIALS BALANCE FOR BUREAU OF MINES STIRRED FIXED BED PROCESS

Input	Quantity	Output	Quantity
Coal	10,000 tpd[a]	Intermediate-Btu gas	48,732 tpd
Steam	5,224 tpd	Tar	353 tpd
Air	37,533 tpd	Ammonium sulfate	696 tpd
Water	12.3 mmgpd[b]	Solid wastes	1,104 tpd
		Gaseous wastes	1,336 tpd

Source: Interagency Synthetic Fuels Task Force, 1974: 49.

[a]tons per day.

[b]millions of gallons per day.

1.9.1.1.4.3 Bureau of Mines Stirred Fixed Bed

In the BuMines process, pulverized coal is fed into the top of the reactor from a lock hopper and falls downward onto a rotating grate similar to that used in the Lurgi process (Figure 1-30). However, a stirrer is mounted in the center of the reactor, and a variable speed drive both rotates the stirrer and moves it vertically. This prevents clogging and allows caking coals to be used. Steam and air are injected from below the grate.

The dimensions of a commercial-sized reactor have not been determined. The plant has been operated at pressures ranging from atmospheric to 300 pounds per square inch (psi). A materials balance prepared by the Interagency Task Force is listed in Table 1-31.

1.9.1.1.4.4 Westinghouse Fluidized-Bed Gasifier

Two pressurized, fluidized-bed vessels are used in the Westinghouse system, one as the gasifier and the other as a devolatilizer/desulfurizer. Air, steam, and char are reacted in the gasifier to produce a hot gas which is then introduced into the devolatilizer/desulfurizer with crushed coal and dolomite (lime) (Figure 1-31). Hot gases from the gasifier supply the heat for devolatilization and the char produced by devolatilization is used as the feedstock for the gasifier. Sulfur is removed by the dolomite. Materials balance is indicated in Table 1-32.

1.9.1.1.4.5 Ash Agglomerating Fluidized-Bed Gasifier

In this process, pulverized coal is introduced into a pressure vessel and is partially burned at high temperature while suspended by an upward flow of air and steam. The ash slowly agglomerates in the reactor and falls to the bottom where it is removed (Figure 1-32). Fine particulates in the produced gas are removed by a cyclone scrubber. The gas is then cooled to about 1,400^{o}F and passed through a filter where dolomite reacts with any hydrogen sulfide to form a sulfurized solid. The dolomite filter is periodically regenerated by treating it with hot carbon dioxide to drive off the sulphur. The hot, cleaned, pressurized gas (which has a heating value of about 160 Btu's per cf) is then fed to a combined cycle electric power plant.

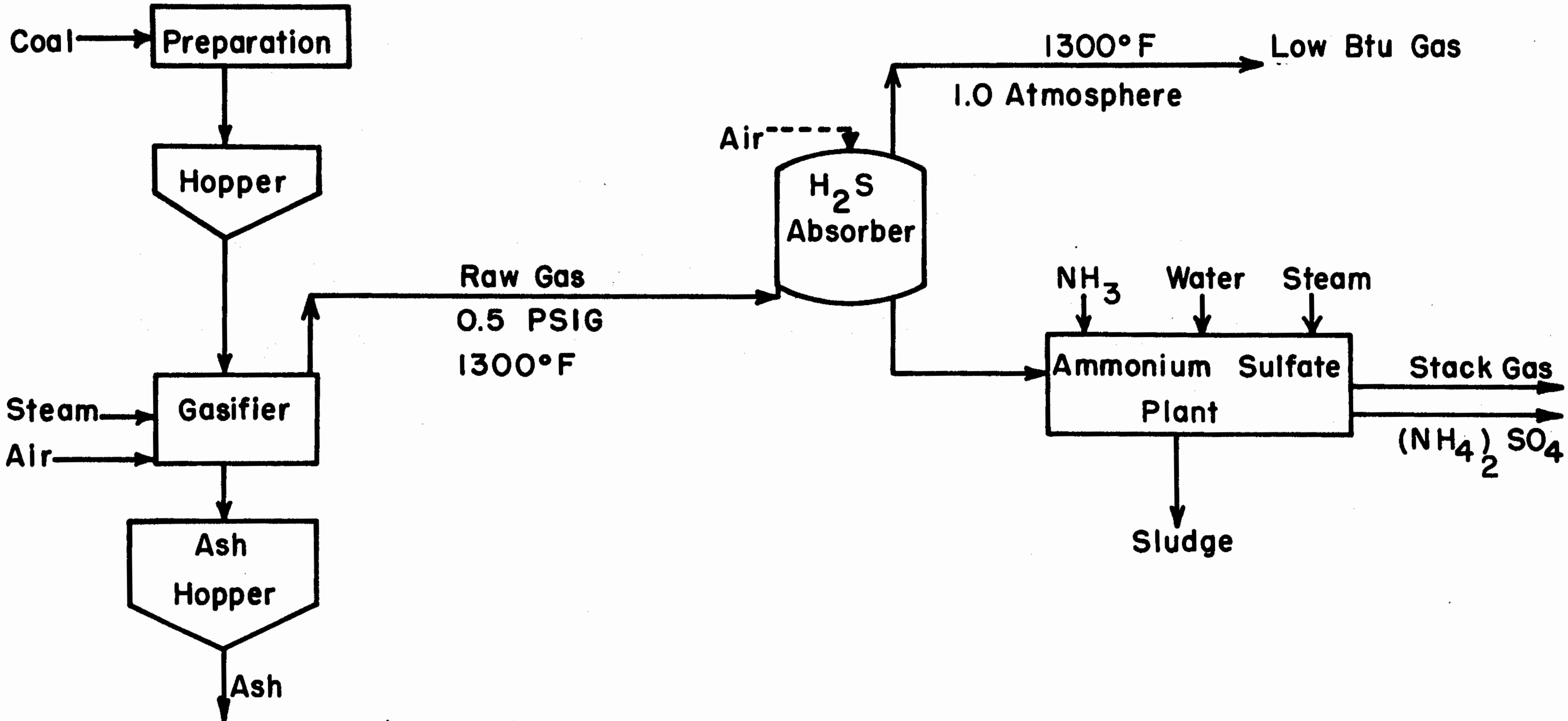


Figure 1-30. Bureau of Mines Stirred Fixed Bed
Coal Gasification Process

Source: Interagency Synthetic Fuels Task Force, 1974.

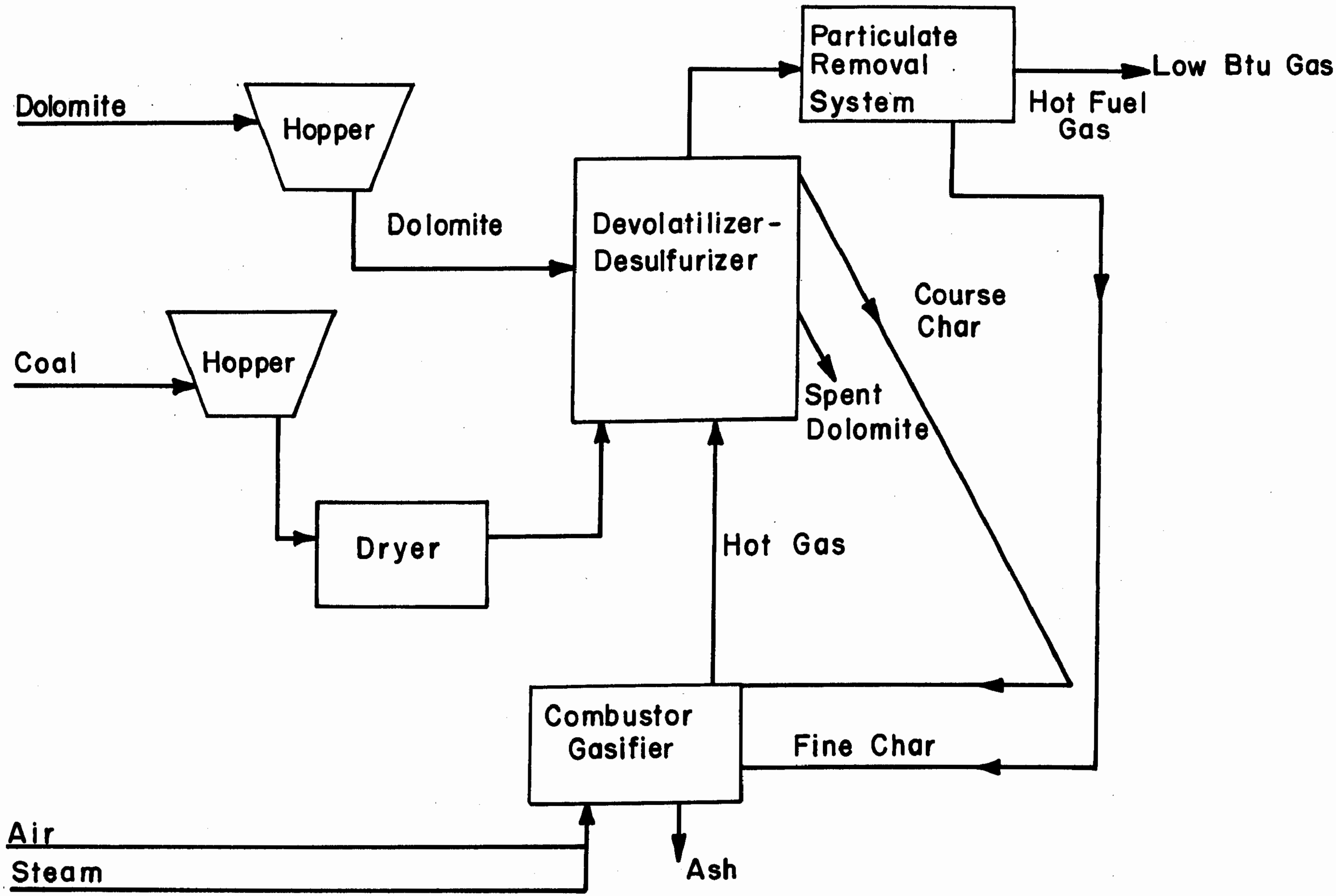


Figure 1-31. Westinghouse Fluidized Bed Coal Gasification Process

Source: Adapted from Archer and others, 1974: 5.

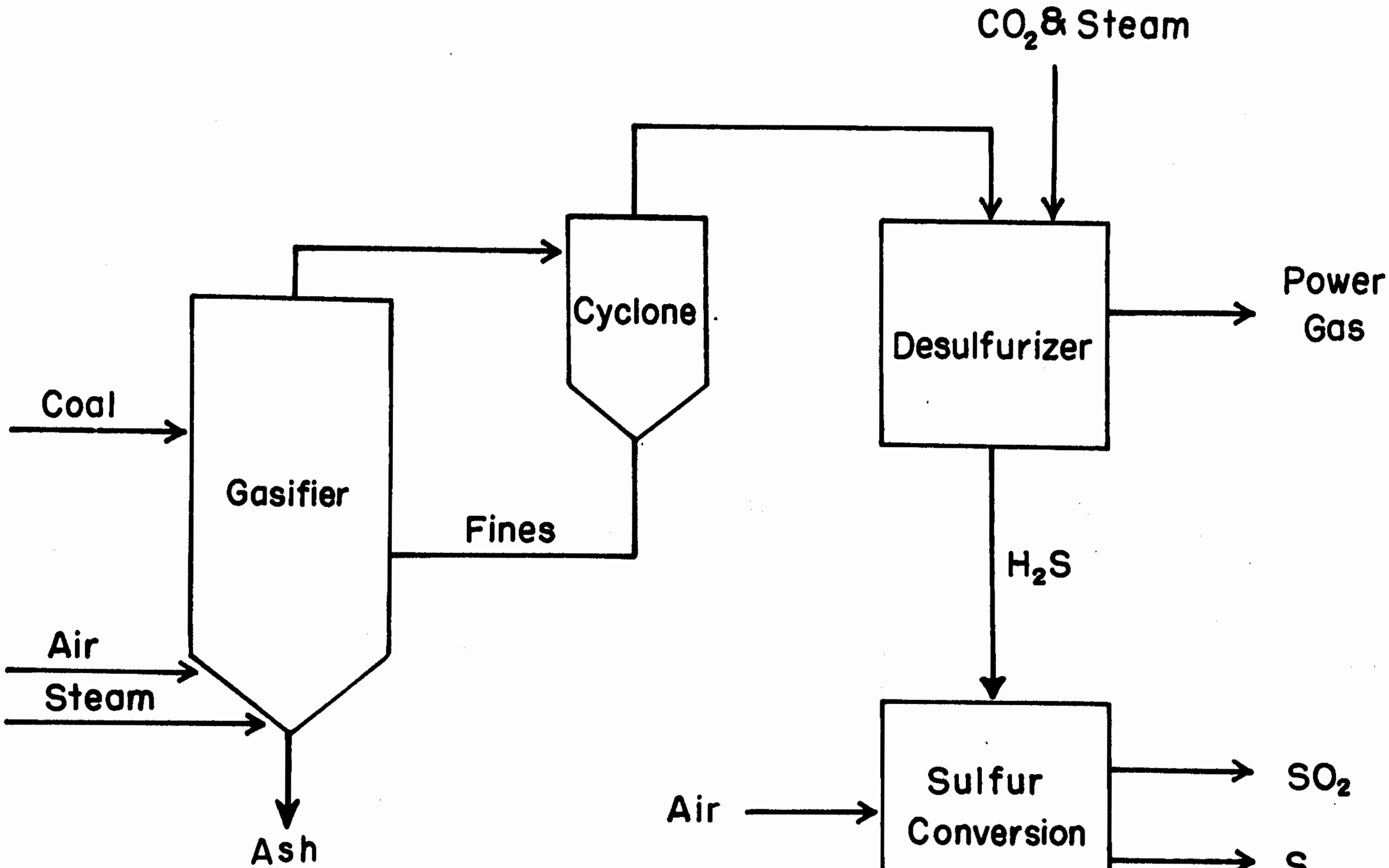


Figure 1-32. Ash Agglomerating Fluidized Bed Coal Gasification Process

TABLE 1-32

MATERIALS BALANCE FOR WESTINGHOUSE FLUIDIZED BED PROCESS

Input	Quantity	Output	Quantity
Coal[a]	8,754 tpd[b]	Low-Btu gas	215×10^9 Btu's
Water	U	Solid waste[c]	1,201 tpd
Dolomite[d]	4,000 tpd	Spent dolomite	4,000 tpd

U = unknown

Source: Archer and others, 1974: Figure 2.

[a]Assumes 95-percent conversion efficiency and coal of 12,927 Btu's per pound.

[b]tons per day.

[c]solid waste as ash.

[d]Based on approximately 2:1 coal-to-dolomite ratio when fed with three-percent sulfur coal.

TABLE 1-33

MATERIALS BALANCE FOR AN ASH AGGLOMERATING FLUIDIZED BED PROCESS

Input	Quantity	Output	Quantity
Coal[a]	9,972 tpd[b]	Low-Btu gas	(5.01×10^{11} cubic feet) (215×10^9 Btu's)
Water (steam)	633 tpd	Sulfur	298 tpd
Dolomite	21 tpd	Sulfur dioxide	4.31 tpd
CO_2	498 tpd	Particulates	13.4 tpd

Source: Teknekron, 1973: Figure 7.1.

[a]Coal contains 11,770 Btu's per pound.

[b]tons per day.

The system, now in prototype development, has a high throughput for a particular reactor vessel size and relies on the agglomerating characteristics of coal to remove ash. Materials balance is indicated in Table 1-33. Daily inputs and outputs are based on a plant capable of producing 250 million cf of high-Btu gas each day.

1.9.1.1.5 Specific High-Btu Gasification

The major characteristics of five high-Btu gasification systems are identified in Table 1-34. All five systems are still in the developmental stage. The Lurgi gasification process has been proven, but the final upgrading and methanation steps have not been used commercially.

TABLE 1-34

SELECTED DESIGN FEATURES OF FIVE HIGH-BTU GASIFICATION PROCESSES

Name	Reactor Type	Bed Type	Pressure (pounds per square inch)	Hydrogen Sources	Oxygen Sources	Heat	Pretreatment	Coal Input
Lurgi	Gasifier	Modified Fixed	300-500	Steam	Oxygen Plant	Direct	Sizing	Noncaking, 1/4x2 inch, no fines
HYGAS	Hydrogasifier	Fluidized	1,000	Hydrogen[a]	Oxygen Plant	Direct	Sizing, heating and slurry	8 to 100 mesh fines all coals
BI-GAS	Gasifier and Hydrogasifier	Entrained Flow	1,000	Steam	Oxygen Plant	Direct	None	Liquid to rank A bituminous pulverized
Synthane	Gasifier devolatilizer	Fluidized	1,000	Steam	Oxygen Plant	Direct	Sizing and heat and volatilize	All coals fines of 200 mesh
CO_2 Acceptor	Gasifier devolatilizer	Fluidized	150	Steam	Air	Direct and Indirect	Sizing	Lignite or subbituminous, 1/8 inch

[a]Hydrogen introduced into the gasifier is produced by reaction of steam, char, and oxygen.

TABLE 1-35

INPUTS AND BY-PRODUCTS FOR A LURGI GASIFICATION PLANT[a]

Input	Quantity	Output	Quantity
Coal[b]	23,600 tpd[c]	Solid waste	1,548 tpd
Water	18 mmgpd[d]	Air emission	37.3 tpd
Nickel	1,000 pounds per 4 months	Ammonia	112 tpd
		Sulfur	116 tpd
		Tar	41×10^9 Btu's per day
		Naptha	63,000 gpd

Source: Hittman, 1975: Vol. II.

[a]250-mmcf-per-day production using Northwest coal of 8.780 Btu's per pound, 6.77-percent ash, and 0.85-percent sulfur.

[b]Assumes 413×10^9 Btu's input per 250-mmcf output.

[c]tons per day.

[d]millions of gallons per day.

Most high-Btu gasification processes include pretreatment, gasification, clean-up, shift conversion, purification, and methanation steps. Differences between systems are greatest in the gasification step. These differences will be highlighted in the following descriptions for the five processes listed in Table 1-34.

1.9.1.1.5.1 Lurgi High-Btu Gasification

The initial gasification step used in Lurgi is essentially the same for both low- and high-Btu gasification. Synthesis gas from the gasifier shown in Figure 1-33 has a Btu value of approximately 285 Btu per cf. The upgrading process is the same as the general process described earlier, including clean-up, shift conversion, purification, and methanation (Corey, 1974: 51). Pilot plant configurations of these steps have been tested in Scotland and South Africa, but data concerning both plants are proprietary.

Each gasifier reactor is capable of producing about 10 million cubic feet (mmcf) of synthetic natural gas per day. The inputs and outputs of a 250-mmcf-per-day Lurgi gasification plant are summarized in Table 1-35.

1.9.1.1.5.2 HYGAS

In the HYGAS process, pulverized coal of a nominal -8/+100 mesh size is slurried with hot aromatic by-product oil and pumped into the gasification reactor. This reactor, which operates at 1,000 psi, has been heated and supplied with a hydrogen-rich gas from a separate char-gasifier vessel (Figure 1-34). As the coal slurry enters the reactor, light oils and gases vaporize upward and the coal falls down into a fluidized bed. Total coal residence time in the gasification reactor is about 30 minutes. The devolatilized coal goes from the gasification reactor into the char gasifier where hydrogen-rich hot gases are produced from the

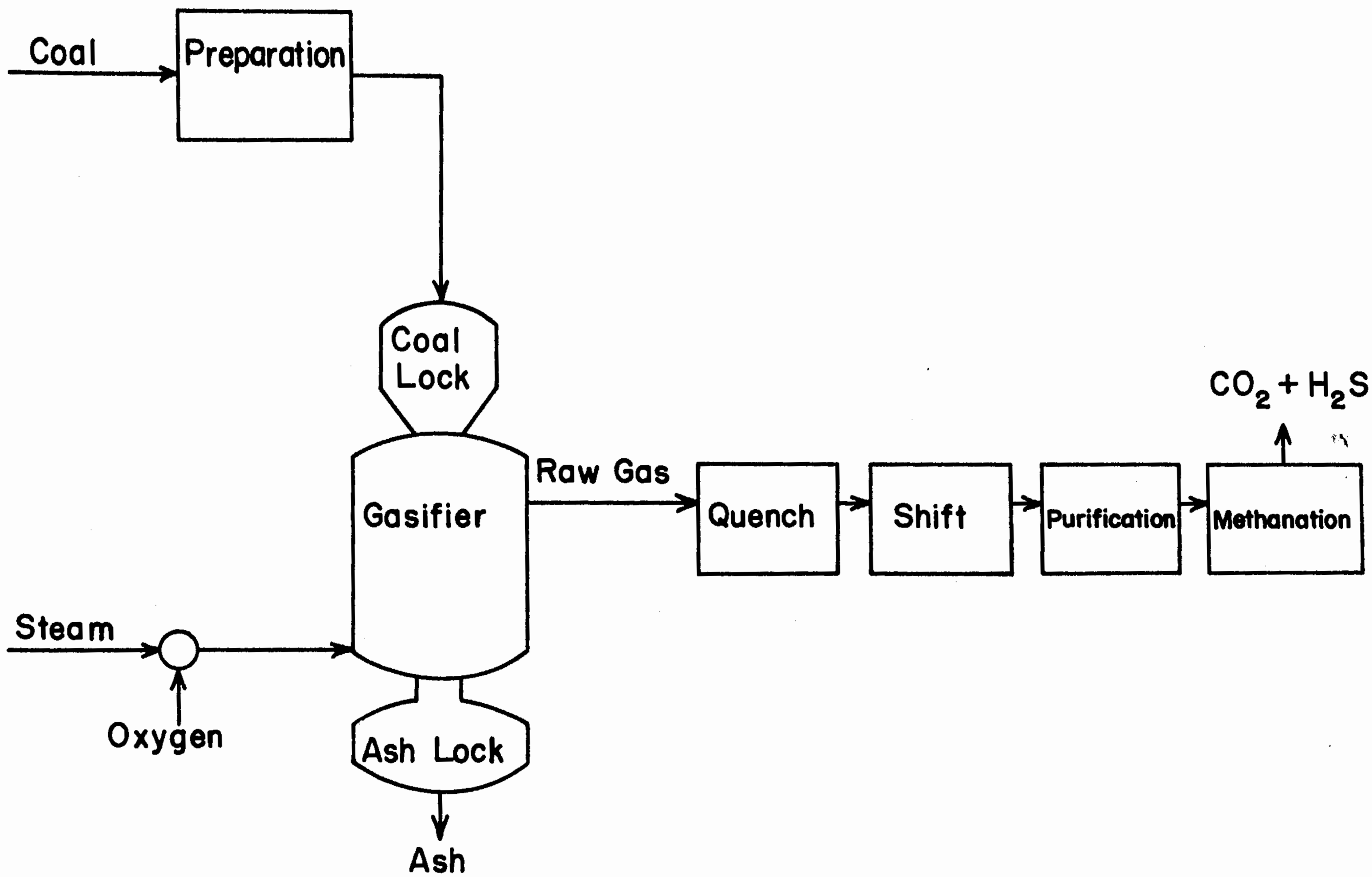


Figure 1-33. Lurgi High-Btu Coal Gasification Process

Source: Adapted from Bodle and Vyas, 1973: 53.

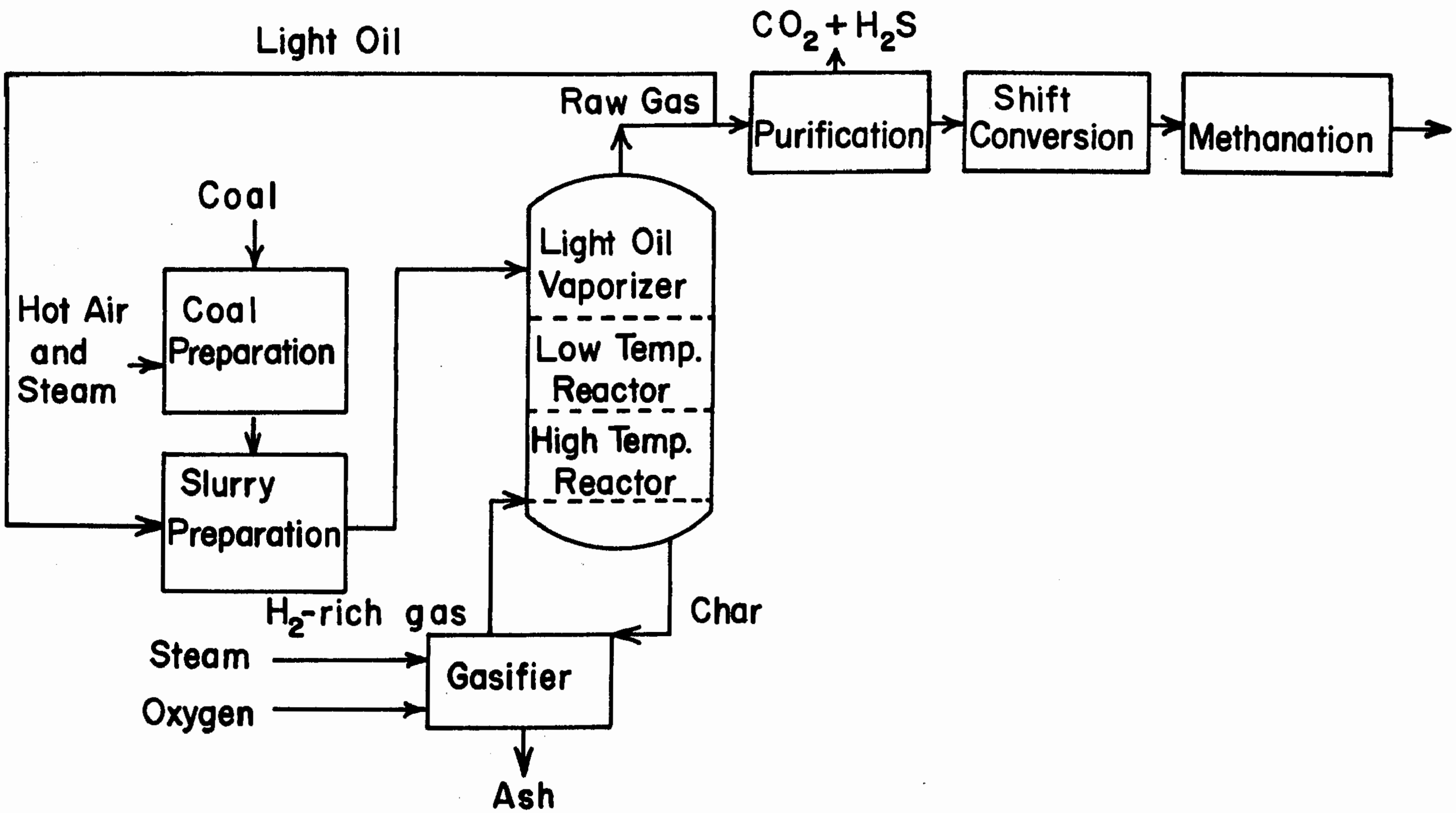


Figure 1-34. HYGAS Coal Gasification Process

Source: Adapted from Bodle and Vyas, 1973: 64.

TABLE 1-36

INPUTS AND OUTPUTS FOR A HYGAS PLANT[a]

Input	Quantity	Output	Quantity
Coal	24,200 tpd[b]	Solid waste	1,577 tpd
Water	19 mmgpd[c]	Air emissions	35 tpd
Nickel	1,000 pounds per 4 months	Ammonia	124 tpd
		Sulfur	103 tpd
		Tar	2.3×10^{10} Btu's per day
		Light oils	46,000 gpd

Source: Hittman, 1975: Vol. II.

[a]250-mmcf-per-day production using Northwest coal of 8,780 Btu's per pound, 6.77-percent ash, and 0.85-percent sulfur.

[b]tons per day.

[c]millions of gallons per day.

reaction of char, steam, and oxygen (Hittman, 1975: Vol. II, p. IV-5). The HYGAS process differs from other processes primarily in its use of slurry feed and a hydrogen-rich gasifier atmosphere.

After leaving the gasification reactor, the raw gas is cooled, the aromatic oil is recycled, and other tars and oils are removed as by-products. The gas is then processed by water-gas shift conversion, purification, and methanation.

The HYGAS process is one of the most complex gasification systems being developed, having separate circulation systems for coal, char, and by-product oil. Its advantages include the use of pumped slurries instead of lock hoppers and the efficiencies gained by using a hydrogen-rich gas for the hydrogasification reactions. Although commercial plant size information is not available, about 10 gasifiers would be needed for a commercial plant. Inputs and outputs of such a plant are listed in Table 1-36.

1.9.1.1.5.3 BI-GAS

In the BI-GAS process, pulverized coal is piston-fed into the middle of a 1,000-psi gasifier reactor where it is mixed with steam. The coal is devolatilized by a rising flow of hot gases which are produced from char (Figure 1-35) (Hittman, 1975: Vol. II, p. IV-5). The gases and char are then separated, and the char is piped to the bottom of the gasifier where it is mixed with steam and oxygen. An ash slag is removed from the bottom of the vessel. The process gas stream undergoes cleaning, shift conversion, purification, and methanation. Materials inputs and outputs for a plant using western subbituminous coal are listed in Table 1-37.

1.9.1.1.5.4 Synthane

In the Synthane process, coal sized to pass through a 200-mesh screen is mixed with steam and oxygen in a pretreatment pressure vessel at 1,000 psi and 800°F (Figure 1-36). In this pretreatment stage, the coal is partially oxidized and volatile

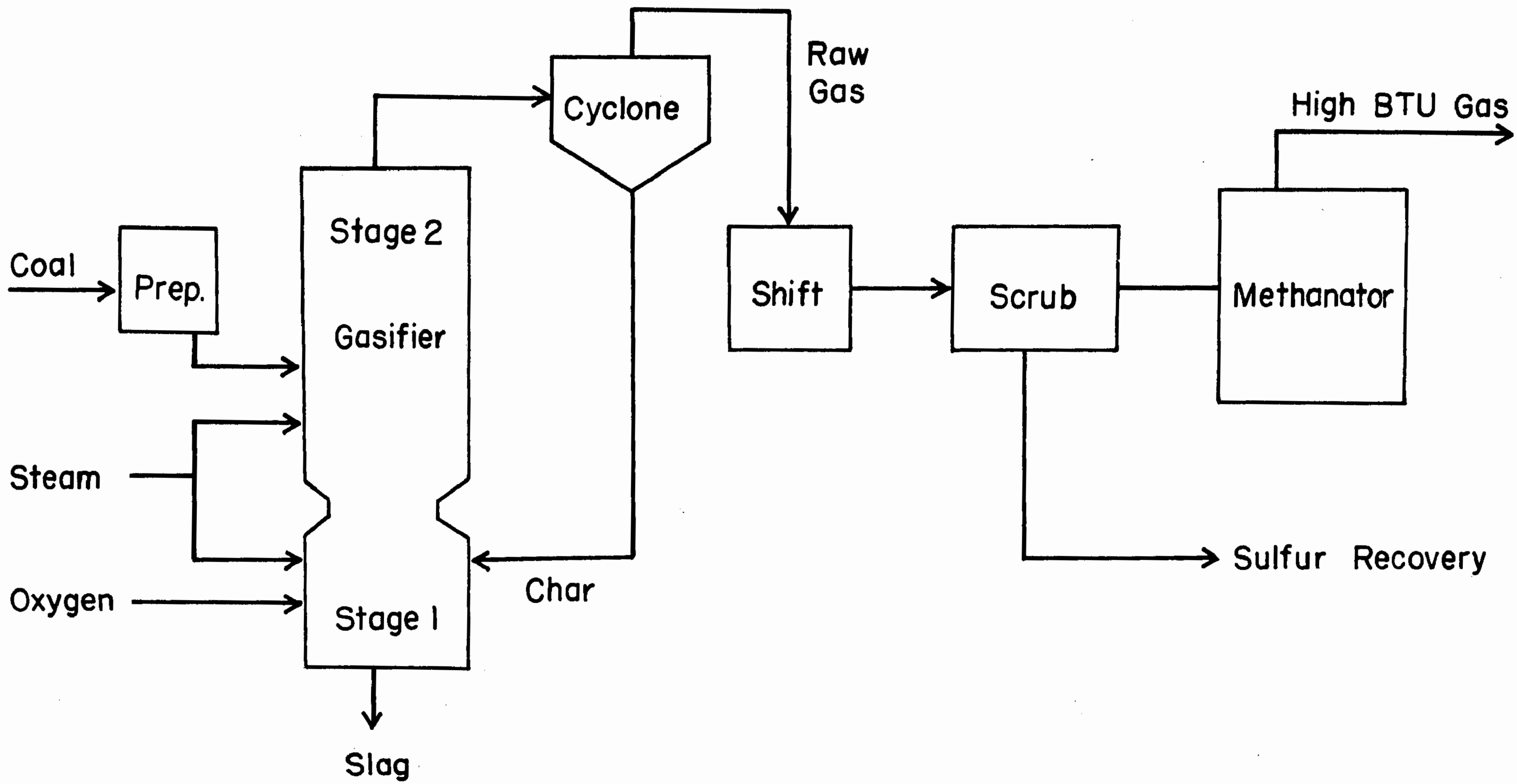


Figure 1-35. BI-GAS Coal Gasification Process

Source: Adapted from Goodrige, 1973: 56.

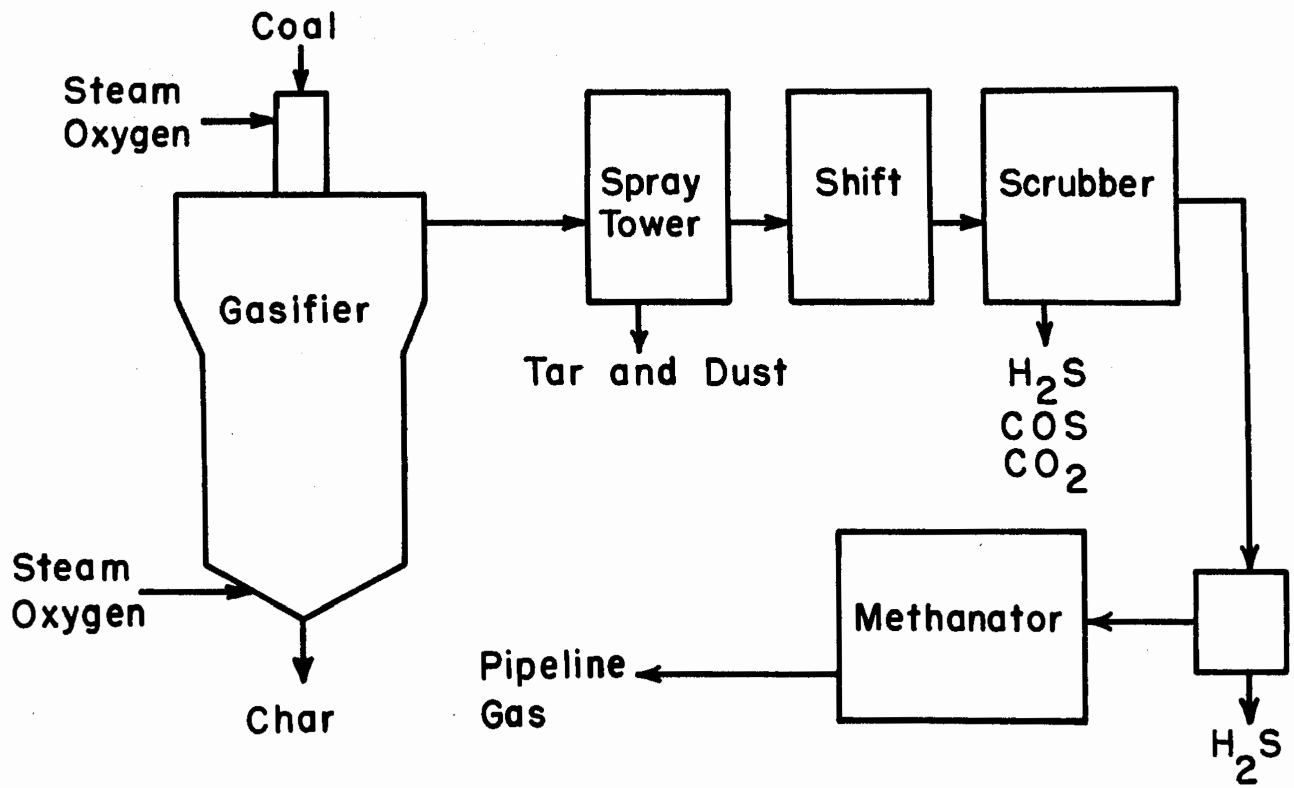


Figure 1-36. Synthane Coal Gasification Process

Source: Adapted from BuMines, 1974c: 11.

TABLE 1-37

INPUTS AND OUTPUTS FOR A BI-GAS PLANT[a]

Input	Quantity	Output	Quantity
Coal	19,600 tpd[b]	Solid waste	1,330 tpd
Water	37.4 mmgpd[c]	Air emissions	27.7 tpd
Nickel	1,000 pounds per 4 months	Ammonia	98.5 tpd
		Sulfur	93.1 tpd

Source: Hittman, 1975: Vol. II.

[a]250-mmcf-per-day production. Plant Btu capacity of 236×10^9 Btu's per day (produces 950 Btu's per cf gas) using Northwest coal of 8,780 Btu's per pound, 6.77-percent ash, and 0.85-percent sulfur.

[b]tons per day.

[c]millions of gallons per day.

matter is driven off. The coal and gases from the pretreater are introduced at the top of the gasifier, and additional steam and oxygen are introduced at the bottom. Partial combustion of the coal increases the temperature of this process to 1,800°F. After the coal passes through the fluidized-bed portion of the gasification vessel, it exits as char at the bottom. The char is burned to produce steam for the pretreater and gasifier (Hittman, 1975: Vol. II, p. IV-5).

The raw gas is cleaned of tars, char, and water and then undergoes a shift conversion. Following those operations, the gas is bubbled through hot carbonate to remove carbon dioxide and sulfur and is then methanated.

The Synthane process achieves a high-Btu raw gas output with a relatively simple high-pressure gasification system. However, all the coal entering the gasifier is not burned, and the remaining high-sulfur char must be burned for process heat. Materials requirements and outputs of a Synthane plant are listed in Table 1-38.

1.9.1.1.5.5 CO_2 Acceptor

In the CO_2 Acceptor process, pulverized coal and hot dolomite are introduced at the top of the reactor and steam is introduced at the bottom (Figure 1-37). Both the heat of the dolomite and its energy-producing reaction with the carbon dioxide (a product of the coal-steam reaction) devolatilize the coal as it passes down the reactor vessel. The partially combusted coal exits as char (Hittman, 1975: Vol. II, p. IV-5). Both the char and spent dolomite are then introduced as separate streams into a dolomite regenerator vessel. In this vessel, the combustion of char with air heats the dolomite and drives off the carbon dioxide as shown in Figure 1-37.

The CO_2 Acceptor process produces a gas low in carbon dioxide, carbon monoxide, and sulfur. A shift reaction is not necessary since the carbon monoxide-to-hydrogen ratio is already suitable for methanation. The advantages of the CO_2 Acceptor process are in the use of dolomite to remove some of the sulfur and carbon dioxide from the synthesis gas stream. Since dolomite is

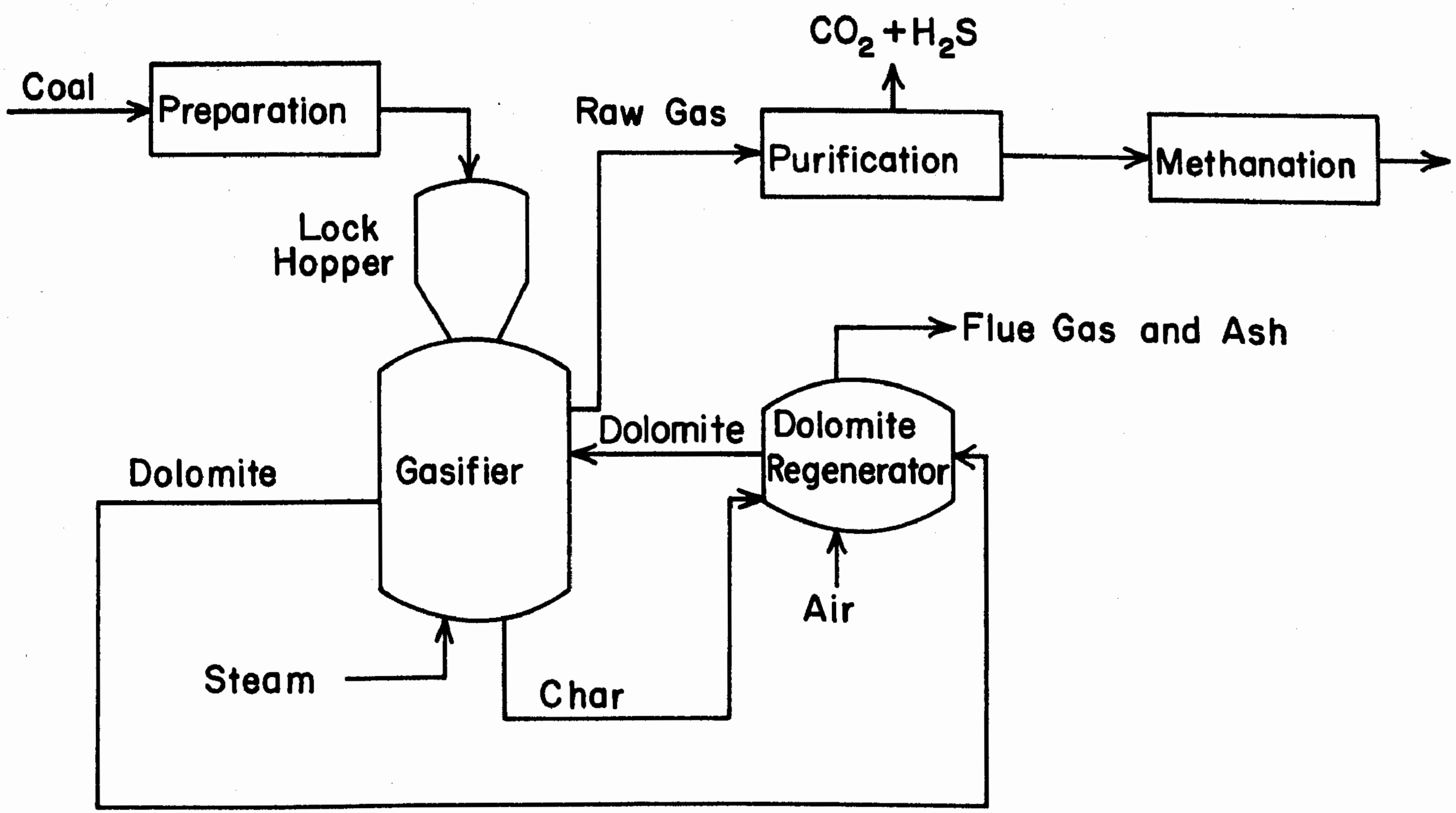


Figure 1-37. CO_2 Acceptor Coal Gasification Process

Source: Adapted from Bodle and Vyas, 1973: 69.

TABLE 1-38

INPUTS AND OUTPUTS FOR A SYNTHANE PLANT[a]

Input	Quantity	Output	Quantity
Coal	23,400 tpd[b]	Solid waste	1,650 tpd
Water	25 mmgpd[c]	Air emission	63.0 tpd
Nickel	1,000 pounds per 4 months	Sulfur	100 tpd
		Ammonia	150 tpd
		Benzene, Toluene and Xylene	25,000 gpd

Source: Hittman, 1975: Vol. II.

[a]250-mmcf-per-day production using Northwest coal of 8,780 Btu's per pound, 6.77-percent ash, and 0.85-percent sulfur.

[b]tons per day.

[c]millions of gallons per day.

TABLE 1-39

INPUTS AND OUTPUTS FOR A CO_2 ACCEPTOR PROCESS[a]

Input	Quantity	Output	Quantity
Coal	22,700 tpd[b]	Solid waste	3,440 tpd
Water	23.7 mmgpd[c]	Air emission	42.4 tpd
Nickel	1,000 pounds per 4 months	Ammonia	137 tpd
Dolomite	1,260 tpd	Sulfur	197 tpd

Source: Hittman, 1975: Vol. II.

[a]250-mmcf-per-day production using Northwest coal of 8,780 Btu's per pound, 6.77-percent ash, and 0.85-percent sulfur.

[b]tons per day.

[c]millions of gallons per day.

used as the oxidizing agent in the gasifier vessel, oxygen does not have to be supplied. These advantages must be balanced with the complexity of plant design for the dolomite regeneration system. Materials inputs for the plant are listed in Table 1-39.

1.9.1.1.6 Underground Coal Gasification

The feasibility of gasifying coal underground by heating it in place and introducing air in deep beds for combustion is being tested experimentally at the present time. This system would involve drilling inlet wells for air injection and one or more outlets for the removal of low-Btu gas. An essential factor is establishing permeability in the coal to be gasified so that the flow of hot gases can be maintained. This permeability could rely on natural cracks within coal beds or could be established by artificially fracturing the beds using explosions or methods developed for oil wells (BuMines 1973: 40).

Although a number of problems need to be solved in underground gasification (including establishing suitable control of the combustion process), production of 150 Btu's per cf of gas has been maintained. One hypothetical configuration of an underground gasification system is diagrammed in Figure 1-38 where inclined and horizontal well holes are used for the injection and removal of gases. Combustion proceeds along a horizontal plane to alternately spaced producing holes (BuMines 1973: 41).

1.9.1.2 Liquid Fuels

There are several methods for producing a liquid fuel from coal. As with gasification, either hydrogen has to be added or carbon removed from the compounds in the coal. In bituminous coal, for example, the carbon-to-hydrogen ratio by weight is about 16:1; in fuel oil, it is about 6:1 (Interagency Synthetic Fuels Task Force, 1974: 12). Although liquefaction is a complex process, it can be viewed as a change in the carbon-to-hydrogen ratio that can be accomplished using one of three reactions: hydrogenation, pyrolysis, or catalytic conversion (Figure 1-39).

In hydrogenation, hydrogen is introduced to react with the coal, either as a gas in the presence of a catalyst or in the form of a hydrogen-rich solvent. If a solvent is used, it donates hydrogen to the coal and is then removed after the reaction has taken place, carrying with it ash and inorganic sulfur from the coal. If gaseous hydrogen is used, the products include liquids, gases, and solids.

Pyrolysis depends on heating the coal in the absence of an oxidizer until it decomposes, producing a liquid hydrocarbon, gases, and char. The char is primarily carbon withdrawn from the coal to allow the remaining carbon-to-hydrogen ratio to reach the liquefaction level.

A further alternative is to produce synthesis (intermediate-Btu) gas, then combine the hydrogen and carbon monoxide in the presence of a catalyst to produce a liquid fuel. For this catalytic conversion, the synthesis gas must be cleaned and shifted to the proper hydrogen-to-carbon monoxide ratio before the liquefaction can take place.

For any of these alternatives, there are a variety of specific technologies that might be used. Different combinations of reactor temperatures and pressures can also be used, and examples of each are identified in Table 1-40. However, only the catalytic conversion methods are in commercial operation. In general, these technologies differ sharply from gasification processes in their use of recycled gas and liquid products for a number of purposes. In any case, the processes usually include one of the liquefaction steps described, plus a cleaning step for sulfur removal and treatment of the product to improve its quality.

1.9.1.2.1 Synthoil

In the Synthoil process, developed by BuMines, crushed coal is slurried in recycled product oil, preheated, and introduced (along with turbulently flowing hydrogen) into a reactor containing a fixed bed of cobalt molybdate catalyst (Figure 1-40). Reactor temperature is 850^{o}F and pressure is 2,000 to 4,000 psi. A transfer of hydrogen to the coal takes place in the reactor, yielding oil and releasing gases. The coal products are then removed and the liquid, gas, and solids are separated. Some of the oil is recycled, but the remainder is a synthetic oil product ready for

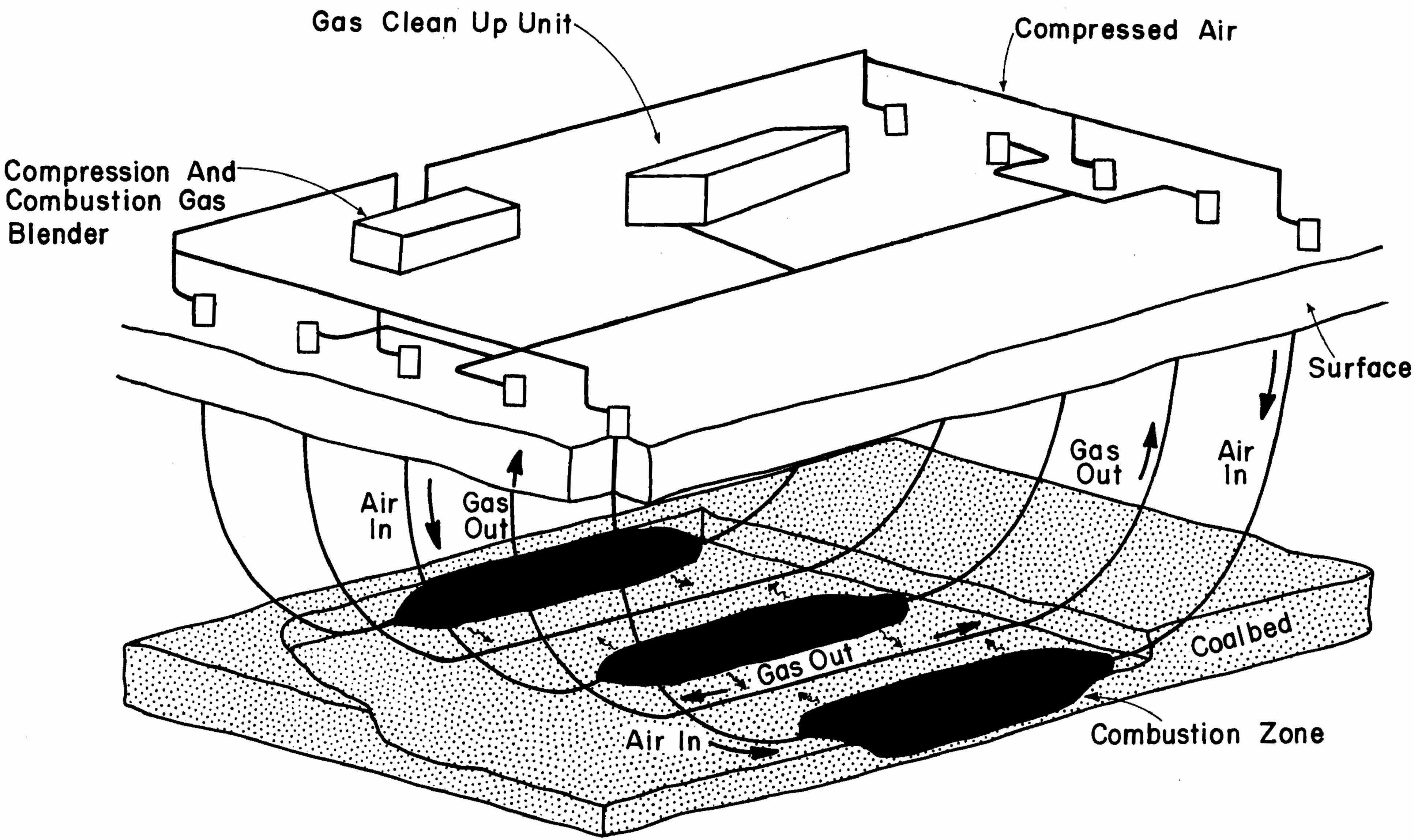


Figure 1-38. Longwall Generator Concept for Underground Coal Gasification

Source: BuMines, 1973: 41.

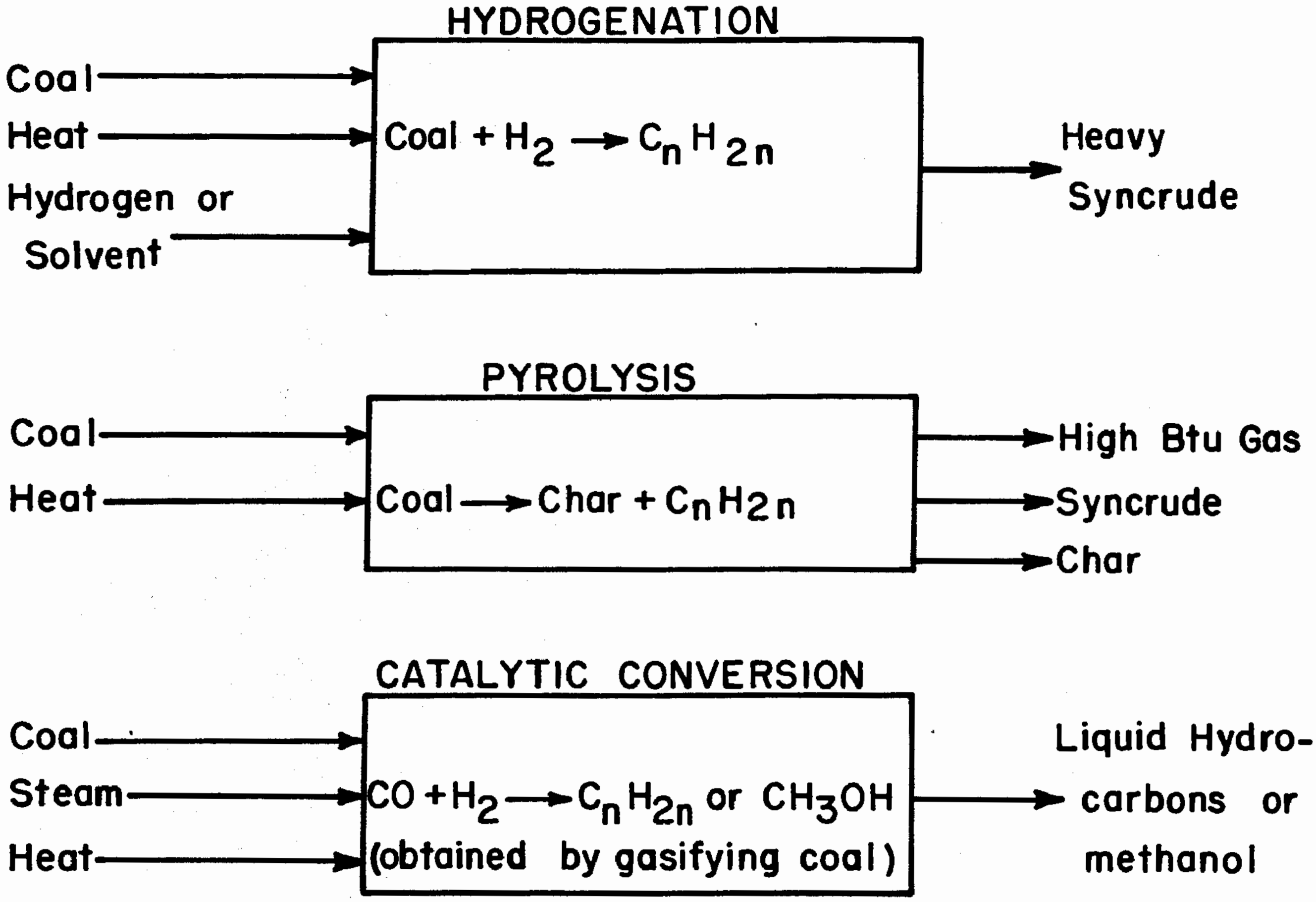


Figure 1-39. Principal Coal Liquefaction Reactions and Processes

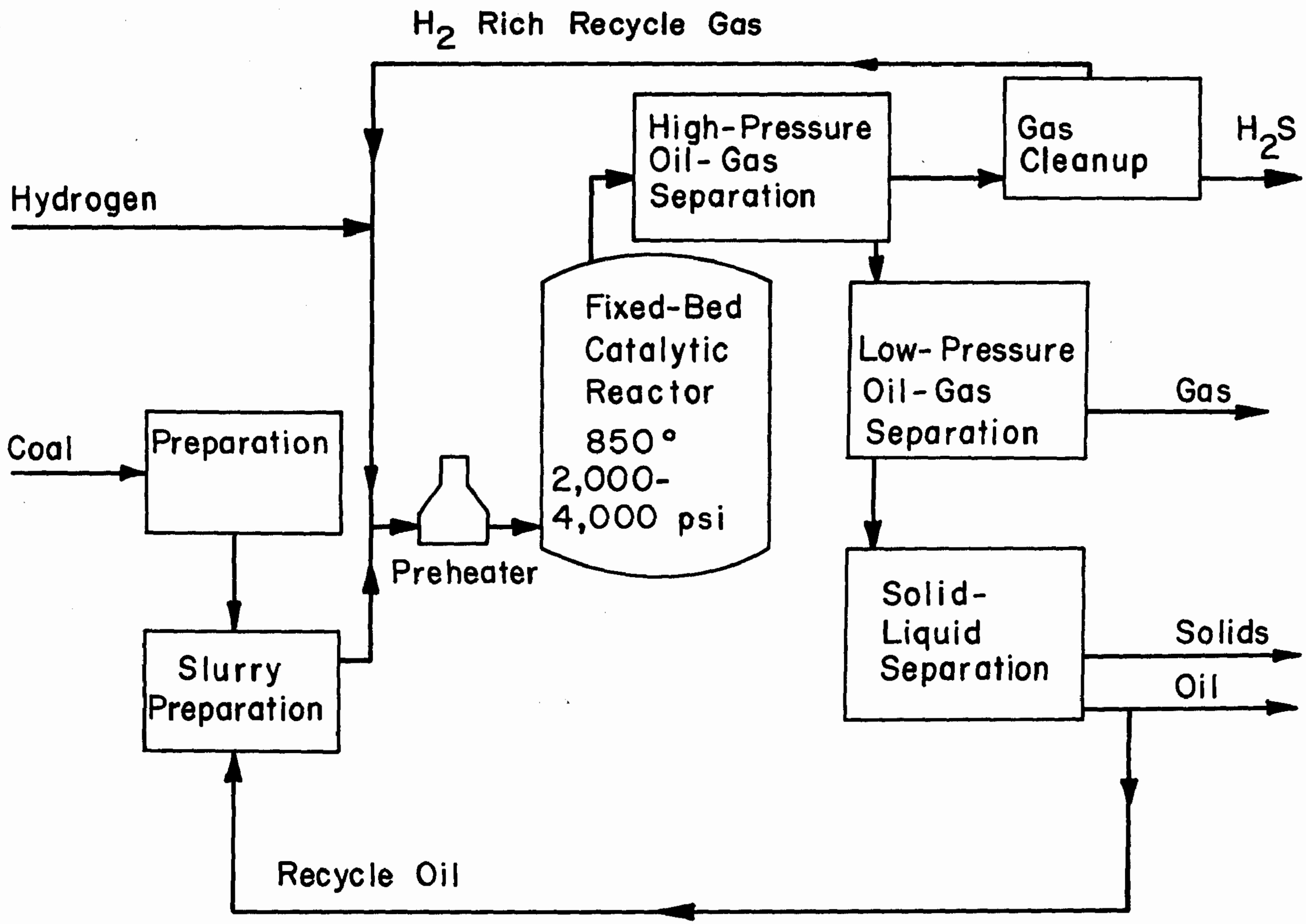


Figure 1-40. Synthoil Coal Liquefaction Process

Source: Adapted from Bodle and Vyas, 1973: 82.

TABLE 1-40

CHARACTERISTICS OF COAL LIQUEFACTION TECHNOLOGIES

Process	Coal Feedstock	Reactor Temperature ($^{\circ}$F)	Reactor Pressure (pounds per square inch)	Product Oil Grade ($^{\circ}$API)	Heating Value of Oil (Btu's per pound)	Yield (barrels per ton of coal)
Hydrogenation						
Synthoil	Pulverized, dried, caking or noncaking	850	2,000 to 4,000	NA	17,700	3.0
H-Coal	Pulverized, dried, caking or noncaking	nominally 850	2,700	5 to 17	U[a]	4.4
Solvent Refined Coal	Pulverized, dried, caking or noncaking	800	1,000	U	U	U
Consol Synthetic Fuel	Pulverized, dried, caking or noncaking	800	1,000	U	U	U
Pyrolysis						
COED	Pulverized, dried, caking or noncaking[b]	600 to 1,600 in four reactors	6 to 10	25	U	1.0 to 1.5
TOSCOAL	Pulverized, dried, caking or noncaking	970	Atmospheric	6 to 13	16,000	0.5
Catalytic Conversion						
Fischer-Tropsch	Depends on gasification process	Two reactors at different temperatures	330 to 360	Various	Various	U
Methanol	Depends on gasification process	U	U	U	U	U

U = unknown.

[a]Different coal feedstocks may require a greater number of pyrolysis feedstocks.

[b]One reported run; lower temperatures give lower yield of liquids.

use as a fuel oil or for further refining into other petroleum products.

In addition to the energy for pressurization, inputs are coal, hydrogen, a start-up slurry medium, the catalyst, and cooling water. Water requirements for cooling and other purposes are expected to be about 20,000 acre-feet of water per year for a 100,000-barrel-per-year plant. This requirement is apparently applicable to the liquification plants described below (Davis and Wood, 1974: 12). In addition to the fuel oil, outputs are hydrogen sulfide, ammonia, and other gases, along with ash and other solid residues. Approximately three barrels of oil are produced from each ton of coal in the pilot plant.

1.9.1.2.2 H-Coal

In the H-Coal process, a pretreated hydrogen-enriched slurry of pulverized coal in oil is introduced into a reactor containing a catalyst at 2,700 psi and 850°F (Figure 1-41). The cobalt molybdate is continuously added and withdrawn to maintain its catalytic activity. Liquefied coal and ash residues leave the reactor in the slurry along with some gases. The slurry is rapidly depressurized, causing most of the liquid to vaporize and separate from the residues. The vapor then goes through an atmospheric distillation step where the remaining heavy slurry is processed by vacuum distillation to separate recyclable oil from a char-rich bottom slurry product. The technology is notable for its application of conventional petroleum refining operations, building into the operation several different distillation processes.

Inputs at the pilot plant stage are the same as for Synthoil; outputs are similar as well, but H-Coal has the capability of producing liquids of more than one grade at the same time. The other principal difference between the two processes is in the specific internal dynamics of the catalytic reactors.

1.9.1.2.3 Solvent Refined Coal

In the Solvent Refined Coal (SRC) process, crushed coal is slurried with a hydrogen donor solvent and exposed to 1,000 psi and 800°F in a hydrogen atmosphere (Figure 1-42). Under these conditions, the coal dissolves into the solvent and picks up hydrogen. The solution is filtered, removing most of the ash and some undissolved coal. The remainder is a liquid containing solvent, dissolved coal, and a light oil--a product of the reaction of coal with hydrogen. In a vacuum-flash operation, the pressure of the mixture is reduced quickly, the solvent boils off, and a material is left which solidifies at about 350°F. This solid has a considerably lower ash and sulfur content than the original coal. A variety of other products result as well, including fuel oils and high-Btu gas. To manufacture a predominately liquid product, an additional hydrogenation step is necessary.

An SRC pilot plant is under construction, but it will not include the second hydrogenation step required to produce a liquid product.

1.9.1.2.4 Consol Synthetic Fuel

The Consol Synthetic Fuel (CSF) process is a solvent extraction process coupled with a catalytic hydrogenation step and hydrogen manufacture in a Lurgi gasifier. The solvent extraction is carried out under conditions very similar to those of the SRC process above, and the catalytic hydrogenation is done under conditions similar to those used in the H-Coal process (Figure 1-43).

Parts of the CSF process have been evaluated in pilot plant operations. The solvent extraction has been tested in a 20-ton-per-day pilot plant in West Virginia, and the catalytic hydrogenation process has been operated commercially in a 15,000-barrel-per-day plant in Kuwait.

At the pilot stage, the CSF process is designed to have coal and water as its only inputs and to produce boiler fuel, distillate

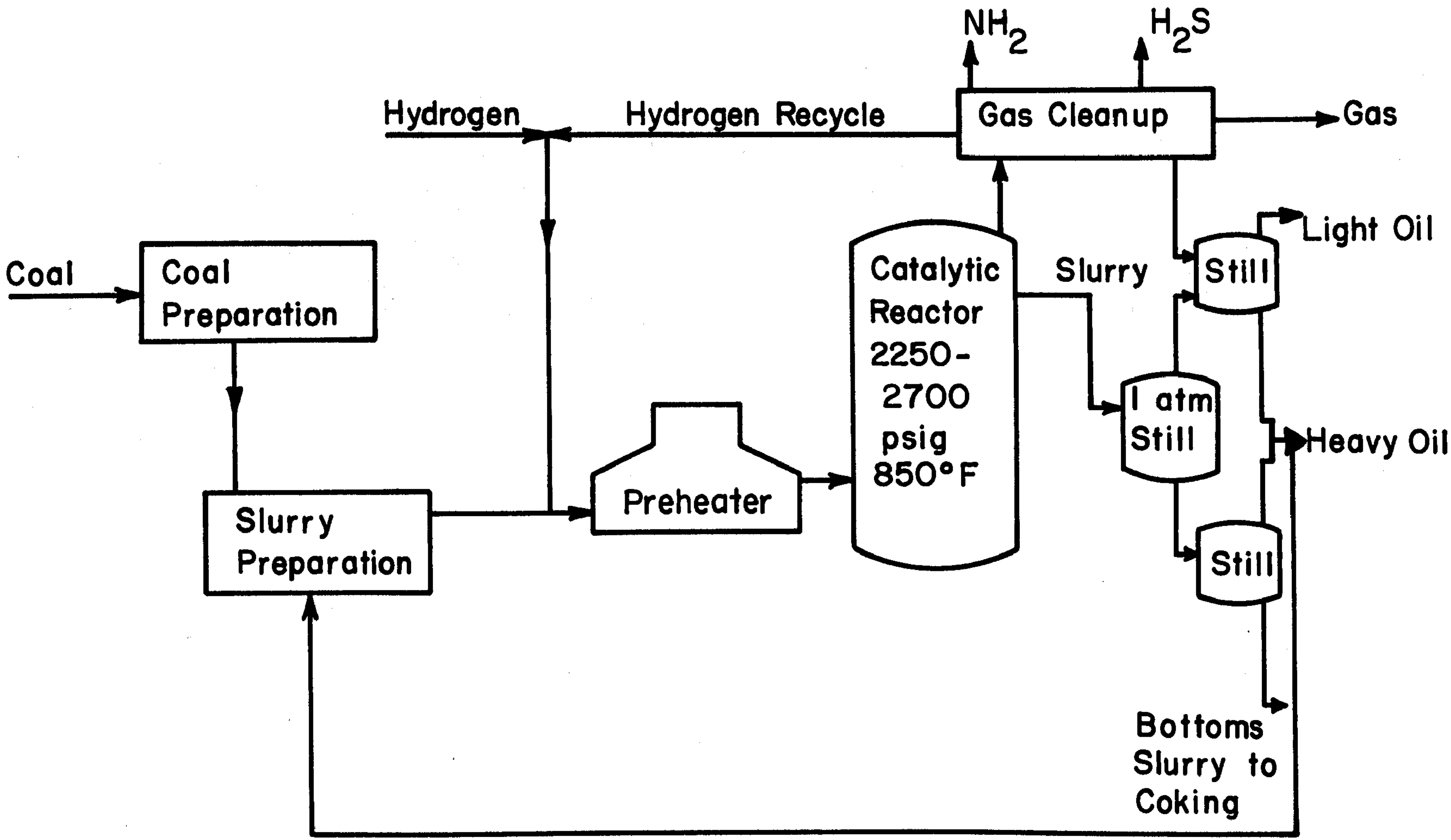


Figure 1-41. H-Coal Coal Liquefaction Process

Source: Adapted from Bodle and Vyas, 1973: 84.

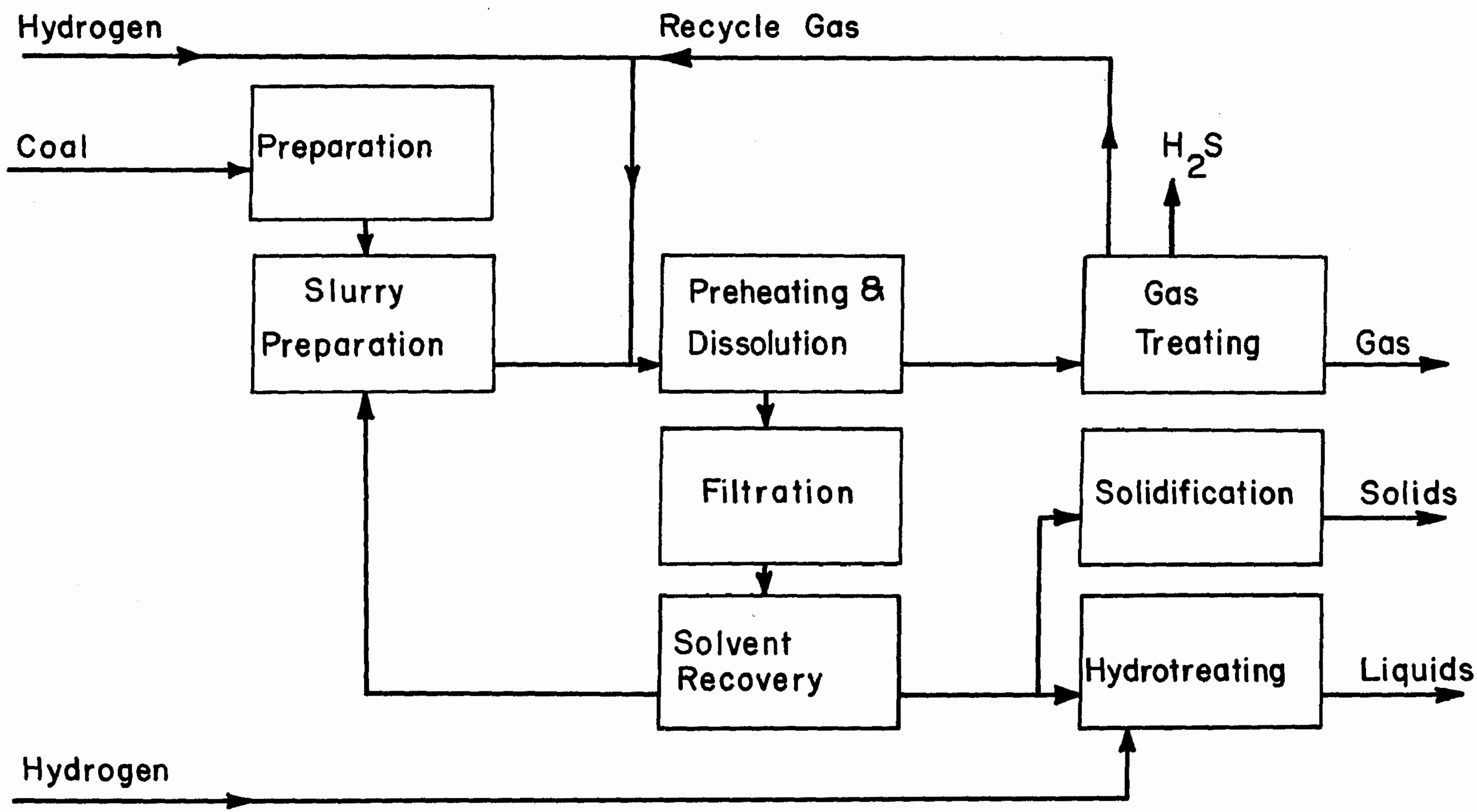


Figure 1-42. Solvent Refined Coal Process

Source: Adapted from Bodle and Vyas, 1973: 88.

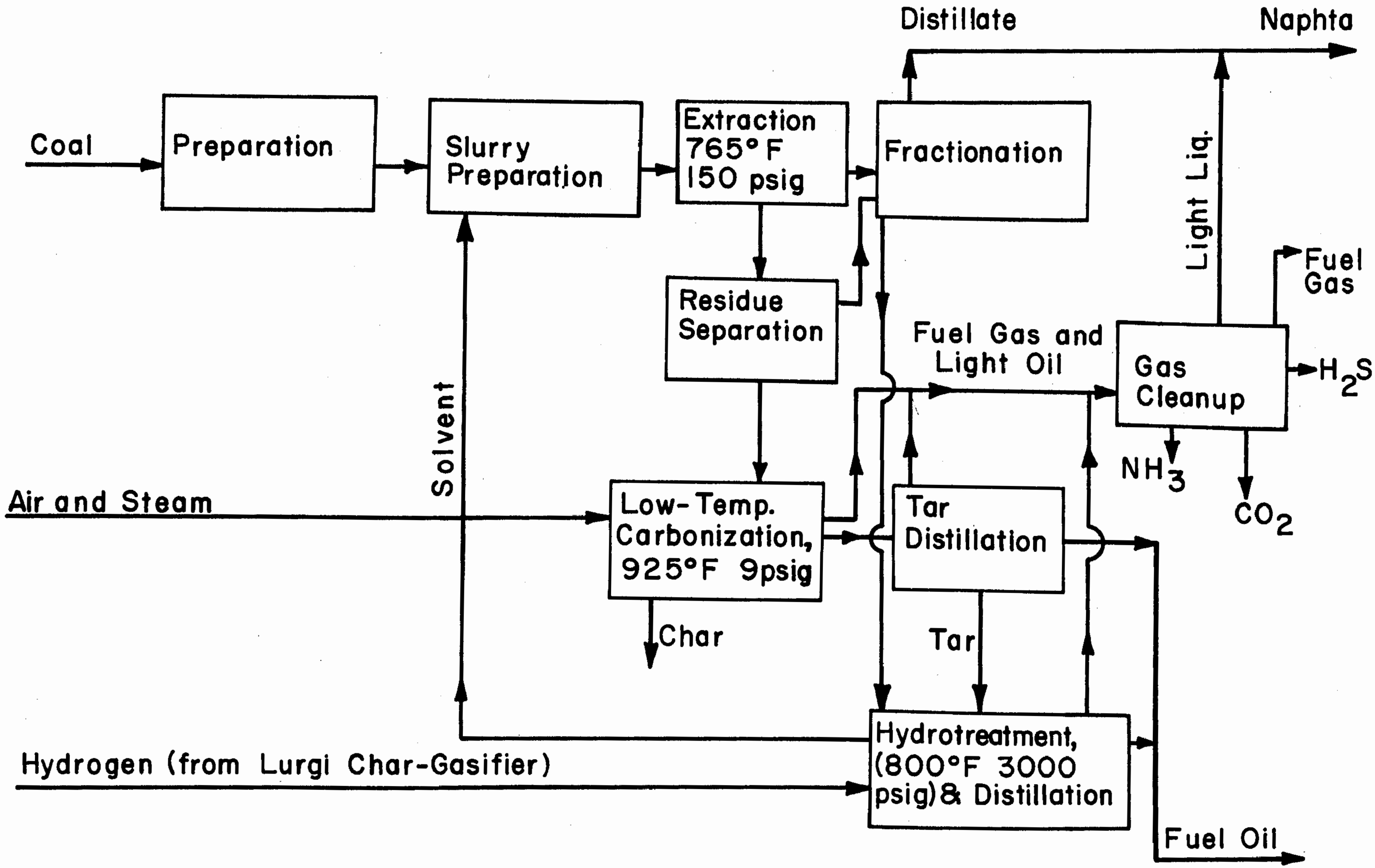


Figure 1-43. Consol Synthetic Fuel Process

Source: Adapted from Bodle and Vyas, 1973: 86.

fuel, liquefied petroleum gas, and high-Btu gas as primary outputs, with ash, hydrogen sulfide, and ammonia as waste outputs.

1.9.1.2.5 COED

COED is a pyrolysis process in which crushed coal is exposed to progressively higher temperatures in four successive fluidized-bed reactors (Figure 1-44). For example, with a particular coal the sequence is from 600 to 850 to 1,000 to 1,600°F (Bodle and Vyas, 1973: 78,79). The specific sequence of temperatures and number of reactors are dependent on the caking quality of the coal; coals with high-caking properties require more reactors with smaller temperature differences. Char from the first reactor flows toward the hotter reactors while steam and oxygen, introduced into the last reactor, flow counter-current, activating the fluidized-beds in the second and third reactors. Staging the temperature increase allows volatile liquids to be drawn off as they are produced, maximizing liquid yield and avoiding agglomeration of the char before most of the hydrocarbons have been removed. The tar-like product oil (mostly evolved in the second stage) is treated with hydrogen (hydrotreated) to remove sulfur and upgrade it to a synthetic crude oil. An intermediate-Btu gas (about 500 Btu's per cf after cleaning) and char are also produced by the pyrolysis process.

At the pilot plant stage, about one barrel (bbl) of oil per ton of coal has been produced together with 8,000 to 10,000 cf of gas and about 1,180 pounds of char. Inputs to the process are 55 pounds of steam and 375 cf of oxygen per ton of coal (Jones, 1973: 390). Oxygen-free flue gas needed for the first stage and hydrogen needed for the hydrotreater are assumed to be generated internally in a commercial plant. Outputs (in addition to the crude oil, intermediate-Btu gas, and char which have energy value) are hydrogen sulfide and vent gas.

1.9.1.2.6 TOSCOAL

The TOSCOAL process is a pyrolysis process which uses externally heated ceramic balls to provide heat. It is similar to a process developed by The Oil Shale Corporation (TOSCO) to retort oil shale. The crushed, preheated coal is introduced into a rotating pyrolysis drum where it is heated by contact with separately heated ceramic balls (Figure 1-45). This treatment produces gases (including vaporized hydrocarbon liquids and water vapor) and large quantities of char.

When separated from the gaseous products, the liquids can be refined like crude oil, and the gases are burned in the ball heater.

Inputs for the pilot plant are coal, ceramic balls, and air. Outputs are hydrocarbon liquids, char, hydrogen sulfide, and relatively large amounts of water. A distinctive feature of the process is the heating value left in the char, about 80 percent of the heating value of the raw coal. The oil yield is low, only about half a barrel per ton of coal, but 970 pounds of char per ton of coal are produced as well. In experiments at the pilot plant, this char had a heating value of 13,000 Btu's per pound. Water yield from the gasification steps is about 700 pounds per ton of coal (Bodle and Vyas, 1973: 81).

1.9.1.2.7 Fischer-Tropsch

The Fischer-Tropsch process is a catalytic conversion system which produces hydrocarbon liquids from coal-derived, intermediate-Btu synthesis gas. The process is in commercial operation in South Africa where a Lurgi gasifier is used to produce the synthesis gas. The gas from the Lurgi gasifier is cleaned of hydrogen sulfide, carbon dioxide, and impurities, then shift-converted before it enters a catalytic reactor which produces hydrocarbon liquids (Figure 1-46). In this plant, two reactors, using different catalysts and temperatures, process gases with

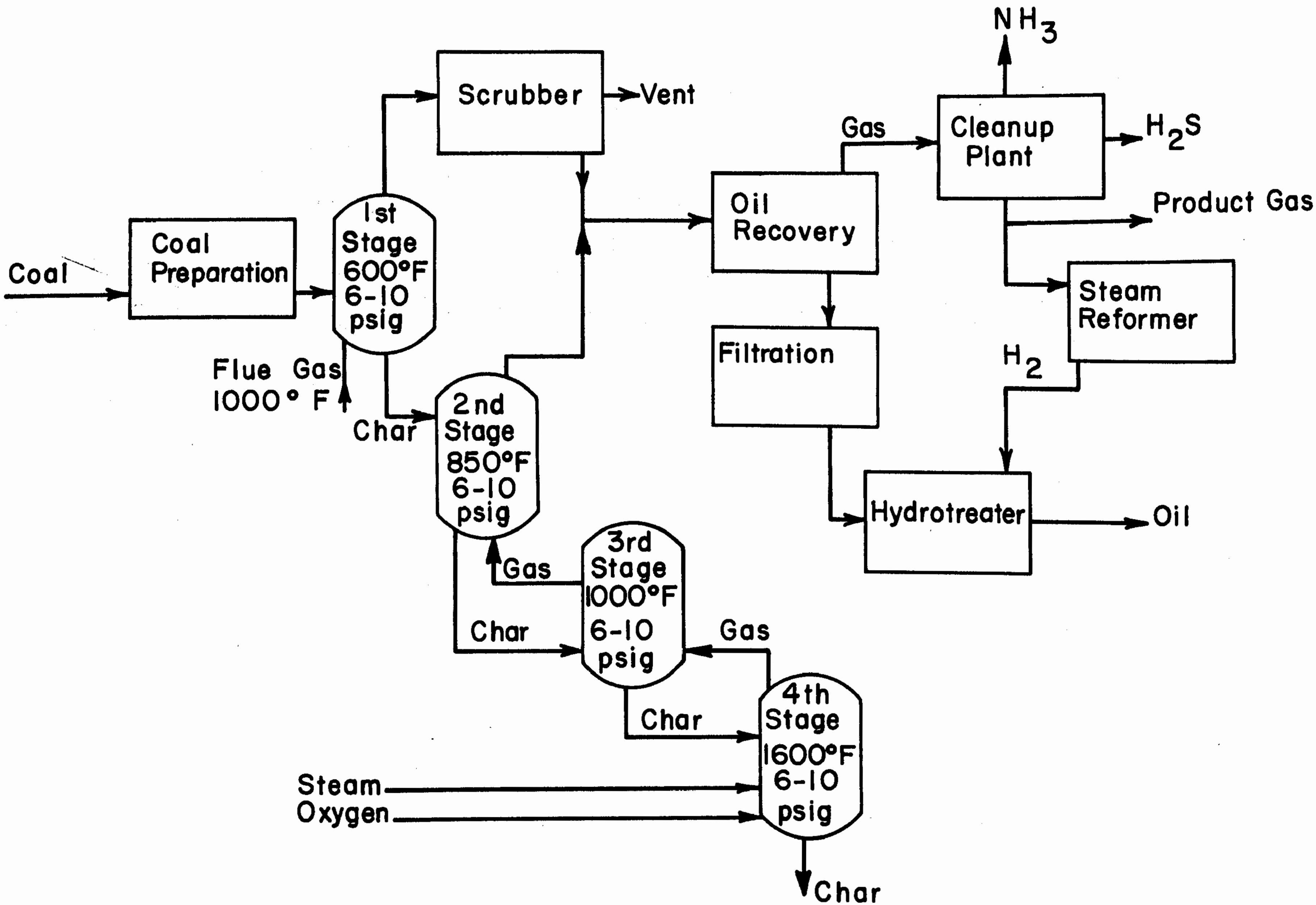


Figure 1-44. COED Coal Liquefaction Process

Source: Adapted from Bodle and Vyas, 1973: 78.

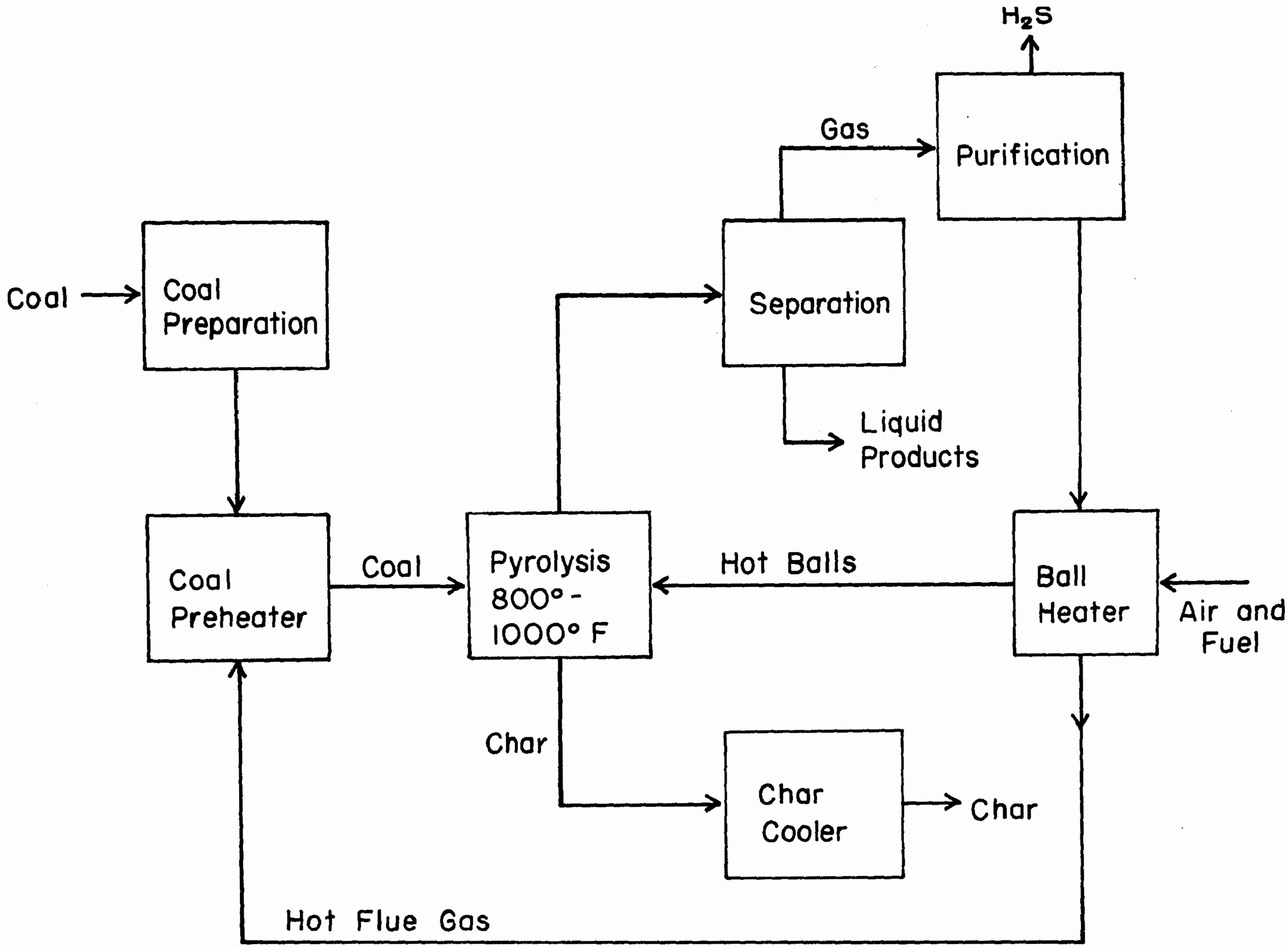


Figure 1-45. TOSCOAL Coal Liquefaction Process

Source: Adapted from Bodle and Vyas, 1973: 80.

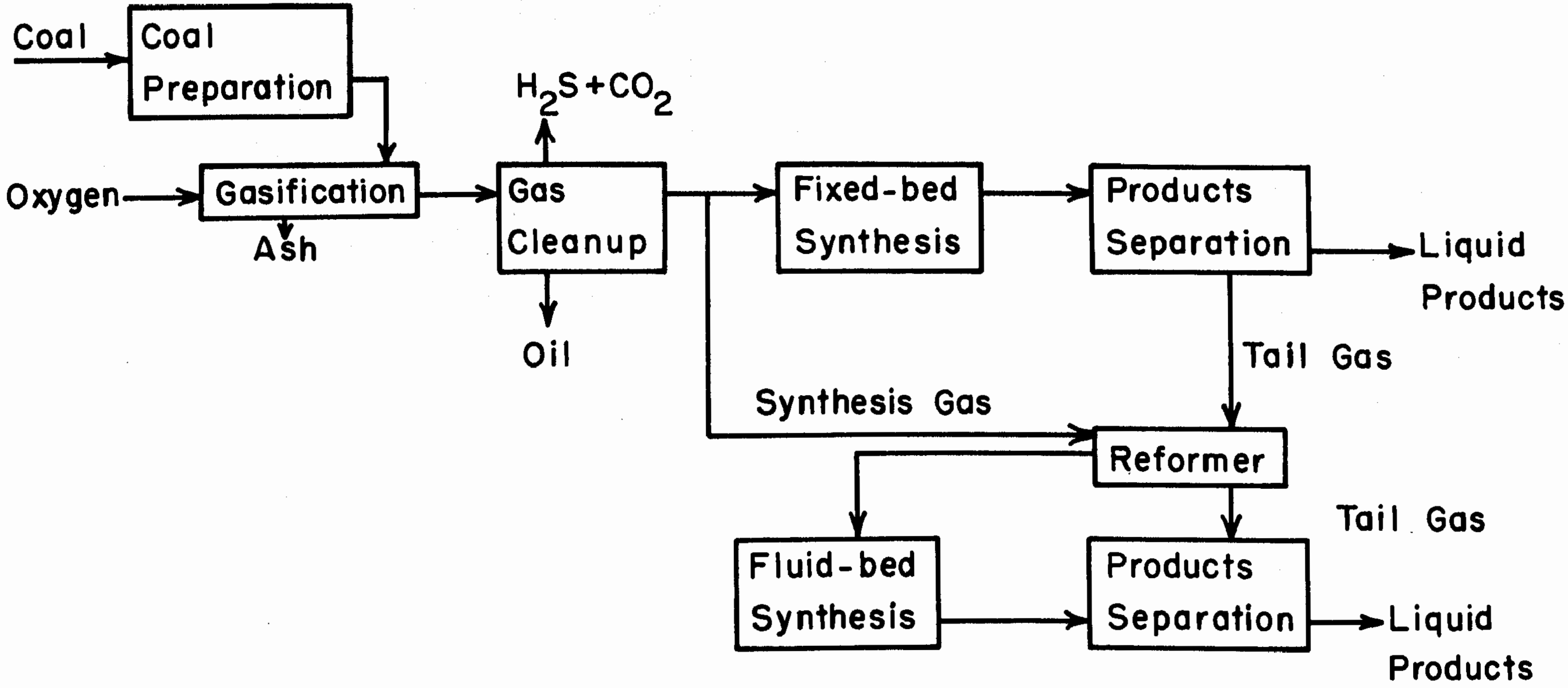


Figure 1-46. Fisher-Tropsch Coal Liquefaction Process

Source: Adapted from Bodle and Vyas, 1973: 76.

different carbon-to-hydrogen ratios into different products. Reactor products include gasoline, diesel/other fuel oils, waxes, alcohols, and ketones.

The South African plant has a capacity of 6,600 tons of coal per day. The inputs are coal and cooling water, and the outputs, as mentioned above, are quite diverse. The principal advantage of the process is that it has been demonstrated commercially. Its main drawbacks are that a great deal of reaction heat is produced (posing a major cooling requirement) and that the process is relatively expensive.

1.9.1.2.8 Methanol

Methyl alcohol (methanol) is manufactured commercially from synthesis gas in a catalytic reactor. Consequently, methanol can be derived from coal if the coal is gasified to produce intermediate-Btu synthesis gas. This is not now being done, but all the process steps involved have been demonstrated commercially. The synthesis gas must be shift-converted to the proper carbon-to-hydrogen ratio and the proper catalyst used. When this is done, methanol becomes an alternative product from any process that can produce high-Btu gas.

1.9.1.3 Solvent Refined Solid Fuels

The Solvent Refined Coal process described above has been proposed to transform a high-sulfur feedstock coal to manufacture a lower sulfur solid which could then be used as a boiler fuel. A pilot plant is being built to test the feasibility of this process.

1.9.2 Energy Efficiencies

Data in Table 1-41 are taken from Hittman. Hittman describes most of these data as "good" with a probable error of less than 25 percent. Ancillary energies for all low-Btu gasification technologies are described as less reliable, with the probable error being less than 50 percent. Differences in efficiencies by plant location are based on process inputs and outputs when fed coal from selected hypothetical mines.

1.9.2.1 Gaseous Fuels

1.9.2.1.1 Low-Btu Gasification

Primary efficiencies for low-Btu gasification processes range from 73 percent for the Westinghouse process to 95 percent for the BuMines pressurized process. Ancillary energy represents the power requirements for fuel gas production, cooling, and treating. All ancillary energy is consumed in the form of electricity. Overall efficiencies range from 65 to 80 percent. Since their ancillary energy requirements are an order of magnitude higher than for the other gasification technologies, the BuMines processes are lowest in overall efficiency. Given the questionable quality of the data, however, differences among the technologies and areas may not actually exist.

1.9.2.1.2 High-Btu Gasification

In high-Btu gasification processes, primary efficiencies range from 54 to 68 percent, with BI-GAS appearing to be the most efficient. Using Central area coal, which has a high heat content, also appears more efficient. However, these data are of questionable quality and the indicated variations in the data among areas and processes may not reflect actual differences in the technologies or locations.

Ancillary energy requirements are zero because the processes are self-sustaining with process heat requirements generated on site.

1.9.2.2 Liquid Fuels

In Table 1-41, the CSF process appears to be more efficient than the SRC process. Although no area variations are obvious, Hittman's calculations were based on Central coal and assume that Appalachian and

TABLE 1-41

COAL PROCESSING EFFICIENCIES

Process	Primary Efficiency (percentage)			Ancillary Energy Needs[a] (10^9 Btu's per 10^{12} Btu's)			Overall Efficiency (percentage)		
	Appalachia	Central	Northwest	Appalachia	Central	Northwest	Appalachia	Central	Northwest
Low-Btu Gasification									
Lurgi	NC	NC	75.8	NC	NC	27.8	NC	NC	73.7
Koppers-Totzek	82.0	81.1	74.4	14.8	14.4	13.4	80.8	80.0	73.4
BuMines Atmospheric	78.5	78.3	73.3	84.9	96.9	126.6	72.4	71.4	65.0
BuMines Pressurized	73.4	73.0	73.3	85.8	98.1	128.4	67.6	66.5	65.0
Westinghouse[b]	NC	95.0	NC	NC	NC	NC	NC	95.0	NC
Agglomerating fluidized bed	81.8	NC	NC	NC	NC	NC	NC	NC	NC
High-Btu Gasification							Same as Primary Efficiency		
Lurgi	NC	54.1	60.5	0	0	0			
HYGAS-Steam-Oxygen	58.7	63.7	58.8	0	0	0			
BI-GAS	65.4	67.4	68.2	0	0	0			
Synthane	53.5	58.0	58.4	0	0	0			
CO_2 Acceptor	NC	NC	62.5	0	0	0			
Liquefaction							Same as Primary Efficiency		
Consol Synthetic Fuel Process	69.1	69.1	69.1	0	0	0			
Solvent Refined Coal Process[d]	62.5	62.5	62.5	0	0	0			
Solvent Refined Solids									
Solvent Refining	76.8	68.6	NC	76.6	68.1	NC	71.3	64.2	U

NC = not considered, U = unknown.

Source: Hittman, 1975: Vol. II.

[a]Ancillary energy values are three times the Hittman values which accounts for conversion of electricity to Btu at an average heat rate of 10,500 Btu's per kwh (rather than 3,400 Btu's per kwh used by Hittman). Ancillary energy values for high-Btu technologies are zero as all energy inputs are assumed to be supplied by input coal.

[b]Data from Westinghouse Corporation.

[c]Battelle estimates the primary efficiency to be 66 percent, location not specified (Battelle, 1973: 102).

[d]Battelle estimates 75-percent primary efficiency, which apparently does not include process heat (Battelle, 1973: 78).

Northwestern coals would produce the same results.

The ancillary energy requirement is zero because the process is self-sustaining with all power and steam requirements generated on site. The best overall efficiency is 69 percent for the CSF process.

1.9.2.3 Solvent Refined Solids

Primary efficiency for solvent refining appears higher for Appalachian coal than for Central coal (Table 1-41). However this may not be accurate because coal with a heating value of 12,000 Btu's per pound was used in both estimates.

The ancillary energy source was assumed to be natural gas and was calculated using 13,800 Btu's per pound for Central coal and 12,000 Btu's per pound for Appalachian coal. Primary efficiency is in the 70- to 75-percent range, and overall efficiency is in the 65- to 70-percent range.

1.9.2.4 Summary

High-Btu gasification and liquefaction are generally less efficient than low-Btu gasification or the production of solvent refined coal (Table 1-42). However, low-Btu gas and solvent refined coal are not ready for consumer use as these are feedstocks for electric power generation. Thus, depending on the overall trajectory, low-Btu gasification or solvent refining may have a low efficiency.

TABLE 1-42

SUMMARY OF OVERALL COAL PROCESSING EFFICIENCIES

Process	Efficiency (percent)
Solvent refined solids	65 to 70
Liquefaction	62 to 69
Low-Btu gasification	65 to 95
High-Btu gasification	54 to 68

1.9.3 Environmental Considerations

Residuals data are drawn from the Hittman, Battelle, and Teknekron studies. Hittman's data assume maximum environmental control; for example, it is assumed that water is recycled and that no effluent leaves the facility. The data have an error of less than 50 percent. The Battelle and Teknekron data are often based on technologies that provide more limited environmental control, and this is reflected in higher values for environmental residuals.

1.9.3.1 Gaseous Fuels

1.9.3.1.1 Low-Btu Gasification

Residuals for five low- to intermediate-Btu gasification processes, using coal from several areas, are given in Table 1-43. Table 1-44 summarizes important pollutants.

1.9.3.1.1.1 Water

Since all water is assumed to be recycled or placed in evaporation ponds, all water pollutants are zero. Potential sources of water effluent are from boiler blowdown, the raw gas cooling system, and overfill of the water clarifier. For example, boiler blowdown water from the Koppers-Totzek process contains 40 ppm suspended solids, 30 milligrams per liter Biochemical Oxygen Demand (BOD), and 25 milligrams per liter Chemical Oxygen Demand (COD). Both boiler blowdown water and water from raw gas cooling will be routed to a clarifier. Clarified water containing about 250 ppm total dissolved solids is filtered, treated, and recycled. For every 10^{12} Btu's of coal gasified, 1.3 million gallons of water will be produced from boiler blowdown. Additionally, the clarifier will require 80 gallons per minute in make-up water because of evaporation losses in quenching the ash from the gasifier (Hittman, 1975: Vol. II, footnote 8090).

1.9.3.1.1.2 Air

Major air emissions (Table 1-44) result from the sulphur recovery processes, an ammonia sulfate plant for the two BuMines

Table 1-43. Residuals for Low- to Intermediate-Btu Coal Gasification

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	$^F/_I$ [a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
CENTRAL COAL																					
BuMines																					
Atmospheric	0	0	0	0	0	0	0	0	0	0	0	0	20.7	0	0	0	7060.	.58/.04 1.07	U	U	U
Pressurized	0	0	0	0	0	0	0	0	0	0	0	0	24.	0	0	0	7060.	.96/.04 .998	U	U	U
Koppers-Totzek	0	0	0	0	0	0	0	0	0	0	4.97	270.	41.2	290.	195.	0	8430.	.12/.96 12.1	U	U	U
NORTHERN APPALACHIAN COAL																					
BuMines																					
Atmospheric	0	0	0	0	0	0	0	0	0	0	0	0	39.5	0	0	0	5060.	.48/.03 .815	U	U	U
Pressurized	0	0	0	0	0	0	0	0	0	0	0	0	39.5	0	0	0	5060.	.2/.04 .75	U	U	U
Koppers-Totzek	0	0	0	0	0	0	0	0	0	0	0	0	8.21	0	0	0	5410.	.11/.32 3.98	U	U	U
NORTHWEST COAL																					
BuMines																					
Atmospheric	0	0	0	0	0	0	0	0	0	0	0	0	12.	0	0	0	3460.	.42/0 .42	U	U	U
Pressurized	0	0	0	0	0	0	0	0	0	0	0	0	14.1	0	0	0	3460.	.42/0 .42	U	U	U
Koppers-Totzek	0	0	0	0	0	0	0	0	0	0	5.42	5.15	17.6	5.5	3.71	0	3460.	.11/0 .11	U	U	U
Lurgi	0	0	0	0	0	0	0	0	0	0	0	0	3.32	0	0	0	3460.	1.66/0 1.66	U	U	U

Table 1-43. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	$^F/_I$[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
EASTERN COAL																					
Agglomerating Fluidized Bed[b]	0	0	0	0	0	0	0	0	0	0	69.	11.3	22.5	0	6.5	0	6500.	0	NC	NC	NC

NC = not considered, U = unknown.

[a]Fixed Land Requirement ($\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}$) / Incremental Land Requirement ($\frac{\text{Acres}}{10^{12}\text{ Btu's}}$).

[b]Teknekron, 1973: 132.

TABLE 1-44

SUMMARY OF LOW- TO INTERMEDIATE-BTU GASIFICATION POLLUTANTS

Process	Water	Air (tons per 10^{12} Btu's input)		Solids[b] (tons per 10^{12} Btu's)
		Sulfur Oxides[a]	Other	
BuMines Atmospheric	0	12 to 40	0	3,500 to 7,000
BuMines Pressurized	0	14 to 40	0	3,500 to 7,000
Koppers-Totzek	0	18 to 41	12.5[c]	3,500 to 8,500
Lurgi	0	3.3	0	3,500

Source: Hittman, 1975: Vol. II, Table 1.

[a]Variation due to the sulfur content difference in coal; only Northwest coal is used in the Lurgi calculation.

[b]Variation due to the ash content difference in coal; only Northwest coal is used in the Lurgi calculation.

[c]Includes 40-percent particulates, 20-percent oxides, 23-percent hydrocarbons, and 17-percent carbon monoxide.

processes and a Claus plant* for the Koppers-Totzek processes (Hittman, 1975: Vol. II, pp. III-19, III-21, III-28). Regional differences in sulfur dioxide emissions result from variations in the sulfur content of the coal. Northwest coal is lowest and Northern Appalachian coal highest in sulfur content. Sulfur dioxide emissions from the ammonia sulfate plant used in the BuMines processes range from 12 to 40 tons per 10^{12} Btu's processed. Emissions are lowest from the Lurgi system, 3.3 tons per 10^{12} Btu's processed.

In addition to sulfur dioxide, emissions from the Koppers-Totzek system include particulates, nitrous oxides, hydrocarbons, and carbon monoxide (Table 1-44). These other air pollutants are emitted from the coal-fired thermal dryer. Large quantities of particulates from the agglomerating gasifier are dolomite dust from the desulfurization step which follows gasification (Teknekron, 1973: 132).

1.9.3.1.1.3 Solids

The solid waste generated by low-Btu gasification ranges from 3,500 to 8,500 tons for each 10^{12} Btu's of coal processed (Table 1-44). This value includes only ash removed from the combustor. The lowest value is for Northwest coal, which has the lowest (6.4-percent) ash content, and the highest is for Central coal, which has the highest (17.3-percent) ash content. Since a typical low-Btu gasification plant would produce about half of the tons per 10^{12} Btu's amount daily, some or all of the waste would require disposal in the mine. If the sulfur recovered in the process cannot be sold, it will also require disposal. The solid waste from a gasifier also contains small quantities of radioactive isotopes. For the agglomerating gasifier discussed by Teknekron (1973: 132), these

*A Claus plant takes emission gas streams containing 10 percent or more hydrogen sulfide and oxides the hydrogen sulfide in the presence of a solid catalyst (either aluminum oxide or bauxite), thus producing elemental sulfur of high purity.

Table 1-45. Environmental Residuals for High-Btu Gasification

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I [a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
HIGH-BTU GASIFICATION																					
Central Coal																					
HYGAS-Steam-Oxygen	U	U	U	U	U	U	U	U	U	0	6.88	68.1	62.9	.895	3.35	.394	5250.	2.75/0 2.75	U	U	U
BIGAS	U	U	U	U	U	U	U	U	U	0	4.75	62.6	81.5	1.	3.35	.423	5340.	3.05/0 3.05	U	U	U
Synthane	U	U	U	U	U	U	U	U	U	0	14.7	111.	51.8	1.86	6.21	.465	5330.	2.67/0 2.67	U	U	U
Lurgi	U	U	U	U	43.1	.9	.426	U	U	0	3.65	73.3	36.8	1.22	4.07	.448	5270.	2.43/0 2.43	U	U	U
Northern Appalachian Coal																					
HYGAS-Steam-Oxygen [b]	U	U	U	U	U	U	U/ .03	U	U	0	3./ 91.	60./ 190.	20./ 400.	.8/ 1.1	2.92	.363	6500./ 24500.	2.53/0 2.53	U	U	U
BIGAS	U	U	U	U	U	U	U	U	U	0	3.66	54.4	17.5	.907	3.02	.409	6560.	2.96/0 2.96	U	U	U
Synthane	U	U	U	U	U	U	U	U	U	0	15.4	99.8	18.7	1.67	5.54	.43	6560.	2.46/0 2.46	U	U	U
Northwest Coal																					
HYGAS-Steam-Oxygen	0	0	0	0	0	0	0	0	0	0	5.71	68.3	5.9	1.15	3.8	.313	3730.	3.75/0 3.75	U	U	U
BIGAS	0	0	0	0	0	0	0	0	0	0	3.42	58.3	14.1	.928	3.1	.301	3840.	4.54/0 4.54	U	U	U
Synthane	0	0	0	0	0	0	0	0	0	0	13.	115.	9.63	1.91	6.37	.354	3830.	3.96/0 3.96	U	U	U
Lurgi	0	0	0	0	0	0	0	0	0	0	2.05	76.9	5.59	1.28	4.27	.292	3730.	3.78/0 3.78	U	U	U
CO_2 Acceptor	0	0	0	0	0	0	0	0	0	0	3.31	38.1	61.7	.595	1.98	.437	8610.	3.16/0 3.16	U	U	U

U = unknown.

[a] Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

[b] Where two numbers occur, the second is taken from Battelle for a HYGAS unit using Eastern coal with an ash content of 14.4 percent and a sulfur content of 3 percent.

TABLE 1-46

SUMMARY OF HIGH-BTU GASIFICATION RESIDUALS

Process	Water	Air (tons per 10^{12} Btu's coal processed)					Solids (tons per 10^{12} Btu's)	Total Land[a] (acres)
		Particulates	Nitrogen Oxides	Sulfur Oxides	Hydrocarbons	Carbon Monoxide		
HYGAS	(Recycled or	3- 7	60- 68	6-63	1	3.5	3,700-6,500	350
BI-GAS	treatment	3- 5	54- 63	14-81	1	3.0	3,800-6,800	350
Synthane	to meet	13-15	100-115	10-52	2	5.0	3,800-6,600	350
Lurgi	standards	2- 4	73- 77	6-37	1	4.0	3,700-5,300	350
CO_2 Acceptor	[Table 1-44])	3	38	62	0.5	2.0	8,600	350

Source: Hittman, 1975: Vol. II, Table 2 and associated footnotes.

[a]Land required is for coal storage, preparation, gasification plant facilities, and evaporation ponds. No additional requirement is assumed for buffer areas surrounding plant facilities (although they would probably be included in a commercial facility, on the order of 1,500 acres).

are 0.00076 curie of radium-226 and 0.0128 curie of radium-228 and thorium-228 and -230 for each 10^{12} Btu's of coal gasified.

1.9.3.1.2 High-Btu Gasification

Table 1-45 gives all residuals as calculated by Hittman for five high-Btu gasification systems and three areas. These are summarized in Table 1-46.

1.9.3.1.2.1 Water

A plant synthesizing 250 mmcf of natural gas per day at 60-percent efficiency will emit 160×10^9 Btu's of waste heat per day. Presumably, most of this will be emitted to the atmosphere through the use of mechanical-draft, wet-cooling towers. These cooling towers will require 20 to 35 million gallons of make-up water each day. Thus, in regions where water is scarce, all process wastewater and impounded runoff (about three million gallons per day) will be treated and used for cooling tower make-up. All blowdown streams are collected and sent to lined evaporative ponds. For this reason, water residuals are zero for the Northwest region (Table 1-45), although settling ponds and process units could rupture or spill into streams or other water courses.

Wastewater treatment will also be required in areas where water is not recycled. Characteristics of untreated wastewater are given in Table 1-47 for the Synthane gasifier unit and the entire Lurgi process. Effluent characteristics from the Lurgi system assume the following treatment: three stages of tar-oil-water separation, filtration, phenol recovery, ammonia recovery in an ammonia still, and activated carbon treatment (Hittman, 1975: Vol. II, p. IV-70).

1.9.3.1.2.2 Air

Air emissions are produced from several by-product streams, but most are from combustion of fuels in the plant boiler and

TABLE 1-47

WASTEWATER CHARACTERISTICS FROM TWO HIGH-BTU COAL GASIFICATION PROCESSES

Parameter	Synthane Gasifier Vessel[a] (parts per million)	Lurgi Process[b]	
		Before Treatment (parts per million)	After Treatment (parts per million)
Thiocyanate	23	0	0
Cyanide	0.23	0	0
Ammonia	9,520	15,900	15.9
Sulfide	U	1,400	1.4
Suspended solids	140	600	33.5
Organics			
Phenols	6,000	9,960	0.498
Oil	0	1,100	15.4
Chemical oxygen demand	43,000	0	0

U = unknown.

Sources: [a]Forney and others, 1974: 3 (Northwest coal).

[b]Hittman, 1975: Vol. II, p. IV (Central Region coal).

the sulfur recovery plant. Stack discharges from the boiler are cleaned with an electrostatic precipitator for particulates and wet scrubbing system for five gases. Emissions are given in Table 1-46 for five air pollutants. For a typical size gasification facility synthesizing 250 mmcf of gas a day, about half the values shown in Table 1-46 would be emitted daily. The range of values for any one process reflects variations due to area coal characteristics. In general, emissions are highest when Central area coal is used and lowest when Northwest coal is used.

Particulates range from 2 to 15 tons for each 10^{12} Btu's processed (1.0 to 7.5 tons daily). They are highest for Synthane and lowest for Lurgi. However, Battelle data (1973: 102) indicate that particulate emissions from a HYGAS unit using Eastern coal with a 14.4-percent ash content are 91 tons per 10^{12} Btu's processed. Oxides of nitrogen range from 38 to 115 tons per 10^{12} Btu's processed. Synthane produces the highest emissions and CO_2 Acceptor the lowest. Sulfur dioxide varies considerably by coal type, with Northwest coal being the lowest in sulfur content. Synthane and Lurgi produce the fewest sulfur dioxide emissions, and CO_2 Acceptor, which uses Northwest coal, produces the most. Hydrocarbon and carbon monoxide emissions are small, 0.6 to 4 tons per 10^{12} Btu's processed. Estimates calculated by Battelle for a number of the residuals are substantially higher than those developed by Hittman (Table 1-45).

1.9.3.1.2.3 Solids

Regional variations in solids requiring disposal are primarily a function of the ash content of the coal. Disposal requirements are lowest for Northwest coal and highest for Northern Appalachian coal. For a high-Btu gasification facility using Northwest coal, 3,700 tons of material (primarily ash) are generated for each 10^{12} Btu's of coal processed (Table 1-46). About 5,300 tons of solids would require disposal from Central coal, and Northern Appalachian coal use would produce about 6,600 tons of solid wastes. Half these amounts would be roughly equivalent to the daily municipal refuse of 640,000 people in the Northwest area or 1.3 million people in the Northern Appalachian area. For this reason, high-Btu gasification plants may have to be mine-mouth activities so that solid wastes can be returned to the mine for burial.

In addition to ash, the CO_2 Acceptor process requires disposal of dolomite. Of the 8,600 tons shown in Table 1-46, spent dolomite is 3,200 tons or 37 percent of that total.

1.9.3.1.2.4 Land

Land requirements given in Table 1-46 are based on 350 acres of fixed area for coal storage, preparation, and gasification plant facilities plus an additional 165 acres for evaporation ponds to handle wastewater streams. The land requirements per 10^{12} Btu's coal input in Table 1-45 are based on an assumed 350-acre requirement and are calculated from the plant.

1.9.3.2 Liquid Fuels

Data presented in Table 1-48 have been developed for two processes, Consol Synthetic Fuel and Solvent Refined coal, and for coal from three Hittman areas: high-sulfur Central coal, medium-sulfur Northern Appalachian coal, and low-sulfur Northwest coal. A summary of important pollutants is given in Table 1-49.

1.9.3.2.1 Water

Process wastewater includes phenols, cyanide, ammonia, sulfide, oil, and suspended solids. Dissolved solids are contributed by boiler and cooling tower blowdown and demineralization. Wastewater

Table 1-48. Solvent Refined Solids and Coal Liquefaction Residuals

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)							$^{F}/_{I}$[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (Tons/10^{12} Btu's)	Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
SOLID COAL																					
Solvent Refined Coal																					
Northern Appalachian Area	U	U	.365	U	590.	1.59	.03	.01	.01	0	18.9	21.1	24.2	4.84	.048	.362	3200.	2.54/0 2.54	U	U	U
Central	U	U	.321	U	522.	1.4	.227	.007	.008	0	17.2	18.7	47.5	4.3	.043	.321	3920.	2.24/0 2.24	U	U	U
Eastern Coal																					
Chemical Cleaning[b]	NC	NC	NC	NC	NC	NC	NC	NC	NC	NC	2.6	21.	52.6	NC	1.	NC	0	9.1	NC	NC	NC
LIQUEFACTION																					
Northwest Area																					
CSF Process	0	0	0	0	0	0	0	0	0	0	2.38	61.3	4.48	.3	2.08	.192	3260.	4.48/0 4.48	U	U	U
SRC Process	0	0	0	0	0	0	0	0	0	0	3.49	88.5	4.81	.296	2.51	.271	3460.	6.22/0 6.22	U	U	U
Central Area																					
CSF Process	U	U	U	U	63.6	.008	.0018	U	U	0	2.68	62.2	24.3	.318	2.12	.249	5010.	2.91/0 2.91	U	U	U
SRC Process	U	U	U	U	52.3	.017	.003	U	U	0	3.32	88.	29.5	.295	2.5	.325	5270.	3.4/0 3.4	U	U	U
SRC Process[c]	0	NC	NC	NC	0	0	NC	NC	NC	0	180.	140.	2.	2.4	8.	NC	3500.	9.10	NC	NC	NC
Northern Appalachian Area																					
CSF Process	U	U	U	U	63.7	.008	.0018	U	U	0	2.63	60.9	9.28	.297	2.05	.22	4000.	2.92/0 2.92	U	U	U
SRC Process	U	U	U	U	52.4	.017	.003	U	U	0	3.25	88.2	14.3	.295	2.5	.3	4210.	3.4/0 3.4	U	U	U

NC = not considered, U = unknown.

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

[b]Battelle, 1973: 76.

[c]Battelle, 1973: 78, location specified as Eastern coal.

TABLE 1-49

SUMMARY OF SOLVENT REFINED SOLIDS AND COAL LIQUEFACTION RESIDUALS

Process	Water (tons per 10^{12} Btu's)			Air (tons per 10^{12} Btu's)			Solids (tons per 10^{12} Btu's)	Land (acres)[c]
	TDS[a]	SS[b]	Organics	Particulates	Nitrogen Oxides	Sulfur Oxides		
Liquefaction								
Consol Synthetic Fuel Process	63	0.008	0.0018	2.5	61	4-25	3,200-5,000	500[d]
Solvent Refined Coal Process	52	0.017	0.003	3.2	88	5-30	3,400-5,300	280[e]
Solid Coal								
Solvent Refined	550	1.5	0.03-0.3	18	20	24-47	3,200-4,000	200

Source: Hittman, 1975: Vol. II, Tables 5 and 6.

[a]Total dissolved solids.

[b]Suspended solids.

[c]Land required is for coal storage, preparation, gasification plant facilities, and evaporation ponds. No additional requirement is assumed for buffer areas surrounding plant facilities (although they would probably be included in a commercial facility, on the order of 1,500 acres).

[d]In the Northwest region, an additional 230 acres is required for evaporation ponds.

[e]In the Northwest region, an additional 265 acres is required for evaporation ponds.

TABLE 1-50

PROCESS WASTEWATER POLLUTANT CONCENTRATIONS
FROM TWO LIQUEFACTION PROCESSES

Parameter	Consol Synthetic Fuel Process (parts per million)	Solvent Refined Coal Process (parts per million)
Sulfide	0.8	14.4
Ammonia	109.2	48
Cyanide	1.8	52.8
Other dissolved solids	27,774	62,936
Total dissolved solids	27,856	63,052
Suspended solids	3.5	21.2
Organics (phenol and oil)	0.8	3.8

Source: Hittman, 1975: Vol. II, pp. VIII-13, VIII-15, VIII-19, VIII-21, VIII-22.

concentrations after treatment are given in Table 1-50 for each process. The summary in Table 1-49 gives the total amount released in tons. Wastewater treatment in the CSF process includes oil-water separation, dissolved air flotation, ammonia stills, activated sludge, clarification, and activated carbon (Hittman, 1975: Vol. II, pp. VIII-13 and VIII-19). SRC wastewater treatment is similar, including oil-water separation, phenol solvent extraction, sour water stripping, clarification, and activated carbon (Hittman, 1975: Vol. II, pp. VIII-15, VIII-21, VIII-22).

Total water pollutants discharged are higher for the CSF than for the SRC process (Table 1-49). As shown in Table 1-50, however, most pollutant concentrations are considerably higher in SRC wastewaters than in CSF wastewaters, especially for dissolved solids and cyanide. Ammonia is the only pollutant with higher concentrations from the CSF process. Total dissolved solids range from 27,856 to 63,052 ppm and cyanide ranges from 1.8 to 52.8 ppm. For perspective, the Public Health Service's recommended limits for drinking water are 500 ppm for total dissolved solids, 0.01 ppm for cyanides, and 0.5 ppm for ammonia.

A liquefaction plant processing 23,000 tons of coal per day will require 15 million gallons of net make-up water (Hittman, 1975: Vol. II, pp. VIII-12, VIII-14, VIII-18, VIII-21, VIII-24, VIII-27). Due to the high value of water in the Northwest area, it is expected that no water would be discharged from a liquefaction plant operating there. The assumptions in the data presented in Table 1-48, which indicates zero water pollutants in the Northwest area, are that process wastewater and impounded runoff are treated and used for cooling tower make-up, while all blowdown streams are collected and sent to lined evaporative ponds.

1.9.3.2.2 Air

Air emissions are presented in Table 1-48 and summarized in Table 1-49. Emission sources are fuel combustion, the sulfur recovery plant, and storage. Particulate emissions are approximately three tons per

10^{12} Btu's of coal processed, oxides of nitrogen are 60 to 90 tons, and sulfur dioxide emissions range from 4 to 30 tons (Table 1-47). Particulates originate in fuel combustion (the coal-fired boiler) and are reduced 99.5 percent by the use of an electrostatic precipitator and a Wellman Lord unit.* Battelle (1973: 78) assumes only 98-percent clean-up efficiency, which results in a greater estimated quantity of residuals. Particulate emissions from the coal thermal dryers are reduced by 85 percent through the use of multiple cyclones and then further reduced to 99 percent by a baghouse in the CSF process or to 90 percent by a Venturi scrub in the SRC process before entering the atmosphere (Hittman, 1975: Vol. II, pp. VIII-11, VIII-13, VIII-17, VIII-20, VIII-23, VIII-26). All nitrous oxides originate from fuel combustion. Sulfur dioxides originate from fuel combustion and from the sulfur recovery plant, which is assumed to be a Claus recovery plant with 94.6-percent removal of the incoming sulfur. Sulfur dioxide emissions vary as a function of the sulfur content of the coal; they are highest for Central coal.

1.9.3.2.3 Solids

The principal solid waste from the liquefaction processes is ash from fuel combustion. It ranges from 3,200 tons to 5,300 tons per 10^{12} Btu's processed. The lower value is for six-percent ash coal in the Northwest; the higher value is for 11.3-percent ash coal in the Central area (Table 1-49). In addition to ash, the total includes suspended solids removed in water treatment. For perspective, note that a 24,000-ton-per-day coal liquefaction plant would produce half these totals or 1,600 to 2,600 tons each day. This is equivalent to the daily municipal refuse generated by 640,000 to 1,040,000 people. Coal liquefaction is considered a mine-mouth activity; thus, all solid waste is returned to the mine for burial.

*The Wellman Lord unit uses wet scrubbing for removal of particulates and sulfur trioxide, and a second gas scrubbing with a potassium sulfite solution for removal of sulfur dioxide.

1.9.3.2.4 Land

Land requirements are estimated at 500 acres for a 24,000-ton-per-day CSF liquefaction facility and 280 acres for a 12,000-ton-per-day SRC facility (Hittman, 1975: Vol. II, pp. VIII-12, VIII-14, VIII-18, VIII-21, VI-7, VI-9, VI-13, VI-16). Battelle (1973: 78) estimates that 750 acres are required for a 7,000-ton-per-day SRC facility.

1.9.3.3 Solvent Refined Solids

Data for residuals in solvent refined solids processing for two coals--high-sulfur Central and medium-sulfur Northern Appalachian--are given in Table 1-48 and summarized in Table 1-49. Data in both tables assume that environmental control technologies are used.

1.9.3.3.1 Water

There are four sources of wastewater streams: the dissolver unit, the coal preparation plant, boiler blowdown water, and sanitary waste. The composition of waste from these sources and effluent concentrations are indicated in Table 1-51. Treatment includes phenol solvent extraction, sour water stripping, primary clarification, activated sludge, and secondary clarification. Total water effluent is 20 million gallons per 10^{12} Btu's coal processed or 4.8 million gallons per day for a typical 10,000-ton-per-day processing plant. Of the water pollutants released (Table 1-51, Column 5), only total dissolved solids is high, 14 times the Public Health Service's recommended limit of 500 ppm for domestic water supplies.

TABLE 1-51

WASTEWATER COMPOSITION FROM SOLVENT REFINED SOLIDS BEFORE AND AFTER TREATMENT

Parameter	Wastewater Stream Discharge (pounds per hour)				Combined Effluents After Treatment (parts per million)
	Dissolver Unit	Preparation Plant	Sanitary Waste	Boiler Blowdown	
Phenols	3,000	1,100	0	0	0.19
Oil	3	1,100	0	0	3.88
Ammonia	160	0	0	0	0.3
TDS[a]	825	0	0	11,043	7,670
SS[b]	51	0	1.3	25	20.6
CN and SCN[c]	27	0	0	0	1.7
BOD[d]	0	0	1.1	0	0.1
COD[e]	0	0	1.4	0	0.1
PO_4[f]	0	0	7.4	0	4.7

Source: Hittman, 1975: Vol. II, pp. VIII-9, VIII-10, VIII-18, VIII-19.

[a]total dissolved solids.

[b]suspended solids.

[c]cyanide and thiocyanate.

[d]biochemical oxygen demand.

[e]chemical oxygen demand.

[f]phosphates.

1.9.3.3.2 Air

Air pollutants associated with the solvent refining process consist primarily of emissions from fuel gas consumption, the sulfur recovery plant (Claus plant tail gas), and the coal preparation plant. Particulate emissions average 18 tons per 10^{12} Btu's of coal processed and nitrous oxides average 20 tons per 10^{12} Btu's. Sulfur dioxide emissions are a function of the total sulfur in the input coal and are lowest for Northern Appalachian coal (1.8 percent) and highest for Central coal (3.5 percent).

1.9.3.3.3 Solids

Solid waste from the solvent refining process is a product of combustion of the filter cake used as supplementary fuel. The quantity of residue is a function of the ash content of the coal and is highest for Central coal (9.4-percent ash). Generated solids average 3,500 tons per 10^{12} Btu's processed or 700 tons per day for a 10,000-ton-per-day installation.

The chemical cleaning process described by Battelle (1973: 76) does not produce solid wastes (except elemental sulfur) because no ash is removed.

TABLE 1-52

SUMMARY OF (1972 ESTIMATED) COAL PROCESSING COSTS

Process	Cost (cents per million Btu's output)[a]			Fixed Charges as Percentage of Cost	Average Cost With Coal at \$6 per Ton (cents per million Btu's)
	Appalachian	Central	Northwest		
Low-Btu Gasification					
Lurgi	NA	NA	26.9	29	67
Koppers-Totzek	U	U	U	U[b]	U
BuMines-Atmospheric	10.4	11.2	16.8	38	54
BuMines-Pressurized	26.4	29.7	39.6	38	72
High-Btu Gasification					
Lurgi	NA	50.1	55.9	70	103
HYGAS-Steam-Oxygen	40.0	40.5	34.5	69	96
BI-GAS	46.5	47.1	41.0	62	95
Synthane	44.3	51.6	45.7	65	96
CO_2 Acceptor	NA	NA	39.0	61	89
Solvent Refined Solids	29.1	30.0	NA	47-59	69
Liquefaction					
CSF Process[c]	42.4	42.1	42.1	55	86
SRC Process[d]	81.1	81.3	80.6	51	129

NA = not applicable, U = unknown.

Source: Hittman, 1975: Vol. II.

[a]Adopted from Hittman by converting to a Btu output basis, coal cost not included.

[b]17 to 206 per million Btu's fixed.

[c]Consol Synthetic Fuel Process.

[d]Solvent Refined Coal Process.

1.9.3.3.4 Land

A typical 10,000-ton-per-day solvent refining facility requires 200 acres (Hittman, 1975: Vol. II, footnotes 9307 and 9338).

1.9.4 Economic Considerations

Because the technologies for processing coal are not fully developed, cost data are unreliable and subject to frequent revision. Table 1-52 summarizes Hittman's cost estimates (1972 dollars) for specific conversion technologies in various areas assuming a 25-year life on capital equipment, 10-percent fixed charge rate on investment, and 90-percent utilization of capacity.

The quality of the economic data has been described by Hittman as good (an error of less than 25 percent) for SRC and fair (an error of less than 50 percent) for all other processing technologies discussed here.

1.9.4.1 Gaseous Fuels

1.9.4.1.1 Low-Btu Gasification

Although data for four low-Btu gasification processes are included in Table 1-51, complete economic data exists only for three of the four: BuMines Atmospheric, BuMines Pressurized, and Lurgi. Total costs, excluding coal costs, range from $0.10 to $0.40 per million Btu's, depending on the technology used and the rank of coal. Appalachian coal is the cheapest and Northwestern coal is the most expensive to process. Although the BuMines Atmospheric process appears to be the least expensive technology, the probability of error in the data means that differences may not be significant. Processing costs, including the costs of the coal feedstock, range from $0.49 to $0.77 per million Btu's.

Low-Btu gasification is treated by Hittman as a subprocess in an integrated electricity generation facility. Hittman calculates that the electric generation step would add another $0.16 per million Btu's for a total of 6.5 to 9.3 mills per kwh.

1.9.4.1.2 High-Btu Gasification

Data on six high-Btu gasification processes are included in Table 1-52. Process costs, excluding coal costs, range from $0.40 to $0.56 per million Btu's depending on the process and rank of coal. Northwestern coal is generally cheapest to process, and the CO_2 Acceptor is the least expensive technology. Except for Lurgi, the other processes average about $0.49 per million Btu's. When coal costs are included, the average is $0.96 per million Btu's. Note that in the case of natural gas, a million Btu's is the same as a thousand cubic feet (mcf). This means that Hittman costs average $0.96 per mcf of gas.

Recently, the total cost for Synthane was estimated to be $0.85 per mcf; however, officials at BuMines believe costs will be $1.75 to $2.00 per mcf higher in 10 years. Another recent study estimates BI-GAS costs to be $0.82 per mcf ($0.30 per million Btu's of coal) (Hegarty and Moody, 1973).

TABLE 1-53

ESTIMATED PRICES OF SYNTHETIC NATURAL GAS (CENTS PER MILLION BTU'S)

Technology	Bituminous Coal Price per Ton			
	$2.00	$4.00	$6.00	$8.00
Lurgi	61	88	115	142
HYGAS	53	76	98	120
BI-GAS	50	70	89	109
Synthane	45	63	81	99
CO_2 Acceptor	49	71	92	114
	Lignite Price per Ton			
	$1.50	$3.00	$4.50	
CO_2 Acceptor	53	79	150	

Source: OCR, 1972: Table 7, p. 29.

This study indicated that the gasification facility itself was a small part of the total fixed investment. The major part of the capital investment goes for coal preparation, acid gas removal, sulfur recovery, utilities, and offsite facilities. The capital outlay for high-Btu gasification is 70 percent of total costs (Table 1-52), which is 20 to 30 percent higher than for other coal processing technologies.

For comparison with Hittman estimates, the Office of Coal Research's (OCR) hypothetical prices for high-Btu gas produced with various technologies and various coal prices are given in Table 1-53. Column three of this table compares favorably with Hittman estimates.

1.9.4.2 Liquid Fuels

Both the CSF and SRC processes are included in Table 1-52. As noted there, the SRC process is twice as expensive as the CSF process when coal costs are excluded. When coal costs are included, the range is $0.86 to $1.29 per million Btu's. This agrees with OCR's estimate of $0.82 per million Btu's for the Coal-Oil-Gas (COG) liquefaction process (OCR, 1971). Continental Coal Development Company estimates that it will cost between $1.40 and $1.70 (estimated 1978 dollars) per million Btu's to produce a synthetic crude from coal by 1978. This agrees with the Hittman estimates if they are translated into 1978 dollars (Reichl, 1973: 34).

1.9.4.3 Solvent Refined Solids

For solvent refining, data on only one process, that developed by the Pittsburg and Midway Coal Company, are available. Including coal costs, this process averages $0.69 per million Btu's. The cost is slightly cheaper when Appalachian rather than Central coal is used (Table 1-52), primarily due to the lower sulfur content of Appalachian coal. About half the total cost, excluding coal, is capital outlay; the other half is operating cost.

When solvent refined coal costs are added to Hittman's estimate for electric power generation, a total cost of $1.362 per million Btu's is obtained ($0.672 for electric power and $0.69 for processing). At a rate of 10,000 Btu's per kwh, this converts to 13.6 mills per kwh.

1.9.4.4 Summary

For the four technology groups, solvent refining and low-Btu gasification are considerably less expensive overall than liquefaction and high-Btu gasification. This is to be expected because the latter two technologies produce a product ready for consumer use while the former are feedstocks for electric power generation.

1.10 TRANSPORTATION

After mining, coal must be transported to either a processing facility or to the place where it is to be consumed. If it is to be processed, the resulting solid, gaseous, or liquid products also have to be transported.

TABLE 1-54

METHODS OF COAL TRANSPORTATION

Method	Bituminous Coal[a]
Rail	69.2
Barge	10.7
Truck	10.7
Other[b]	9.2

Source: National Coal Association, 1972: 91.

[a]Percent moved.

[b]Includes tramway, conveyor, and private railroad.

1.10.1 Technologies

1.10.1.1 Transporting Raw Coal

Raw coal is almost always moved from the mine to either its consumption point or a processing facility by rail, barge, truck, or pipeline. When barges are used, the transportation system often includes moving coal from the mine to a barge loading facility by either truck or train.

1.10.1.1.1 Railroads

As shown in Table 1-54, railroads (usually either diesel or electrically powered) currently transport almost 70 percent of all bituminous coal mined in the U.S.* Three types of trains are used in transporting raw coal: conventional, unit, and dedicated. When conventional trains are used, cars carrying coal are treated

*Data for all coals are not available. Since bituminous coal represents all but a small fraction of coal mined, it is safe to say that rails ship about 70 percent of all U.S. coal.

like any other car. Unit trains, on the other hand, are made up entirely of cars carrying coal. When coal is transported by conventional trains, the Interstate Commerce Commission's (ICC) general rates apply. In contrast, a special rate, almost one-third less, applies to unit trains.

Unit trains offer several other advantages, including better utilization of equipment, elimination of standard railroad tie-ups such as classification yards and layover points, and promotion of better coordination between mine production and consumers, particularly consumers dependent on coal being supplied by a single mine (NAE, 1974: 36-38).

The dedicated railroad, the third rail option, is used exclusively for transporting coal. A dedicated railroad is generally used only when an existing railroad is not available and when the railroad will link a mine to a single-source user.

1.10.1.1.2 Barges

As indicated in Table 1-54, barges move only about 11 percent of the raw coal shipped in the U.S.* In some areas, such as the Ohio River Valley, barges can be loaded directly from the mine. When mines are not located adjacent to a navigable river, the coal has to be transported to the barge-loading facility by either truck or train (usually by train).

1.10.1.1.3 Trucks

Trucks move as much coal as barges do. Their major advantage is flexibility; their major disadvantage is that they are not cost effective for moving large quantities long distances.

*Again, the generalization is based on the fact that bituminous accounts for more than 90 percent of all coal produced in the U.S.

1.10.1.1.4 Pipelines*

Slurry pipelines, such as those described in Section 1.6, can be used to transport pulverized coal suspended in water. When this system is used, the coal has to be processed to obtain the proper particle size. Pumping stations, dewatering facilities, and (in some cases) storage facilities are also required. The major advantage of slurry pipelines for transporting coal long distances is low operating cost (Mutschler and others, 1973: 1). The major disadvantages are that capital costs are high and water requirements are substantial.

A slurry pipeline is currently being used to tranport coal from Peabody Coal's Black Mesa, Arizona mine to an electrical generating plant more than 270 miles away. This line requires 3,200 acre-feet of water annually or approximately 11 million gallons per 10^{12} Btu's of coal input (Davis and Wood, 1974: 1, 2). Although the pipeline has apparently worked out very well, there have been problems at the power plant, primarily in centrifugal dryers used to prepare the coal for combustion. A slurry pipeline is being planned that will transport coal from Wyoming to Arkansas, a distance of nearly 1,000 miles.

1.10.1.2 Transporting Coal Products

As previously described, coal can be processed to produce solid, gaseous, or liquid fuels. None of these products pose any special transportation problems.

Processed solids will probably be transported in the same manner as raw coal. Given their low heating value, low- and intermediate-Btu gases will almost always be used at or near the site where they are generated. On the other hand, high-Btu gas can be economically transported long distances and is likely to be fed into the

*Pipelines are described in more detail in Chapter 3.

existing natural gas pipeline complex that covers most of the U.S.

If produced liquids are to be used as a refinery feedstock, a single coal processing complex might well combine liquefaction and refining, in which case the finished product would be transported by truck, train, barge, or pipeline. These same modes of transportation could be used to move the unrefined liquids as well. If the thickness of the produced liquid makes pipelining difficult, it will probably be at least partially refined for easier transportation. Heating the pipeline, the method chosen by Standard Oil of California to move heavy crude in Utah, also makes heavy liquid movement easier (Oil and Gas Journal, 1973: 24).

1.10.2 Energy Efficiencies

Only the predominant modes of transportation used in specific areas are considered in the analysis of energy efficiencies. Distances are adjusted to reflect the mileage from the mines to major markets for each region.

The primary efficiencies for coal transportation given in Table 1-55 have an error of less than 50 percent and reflect losses from the wind. These wind losses account for one percent of the tonnage shipped by unit trains, barges, and trucks. Other losses occur mainly during handling at end points. Losses in conventional train transportation are two percent. Spillage at transfer points accounts for a one-percent loss when covered conveyors are used. Thus, primary efficiencies are 98 percent for conventional trains and 99 percent for other modes of transportation, regardless of area. The pipeline slurry efficiency of 98 percent is not a loss of coal in transportation but represents a reduction in the coal's heating value because of its slurry water content.

Table 1-55 also gives ancillary energy requirements which are based on the average haul distance by area for coal transportation technologies. These data should be considered poor, with an error of up to 100 percent. Since energies are not given on an equal haul-distance basis, they are not directly comparable. The ancillary energy source for unit trains, conventional trains, and trucks is diesel fuel. Conveyors and slurry pipelines use electricity. The average loads assumed are: unit trains, 10,000 tons per trip; mixed trains, 1,000 tons per trip; and river barges, 25,000 tons per trip. The average truck capacity is 20 tons.

The range of ancillary energies is 0.4 to 19.0×10^9 Btu's per 10^{12} Btu's transported. Note that when a conveyor is used for coal distribution, it is generally in conjunction with another mode of transportation (e.g., a barge or train). Haulage distances for conveyors are short, averaging five miles. Similarly, trucks are normally used only between mines and nearby processing facilities (10 miles average).

On an equal haul-distance basis, river barges are the most energy-efficient, consuming 378 Btu's per ton-mile. Freight train energy consumption is 690 Btu's per ton-mile, and truck consumption is 966 Btu's per ton-mile. Slurry pipelines appear to be as efficient as river barges.

1.10.3 Environmental Considerations

From the standpoint of resources required for a technology, the National Academy of Engineering (NAE) has pointed out that all new overland transportation systems will need additional rights-of-way and new facilities, crews, and rolling stock. Further, shortages of locomotives, gondola cars, and hopper cars (NAE, 1974) already exist. The NAE conclusion is that railroads and barge systems alone will not be able to transport all western coal. Thus, utilization of pipelines is expected to increase.

TABLE 1-55

COAL TRANSPORTATION ENERGY EFFICIENCIES

Method and Location	Primary Efficiency (percent)	Ancillary Energy Requirement (10^9 Btu's per 10^{12} Btu's transported)	Average Haul Distance (miles)
Unit Trains	99		
Northwest		9.9	150
Central		15.8	290
Northern Appalachian		15.8	320
Central Appalachian		18.7	395
Southwest		5.89	100
Mixed or Conventional Train	98		
Northwest		7.82	150
Central		12.5	290
Northern Appalachian		12.6	320
Central Appalachian		10.7	275
River Barge	98		
Central		8.9	300
Northern Appalachian		21.3	800
Central Appalachian		7.76	300
Trucking	99		
Northwest		1.27	10
Central		1.07	10
Northern Appalachian		0.96	10
Central Appalachian		0.93	10
Conveyor	99		
Central		0.42	5
Northern Appalachian		0.37	5
Central Appalachian		0.38	5
Slurry Pipeline	98	7.09	273

Source: Hittman, 1974: Vol. I, Tables 3-12.

Included in Table 1-56 are environmental residuals for six transportation technologies by region. Only the predominant modes of transportation for a specific region are considered.

1.10.3.1 Water

River barges may contribute dissolved solids to the river water. Quantities are unknown but are expected to be negligible. Drying the coal, after transporting via a slurry pipeline, produces a water effluent with negligible amounts of coal in it. Other modes of coal transportation do not involve water.

1.10.3.2 Air

Particulates, ranging from 1 to 46 tons per 10^{12} Btu's transported (Table 1-56), represent those associated with wind losses along the route and at the end points. These data should only be considered valid to within an order of magnitude. A two-percent wind loss is assumed for conventional trains as opposed to one percent for unit trains, river barges, and trucks. Based on these assumptions, transportation methods emit more particulates than any of the technologies in the coal development system. Other air emissions from transportation methods are due to diesel fuel combustion; thus, haul distances govern the magnitude of the total amounts emitted. In any case, the nitrous oxide and sulfur dioxide emissions are low, ranging from 0.5 to 4.3 tons and 0.1 to 4.4 tons, respectively, for each 10^{12} Btu's transported. Comparisons between transportation modes are not meaningful because equal haul distances have not been assumed.

1.10.3.3 Solids

No solids are generated by any mode of transportation, as losses along the route are assumed to be air residuals.

1.10.3.4 Land

Railroad land use requirements for coal transport are based on the percentage of coal-to-total rail freight and on the percentage of coal originating in the area. Since haul distances are not equal among the six transportation modes, values given in Table 1-56 are not directly comparable. Land utilization for coal transported ranges from 1 to 70 acres per 10^{12} Btu's transported. Of additional interest are the assumptions that rail right-of-way averages six acres per mile (approximately 55 feet wide), a conveyor requires 30 feet of right-of-way along its length (3.64 acres per mile), and trucks average 1.67×10^{-6} acres per ton-mile (to within 50 percent error in the data). However, the Black Mesa slurry pipeline in Arizona requires 62.5 feet of right-of-way along its length (7.58 acres per mile) and 50 acres each for four pumping stations.

1.10.4 Economic Considerations

Fixed costs, operating costs, and total costs for six modes of transportation are given in Table 1-57. These 1972 estimates are based on transporting 10^{12} Btu's of coal typical distances for each mode. The haul distance assumed is included in column four of this table, and the cost per ton-mile is calculated for that distance. As expected, conveyors and trucking are the most expensive modes, costing \$0.076 and \$0.045 per ton-mile respectively. For long distances, river barge is cheapest (\$0.03 per ton-mile). Slurry pipelines and unit trains have almost equivalent costs for overland coal transportation; conventional trains are more expensive (Table 1-56). Because of the ICC rate applications mentioned earlier, the freight rate for a typical 300-mile trip is \$2.04 per ton for a unit train and \$3.70 per ton for a conventional train.

Table 1-56. Residuals for Coal Transportation

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year/10^{12} Btu's	Deaths	Injuries	Man-Days Lost
UNIT TRAIN																					
Northwest Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	23.7	2.67	2.32	1.78	2.5	.392	NA	75.1/0 75.1	.075	.599	55.6
Central Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	20.3	4.17	3.7	2.85	3.99	.626	NA	30.4/0 30.4	.066	.876	81.3
Northern Appalachian Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	18.4	4.28	3.71	2.85	4.	.627	NA	27.6/0 27.6	.065	.856	79.6
Central Appalachian Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	18.1	5.06	4.39	3.38	4.73	.743	NA	26.6/0 26.6	.062	.767	71.4
Southwest Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	20.9	1.59	1.38	1.06	1.49	.234	NA	67.2/0 67.2	.067	.0534	49.6
MIXED OR CONVENTIONAL TRAIN																					
Northwest Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	46.3	2.12	1.83	1.41	1.97	.31	NA	75.1/0 75.1	.075	.599	55.6
Central Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	38.9	3.42	2.96	2.28	3.18	.502	NA	30.4/0 30.4	.066	.876	81.3
Northern Appalachian Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	35.	3.4	2.94	2.27	3.17	.499	NA	27.6/0 27.6	.065	.856	79.6
Central Appalachian Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	33.8	2.89	2.51	1.93	2.7	.424	NA	26.6/0 26.6	.062	.767	71.4
SLURRY PIPELINE	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	19.9	0	0	0
RIVER BARGE Central Coal	NA	NA	NA	NA	0	0	0	0	0	0	20.	.794	.85	.566	.67	.045	NA	NA	.0019	.0032	.243
Northern Appalachian Coal	NA	NA	NA	NA	U	0	0	0	0	0	19.7	1.9	2.04	1.22	1.63	.095	NA	NA	.0019	.0032	.243
Central Appalachian Coal	NA	NA	NA	NA	U	0	0	0	0	0	17.4	.689	.739	.443	.591	.034	NA	NA	.0019	.0032	.243

Table 1-56. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
TRUCKING																					
Northwest Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	22.9	1.69	.124	.169	1.03	.027	NA	0	.032	.692	45.4
Central Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	19.	1.4	.104	.14	.866	.023	NA	1.84/0 1.84	.032	.692	45.4
Northern Appalachian Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	17.	1.28	.093	.128	.776	.021	NA	1.67/0 1.67	.032	.692	45.4
Central Appalachian Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	16.4	1.29	.09	.124	1.754	.02	NA	1.6/0 1.6	.032	.692	45.4
CONVEYOR																					
Central Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	NA	NA	NA	.42/0 .42	0	0	0
Northern Appalachian Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	NA	NA	NA	.386/0 .386	0	0	0
Central Appalachian Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	NA	NA	NA	.376/0 .376	0	0	0

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement (Acre - year / 10^{12} Btu's) / Incremental Land Requirement (Acres / 10^{12} Btu's).

TABLE 1-57

COSTS OF COAL TRANSPORTATION
(1972 ESTIMATES)

Type	Costs (dollars per 10^{12} Btu's transported)			Distance Assumed (miles)	Cost per Ton-Mile (cents per ton-mile)
	Fixed	Operating	Total		
Unit Train	5,100	79,800	84,900	300	0.7
Conventional Train	9,240	145,000	154,000	300	1.3
River Barge	4,850	35,600	40,400	300	0.3
Slurry Pipeline	48,500	20,800	69,300	273	0.6
Trucking	1,850	16,700	18,500	10	4.5
Conveyors	10,500	5,100	15,600	5	7.6

Source: Hittman, 1974, Vol. I, Tables 1 and 2 and associated footnotes.

Of the total cost given in Table 1-57 for train transport, fixed costs are six percent and account only for depreciation. Fixed costs are 12 percent of the total for river barge transport and include depreciation and insurance. Fixed costs are 70 percent for the slurry pipeline and include power costs and maintenance.

BuMines estimates that transportation costs account for one-third to one-half of total costs by the time coal reaches the point of utilization (Mutschler and others, 1973: 29). Thus, trade-offs between processing coal at the mine site and transporting a different fuel form (e.g., electricity, oil, or gas) become important.

REFERENCES

Aiken, George E., and Reinhard P. Wohlbier (1968) "Continuous Excavators (Bucket Wheel and Chart Diggers)," pp. 478-502 in E.P. Pfleider (ed.) Surface Mining. New York: American Institute of Mining, Metallurgical and Petroleum Engineers.

Archer, D.H., D.L. Keairns, and E.J. Vidt (1974) "Development of a Fluidized Bed Coal Gasification Process for Electric Power Generation." Paper presented at the 4th Synthetic Fuels From Coal Conference, Oklahoma State University, Stillwater, Oklahoma, March 6-7, 1974.

Averitt, Paul (1970) Stripping-Coal Resources of the United States--January 1, 1970, USGS Bulletin 1322. Washington: Government Printing Office.

Averitt, Paul (1973) "Coal," pp. 133-142 in Donald A. Brobst and Walden P. Pratt (eds.) United States Mineral Resources, USGS Professional Paper 820, Washington: Government Printing Office.

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

Bodle, William W., and K.C. Vyas (1973) "Clean Fuels from Coal--Introduction to Modern Processes," pp. 49-89 in Symposium Papers: Clean Fuels from Coal, Illinois Institute of Technology, Chicago, September 10-14, 1973.

Bureau of Land Management (1974) Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program. Washington: Government Printing Office, 2 vols.

Bureau of Mines (1971) Strippable Reserves of Bituminous Coal and Lignite in the United States, Information Circular 8351. Washington: Government Printing Office.

Bureau of Mines (1972) Cost Analyses of Model Mines for Strip Mining Coal in the United States, Information Circular 8535. Washington: Government Printing Office.

Bureau of Mines (1973) Technology of Coal Conversion. Washington: Government Printing Office.

Bureau of Mines, Pittsburgh Energy Research Center (1974) "Clean Energy from Coal--New Developments."

Corey, Richard C. (1974) "Coal Technology," pp. 23-61 in Riegels' Handbook of Industrial Chemistry, 7th ed. New York: Van Nostrand Reinhold Company.

Davis, George H., and Leonard A. Wood (1974) Water Demands for Expanding Energy Development, USGS Circular 703. Reston, Va.: USGS.

Department of the Interior (1972) United States Energy through the Year 2000. Washington: Government Printing Office.

Environmental Protection Agency (1973) Processes, Procedures and Methods to Control Pollution from Mining Activities. Washington: Government Printing Office.

Forney, Albert J. (1974) Analyses of Tars, Chars, Gases and Water Found in Effluents from the Synthane Process, Bureau of Mines Technical Progress Report 76. Washington: BuMines.

Gartner, Ing. E.H. Ervin (1969) "Garsdorf Lignite Strip Mine--Operations to Unusual Depths," pp. 12-35 in Howard L. Hartman (ed.) Case Studies of Surface Mining: Proceedings of the II International Surface Mining Conference, Minneapolis, Minn., September 18-20, 1968. New York: American Institute of Mining, Metallurgical and Petroleum Engineers.

Goodridge, Edward (1973) "Status Report: The AGA/OCR Coal Gasification Program." Coal Age 78 (January 1973).

Gouse, S. William, Jr., and Edward S. Rubin (1973) A Program of Research, Development and Demonstration for Enhancing Coal Utilization to Meet National Energy Needs, Results of the Carnegie-Mellon University Workshop on Advanced Coal Technology.

Grim, Elmore C., and Ronald D. Hill (1974) Environmental Protection in Surface Mining of Coal, EPA Environmental Protection Technology Series. Washington: Government Printing Office.

Hegarty, W.P., and B.F. Moody (1973) "Coal Gasification: Evaluating the BI-GAS SNG Process." Chemical Engineering Progress 68 (March 1973): 37-42.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

Interagency Synthetic Fuels Task Force (1974) Report to Project Independence Blueprint, Federal Energy Agency, Supplement 1, prepared under the direction of Interior Department.

Johnson, Kenneth S. (1974) Oklahoma Geological Survey, personal communication.

Jones, J.F. (1973) "Project COED (Char-Oil-Energy Development)," pp. 383-402 in Symposium Papers: Clean Fuels from Coal, Illinois Institute of Technology, Chicago, September 10-14, 1973.

Katell, Sidney, and E.L. Hemingway (1974a) Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines; 72-Inch Coalbed, Bureau of Mines Information Circular 8632. Washington: Government Printing Office.

Katell, Sidney, and E.L. Hemingway (1974b) Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines; 48-Inch Coalbed, Bureau of Mines Information Circular 8641. Washington: Government Printing Office.

Killebrew, Clarence E. (1968) "Tractor Shovels, Tractor Dozers, Tractor Scrapers," pp. 463-477 in E.P. Pfleider (ed.) Surface Mining. New York: American Institute of Mining, Metallurgical and Petroleum Engineers.

Mutschler, P.H., R.J. Evans, and G.M. Larwood (1973) Comparative Transportation Costs of Supplying Low-Sulfur Fuels to Midwestern and Eastern Domestic Energy Markets, Bureau of Mines Information Circular 8614. Washington: Government Printing Office.

National Academy of Engineering, Task Force on Energy (1974) U.S. Energy Prospects: An Engineering Viewpoint. Washington: NAE.

National Academy of Engineering/National Research Council (1973) Evaluation of Coal-Gasification Technology, Part II: Low- and Intermediate-Btu Fuel Gases. Washington: NAE/NRC.

National Coal Association (1972) Bituminous Coal Facts, 1972. Washington: NCA.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee (1972) U.S. Energy Outlook: An Initial Appraisal by the Oil Shale Task Group, 1971-1985. Washington: NPC.

Office of Coal Research (1971) Development of a Process for Producing Ashless, Low-Sulfur Fuel from Coal, Vol. I: Engineering Studies, Part 3: COG Refinery Economic Evaluation--Phase II, Research and Development Report No. 53, Interior Report No. 4, prepared by Chem Systems, Inc. Washington: Government Printing Office.

Office of Coal Research (1972) Optimization of Coal Gasification Processes, Research and Development Report No. 66, Interim Report No. 2. Washington: Government Printing Office.

Oil and Gas Journal (1973) "SOCAL Slates Rail Shipments of Uinta Oil to Richmond Refinery." Oil and Gas Journal 71 (December 24, 1973): 24.

Reichl, Eric H. (1973) "Longer Term Prospects for Coal Utilization," pp. 25-34 in Coal and the Energy Shortage, A Presentation by Continental Oil Company to Security Analysts, December 1973.

Senate Committee on Interior and Insular Affairs (1971) A National Fuels and Energy Policy Study, Hearings, 92d Cong., 1st sess., October 20, 1971 (pp. 94-102, reprinted from Scientific American, Vol. 225, September 1971).

Senate Committee on Interior and Insular Affairs (1973) Coal Surface Mining: An Environmental and Economic Assessment of Alternatives, by the Council on Environmental Quality. Washington: Government Printing Office.

Soo, S.L. (1972) "A Critical Review on Electrostatic Precipitators," pp. 185-193 in R.W. Coughlin, A.F. Sarofim, and N.J. Weinstein (eds.) Air Pollution and Its Control, AIChE Symposium Series, Vol. 68, No. 126. New York: American Institute of Chemical Engineers.

Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif.: Teknekron.

Theobald, P.K., S.P. Schweinfurth, and D.C. Duncan, eds. (1972) Energy Resources of the United States, USGS Circular 650. Washington: Government Printing Office.

Weimer, W. Henry, and Wilbur A. Weimer (1973) "Surface Coal Mines," pp. 17-22 through 17-151 in Arthur B. Cummins and Ivan A. Given (eds.) SME Mining Engineering Handbook. New York: American Institute of Mining, Metallurgical and Petroleum Engineers.

Young, W.H. (1967) Thickness of Bituminous Coal and Lignite Seams Mined in 1965. Bureau of Mines Information Circular 8345. Washington: Government Printing Office.

CHAPTER 2

THE OIL SHALE RESOURCE SYSTEM

2.1 INTRODUCTION

Oil shale, "the rock that burns," has long been known as a potential source of energy. Early in its history, the U.S. considered developing a shale oil industry in Appalachia, but the 1859 discovery of oil in Pennsylvania provided a cheaper, more accessible energy source. Interest in oil shale was revived with the discovery of rich deposits in several western states from 1912 to 1915, and that interest was heightened by a petroleum shortage following World War I. However, before any significant work was done, huge oil fields were discovered in Texas, again making oil shale extraction uneconomical. During the 1950's and 1960's, several processes were tested for producing a liquid fuel from oil shale, but the continuing availability of less expensive crude oil negated commercial development.

Outside the U.S. (generally in countries where domestic crude oil was limited and imports were insufficient), oil shale has been commercially mined and processed into liquid fuels like those refined from petroleum. The first commercial processing occurred in France in 1838; production continued there and in Scotland and South Africa until the early 1960's. Currently, oil shale is commercially processed in China, Sweden, and Spain; raw oil shale is being burned to power thermal electrical generation plants in Estonia and the Federal Republic of Germany (UN, 1967: 11-13).

If the demand for liquid fuels grows and the interest in being domestically self-sufficient continues in the U.S., oil shale should become increasingly prominent in the discussion of energy options. A recognition of this was the Prototype Oil Shale Leasing Program, announced by the Department of the Interior (Interior) in 1971 and approved for implementation in 1973. Intended to "provide a new energy source by stimulating private commercial technological development" while assuring "the environmental integrity of affected areas" (House Committee on Science and Astronautics, 1973: 54), this program was designed to lease six federal land tracts of approximately 5,000 acres each, using a bonus-bid fixed royalty system. The program was completed by mid-1974; two tracts each were leased in Colorado and Utah, but there were no bids on the two Wyoming tracts.

The development of oil shale resources involves six major activities: exploration, mining, preparation, processing, reclamation, and transportation. This chapter describes U.S. oil shale resources, then delineates the activities and technologies associated with oil shale. In most cases, a major activity can be achieved by using any of several technological alternatives. The principal oil shale development technologies are shown in Figure 2-1; these methods, other alternatives, and points at which options are available are identified and discussed.

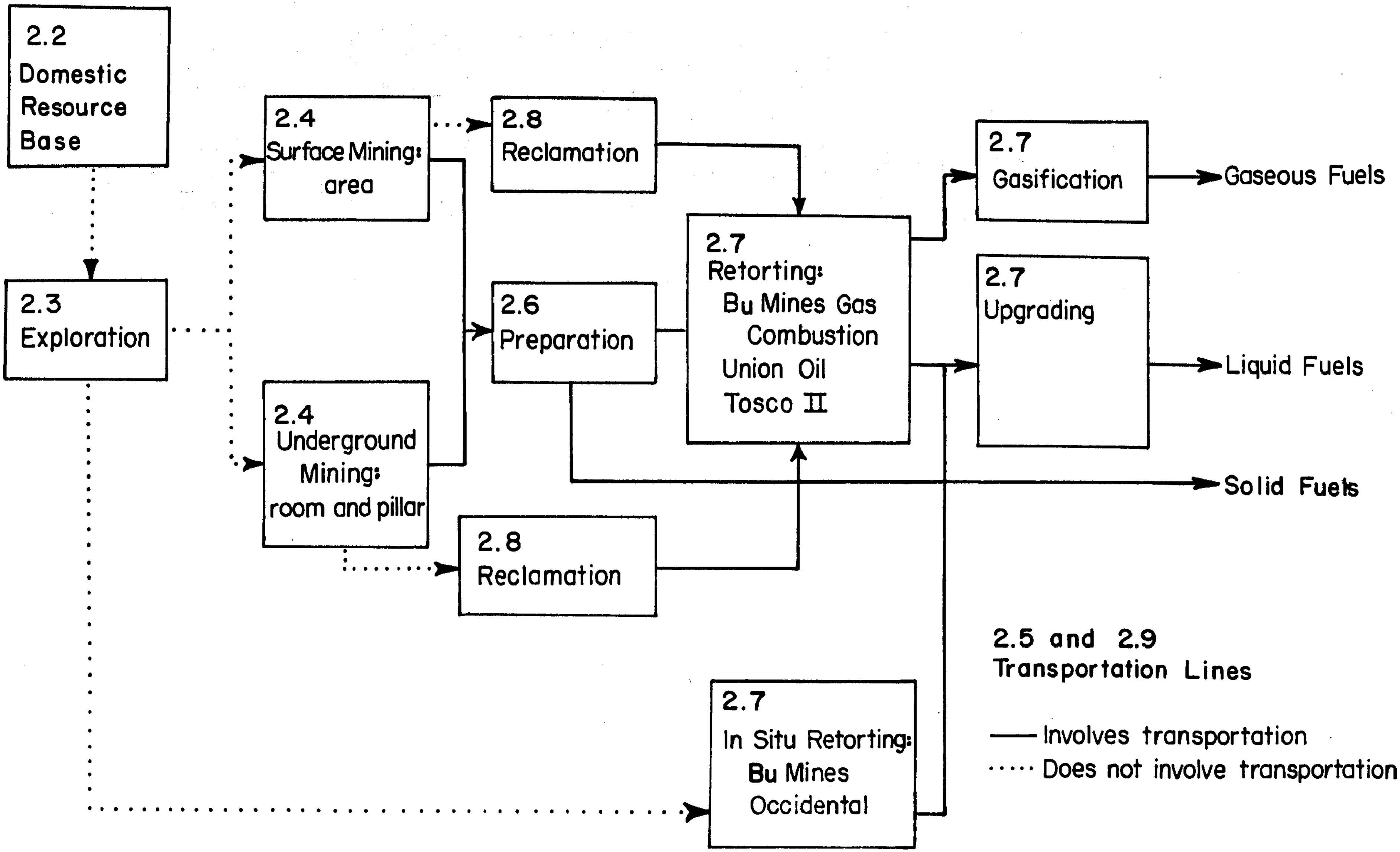


Figure 2-1. Oil Shale Resource Development

2.2 RESOURCE DESCRIPTION

Oil shale is a fine-grained, sedimentary rock containing a solid, largely insoluble organic material called kerogen. When this shale is heated, it releases the kerogen both as gas and a heavy oil that can be upgraded to syncrude (synthetic crude oil), which is equivalent to a high-grade crude oil. Deposits of oil shale are usually found in a layer or series of layers, known as a "zone," sandwiched between other layers of sedimentary rock.

The following portions of this section describe the total quantity, characteristics, location, and ownership of U.S. oil shale resources.

2.2.1 Total Resource Endowment

The U.S. Geological Survey (USGS) estimates that U.S. oil shale deposits contain more than two trillion barrels (bbl) of oil. A more speculative estimate, based on the assumed average hydrocarbon content of all sedimentary rock in the U.S., is 27 trillion bbl. However, only a very small portion of these resources could be classified as "reserves" (both known to exist and economically recoverable using currently available technologies).

Although no oil shale is presently regarded as economically recoverable by the USGS, 418 billion bbl either border on being economically producible or are not producible solely because of legal or political circumstances (Table 2-1). The portion of these 418 billion bbl that can be considered reserves depends heavily on the economic criterion used, which in turn depends on assumptions about the production costs of alternative energy sources. Consequently, a precise estimate of reserves is difficult to obtain. For example, Interior's final Environmental Impact Statement for its Prototype Oil Shale Leasing Program estimated that 80 billion bbl were actually recoverable under 1973 conditions (1973: Vol. I, p. II-6), and the National Petroleum Council's 1972 review of the U.S. energy outlook suggested that 129 billion bbl were recoverable under 1972 conditions (1972a: 208). Using either of these estimates, oil shale reserves contain more energy than the total U.S. oil and natural gas reserves. Another useful comparison may be that the U.S. used about 4.8 billion bbl or petroleum products in 1968 (API, 1971: 283).

2.2.2 Characteristics of the Resource

Oil shale resources are described primarily by their average oil yields, as measured by a standardized laboratory technique called a Fischer Assay. High-grade shale is normally defined as a deposit that averages 30 or more gallons of oil per ton of shale. Low-grade shale averages 10 to 30 gallons per ton. Shale with an average yield of less than 10 gallons per ton is normally omitted from USGS resource estimates. Since an oil shale zone is often composed of a large number of thin layers with different yields, a zone average may be composed of widely varying yields.

In addition to yield, several other factors are important in determining whether or not an oil shale deposit is recoverable. These include zone thickness, overburden thickness, and the presence of other materials in the shale. National data for these characteristics are unavailable.

As with coal, the amount of overburden that can be economically removed in oil shale mining is determined by the zone thickness. In practice, the minimum zone thickness considered for mining is 10 to 15 feet. Many high-quality deposits are known to be well over 100 feet thick (including, by definition, all the 418 billion bbl of identified paramarginal resources).

The presence of materials other than kerogen in the shale is of interest when the materials might themselves be recoverable and marketable. Although data are sparse, some of the western oil shales are

TABLE 2-1

OIL SHALE RESOURCES OF THE U.S.[a]
(BILLIONS OF BARRELS OF OIL YIELD)

Feasibility of Recovery	Knowledge of Resource		
	Identified[b]	Undiscovered[c]	
		Hypothetical[d]	Speculative[e]
Recoverable	0	0	0
Paramarginal[f]	418	300	600
Submarginal[g]	1,600	1,600	23,000

Sources: Culbertson and Pittman, 1973; Duncan and Swanson, 1965.

[a]Reliability of estimate decreases downward and to the right.

[b]Specific bodies known from geological evidence supported by engineering measurements.

[c]Unspecified bodies of mineral-leasing material surmised to exist on the basis of broad geologic knowledge and theory.

[d]Undiscovered materials that may reasonably be expected to exist in a known mining district.

[e]Undiscovered materials that may occur either in known types of deposits in a favorable geologic setting where no discoveries are made or in as yet unknown types of deposits that remain to be recognized.

[f]That portion of subeconomic resources that (1) borders on being economically producible or (2) is not commercially available solely because of legal or political circumstances.

[g]The portion of subeconomic resources which would require a substantially higher price (more than 1.5 times the price at the time of determination) or a major cost-reducing advance in technology.

known to contain sodium carbonate or sodium bicarbonate (nahcolite, halite, trona, and others) and alumina (dawsonite). Eastern deposits contain small amounts of uranium, vanadium, other metals, and phosphate.

2.2.3 Location of the Resources

About 90 percent of the identified oil shale resources of the U.S. are located in a single geological formation in western Colorado, Utah, and Wyoming known as the Green River Formation (Figure 2-2 and Table 2-2). Other oil shales underlie large areas in the eastern and central parts of the 48 contiguous states and the northern part of Alaska.

The Green River Formation underlies 25,000 square miles of land, some 17,000 of which are believed to contain oil shale deposits with commercial development potential. These deposits occur in several geologic basins (Figure 2-3) and, in many instances, are exposed at the basin edges but slant deeply underground toward the centers. Although substantial deposits are found in all three states, about 80

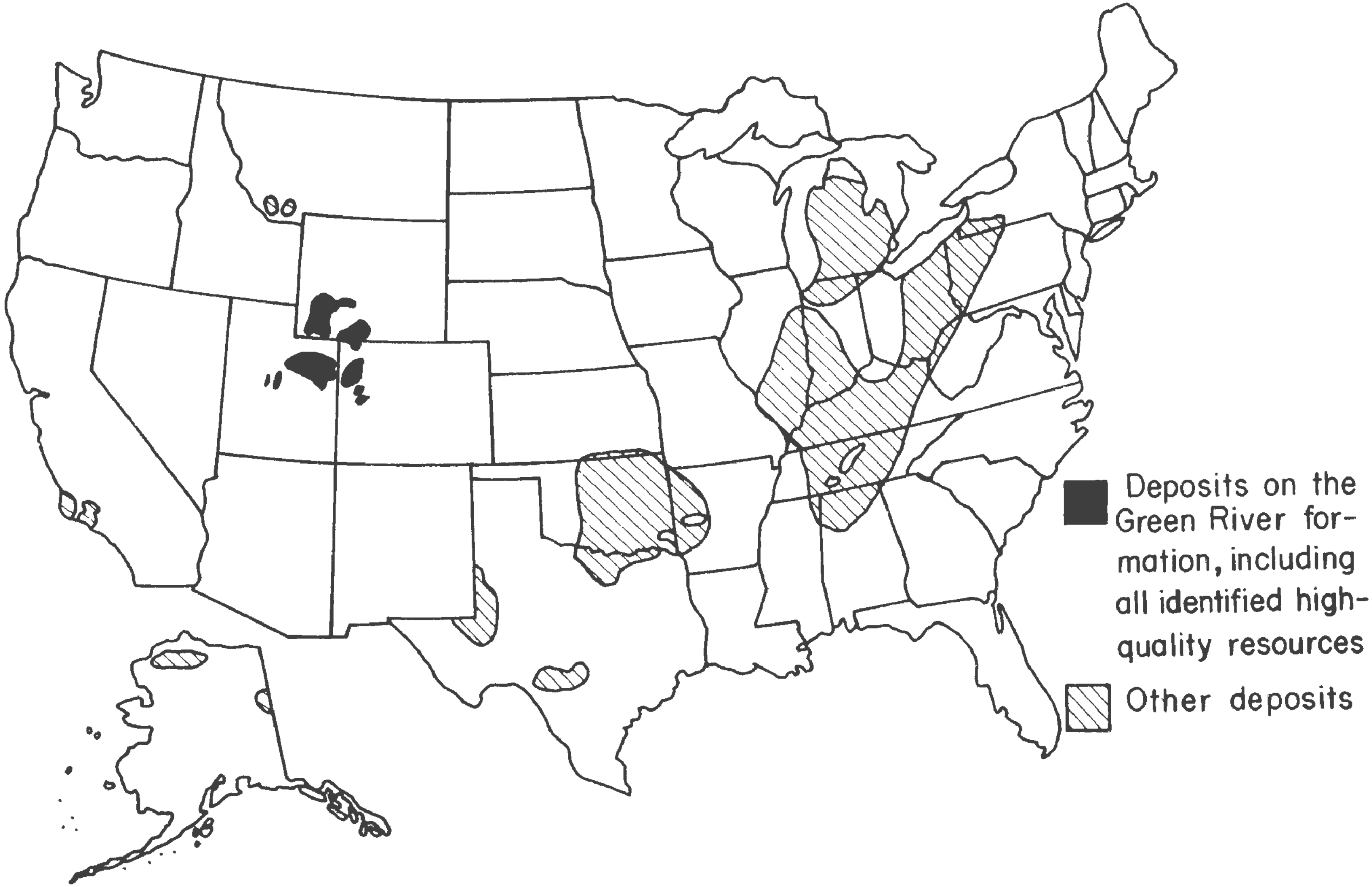


Figure 2-2. Distribution of U.S. Oil Shale Resources

Source: Duncan and Swanson, 1965.

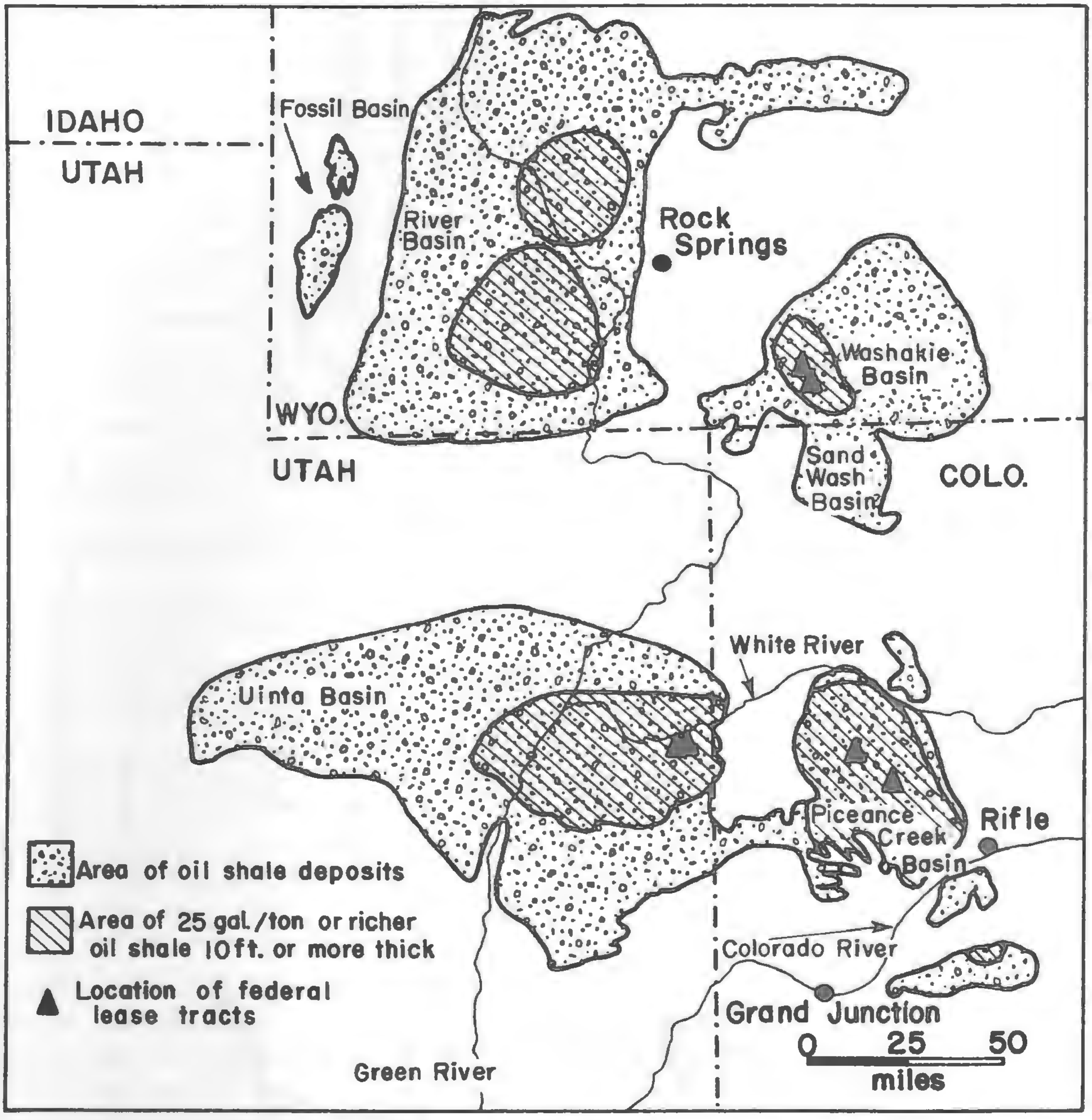


Figure 2-3. Oil Shale Areas in Colorado, Utah, and Wyoming

Source: Interior, 1973: Vol. I, p. II-3.

TABLE 2-2

LOCATION OF OIL SHALE RESOURCES[a]
(BILLIONS OF BARRELS OIL YIELD)

Location	Identified		Hypothetical		Speculative	
	25-100 Gallons per Ton	10-25 Gallons per Ton	25-100 Gallons per Ton	10-25 Gallons per Ton	25-100 Gallons per Ton	10-25 Gallons per Ton
Green River Formation (Colorado, Utah, and Wyoming)	418	1,400	50	600	0	0
Chattanooga shale and equivalent formations (Central and Eastern U.S.)	0	200	0	800	0	0
Marine shale (Alaska)	small	small	250	200	0	0
Other shale deposits	0	small	NE	NE	600	23,000
TOTAL	418+	1,600+	300	1,600	600	23,000

NE = not estimated.

Source: Culbertson and Pitman, 1973: 500.

[a]For definition of categories, see Table 2-1.

percent of the higher grade zones are in Colorado, mostly in the Piceance Basin (Table 2-3). The current focus in the Piceance Basin is on the "Mahogany Zone," a high-quality and relatively accessible deposit ranging from 100 to 1,000 feet below the surface (except where it outcrops at the basin edges) and from 30 to more than 100 feet in thickness. Figure 2-4 is a schematic cross-section of the Green River Formation as it occurs in the Piceance Basin.

The population density of the Green River Formation Region is about three persons per square mile (Interior, 1973: Vol. I, pp. II-11 through II-16), most of whom live in small towns in the river valleys adjacent to the shale lands. Farming, ranching, and mining are mainstays of the economy. The arid to semiarid lands overlying the oil shale deposits are characterized by prominent oil shale cliffs, plateaus, low escarpments, and some flat lands.

Water is scarce in the region. The main water supply is the Colorado River and its major tributaries, such as the Green and the White Rivers. These rivers are fed by the winter snows that constitute most of the region's precipitation. Average precipitation ranges from seven inches per year in Wyoming to twenty-four inches per year in upland parts of the Colorado oil shale lands. Runoff from oil shale lands is legally committed to agricultural and stock-watering use, and water in the rivers is controlled by an intricate system of water rights covering the entire Colorado River system. Complicated by annual variations in stream-flow and conflicting results of litigation, the actual rights to water are not always clear.

Regional water quality is an international concern because the increasing salinity of Colorado River water affects both American and Mexican usage. Since mining the Colorado oil shale will require using

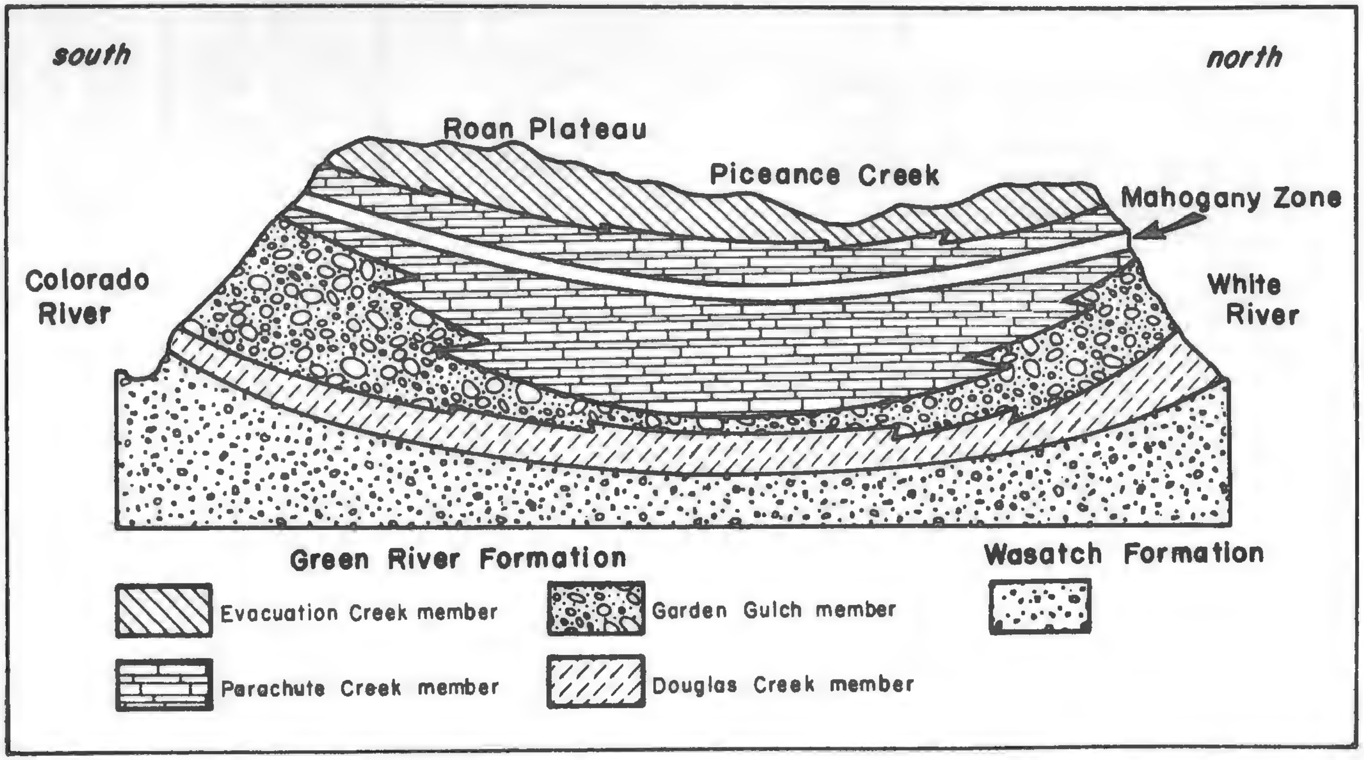


Figure 2-4. Diagrammatic Cross Section of Green River Formation

Source: Atwood, 1973: 619 (After Neilson).

TABLE 2-3

OIL SHALE RESOURCES IN THE GREEN RIVER FORMATION
(BILLIONS OF BARRELS)

Location	Resource Class[a]				
	Class 1	Class 2	Class 3	Class 4	Total
Piceance Basin Colorado	34	83	167	916	1,200
Uinta Basin Colorado and Utah	0	12	15	294	321
Wyoming	0	0	4	256	260
TOTAL	34	95	186	1,466	1,781

Source: NPC, 1972a: 207-208.

[a]Classes 1,2: Resources satisfying a basic assumption limiting resources to deposits at least 30 feet thick and averaging 30 gallons of oil per ton of shale, by assay. Only the most accessible and better defined deposits are included. Class 1 indicates the portion of these resources which would average 35 gallons per ton over a continuous interval of at least 30 feet.

Class 3: Although matching Classes 1 and 2 in richness, more poorly defined and not as favorably located.

Class 4: Lower grade, poorly defined deposits ranging down to 15 gallons per ton.

water from the Colorado River and/or its tributaries to meet mining and processing needs, these net withdrawals, plus runoff from the spent shale, may increase salinity even further.

Although groundwater resources in the Piceance Basin are not well known, the area is believed to have substantial water in a leached zone beneath the Mahogany Zone. Other basins have more limited prospects.

2.2.4 Ownership of the Resources

About 80 percent of the high-grade shale lands in the Green River Formation are owned by the federal government (House Committee on Science and Astronautics, 1973: 4). Private lands extend almost uninterrupted along the southern margin of the Piceance Basin. Several pilot-scale development operations have been conducted on the private lands, and the first commercial-scale operation will be located in this area. Federal ownership predominates elsewhere, although the title to much of the land is under challenge on the basis of prior claims not yet litigated (Table 2-4). About 85 percent of the federal oil shale land has a clouded title. More than 75 percent of the private acreage is controlled by seven firms (Interagency Task Force, 1974: 100).

2.3 EXPLORATION

Oil shale resource development involves a sequence of activities beginning with exploration (Figure 2-1) and terminating with the transportation of upgraded syncrude or refined products. This section describes the exploration technologies.

2.3.1 Technologies

Exploration activities for oil shale are essentially the same as those described for coal: regional appraisal, based heavily

TABLE 2-4

OWNERSHIP OF GREEN RIVER FORMATION OIL SHALE LANDS
(THOUSANDS OF ACRES)

Ownership	Colorado	Utah	Wyoming	Total
Federal oil shale land (clear title)	320	780	70	1,170
Federal oil shale land (clouded title)	1,100	3,000	2,600	6,700
Nonfederal oil shale lands including Indian and state lands	380	1,120	1,630	3,130
TOTAL	1,800	4,900	4,300	11,000

Source: Interior, 1973: Vol. I, pp. II-104 through II-106.

on inferences from exposed rock formations, and physical evaluation, involving extensive drilling and coring. The current focus is on the physical evaluation of tracts in the Piceance Basin. A large portion of the exploration effort, past and present, has been handled by USGS.

2.3.2 Energy Efficiencies

The energy inputs during exploration are ancillary. Precise amounts have not been calculated, but the inputs appear to be small compared to those required by the other activities.

2.3.3 Environmental Considerations

Environmental residuals from exploration are limited to surface and subsurface physical disturbances associated with drilling and coring and to emissions from vehicles used in the exploration process. The residuals are usually localized and small. An estimate of the quantity of dust produced by these activities has not been made.

2.3.4 Economic Considerations

Although no data are available on oil shale exploration costs, the techniques are similar to those used for coal and thus the discussion of exploration costs in Chapter 1 should be relevant. This would suggest that costs are less, proportionately, for high-quality deposits, thicker zones, and deposits close to the surface. Some regional appraisals are done by government, and the results (together with resource data compiled from other sources) are made available at minimal direct cost to private developers.

2.4 MINING

As Figure 2-1 indicates, the oil shale development sequence proceeds in one of two directions after the exploration stage. The oil-bearing rock can be mined and then processed on the surface, or the rock can be processed underground (<u>in situ</u>) and the resulting liquids withdrawn by wells. This section is limited to a description of oil shale mining; the <u>in situ</u> approach is described in Section 2.7, Processing. Although reclamation is a corollary of mining, its discussion follows the processing section because by-products from surface processing are primarily a reclamation problem.

2.4.1 Technologies

Although the broad categories of technologies used to mine oil shale are similar to those used in mining coal, the actual operation and specific equipment items in an oil shale mine differ significantly from coal mining, primarily because the characteristics of the two resources are so different. For example, oil shale deposits are often much thicker than coal seams, and oil shale is considerably harder than coal.

Like coal, oil shale can be mined either underground or from the surface. Although there is no commercial oil shale mining operation in the U.S. at present, two prototype underground mines have been developed and the techniques used in these mines are believed to be feasible on a commercial scale. Surface mining of oil shale has not been attempted in the U.S., but two of the four tracts leased in the prototype leasing program are expected to be mined from the surface.

2.4.1.1 Surface Mining

In general, surface oil shale mines involve the same specific activities as surface coal mines: surface preparation, fracturing, and excavation.* The drilling, blasting, and excavation technologies described for surface coal mining also apply to surface oil shale mining. However, since oil shale zones can be very thick, some surface oil shale mines may be deeper and larger than surface coal mines. These mines are more like limestone quarries or open-pit copper mines than coal mines. A deep mine of this sort is likely to have several working benches, such as the mine illustrated in Figure 2-5.

Primarily for economic reasons, surface mining is likely to be preferred for very thick (e.g., over 100 feet) oil shale deposits relatively near the surface. Surface mining might also be feasible for very thick, deeper seams as well, but the size of the mine would have to be enormous to be economical (Hottel and Howard, 1971: 195).

2.4.1.2 Underground Mining

To date, the only oil shale mining in the U.S., even on a prototype or pilot scale, has been underground. Although generally similar to underground coal mining, underground oil shale mining involves some significant differences, mainly because of the greater thickness and hardness of the producing zones.

Access to a production zone is usually through a tunnel dug into the side of a valley where an outcrop appears. (An outcrop is a place where an underground rock formation surfaces.) These tunnels are larger than those found in coal mines but, in the prototype mines, they have been dug using conventional drilling, blasting, and loading equipment and techniques. In a commercial-scale mine, moles and other advanced cutting machines might be used. If such machines are found to be capable of efficiently cutting materials as hard as oil shale, they would allow the operation to proceed more rapidly, be less labor-intensive, and produce more stable tunnels, thus requiring less auxiliary support. However, these machines would be more capital-intensive and less versatile than conventional equipment, which will probably be used in the first commercial oil shale mines (Senate Interior Committee, 1973: 51).

Underground oil shale mines will probably use the room and pillar approach, primarily because it offers the most efficient method for mining hard materials underground

*See Chapter 1 for a discussion of these activities.

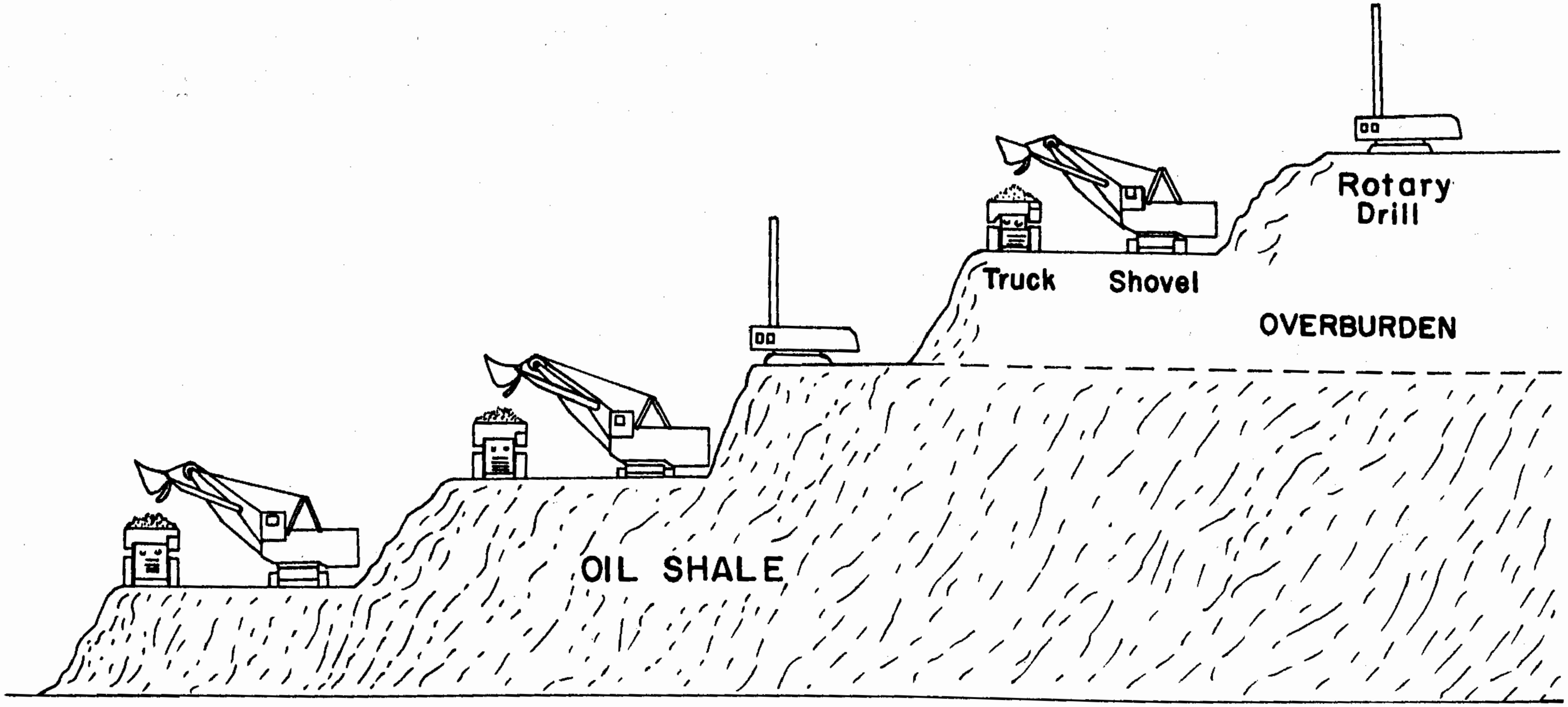


Figure 2-5. Hypothetical Oil Shale Surface Mine

Source: NPC, 1972b: 51.

(Welles, 1970: 26-30).* However, the oil shale mines will differ from coal mines in that the rooms and pillars will be larger (on the order of 60 feet square) and the floor-to-ceiling clearance will be greater (ranging from about 60 to 80 feet) (East and Gardner, 1964: 33). The prototype method illustrated in Figure 2-6 allows mining on two levels. First, the upper 30 feet or so are removed, then deeper cuts are made in selected areas. When the mine is in full operation, extraction proceeds on both levels at the same time.

The steps in the oil shale mining sequence (fracturing and excavation) are the same as those for coal, and the technologies presently used are similar. Rotary drills prepare holes for blast charges which fragment a part of the oil shale zone. After fragmentation, the shale is loaded onto a large truck or conveyor by a large front-end loader and moved to a crushing facility outside the mine. A preliminary study conducted by the U.S. Bureau of Mines (BuMines) indicates that a continuous miner could be used for excavation (East and Gardner, 1964: 127) but the system has not yet been tested.

Although the extracted material is almost entirely oil shale, the oil content of the shale may vary considerably because, as mentioned earlier, a single zone contains layers of varying quality. Generally, the mined zone consists of a thick stack of layers with an average yield of 30 gallons per ton or higher. Lower yield layers of oil shale above the mineral zone are treated as overburden, but there is no separation of material within the zone into high- and low-quality seams.

Underground mining is likely to be preferred whenever deposits are too thin or deep for surface mining to be attractive. The prototype mines involve more or less horizontal movement into a 60- to 80-foot thick deposit from the edge of a basin.

*Room and pillar mines are described in Chapter 1.

2.4.1.3 Mine Safety

Safety techniques in both underground and surface oil shale mines should be similar to those used in surface coal mines. Most of the shoring techniques required in underground coal mines will probably not be needed in oil shale mines because the shale's greater strength results in a more stable roof. However, both expanding-head and epoxy roof bolts (as described in Chapter 1) will be used to provide an additional safety margin.

Since tunnels and rooms will be much larger, ventilation in oil shale mines should not be a major problem, and there is no danger of toxic gases being trapped in the zone.

2.4.2 Energy Efficiencies

The conditions under which oil shale resource development will take place may vary significantly from place to place, and some of the conditions can be affected by the scale of the operation. The Hittman estimates of energy efficiencies and environmental residuals for oil shale are based on a few prototype or pilot mines and thus are indicative rather than authoritative. These estimates include assumptions that the land used will be reclaimed and that treatment of mining water, as part of the mining process, will reduce water contamination to zero.

The efficiency of oil shale mining is assessed by the percentage of in-place oil shale that is recovered (there is some variation in how this is defined) and by the ancillary energy required to power the mining equipment under controlled conditions. Although neither is the equivalent of an overall efficiency measure, these two measures provide a basis for comparing the relative efficiencies of surface and underground mining methods.

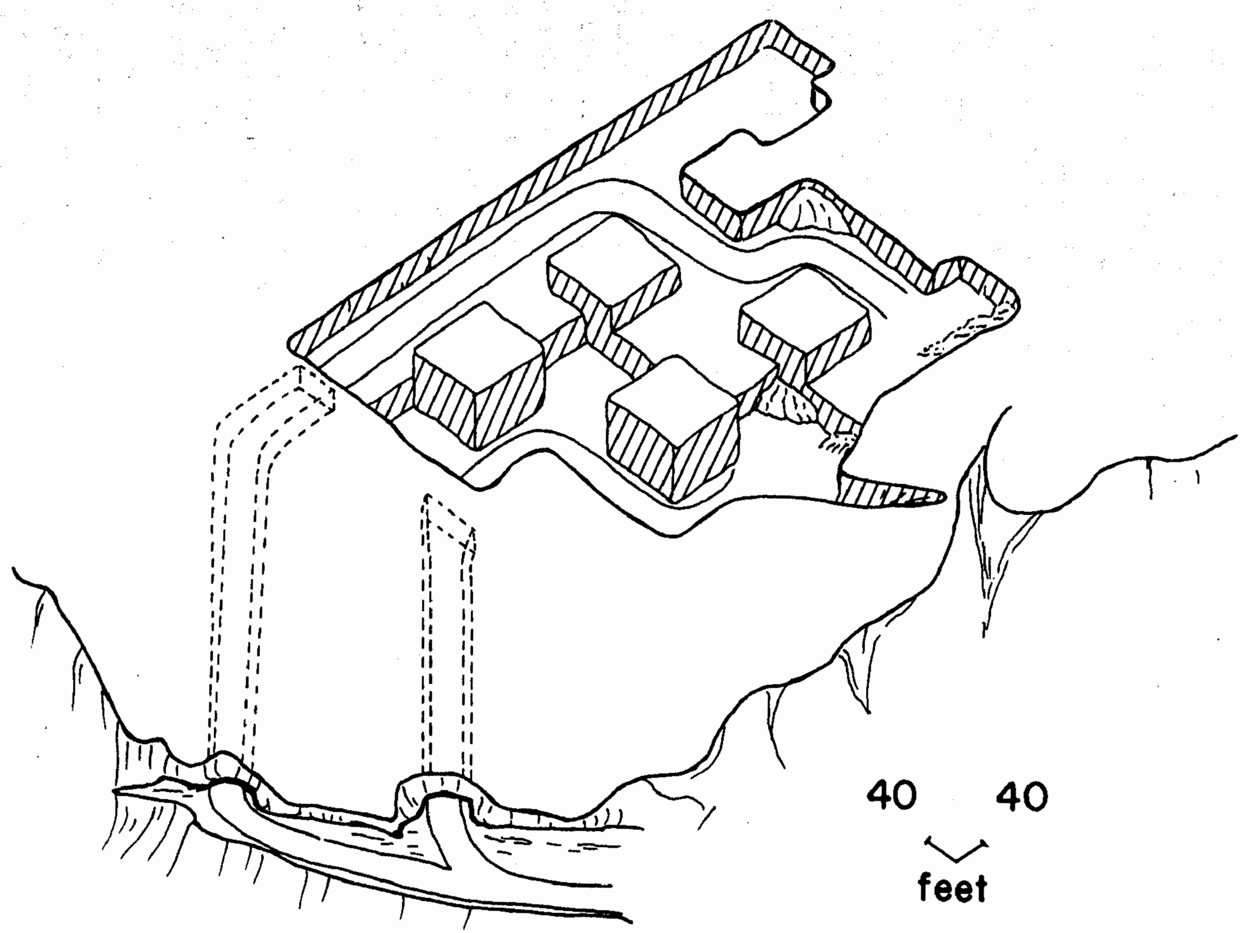


Figure 2-6. Small Room and Pillar Oil Shale Mine

Source: East and Gardner, 1964: 33.

TABLE 2-5

ENERGY EFFICIENCIES FOR OIL SHALE MINING

Method	Recovery Efficiency (percent)[a]	Ancillary Energy (10^9 Btu's per 10^{12} Btu's)[b]
Surface mining	62	0.57
Underground mining	65	1.27

Source: Hittman, 1975: Vol. II, Table 3 and footnotes.

[a]These figures appear to be based on different conceptions of how the "resource in place is defined" (see the text) and are not directly comparable.

[b]This is calculated on the basis of the energy value of the resource in place, not the energy value of the resource extracted or that portion of the mined resource that may be subsequently processed.

2.4.2.1 Surface Mining

Estimates of the recovery efficiency and ancillary energy requirements for surface mining are presented in Table 2-5. Recovery efficiency data are estimated to have errors of less than 25 percent, while ancillary energies are less certain, with errors less than 50 percent. The recovery efficiency for a mine supporting a 100,000-barrel-per-day processing operation is estimated at 62 percent. (The remaining 38 percent consists of lower grade oil shales--less than 30 gallons per ton--which are not processed.) This suggests that the efficiency figure is a proportion of all the oil shale in a deposit, not just a target zone with especially high yield, because nearly 100 percent of the target zone will be mined.

Ancillary energy requirements are almost equally divided between electricity for shovels and diesel fuel for hauling. These needs are relatively small, less than 0.1 percent of the energy value extracted.

2.4.2.2 Underground Mining

Table 2-5 also includes estimates of the recovery efficiency and ancillary energy requirements for underground mining. Data uncertainties are the same as for surface mining. For a mine supporting a 50,000-barrel-per-day processing operation, the recovery efficiency is estimated by Hittman at 65 percent; the remainder is left in the mine as roof-support pillars to prevent land subsidence. Here, the efficiency figure is based solely on the target zone, from which nearly all of the extracted rock is processed. An underground mining efficiency comparable to the surface mining figure, which includes lower-grade deposits overlying the target zone, is 40 percent.

Although ancillary energy in underground mining is used for the same purposes as in surface mining, electricity requirements are more than six times greater and diesel fuel requirements are about one-fifth those of surface mining. However, the total ancillary energy needs are still small, approximately 0.1 percent of the energy value extracted.

2.4.3 Environmental Considerations

2.4.3.1 Surface Mining

Just as for other minerals, surface mining of oil shale involves many forms of residuals. Table 2-6 gives estimates of

Table 2-6. Residuals for Oil Shale Mining[a]

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[b]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
UNDERGROUND																					
Room and Pillar	0	0	0	0	0	0	0	0	0	0	.354	.076	.005	.008	.046	.0006	17.5	.04/.13 1.97	.0041	.189	NA
SURFACE																					
Open Pit	0	0	0	0	0	0	0	0	0	0	.013	.379	.028	.038	.231	.003	50300	0/.27 3.99	.0011	.054	NA

[a]Residuals are based on 10^{12} Btu's of energy in the ground, not 10^{12} Btu's extracted. To convert the listed values to a base of 10^{12} Btu's extracted, divide by the primary efficiency. (See text for an explanation.)

[b]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

air and water pollutants, solid wastes, and land consumption that would result from oil shale mining under controlled conditions. Data uncertainties are on the order of 50 percent. However, total control of water pollutants will require that surface runoff be directed away from the mine, that seepage be used for dust control and reclamation, and that any other contaminated water be either injected into deep wells or purified before being released. The feasibility of these controls for a commercial-scale mine has not yet been demonstrated. The contamination of groundwater supplies by saline mine water is a possibility, but no amount has been estimated.

2.4.3.1.1 Air Pollutants

The air pollution estimates given in Table 2-6, which amount to less than one ton of air pollutants per 10^{12} Btu's of oil shale energy in the ground, assume that air emissions are from vehicular traffic and that dust will be controlled by water sprays (a difficult job in a dry area like western Colorado or Utah). The data assume an average conveyor (shovel-to-crusher) distance of 2,000 feet, an average overburden thickness of 450 feet, and a haul distance for overburden disposal of one mile. If an actual mine involves more vehicular movement, the residuals will be higher.

2.4.3.1.2 Solid Wastes

Solid wastes consist of the overburden removed to expose the oil shale and low-grade oil shales which are not processed. During the first 16 years of commercial production, the expected average quantity of solid wastes is 94,200 tons per 10^{12} Btu's of energy value in the ground; the expected average over 30 years is 50,300 tons. These estimates assume an average overburden of 450 feet, a portion of which will be used to fill mined-out cavities after the first 16 years of a 30-year mine lifetime. If a mine is supporting a 100,000-barrel-per-day processing operation, it will produce an average of nearly 90,000 tons of solid wastes per day--an amount that would cover 25-plus acres to a depth of one foot. Obviously, the amount would be less for a mine with a shallower overburden. For information on the handling of these wastes (and the spent shale from processing activities), see the description of reclamation activities in Section 2.8.

2.4.3.1.3 Land

As an average, about six acres will be affected for each 10^{12} Btu's of energy extracted, including the mine pit and the disposal of overburden and waste shale (shale averaging less than 30 gallons per ton in yield). This average assumes that the disposal will be handled largely by filling deep canyons near the mine and backfilling into the mined-out pit (Section 2.8). Obviously, solid waste disposal accounts for a major portion of the total land requirement per mine.

2.4.3.1.4 Water Production and Use

Surface mining requires water for dust suppression and reclamation of solid wastes. Some water may result from seepage in the deep mine pit, but the quantities of water required will usually necessitate an outside-mine source. The actual mining operation uses only about two percent of the water required in a complete oil shale development trajectory. Solid waste reclamation can require a much higher percentage (Section 2.8).

2.4.3.2 Underground Mining

Environmental data for controlled underground mining are shown in Table 2-6. These data have an error probability of 50 percent or less.

2.4.3.2.1 Water Pollutants

Water pollutants are defined by Hittman as negligible. If low-quality mine water with dissolved solids ranging from 200 to 63,000 parts per million (ppm) is encountered, it is to be used for dust control and reclamation, filling a need that otherwise must be met from nearby surface sources. The possibility exists that water with higher salinity might be encountered, and this would be more difficult to treat or use.

2.4.3.2.2 Air Pollutants

Air pollutant estimates (which total about one-half ton of material per 10^{12} Btu's of oil shale energy in the ground) outside the mine include particulates from both vehicular traffic and blasting within the mine. Other emissions, from vehicular traffic inside the mine, are dispersed into the atmosphere by exhaust fans.

2.4.3.2.3 Solid Wastes

Solid wastes from underground mining consist mainly of rock removed to an access to a high-grade zone. The solid waste data assume that overburden removal to gain entrance to the mine is a onetime activity rather than a continuing production. The waste from four mine shafts, if each was 25 feet in diameter and 1,500 feet deep, would amount to 17.5 tons per 10^{12} Btu's in the mined zone. However, this estimate is less than 0.1 percent of the equivalent residual for surface mining. Spent shale is considered in Section 2.7.

2.4.3.2.4 Land

Land use is about two acres per 10^{12} Btu's in the ground or about three acres per 10^{12} Btu's recovered. This includes incremental use of land for the portion of waste shale disposal that cannot be returned to underground voids as well as land for mine openings, equipment storage, maintenance, etc. Subsidence of the land surface from underground oil shale mining is not considered likely.

2.4.3.2.5 Water Production and Use

The primary water requirement in underground mining is for dust suppression. Although less dust suppression water (and considerably less solid waste disposal water) is needed in underground mines, shaft and tunnel seepage will probably not meet total water requirements.

2.4.3.3 Environmental Summary

Environmental residuals are generally lower in underground mines than surface mines, particularly in the amount of solid wastes. The only exception, a minor one, is the quantity of particulates emitted into the air, which reflects the greater practicability in surface mines of using water sprays for dust suppression. This suggests that, on a basis of environmental impact, underground mining is preferable.

2.4.4 Economic Considerations

Cost estimates for oil shale mining are listed in Table 2-7. Underground mining is perhaps twice as expensive as surface mining, but larger mines probably reduce costs per 10^{12} Btu's recovered in either case. In the Hittman estimates, the costs include the assumptions mentioned above and environmental pollution controls. The Hittman estimates have a probable error of less than 50 percent. Fixed costs include deferred capital and interest during construction, and operating costs include payroll, supplies, labor, taxes, and insurance.

2.5 WITHIN AND NEAR-MINE TRANSPORTATION

2.5.1 Technologies

Mine transportation consists of mine-to-crusher (preparation) and crusher-to-processor links. Oil shale may be moved from excavations to crushing facilities by either truck or conveyor. From the crusher to the processor, the shale normally is moved by conveyor. The general technologies for these transportation systems are described

TABLE 2-7

COSTS FOR OIL SHALE MINING
(DOLLARS PER 10^{12} BTU'S EXTRACTED)[a]

Method	Hittman Estimates			Interagency Oil Shale Task Force
	Fixed Cost	Operating Cost	Total	Total
Underground (room and pillar)	7,740	79,300	87,400[b]	105,440[c] 96,940[d]
Surface (open pit)	8,430	30,300	38,700[e]	90,700[f]

Source: Hittman, 1975: Vol. II; Interagency Oil Shale Task Force, 1974a: Appendix H.

[a]Estimated costs are strongly influenced by assumptions about mine size.

[b]Mine size: 73,600 tons per day.

[c]Mine size: 50,000 tons per day.

[d]Mine size: 100,000 tons per day.

[e]Mine size: 147,200 tons per day.

[f]Mine size: 100,000 tons per day.

in Chapter 1. Surface oil shale mines use equipment similar to that used in surface coal mines. In underground oil shale mines, however, the larger rooms and shafts allow use of surface-type diesel trucks rather than the low-profile equipment used in coal mines. The movement distances are expected to be short because of the great bulk of the resource.

2.5.2 Energy Efficiencies

According to the Hittman data, the primary efficiency of the within and near-mine transportation options is 100 percent. Based on a movement distance of one mile, ancillary inputs for trucks (total diesel fuel consumption) are 3×10^8 Btu's per 10^{12} Btu's transported or about .03 percent. For a 1,000-foot rise/fall inclined-belt conveyor, ancillary inputs (electricity) are estimated to be 2.6×10^9 Btu's per 10^{12} Btu's or somewhat less than 0.3 percent.

Thus, although a conveyor requires 10 times more ancillary energy than a trucking system, both amounts are small in terms of the energy value of the transported oil shale. Also, the conveyor estimate apparently includes an assumption of a steeper grade than the truck estimate. The energy efficiency and ancillary energy estimates are considered to be good, with a probable error of less than 25 percent.

2.5.3 Environmental Considerations

Environmental residual estimates are listed in Table 2-8 and are considered good to fair, with an error of less than 50 percent. Water pollution is assumed to be controlled and thus is zero according to Hittman. This is apparently based on engineering criteria and has not been demonstrated on any large scale. Air pollution, amounting to about one-half ton of pollutants per 10^{12} Btu's transported, is limited to particulate dust from conveyors and

Table 2-8. Within and Near-Mine Transportation Residuals for Oil Shale

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)							F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (Tons/10^{12} Btu's)	Land $\frac{\text{Acre-year}}{10^{12}\text{ Btu's}}$	Deaths	Injuries	Man-Days Lost
Conveyor	0	0	0	0	0	0	0	0	0	0	.481	0	0	0	0	0	0	.04/0 .04	U	U	U
Truck	0	0	0	0	0	0	0	0	0	0	.014	.404	.029	.04	.245	.003	0	.02/0 .02	U	U	U

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

trucks, and emissions from engine exhaust. Dust is controlled by water sprays. Oil shale dust from the loading operation is also assumed to be suppressed. Solid wastes are negligible. Land use consists of one mile of right-of-way, 60 feet wide for a 48-inch conveyor and 30 feet wide for a road. Water requirements, which are almost entirely for dust suppression, can be considerable for a one-mile truck transportation system in a dry climate.

2.5.4 Economic Considerations

Economic data, shown in Table 2-9, can be considered fair, with a probable error of less than 50 percent. They indicate that truck transportation is five or six times more expensive than conveyor transportation because of a sharp difference in operating costs. The conveyor figures refer to an inclined-belt conveyor system handling 2,100 tons per hour. The truck estimates are based on two road graders, two water trucks, and 50 100-ton dump trucks. The operating cost advantage of conveyors is striking (40 to 50 times less) despite the higher ancillary energy input required. However, trucks may be the better choice for a specific mine because a conveyor is a less flexible piece of equipment, equipment breakdown in a conveyor system can be more disruptive, and these transportation costs are a relatively small part of the total trajectory costs. In prototype mines, the only technology used so far has been trucks.

TABLE 2-9

WITHIN AND NEAR-MINE TRANSPORTATION COSTS FOR OIL SHALE (DOLLARS PER 10^{12} BTU'S TRANSPORTED)

Method	Fixed Cost	Operating Cost	Total Cost
Conveyor	1,490	146	1,640
Truck	2,460	6,740	9,200

Source: Hittman, 1975: Vol. II, Table 3.

2.6 PREPARATION

2.6.1 Technologies

When mined, oil shale tends to break into large pieces weighing as much as several tons. Since the feedstock for processing must be within certain size limits, crushing and sizing is required, with the activity located near (or even in) the mine to facilitate transportation. The location of the crusher depends on the configuration of the within and near-mine transportation system.

The crushing is done in several stages. In one system, the first stage reduces pieces to less than about one foot in diameter, the second to less than about four inches, and the third to less than about three inches. The stages are linked by conveyor. Beyond this point, preparation activity depends on the needs of the processing technology to be used. If the processor cannot accept fine particles, these particles (smaller than about one-quarter of an inch) are removed, crushed further, mixed with oil, and formed into briquettes large enough to be used. If the processor can accept fine particles, the three-inch material is crushed to the maximum particle size for the process but is not screened. After any of the crushing stages, the oil shale may be routed through a storage facility (stockpiled) as protection against an interruption in supply. For example, to guard against processor shutdowns resulting from conveyor breakdowns, a three-day supply of oil shale may be stored between the primary and final crushing stages.

The main technological challenge in the crushing operation is dust suppression. Figure 2-7 illustrates one concept for this in the first crushing stage--the conversion of material direct from the mine into moderate-sized chunks.

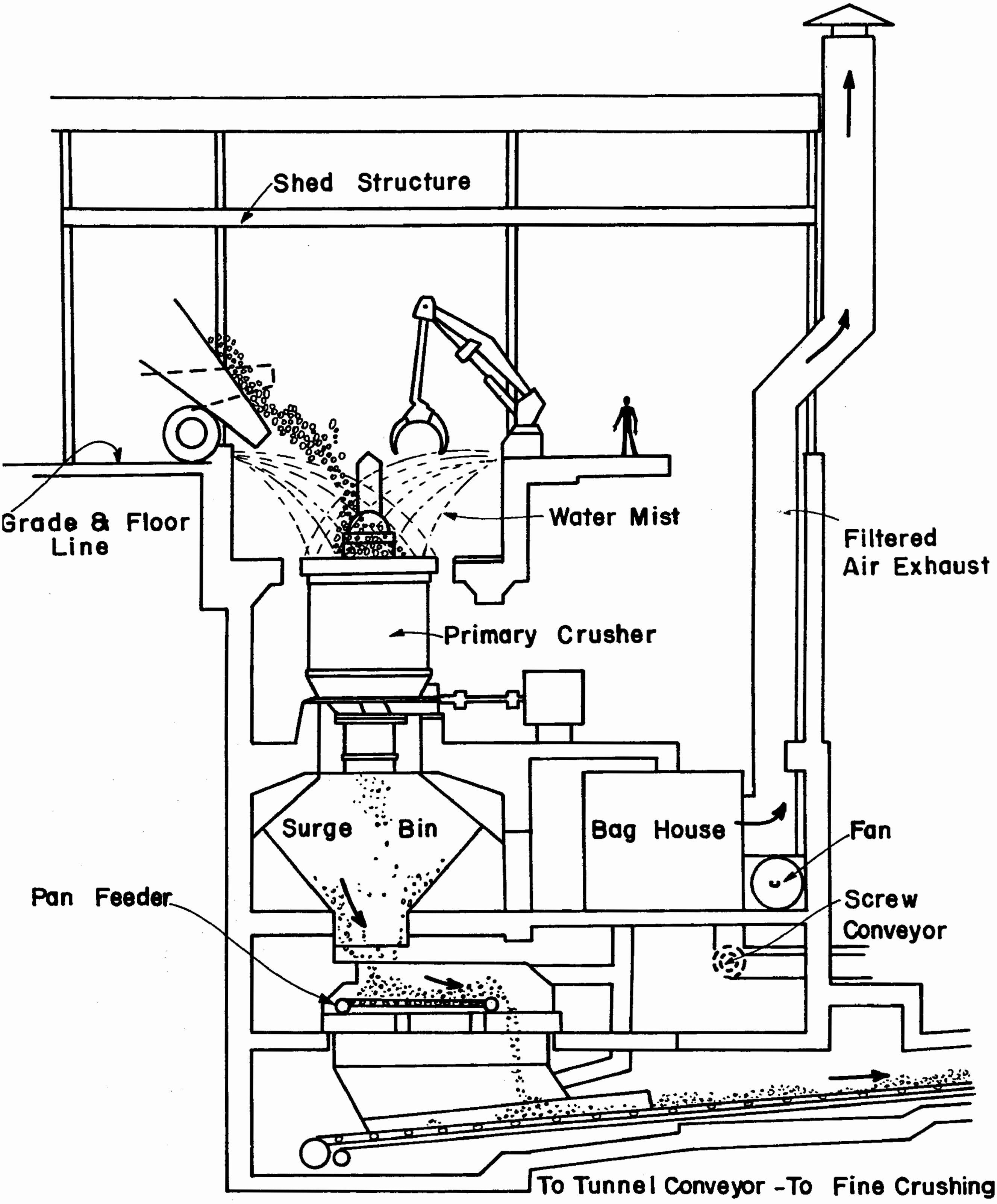


Figure 2-7. Primary Crusher Dust Control

Source: Adapted from Colony Development Operation, 1974: 178.

2.6.2 Energy Efficiencies

Hittman estimates the primary energy efficiency for the crushing operation, with a probable error of less than 25 percent, to be 98.7 percent. The losses are in dust and spillage. Ancillary energy inputs, the power required to operate the crushing equipment, amount to 8.4×10^8 Btu's per 10^{12} Btu's entering the crushing stage or less than 0.1 percent of the energy value.

2.6.3 Environmental Considerations

Environmental residuals from crushing are listed in Table 2-10 and should be considered good, with a probable error of less than 25 percent. Although wastewater from wet collection devices is high in suspended solids and contains a dust suppressant (sulfonate), water residuals are assumed to be zero. This assumption requires that the wastewater be piped to reclamation areas and used for irrigation of spent shale, with any excess runoff from the spent shale pile being trapped in holding ponds and recycled. Water requirements for dust suppression are expected to amount to three to five percent of the total water use in an oil shale development trajectory involving mining.

Air pollution is in the form of fugitive dust and amounts to 0.84 ton per 10^{12} Btu's crushed. This assumes that the crushing system includes wet and dry dust collection devices. Solid wastes are wastes from the dust control devices and spillage from the crushers. A mine with an output of 73,600 tons of oil shale per day would generate about 960 tons of waste oil shale per day. The land-use figure in Table 2-10 refers to a 15-acre crushing operation handling 73,600 tons per day with three days storage. Because data are available on only one operation, they are of questionable validity and should be assumed to have a probable error of less than 100 percent.

2.6.4 Economic Considerations

According to Hittman, the fixed crushing cost for an oil shale input of 10^{12} Btu's of energy value will be $6,770 (assuming a 10-percent fixed charge rate), and the operating cost, based solely on ancillary energy consumption, will be $1,330. The total cost is $8,100 per 10^{12} Btu's. This assumes a 73,600-ton-per-day crushing operation. The probable error of the economic data is less than 100 percent.

2.7 PROCESSING

2.7.1 Technologies

Two stages are involved in the processing of oil shale to recover the hydrocarbons it contains. First, the oil shale is heated to form gas and oil by a pyrolysis reaction called "retorting." ("Pyrolysis" is the heating of organic material in an atmosphere that does not allow complete oxidation.) Under these conditions, the solid hydrocarbons decompose, producing a liquid hydrocarbon and a variety of gases. In the second stage, the liquid is upgraded for transportation and use (refineries or consumers of fuel oil). The major technology choices have to do with the retorting stage.

Of the oil shale products, the liquid (a synthetic crude oil) has received by far the most attention, and the descriptions that follow will focus on this syncrude. The gases are expected to be used within the processing complex as a source of power and a source of hydrogen for upgrading.

An oil shale processing complex will require substantial amounts of electricity and may therefore involve a power plant at the processing site. Such a plant would, of course, be a major consideration in the calculation of the various residuals. For example, water use would be significant.

2.7.1.1 Retorting

Retorting may be accomplished either on the surface after mining or underground.

2.7.1.1.1 Surface Retorting

Until very recently the only processing approach tested on a pilot-plant scale was surface extraction of the oil from mined shale in heating facilities called "retorts." In this approach, the shale is prepared (crushed) and heated in a closed vessel to a temperature between 850 and 950°F, at which the waxy, solid kerogen is converted into liquid and gaseous hydrocarbons. The reaction involves a decomposition of carbon compounds rather than their combination with other inputs. Inputs to the process are oil shale and heat; outputs are oil, gas, and spent shale.

Retort yields are compared by reference to the Fischer Assay yield of an oil shale sample. The actual yield for a particular process is determined largely by the method of introducing heat into the retort. Internal heating uses the combustion of part of the shale itself to provide the necessary heat; external heating generates heat in a separate combustor and transfers the heat to the reactor in hot solids or gases. Since it does not make direct use of any of the hydrocarbons in the shale introduced into the retort, external heating gives higher yields but has the disadvantages of greater complexity and a need for an energy source for the separate combustor.

The heating method also has an effect on the sizing of the oil shale injected into the retort. For internal heating, the particles have a lower size limit, constrained by the need to maintain a flow of gases inside the retort. External heating retorts can cope with fine particles. Because of the difference in feedstock sizes, the type of retort will determine the texture of the spent oil shale discharged.

In addition to the hydrocarbon liquid (called "shale oil"), several other outputs are characteristic of surface retorting and upgrading:

1. Gases which are used within the processing complex for power generation and as a source of hydrogen. The Btu content of these gases depends on the retorting method.
2. Spent shale, from which most of the hydrocarbons have been removed. This waste material has a greater volume than the very dense oil shale from which it was derived. Its disposal is the principal reclamation problem in the oil shale development sequence (Section 2.8).
3. Water vapor, which forms part of the pyrolysis gas from retorting. Therefore, the production of oil shale is water-forming (Hubbard, 1971: 21-25). The amount of water varies with the feedstock and the method of retorting, but it is a volume equal to about 20 to 40 percent of the oil produced or two to four percent of the weight of the shale processed (Hubbard, 1971: 21). The recovered water is expected to be used in upgrading and spent shale disposal near the processing site.

Mined oil shale might be processed by techniques other than pyrolysis retorting, but no other method appears technically and economically feasible at present. Also, unprocessed oil shale can be burned to generate heat for electrical power plants (UN, 1967: 97), but the sulfur and nitrogen content of kerogen is high and the heating value of American oil shale is low. The Institute of Gas Technology has done tests of the direct hydrogasification of raw oil shale, producing a gas with a heating value of 800 Btu's per cubic foot (cf) (as compared to 1000 Btu's per cf for natural gas), but the process does not appear commercially attractive at this time (FPC, 1973: VIII-2 through VIII-9).

Internal heating retort processes have been developed by BuMines and the Union Oil Company, and an external heating retort process has been developed by The Oil Shale Corporation (TOSCO). All three have been demonstrated in pilot plants, and the two internal heating processes have recently been expanded to include an external heating component. These processes are described below and compared in Table 2-11.

Table 2-10. Residuals for Oil Shale Preparation

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)							F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (Tons/10^{12} Btu's)	Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
Crushing	0	0	0	0	0	0	0	0	0	0	.84	0	0	0	0	0	1730.	.08/0.08	U	U	U

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

Table 2-11. Summary of Aboveground Retort Alternatives

Alternative	Feedstock Size (inches)	Cooling	Oil Gravity API	Oil Sulfur (percent)	Oil Nitrogen (percent)	OUTPUTS		Spent Shale Size (mean)	Spent Shale Compounds
						Gas (Btu's)	Gas (cubic foot per barrel)		
Union (internal heating)	1/8-5[a]	none	21	0.77	2.0	100	10,000	0.2 cm	oxides
Gas combustion (internal heating)	1/4-3[a]	none	20	0.74	2.2	100	10,000	0.2 cm	oxides
TOSCO (external heating)	less than 1/2	water cooled	28	0.80	1.7	775	923	0.007 cm	carbonates

Source: Interior, 1973: Vol. I.

[a]Neither the maximum nor the minimum feedstock dimension is firmly fixed.

2.7.1.1.1.1 Gas Combustion Retort

The BuMines gas combustion retort, developed during the 1950's, has served as a basis for several processes, including Petrosix and Paraho. In its basic form, it is a vertical reactor in which crushed oil shale is introduced at the top while air and other gases enter near the bottom (Figure 2-8). The shale is fed by gravity, falling downward through four zones in the reactor. The top zone preheats the shale; the second zone retorts the shale (heats the shale to 850 to 950^{o}F, the pyrolysis level); the third zone introduces air to burn the hydrocarbons remaining in the shale after pyrolysis, thus heating the higher zones; and the fourth zone cools the shale before it is passed through a grate and removed through a lock hopper.

Recycled gas (mostly inert) flows up from the bottom, air enters through nozzles above the cooling zone, and hot gases and vapor from the combustion and retorting zones are carried up to an outlet at the top of the retort. This mist is directed through centrifugal separators and an electrostatic precipitator to separate the oil and gas products. Part of the gas is then recycled to the retort while the rest is used in a power plant for the processing complex. An advantage of this process is that the solids flow through the reactor without the use of external pumps. The inputs and outputs of a 50,000-barrel-per-day processing system, using the Gas Combustion retort, are summarized in Table 2-12.

Cameron Engineers, in cooperation with Petrobas (the Brazilian national petroleum corporation) has modified the BuMines process to burn recycled gas outside the retort and use the hot gas as the source of pyrolysis heat (Petrosix). After start-up, this eliminates combustion inside the retort, simplifying temperature control and reducing problems with agglomeration inside the retort. The process is being tested in a pilot plant in Brazil.

The Petrosix process has been further modified by Development Engineering, Incorporated, under contract to a consortium of 17 companies and a program of tests is underway (the "Paraho" program).

2.7.1.1.1.2 Union Oil "A" Retort

Although the Union Oil retort is also a vertical internal-heating reactor, the flows in this retort are basically the reverse of those in the Gas Combustion retort. In this process, oil shale is introduced at the bottom of the reactor by a rock pump, and air enters at the top (Figure 2-9). The shale is pumped upward, where it meets downward-moving air, creating three zones of activity. At the top, cool air meets hot spent shale, cooling the shale and heating the air. Immediately below this area, in a combustion zone, the hydrocarbons remaining in the shale are oxidized, producing hot gases that heat the lower feedstock shale to pyrolysis temperature in a retorting zone. The retorting produces shale oil, which is drawn off at the bottom of the reactor with product gas and steam. The spent shale leaves the top of the reactor as clinkers.

As in the BuMines design, the heat transfer properties of the Union Oil retort negate the need for cooling water. The advantage of this design over the Gas Combustion design is that oil products cannot, before vaporizing, drip down to hotter parts of the reactor and leave heavy residues that eventually must be removed.

Union Oil has proposed an alternative system that would use several reactors, only one internally heated. One would gasify coke (from retorted shale) to produce hot gases which would provide pyrolysis heat to one or more retorts. These gases would be supplemented by heated recycled gas (Interagency Task Force, 1974b: 263,264).

2.7.1.1.1.3 TOSCO II Retort

TOSCO II retort is an externally-heated reactor that uses hot ceramic balls to heat

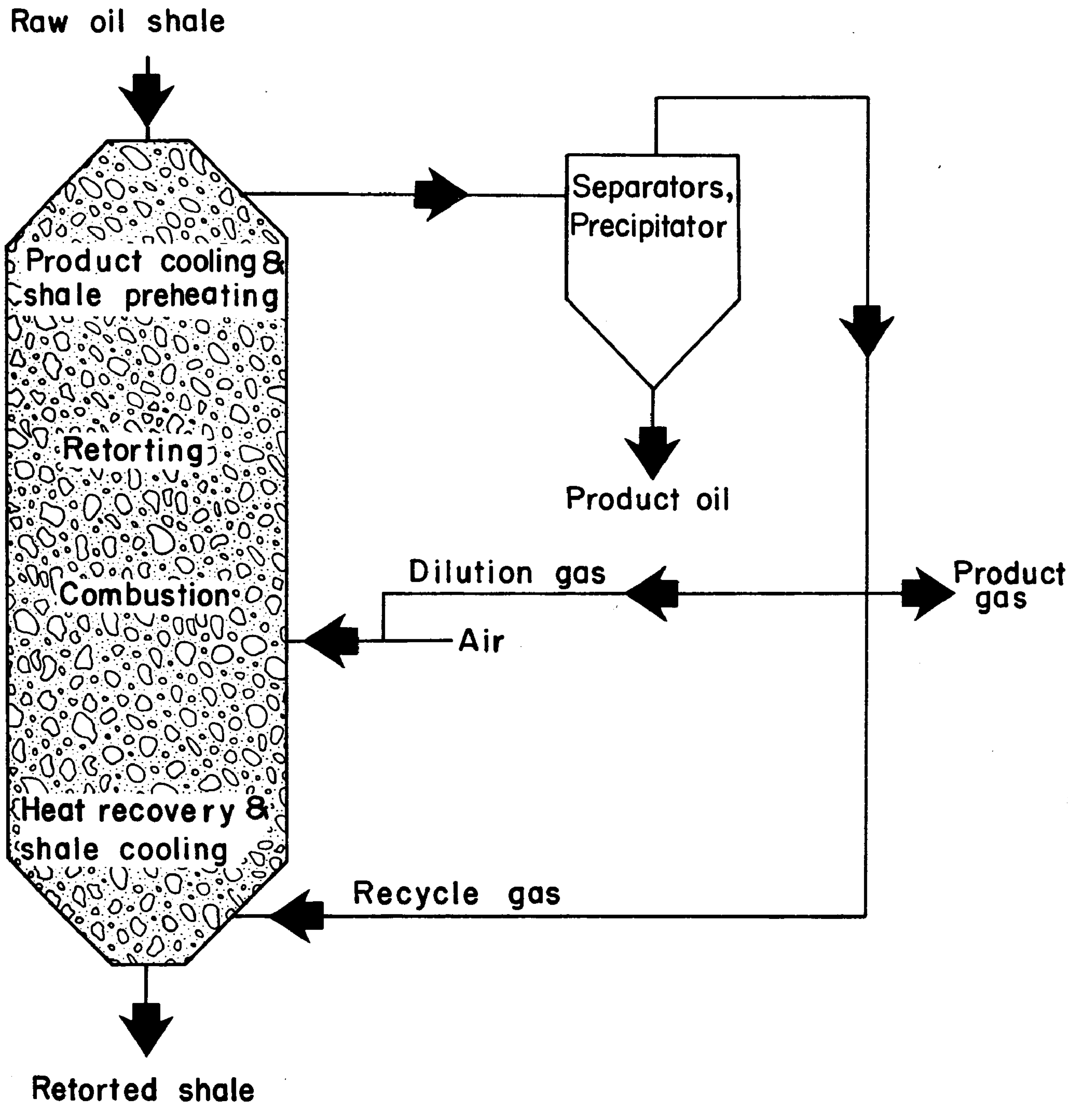


Figure 2-8. Gas Combustion Process

Source: BuMines.

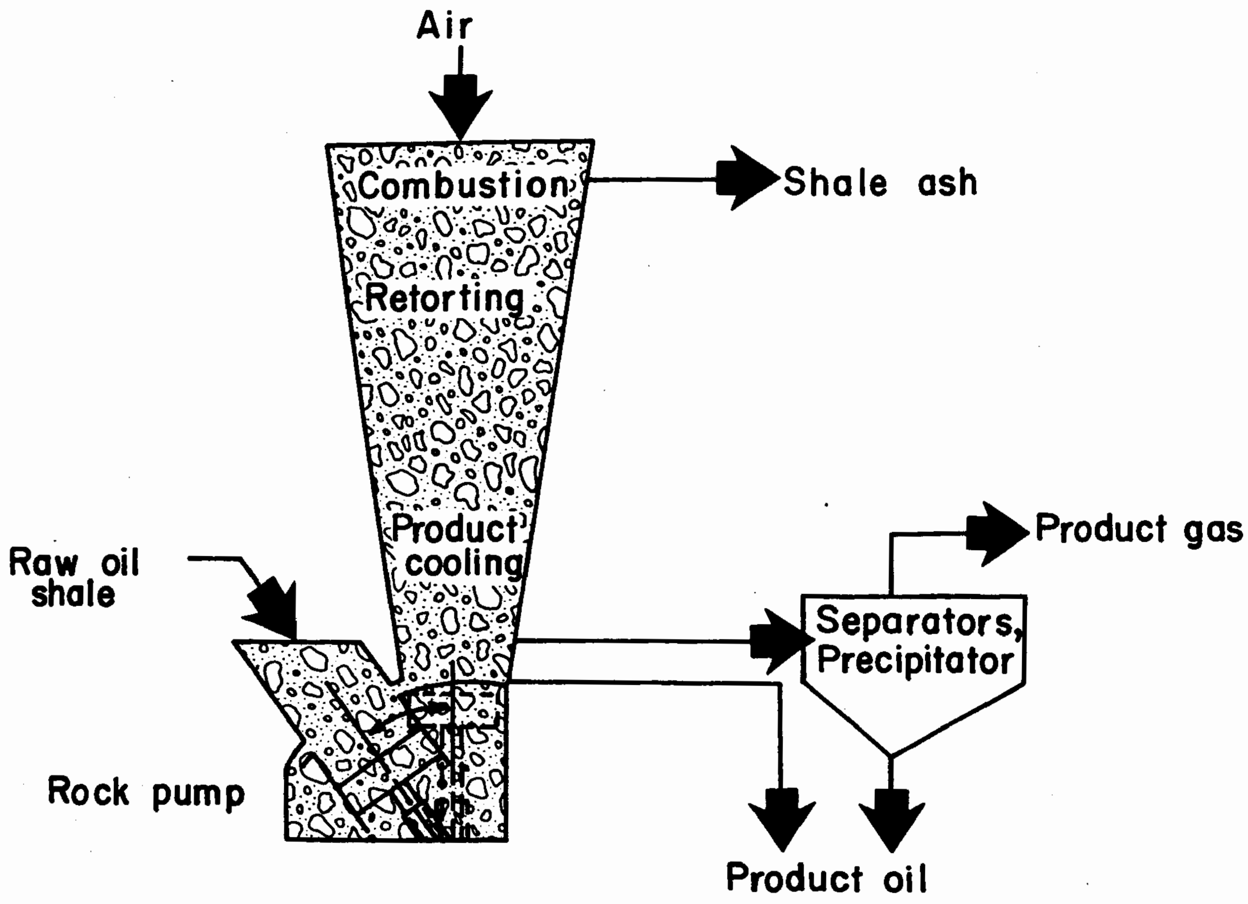


Figure 2-9. Union Oil Process

Source: BuMines.

TABLE 2-12

SUMMARY OF INPUTS AND BY-PRODUCTS FOR A GAS COMBUSTION RETORTING SYSTEM[a] (50,000-BARREL-PER-DAY CAPACITY, UPGRADING STAGES INCLUDED)

Input	Quantity	Output	Quantity
Oil shale	73,600 tons per day	Spent shale, air emissions	59,900 tons per day 24 tons per day
Water[b]	5.04 to 8.15 million gallons per day	Coke	2,050 tons per day
		Synthetic crude oil, at 42° API	50,000 barrels per day
		Water[b]	1,750 to 3,000 tons per day

Source: Hittman, 1975: Vol. II, Table 3 and associated footnotes; Table 16, this chapter; footnote 13, this chapter; Hubbard, 1971.

[a]Outputs, like low-Btu gas, and inputs, like heat, which are handled internally within a processing complex are omitted.

[b]See the discussion of water in the environmental considerations section.

the shale to pyrolysis temperature in a horizontal, rotating kiln (Figure 2-10). The shale, crushed to less than one-half-inch size, is fed into a fluidized bed* where it is preheated by hot combustion gases from a separate ball heater. After preheating, the shale is moved into the reactor and mixed with half-inch diameter heated ceramic balls from the ball heater. The heat in these balls transfers to the shale, effecting pyrolysis. The oil, steam, and gases are given off as a mist, which is fed to a fractionator for product recovery. The spent shale and ceramic balls are discharged from the pyrolysis drum and separated by a trommel screen. The balls are returned to the ball heater, and the spent shale is removed for disposal.

A fractionator (cyclone separator) separates the oil from the gas output. The gas is then burned to heat the balls in the ball heater. Since no combustion takes place in the reactor vessel, the resulting gas has a higher energy content and the oil a lower viscosity than that from an internally heated retort. These features, and the reactor's ability to handle fine particles, are advantages of the TOSCO II process.

2.7.1.1.2 In Situ Retorting

An alternative to surface preparation and retorting is underground (*in situ*) processing. The *in situ* approach involves fracturing the oil shale underground, introducing heat to cause pyrolysis underground, and collecting and withdrawing the shale oil, through wells, to the surface for upgrading. Two principal methods have been suggested: "horizontal sweep," with a pyrolysis zone advancing horizontally from a zone of heat injection to a line of liquid extraction wells, and "mine and collapse," with a pyrolysis zone advancing vertically in a large underground version of an internal heating retort. Garrett Research and Development Company, a subsidiary of

*Fluidized-bed reactors are described in Chapter 12.

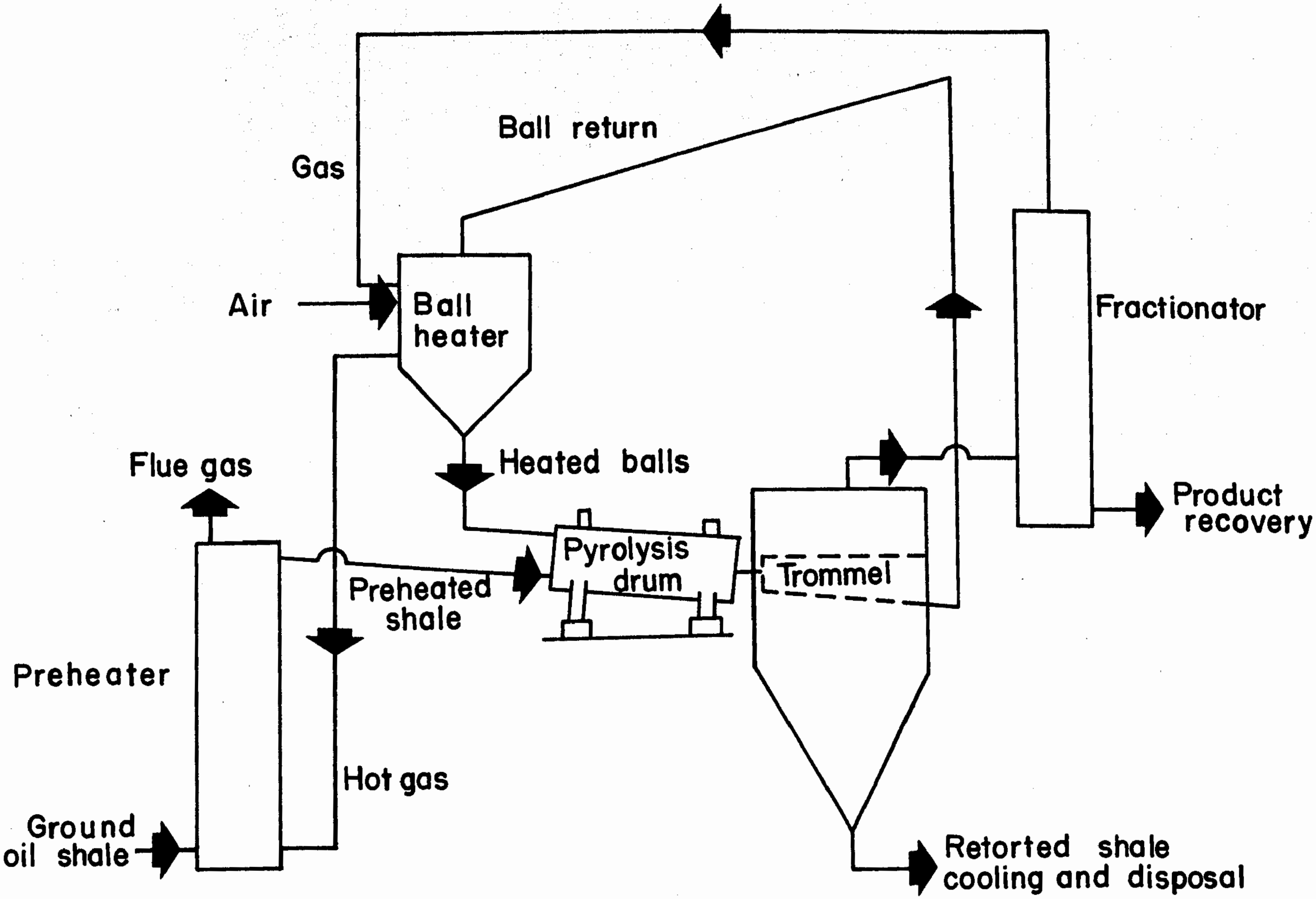


Figure 2-10. TOSCO II Process

Source: BuMines.

Occidental, has successfully tested one "mine and collapse" method at a pilot plant scale.

Many fracturing technologies are under study. Liquid chemical explosives, hydraulic pressure, and high-voltage electricity are being investigated (Hottel and Howard, 1971: 202), and the Garrett test used conventional explosives. Drilling and blasting technologies are described in Chapter 8.

Pyrolysis heat is generated by partial combustion of the fractured shale through the use of injected air, a mixture of air and recycled gas, or another method of oxidation, depending in part on whether the flow of retorting gases to recovery wells can be controlled.

The withdrawal of shale oil by wells involves essentially the same pumping technologies as for crude oil,* but the wells are relatively shallow (the overburden is seldom more than 2,000 to 3,000 feet thick).

There are advantages and disadvantages to in situ processing compared with mining and surface retorting (Hottel and Howard, 1971: 202,203; House Committee on Science and Astronautics, 1973: 14). Advantages include the avoidance of the costs and environmental residuals of mining and solid waste disposal, notably including a large part of the water requirements. Disadvantages are generally related to the early stage of technology development for in situ processing, especially an uncertainty as to how well combustion can be controlled, and the low recovery efficiency associated with current in situ processing technologies. However, the recent Garrett test indicates that these factors may no longer be serious problems, which improves the prospects of in situ processing substantially.

Two in situ processes merit specific description: a BuMines horizontal sweep approach and the Garrett mine and collapse method.

*See Chapter 3.

2.7.1.1.2.1 Bureau of Mines Process

The BuMines process, shown in Figure 2-11, calls for a series of wells to be drilled along two opposing sides of an oil shale deposit. The shale is then fractured by hydraulic pressure. Because of the shale's structural characteristics, the fracturing tends to occur along horizontal planes (Interior, 1973: Vol. I, p. I-14). The wells on one side are then used to introduce heat to the formation, either by pumping air down the wells and igniting the shale or by pumping down heated retorting gases which carry the necessary heat for pyrolysis with them. In either case, the heat decomposes the kerogen, and the pressure from the injection wells forces the oil along the fracture lines toward the opposing wells, through which the oil is recovered.

In theory, the process operates like a horizontal retort, with a retorting zone advancing across the formation ahead of a combustion zone, pushing the retorted shale oil ahead of it. This process has been tested on a small scale, but process control is difficult because the pattern of fracturing is still difficult to predict and it is hard to control the pace and extent of combustion.

2.7.1.1.2.2 Garrett Process

The Garrett process has been tested by a 25-gallon-per-day pilot plant operation near Grand Junction, Colorado (Chew, 1974). The process begins with the excavation of rock from just below the target zone, using conventional underground oil shale mining techniques. Shale oil collector pipes are installed in the floor of the mined area. From the surface, explosives are then sunk to the top of the formation and used to fracture the oil shale, filling the mined area and the overlying part of the zone with fragments. The result is a large room, 120 feet in diameter and 300 feet high, containing broken oil shale intermixed with air. The room is

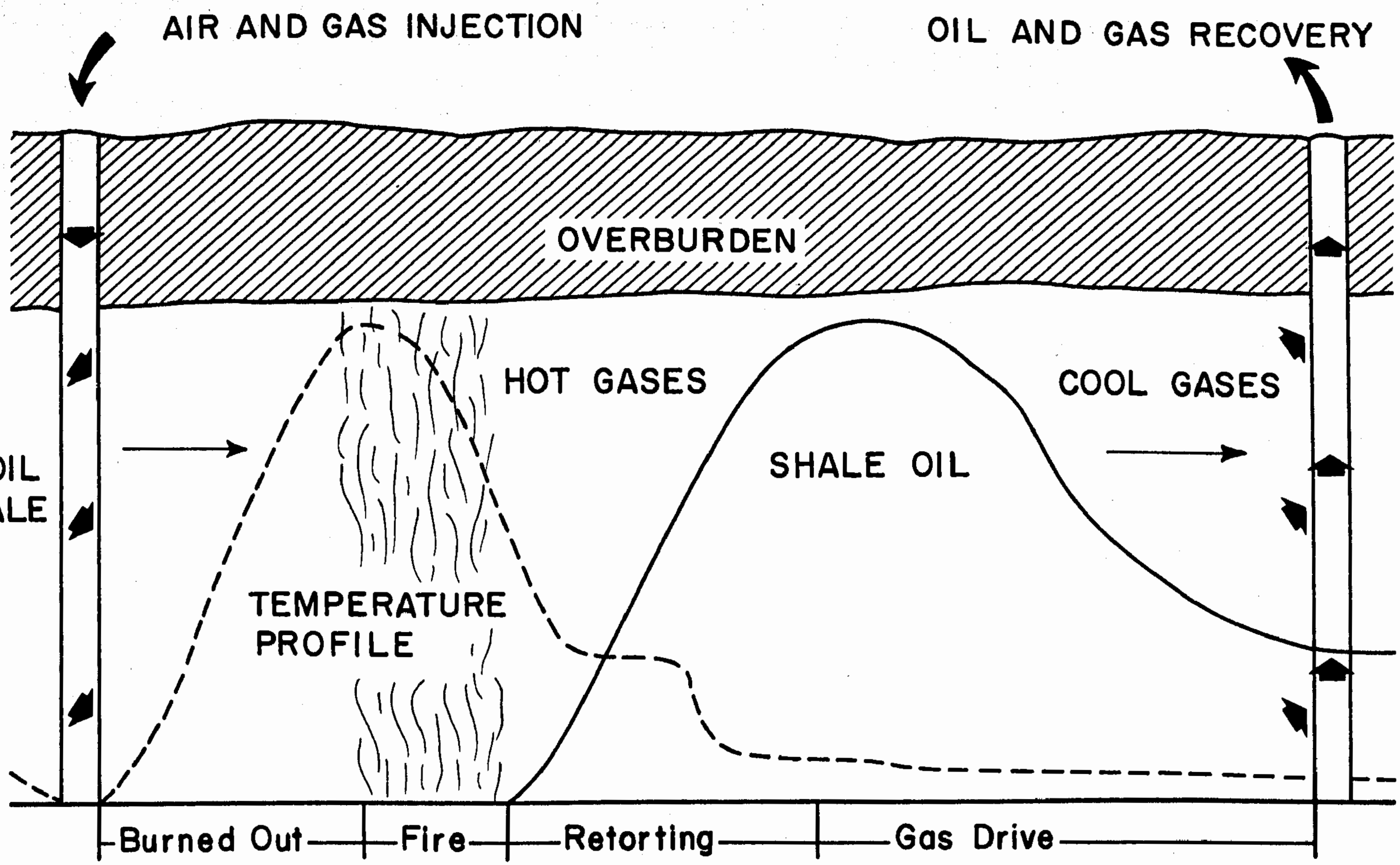


Figure 2-11. <u>In-Situ</u> Retorting Operation

Source: Interior, 1973: Vol. I, p. I-37.

used as a large underground retort, with fire introduced at the top and air or gas from the bottom. The downward-moving fire front releases oil that flows to the bottom and is removed through the collector pipes.

Garrett envisions two underground mines 75 feet apart, each 25 feet in diameter, extending horizontally under rows of retorts which are fired in retreating order. Pillars and bulkheads separate individual retorts, providing combustion control. The retorts are operated at low-velocity and low-pressure, burning slowly. As long as the yield of the oil shale is above 15 gallons per ton, the combustion consumes excess carbon, not shale oil. Activating 50 retorts at a time would produce 30,000 to 50,000 bbl of shale oil daily.

2.7.1.2 Upgrading

The upgrading stage is similar to the first stage in a conventional crude oil refinery, and the technologies are similar to those developed for crude oil refining (see Chapter 3). Upgrading is usually accomplished near the retorting site because the high viscosity of the heavy shale oil makes it hard to transport at ambient temperatures and the high sulfur and nitrogen content of the shale oil complicates conventional refining and use. Some of the differences between shale oil and pipeline-quality syncrude are indicated in Table 2-13.

Upgrading includes a number of steps. Figure 2-12 shows one representative configuration, illustrating the extensive internal use of products generated by individual steps in the process. However, the production of syncrude from the retorted shale oil directly involves only the following phases:

1. Sulfur and nitrogen removal by catalytic hydrogenation, using nickel and cobalt molybdate catalysts to combine hydrogen with nitrogen (as ammonia, NH_3) and sulfur (as hydrogen sulfide, H_2S).
2. Distillation by flash separation, separating the lighter hydrocarbons in the oil from the heavier ones.
3. Delayed coking, separating the lighter components from the heavier stream.
4. Hydrotreating, adding hydrogen to the lighter liquids to make them still lighter and less viscous (more easily flowing).

As indicated above, these technologies are standard, resembling the first stages in a conventional crude oil refinery (Chapter 3), and will not be described here.

As Figure 2-12 indicates, the upgrading stage generates two kinds of outputs in addition to those from the retorting stage:

1. Coke, a combustible solid output from the delayed-coking stage in upgrading. Although this is a possible fuel source, it does not appear to be economically feasible to transport it away from the processing plant.
2. Chemical by-products from catalytic hydrogenation and any other cleaning steps, like ammonia and elemental sulfur.

2.7.2 Energy Efficiencies

The Hittman estimates provide data on three alternatives: the Gas Combustion internal-heating surface retort, the TOSCO II external-heating surface retort, and the BuMines _in situ_ retort (all estimates include upgrading but not catalytic hydrogenation). The efficiency figures listed in Table 2-14 range from 53 to 67 percent and should be considered to be accurate to within 25 percent probable error. It is questionable whether the primary efficiency of the TOSCO process is as superior as the estimates show and whether _in situ_ efficiency is likely to be as high as 53 percent; Garrett reports 40- to 45-percent efficiency. Note that _in situ_ efficiency should be compared with the product of mining and surface retorting efficiencies.

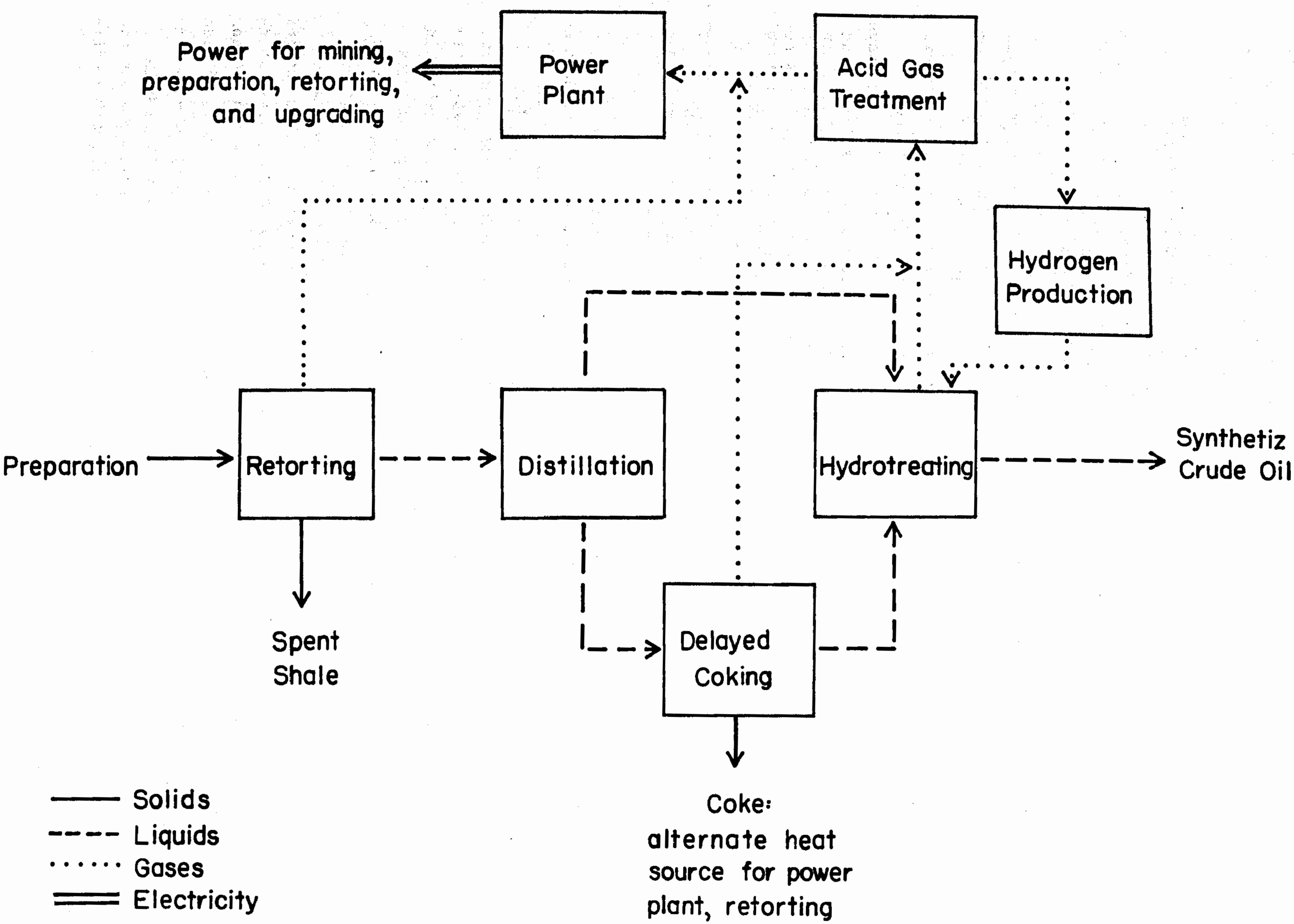


Figure 2-12. Oil Shale Processing Sequence

Source: Adapted from Hittman, 1974: Tasks 7 and 8, p. V-5.

TABLE 2-13

CHARACTERISTICS OF SHALE OIL AND SYNCRUDE

Oil Type	Typical Viscosity (Saybolt Universal seconds at 100°F)[a]	Sulfur (percent by weight)	Nitrogen (percent by weight)
Shale oil (TOSCO process)	120	0.8	1.7
Syncrude	40	.005	.035

Source: Interior, 1973: Vol. 1, p. I-17, I-29.

[a]This index refers to the number of seconds required for a standard quantity to drain out through an orifice of a standard size.

TABLE 2-14

ENERGY EFFICIENCIES FOR OIL SHALE PROCESSING TECHNOLOGIES

Technologies	Primary Efficiency (percent)	Ancillary Inputs (Btu's per 10^{12} Btu's)
Gas combustion	53.1	0
TOSCO II	66.7	0
BuMines <u>in situ</u>	53.1	$5.99x10^{10}$

Source: Hittman, 1975: Vol. II, Table 3.

The surface retorting methods, together with upgrading, are considered to be self-sufficient (requiring no ancillary energy inputs) because necessary heating and electrical power are furnished by internal by-products. <u>In situ</u> retorting by the BuMines process has substantial ancillary requirements, equal to about six percent of the energy value of the oil shale processed. Because the recoverable retort gas is expected to be too low in heating value to be used for power generation, it is assumed that natural gas will be purchased to fire a steam-powered generator. Garrett, however, reports that they plan to use 50-Btu off-gas to generate needed electricity (Chew, 1974).

2.7.3 Environmental Considerations

Environmental data are presented in Table 2-15. These Hittman estimates consider residuals from retorting and all the upgrading steps except catalytic hydrogenation. Retorting residuals are discussed first, followed by upgrading residuals. Power generation residuals are grouped with upgrading residuals where the power generated is used only for on-site ancillary energy needs for extraction, crushing, retorting, and upgrading.

Since residuals are given for each of the seven steps on the basis of a per-10^{12} Btu's input to that unit, and since many of the residuals are absorbed by other steps, summing the columns of residuals

Table 2-15. Environmental Residuals for Oil Shale Processing

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	$^F/_I$ [a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
GAS-COMBUSTION	0	0	0	0	0	0	0	0	0	0	4.	35.5	30.6	12.3	.04	.3	1.08 x10^5	1.78/0 1.78	.0014	.155	.444
Retorting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.08 x10^5	.055/0 .055	.0014	.144	U
Distillation	NA	NA	NA	NA	.604	U	4.3	U	U	0	0	0	0	2.73	0	0	NA	U	U	U	U
Delayed Coking	NA	NA	NA	NA	.477	U	.0247	1.02	1.02	0	0	0	0	2.13	0	0	NA	U	U	U	U
Hydrogen Manufacture	NA	NA	NA	NA	U	U	U	U	U	0	0	0	0	1.49	0	0	NA	U	U	U	U
Hydrotreating	NA	NA	NA	NA	.604	U	.733	.0863	1.72	0	0	0	0	2.59	0	0	NA	U	U	U	U
Gas Treating	0	0	0	0	0	0	0	0	0	0	0	0	33.9	0	0	0	0	2.55/0 2.55	U	U	U
Power Generation	0	0	0	0	3.4	0	.003	0	0	0	21.5	189.	155.	19.4	.194	1.46	0	2.76/0 2.76	.0006	.057	2.36
TOSCO II	0	0	0	0	0	0	0	0	0	0	.2	12.9	37.4	12.2	.01	.1	1.08 x10^5	1.78/0 1.78	.0014	.145	.141
Retorting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.08 x10^5	.028/0 .0278	.0014	.144	U
Distillation	NA	NA	NA	NA	.604	U	4.3	1.73 x10^{-3}	U	0	0	0	0	2.73	0	0	NA	U	U	U	U
Delayed Coking	NA	NA	NA	NA	.477	U	.0247	U	1.02	0	0	0	0	2.13	0	0	NA	U	U	U	U
Hydrogen Manufacture	NA	NA	NA	NA	NA	U	U	U	U	0	0	0	0	1.49	0	0	NA	U	U	U	U
Hydrotreating	NA	NA	NA	NA	.604	U	.733	.0863	1.72	0	0	0	0	2.59	0	0	NA	U	U	U	U
Gas Treating	0	0	0	0	0	0	0	0	0	0	0	0	33.9	0	0	0	0	2.55/0 2.55	U	U	U
Power Generation	0	0	0	0	3.4	0	.003	0	0	0	2.62	190.	522.	19.5	.195	1.46	0	2.76/0 2.76	.0006	.057	2.36

Table 2-15. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
BuMINES IN SITU	0	0	0	0	0	0	0	0	0	0	6.5	7.5	264.	160.	11.3	.13	0	1.41/.43 7.84	.0036	.571	.097
Retorting	0	0	0	0	0	0	0	0	0	0	6.22	U	262.	151.	11.3	U	0	0/.43 6.47	.0036	.569	U
Distillation	NA	NA	NA	NA	.604	U	4.3	1.73×10^{-3}	U	0	0	0	0	2.73	0	0	NA	U	U	U	U
Delayed Coking	NA	NA	NA	NA	.477	U	.0274	U	1.02	0	0	0	0	2.13	0	0	NA	U	U	U	U
Hydrogen Manufacture	NA	NA	NA	NA	NA	U	U	U	U	0	0	0	0	4.08	0	0	NA	U	U	U	U
Hydrotreating	NA	NA	NA	NA	.604	U	.733	.0863	1.72	0	0	0	0	2.59	0	0	NA	U	U	U	U
Gas Treating	0	0	0	0	0	0	0	0	0	0	0	0	33.9	0	0	0	0	2.55/0 2.55	U	U	U
Steam Generation	0	0	0	0	3.4	0	.003	0	0	0	7.34	191.	.293	19.6	.19	3.43	0	2.76/0 2.76	.0006	.057	2.36

NA = not applicable, U = unknown.

[a]Fixed Land Requirement (Acre - year / 10^{12} Btu's) / Incremental Land Requirement (Acres / 10^{12} Btu's).

will not yield correct totals for the three processes. Thus, a summary row, representing the actual total residuals per 10^{12} Btu's of oil shale input to a processing complex is given in Table 2-15 for the technologies, and these totals are discussed in the summary section following the retorting and upgrading discussions. The residual data are based upon pilot plant operation and should be considered fair, with a probable error of less than 50 percent.

2.7.3.1 Retorting

2.7.3.1.1 Water

Water residuals from the Gas Combustion and TOSCO II retorting processes are defined as zero, although large quantities of water are used and large quantities of wastewater are generated. Wastewater generated in the retorting activity is a result of boiler blowdown, steam generation, wet scrubbing, and process water. (Process water is water driven out of the oil shale during retorting.) Wastewater from retorting will receive chemical treatment with lime to remove carbonates (40,000 ppm in the wastewater), most of the ammonia, and some organic material. This treated water will be used for dust control or consumed in the spent shale disposal system.

Water generated from BuMines in situ retorting will require primary treatment with lime and advanced treatment by carbon absorption and ion exchange resins. Even though the wastewater will still contain 1,890 ppm dissolved solids after treatment, it will be suitable for cooling tower makeup, which is where the treated water is expected to be used (Hittman, 1975: Vol. II, 27). In theory, then, no effluents will be released outside the boundary of the oil shale processing complex. However, the feasibility of such a pollution control system has not yet been demonstrated at a commercial scale.

2.7.3.1.2 Air

Although significant quantities of air pollutants are generated in both the TOSCO II and Gas Combustion retorts, air residuals are zero in Table 2-15 because the tail gas from the retort is fed to the power plant. Thus, electrical generation accounts for all the air pollution from these processes as total complexes.

In the BuMines in situ retorting activity, air residuals are large and result from flaring the low-Btu product gas. Particulate emissions are six tons, sulfur dioxides are 262 tons, and hydrocarbons are 11 tons per 10^{12} Btu's retorted. Nitrogen oxides are assumed to be present, but the quantity is unknown. Air residuals from the Garrett process will be negligible if the gas is used for power generation.

2.7.3.1.3 Solids

Solid wastes from the retorts are in the form of spent shale and the amount is highly significant, over 100,000 tons of waste per 10^{12} Btu's of oil shale retorted or nearly 60,000 tons per day from a 50,000-barrel-per-day retorting operation. This amount of residue would cover 20 acres of land to a depth of one foot (NPC, 1972b: 67,68) and is greater than the daily solid waste residuals from surface mining. Obviously, the logistics of moving and disposing of this much material will be formidable. Another point is that the texture of the solid waste from the Gas Combustion process and TOSCO II retorts differ. Waste from the Gas Combustion process is pebbly, and TOSCO II waste is sandy, even powdery. Thus, disposal techniques (and costs) must vary accordingly.

Hittman data assume that the BuMines in situ retorting technique does not produce solid wastes.* The Garrett process produces waste rock with a volume equal to

---

*Some solids are produced in drilling the injection wells and chimneys.

15 to 20 percent of the oil shale processed, a sizeable amount but less than 15 percent of the volume from surface processing (not taking into account additional solid wastes from mining to support surface processing).

2.7.3.1.4 Land

Fixed land impact for the surface retorts is about 10 acres for a 50,000-barrel-per-day operation. Land use for the disposal of spent shale is not included in the estimate.

For BuMines <u>in situ</u> retorting, the land impact is that required for drilling and restoration. Based on the time average land impact for the Colorado, Utah, and Wyoming tracts (Hittman, 1975: Vol. II, p. V-25), this is 1,088 acres over a 30-year period. The land impact of the Garrett process has not been estimated because the approach to solid waste disposal and reclamation is only beginning to be investigated. If <u>in situ</u> processing is done on a grand scale far underground, subsidence of the land surface may be a possibility.

2.7.3.1.5 Water Requirements

The retorting stage of surface processing is estimated to use 600 to 700 acre-feet of water per year for a 50,000-barrel-per-day operation, largely for dust suppression and, in the TOSCO II process, cooling. Water requirements for <u>in situ</u> processing have not been estimated.

2.7.3.2 Upgrading

Upgrading residuals are given in Table 2-15 for distillation, delayed coking, hydrogen manufacture, hydrotreating, gas treating, and power generation (supplying power for extracting, crushing, retorting, and upgrading).

2.7.3.2.1 Water

Although water residuals that leave the plant boundary are given in Table 2-15 as zero for the three processes, the wastewater exiting the gas treating facility contains hydrogen sulfide and ammonia. Steam stripping of the sour refinery tail gas is assumed to remove enough of these compounds to make the water available for reuse.

2.7.3.2.2 Air

Although hydrocarbons are emitted from each unit in the upgrading process, the principal source of air pollutants is from electric power generation (and steam generation only for <u>in situ</u>). These pollutants range from 2 to 21 tons of particulates emitted per 10^{12} Btu's of gas input to the power generation plant, with TOSCO II having the lowest value and Gas Combustion having the highest value. Nitrogen oxide emissions are 189 tons for Gas Combustion and 190 tons for TOSCO II per 10^{12} Btu's input to the power plant. Sulfur dioxide emissions are 155 tons for Gas Combustion and 522 tons for TOSCO II per 10^{12} Btu's input to the power plant. The differences reflect the fact that the retort gases, which are used as feedstock for the power plants, have different compositions.

Feedstock for the steam generator used in the <u>in situ</u> process is assumed to be purchased natural gas. This explains the low sulfur dioxide emissions from the <u>in situ</u> steam generator (0.3 ton per 10^{12} Btu's of gas input to the boiler).

2.7.3.2.3 Solids

No solids are assumed to result from the upgrading process. Not considered are the solid waste products of the delayed coking step and solids recovered from wastewater treatment. Both are small compared to quantities of overburden and spent shale.

2.7.3.2.4 Land

Land impact is the fixed land required for facilities. This has not been subdivided unit by unit for the upgrading process.

Total land impact for retorting and upgrading is given in Section 2.7.3.3.

2.7.3.2.5 Water Requirements

Water requirements in oil shale processing are substantial. The upgrading stage (for both surface and in situ retorting) uses 1,400 to 2,200 acre-feet of water per year for processing (mostly as process water in acid gas treatment and hydrogen production, along with cooling requirements) and another 700 to 1,000 acre-feet per year for electric power generation (Interagency Oil Shale Task Force, 1974: 154). The water produced from oil shale by surface retorting is insufficient to meet these needs; therefore, water will have to be acquired from other sources. Once on hand, the water can be recycled in some cases, but some continuing inputs of water are likely to be needed. (The water requirements for oil shale resource development are summarized in Section 2.8.)

2.7.3.3 Summary

Residuals are summarized for the BuMines in situ, TOSCO II, and Gas Combustion processes in the summary rows of Table 2-15.

According to the assumptions, no water leaves the plant boundary; thus, no residuals enter receiving waters. However, the practicality of the complicated treatment and recycling system assumed has not been demonstrated. Further, contamination of groundwater has not been considered. Air residuals result principally from power generation in the TOSCO II and Gas Combustion processes and from both retorting and steam generation in the BuMines in situ process. Particulates range from 0.2 to 6.5 tons emitted per 10^{12} Btu's of oil shale input to the process. The highest is for BuMines in situ processing. Nitrogen oxide emissions range from 7.5 to 35.5 tons with the lowest being for BuMines in situ. Sulfur dioxide emissions range from 30 to 264 tons with the highest being from retorting in the BuMines in situ process; this is due to flaring the low-Btu product gas.

2.7.3.3.1 Solids

Solids are 108,000 tons of spent shale per 10^{12} Btu's of oil shale retorted on the surface. This is the most serious output residual in oil shale development and has encouraged the investigation of in situ processing, where less solid wastes are generated.

2.7.3.3.2 Land

For the Gas Combustion and TOSCO II processes, land use is calculated on the basis of a 320-acre site requirement for a 72,700-ton-per-day processing operation (50,000 bbl per day). For BuMines in situ processing, the land use figure represents 230 acres for fixed surface facilities and 0.125 acre per year for well drilling and restoration.

2.7.4 Economic Considerations

The Hittman estimates of processing costs are listed in Table 2-16 and are considered fair, with a probable error of less than 50 percent. The retorting step accounts for half or more of the fixed costs for the surface processing technologies and slightly less than half for BuMines in situ processing. Distillation is the most expensive of the steps in terms of operating costs. These cost figures and any evaluation of their impact on profitability are quite tentative because much of the economic information is proprietary, the government tax and royalty policy is subject to change, and the prices of inputs are constantly changing (NPC, 1973: Chapters 2 and 3). Generally, there should be no major difference between processes, at least in a comparison of surface retorting alternatives. For example, the TOSCO II retort

TABLE 2-16

PROCESSING COSTS FOR OIL SHALE
AT A PRODUCTION RATE OF 50,000 BARRELS PER DAY
(DOLLARS PER 10^{12} BTU'S INPUT)

Process	Fixed Cost	Operating Cost	Total Cost
Gas combustion process	118,000	332,000	489,000[a]
TOSCO II process	75,000	373,000	487,000[a]
BuMines in situ process	111,000	298,000	409,000

Source: Hittman, 1975: Vol. II, Table 3.

[a]Includes $39,600 in power plant costs not incorporated in fixed or operating cost estimates.

is more expensive to build than the Gas Combustion retort, but its recovery is more efficient, thus reducing costs elsewhere (Hottel and Howard, 1971: 203).

Table 2-17 presents a different set of cost estimates, which suggest a higher cost for in situ processing. Table 2-18 summarizes the anticipated profitability of oil shale processing as of mid-1974, assuming that useful by-products are sold. These estimates indicate that surface retorting is probably an economically viable energy option, but late in 1974 the plans for commercial application of the TOSCO II process by Colony Development Operation were suspended, while prototype experiments with the Garrett in situ process were proceeding more optimistically.

Recent estimates (Interagency Oil Shale Task Force, 1974b: 64-77) indicate a rate of return (discounted cash flow) of 11 to 16 percent at a $8.35 per bbl selling price for shale oil (not upgraded) and a rate of return of 15 to 25 percent at a selling price of $12.35 per bbl. However, rising prices for retorts and the possible expense of reclamation make surface retorting less attractive than this would indicate, and in situ retorting is too untried as yet for persuasive economic data to be available.

2.8 RECLAMATION

Reclamation problems in oil shale resource development not only include the wide range of problems associated with coal extraction but also the large quantities of spent shale resulting from surface retorting.

2.8.1 Technologies

For surface mines, reclamation methods will be essentially the same as for the surface mining of coal. Spent shale will be mixed with the overburden that is being replaced, and the reclaimed area will be reshaped and revegetated.

In underground mining, some of the spent shale could be returned to the mine, but this would be difficult to coordinate with ongoing mining and would complicate any future recovery of oil in the pillars. It is more likely that the spent shale, together with mining wastes, will be disposed of on the surface.

If mined-out pits are unavailable, one proposal for surface disposal is a version of the "head-of-hollow" method sometimes discussed in connection with contour coal

TABLE 2-17

PROCESSING COSTS FOR OIL SHALE

Method	Synthetic Crude Oil Cost	
	Dollars per Barrel	Dollars per 10^{12} Btu's output[a]
50,000 barrels per day, underground mining, surface processing	3.45	614,100
100,000 barrels per day, underground mining, surface processing	3.09	550,020
100,000 barrels per day, surface mining, surface processing	3.10	551,800
50,000 barrels per day, *in situ* processing, surface upgrading	8.50[b]	1,513,000

Source: Interagency Oil Shale Task Force, 1974a: Appendix H.

[a]At 178,000 barrels per 10^{12} Btu's.

[b]Operating costs only.

TABLE 2-18

REQUIRED SELLING PRICE OF SHALE OIL
(DOLLARS PER BARREL)

Method	Discounted Cash Flow Rates of Return		
	12 Percent	15 Percent	20 Percent
100,000 barrels per day, underground mining, surface processing	5.15	6.11	7.90
100,000 barrels per day, surface mining, surface processing	5.52	6.63	8.70
50,000 barrels per day, *in situ* processing, surface upgrading	11.95	13.18	15.23

Source: Interagency Oil Shale Task Force, 1974a: Appendix H.

mining. The material would be deposited in a naturally-occurring deep canyon near the mine, moistened and compacted, contoured to some moderate slope angle, and shaped to blend into the natural setting. An upstream reservoir would be built to catch water that would otherwise flow over the surface of the embankment, while a dam downstream would collect rainfall runoff from it. The embankment would be revegetated, which requires the addition of soil or mulch at the surface and regular watering until plant growth takes hold (or perhaps longer if a reduction in watering means that mineral salts in the waste rise to the root zone of the vegetation, killing it). It is possible that enough revegetation could be attained in two or three years so that embankment treatment could be ended (TOSCO, 1973: 7).

It has yet to be demonstrated that the water pollution controls are manageable in a situation requiring the disposal of 60,000 tons of spent shale a day, and the technical and economic feasibility of revegetation at this scale are likewise unsubstantiated by experience. In addition, the general approach requires a particular kind of terrain to be workable and demands a quantity of water that may be unavailable.

The head-of-hollow approach has been investigated specifically for the powdery spent shale from the TOSCO II process. With the chunkier residues from the internal-heating retort processes, revegetation could be expected to be more difficult, and the control of pollution from rainwater falling on the embankment could be more difficult because the aggregated material would be more permeable.

Solid waste from the Garrett <u>in situ</u> process is broken marlstone rock, presently dumped from a valley-side mine mouth. Methods are being explored for speeding the natural process of revegetation of steep rocky slopes in the Piceance Basin area.

2.8.2 Energy Efficiencies

Reclamation energy efficiencies have not been separated from the mining and processing estimates, but some ancillary inputs would be involved apart from transportation of the solid waste to the disposal site. One assessment of the efficiencies of energy systems (Oregon Office of Research and Planning, 1974) indicates that external energy subsidies for oil shale production (including mining, processing, reclamation, and other activities) are higher than for any other system considered.

2.8.3 Environmental Considerations

No separate estimates exist for residuals from the reclamation effort, but runoff water from waste piles clearly constitutes a water pollution danger. Water coming off spent shale under a condition where runoff rate equals rainfall rate has been estimated to contain as much as 45 milligrams per liter of sulfates, carbonates, sodium, calcium, and magnesium salts (Ward and others, 1971).

However, the primary environmental impact of reclamation is likely to be its consumption of water. Water consumption estimates for oil shale development are given in Tables 2-19 and 2-20. For a one-million-barrel-per-day oil shale industry, these estimates suggest a need for between 121,000 and 189,000 acre-feet of water per year, or about 10 percent of the total water usage in the Colorado part of the Upper Colorado River Basin in 1970 (Interior, 1973: Vol. I, p. II-29; House Committee on Science and Astronautics, 1973: 18,19). Assuming a shale oil heating value of 5.4 million Btu's per bbl, a 100-percent load factor, and 58-percent efficiency, this is the equivalent of 36 to 56 acre-feet per 10^{12} Btu's input or 12 to 18 million gallons per 10^{12} Btu's input. This quantity can be reduced 10,000 to 40,000 acre-feet per year by recovering and recycling water from retorting and upgrading

TABLE 2-19

WATER CONSUMPTION FOR SHALE OIL PRODUCTION
(ACRE-FEET PER YEAR)

Use Category	50,000 barrels per day of shale oil, underground mining	100,000 barrels per day of shale oil, surface mining	50,000 barrels per day of shale oil, BuMines *in situ* processing
Process requirements:			
Mining and crushing	370- 510	730- 1,020	0
Retorting	580- 730	1,170- 1,460	0
Shale oil upgrading	1,460- 2,190	2,920- 4,380	1,460-2,220
Processed shale disposal	2,900- 4,400	5,840- 8,750	0
Power requirements	730- 1,020	1,460- 2,040	730-1,820
Revegetation	0- 700	0- 700	0- 700
Sanitary use	20- 50	30- 70	20- 40
Subtotal	6,060- 9,600	12,150-18,420	2,210-4,780
Associated urban:			
Domestic use	670- 910	1,140- 1,530	720- 840
Domestic power	70- 90	110- 150	70- 80
Subtotal	740- 1,000	1,250- 1,680	790- 920
TOTAL	6,800-10,600	13,400-20,100	3,000-5,700
AVERAGE VALUE	8,700	16,800	4,400

Source: Interior, 1973: Vol. I, p. III-34; Interagency Oil Shale Task Force, 1974b: 154.

operations, depending on the processing technology (House Committee on Science and Astronautics, 1973: 19), but an oil shale processing complex clearly would have a powerful impact on water use patterns in the region. Generally, water rights law in the area gives first claim on water to prior users, which means that the necessary water might not be obtainable at all (Interior, 1973: Vol. I, p. III-70).

About 50 percent of the water requirement is for solid waste disposal and reclamation, and very little of this is likely to be recoverable for recycling. Because most available water is already committed to existing activities, the prospects of massive oil shale development based on surface retorting seem to be severely limited in the area of the Green River Formation. The alternatives include: an emphasis on *in situ* technologies, which have a smaller solid waste impact (but which may require external power for upgrading); the transportation of shale oil to an upgrading site elsewhere, avoiding the need for local water for upgrading; water supply augmentation in the region, although any method (e.g., new impoundments) would have environmental impacts of its own; a relaxation of reclamation requirements, which could result in dramatic environmental impacts on the region; or development at a relatively low level of activity.

Oil shale development does *not* consume more water than all other energy systems. For example, its water consumption is considerably less than coal gasification or liquefaction (Davis and Wood, 1974: 12).

TABLE 2-20

CONTINGENT WATER CONSUMPTION FORECASTS[a]
(ACRE-FT PER 10^{12} BTU'S INPUT FOR A ONE-MILLION-BARREL PER DAY SHALE OIL INDUSTRY)

Use Category	Lower Range	Most Likely	Upper Range
Process requirements:			
Mining and crushing	1.6	1.6- 2.1	2.1
Retorting	2.3	2.3- 3.1	3.1
Shale oil upgrading	4.4- 5.5	7.5-11.4	11.4
Processed shale disposal	6.2	12.2-18.2	21.8
Power requirements	2.6	3.9- 6.0	9.6-11.7
Revegetation	0	0 - 3.1	4.7
Sanitary use	0.3	0.3- 0.3	0.3
Subtotal	17.4-18.5	27.8-44.2	53.0-55.1
Associated urban:			
Domestic use	2.3- 2.9	3.4- 4.4	4.4
Domestic power	0	0.3- 0.5	0.5
Subtotal	2.3- 2.9	3.7- 4.9	4.9
TOTAL	19.7-21.4	31.5-49.1	57.9-60.0
Ancillary development:			
Nahcolite/dawsonite	NC	NC	8.3-16.6
GRAND TOTAL	19.7-21.4	31.5-49.1	66.2-76.6

NC = Not Considered

Source: Calculated from Interior, 1973: Vol. I, p. III-44.

[a]Assumption: 100-percent load factor, 55-percent recovery factor, and 5.8×10^6 Btu's per barrel of shale oil.

The central problem is that high quality U.S. oil shale is located in areas where water is scarce, and oil shale is too bulky to transport economically to a location with more water.

2.8.4 Economic Considerations

The costs of reclamation are included with cost estimates for mining and processing as appropriate. For the head-of-hollow method described above, they will be influenced by the depth of the canyons being filled (which affects the ratio of surface area to be treated compared with the volume of material deposited), and they will depend significantly on the difficulty of the water pollution control and revegetation efforts and the regulations established as minimum standards for reclamation.

2.9 TRANSPORTATION OF FINISHED PRODUCTS

Long-distance transportation in the oil shale development system is likely to be limited to movement of the produced syncrude. Because shale oil from the retort is so thick that it is difficult to pump through pipelines at ambient temperatures (and because of the possible product linkages between retorting and upgrading), upgrading will probably take place at the retorting

Table 2-21. Environmental Residuals from Transportation of Synthetic Crude Oil Produced from Oil Shale

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land $\frac{\text{Acre-year}}{10^{12}\text{ Btu's}}$	Deaths	Injuries	Man-Days Lost
Pipeline	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	.2	4.6	.3	.5	2.8	.04	0	63.6/0 63.6	.00003	.0028	.085

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

location, although it is possible that the shale oil will, in some cases, be transported to refineries elsewhere. The main trade-off will be between the added costs of transportation of the oil before upgrading versus the costs of decentralized refining at each retorting site.

2.9.1 Technologies

The upgraded product liquids can be transported by truck, railroad, or pipeline (see the liquid product transportation descriptions in Chapter 1), but the general expectation is that oil shale processing will be linked to a crude oil pipeline network. However, a heated pipeline may be required to reduce viscosity problems in transporting oil shale before upgrading (see the transportation technology descriptions in Chapter 3).

2.9.2 Energy Efficiencies

In pipeline transportation, the primary efficiency is 100 percent. Ancillary energy required to pump 172,500 bbl of syncrude (10^{12} Btu's) 300 miles is 3.4×10^9 Btu's or 0.3 to 0.4 percent of the energy value of the transported product. These data are considered good, with a probable error of less than 25 percent.

2.9.3 Environmental Considerations

Table 2-21 lists the Hittman estimates of environmental residuals from syncrude transportation, and these estimates are considered fair (a probable error of less than 50 percent). The air pollutants, totaling about eight tons per 10^{12} Btu's of oil transported, are emissions from diesel-engine units pumping the oil through the pipeline. For additional information see Chapters 1 and 3.

2.9.4 Economic Considerations

The average cost estimate to transport 10^{12} Btu's of syncrude 300 miles is $25,400 (to within a probable error of 50 percent or less). For further data, see Chapters 1 and 3.

REFERENCES

American Petroleum Institute (1971) Petroleum Facts and Figures. Washington: API.

Atwood, Mark T. (1973) "The Production of Shale Oil." Chemtech (October 1973): 617-620.

Chew, Randall T. (1974), personal communication, November 6, 1974.

Colony Development Operation (1974) An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado; Vol. 1, Part 1: Plant Complex and Service Corridor. Denver, Colo.: Atlantic Richfield Company.

Culbertson, William C., and Janet K. Pitman (1973) "Oil Shale," pp. 497-503 in Donald A. Brobst and Walden P. Pratt (eds.) United States Mineral Resources, U.S. Geological Survey Professional Paper 820. Washington: Government Printing Office.

Davis, George H., and Leonard A. Wood (1974) "Water Demands for Expanding Energy Development," USGS Circular 703. Reston, Va.: USGS.

Department of the Interior (1973) Final Environmental Statement for the Prototype Oil Shale Leasing Program. Washington: Government Printing Office, 6 vols.

Duncan, D.C., and V.E. Swanson (1965) Organic-Rich Shale of the United States and World Land Areas, U.S. Geological Survey Circular 523. Washington: Government Printing Office.

East, J.H., Jr., and E.D. Gardner (1964) Oil Shale Mining, Rifle, Colorado, 1944-56, Bureau of Mines Bulletin 611. Washington: Government Printing Office.

Federal Power Commission (1973) The Supply-Technical Advisory Task Force--Synthetic Gas-Coal: Final Report, prepared by the Synthetic Gas-Coal Task Force for the Supply-Technical Advisory Committee, National Gas Survey.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

Hottel, H.C., and J. B. Howard (1971) New Energy Technology: Some Facts and Assessments. Cambridge, Mass.: MIT Press.

House Committee on Science and Astronautics, Subcommittee on Energy (1973) Energy from Oil Shale: Technical, Environmental, Economic, Legislative, and Policy Aspects of an Undeveloped Energy Source. Washington: Government Printing Office.

Hubbard, A.B. (1971) "Method for Reclaiming Wastewater from Oil-Shale Processing," pp. 21-25 in American Chemical Society, Division of Fuel Chemistry, Preprints, Vol. 15, No. 1, Symposium on Shale Oil, Tar Sands and Related Materials. Lexington, Mass.: ACS.

Interagency Oil Shale Task Force (1974a) Potential Future Role of Shale Oil; Prospects and Constraints, for Federal Energy Administration's Project Independence Blueprint.

Interagency Oil Shale Task Force (1974b) Potential Future Role of Shale Oil; Prospects and Constraints, Final Report, for Federal Energy Administration's Project Independence Blueprint.

National Petroleum Council, Committee on U.S. Energy Outlook (1972a) U.S. Energy Outlook. Washington: NPC.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee (1972b) U.S. Energy Outlook: An Initial Appraisal by the Oil Shale Task Group, 1971-1985. Washington: NPC.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee, Oil Shale Task Group (1973) U.S. Energy Outlook: Oil Shale Availability. Washington: NPC.

Oregon Office of Energy Research and Planning (1974) Energy Study: Interim Report. Salem, Ore.: State of Oregon.

Senate Committee on Interior and Insular Affairs (1973) Legislative Authority of Federal Agencies with Respect to Fuels and Energy. Washington: Government Printing Office.

The Oil Shale Corporation (1973) Annual Report. New York: TOSCO.

United Nations, Department of Economic and Social Affairs (1967) Utilization of Oil Shale: Progress and Prospects. New York: United Nations.

Ward, J.C., G.A. Margheim, and G.O.G. Lof (1971) "Water Pollution Potential of Spent Shale Residues from Aboveground Retorting," pp. 13-20 in American Chemical Society, Division of Fuel Chemistry, Preprints, Vol. 15, No. 1, Symposium on Shale Oil, Tar Sands and Related Materials. Lexington, Mass.: ACS.

Welles, Chris (1970) The Elusive Bonanza. New York: E.P. Dutton.

CHAPTER 3

THE CRUDE OIL RESOURCE SYSTEM

3.1 INTRODUCTION

Since its discovery in 1859, oil has been a significant factor in our national growth and development. Although it did not supplant coal as the primary energy source until the 1940's, oil was important well before that, in large part because of its key role in the development and mass production of the automobile--and the fundamental changes in life style which followed.

In more recent times oil has become the base for many of our necessities, including medicinal drugs and clothing "fibers;" and it is a major substitute for other sources of energy. This flexibility in end use makes oil a particularly valuable resource in all industrialized countries.

The oil industry has grown from a uniquely American business into a worldwide operation. Six of the 10 largest U.S. corporations are oil companies, and technologies developed to produce U.S. oil resources have been the basis for all free world oil development.

The U.S. was a net oil exporter until 1948, when U.S. consumption exceeded supply for the first time. Although the change from exporter to importer created a number of economic and political problems, dependence on oil imports will probably continue for the foreseeable future.

The development of oil resources involves four major sequential activities: exploration, development, refining, and transportation (Figure 3-1). In the following sections, world and national oil resources are outlined, the activities and technologies for recovering those resources are described, and the efficiencies, environmental considerations, and economic considerations for these technologies are discussed.

3.2 CRUDE OIL RESOURCES

3.2.1 Characteristics of the Resource

Crude oil is a mixture of a large number of liquid hydrocarbons which can be separated and altered to produce gasoline, fuel oil, and other petroleum products. In describing oil resources, both foreign and domestic supplies must be considered because oil may be easily transported; in 1973, imports constituted 4 million of the 17 million total barrels (bbl) per day of domestic U.S. consumption.

Since various crude oils may contain over 1,000 different organic (carbon-containing) compounds, any given crude is chemically complex (Peel, 1970: 154). Crude oil is most commonly characterized by its density. The highest energy oil has a low density (about 80 percent of that of water), while the density of low-energy oil is almost the same as water. Density is measured in degrees API ($^{\circ}$API) also termed API gravity.* There is an inverse relationship between density and API gravity, hence

*API stands for the American Petroleum Institute, an overall petroleum interest group.

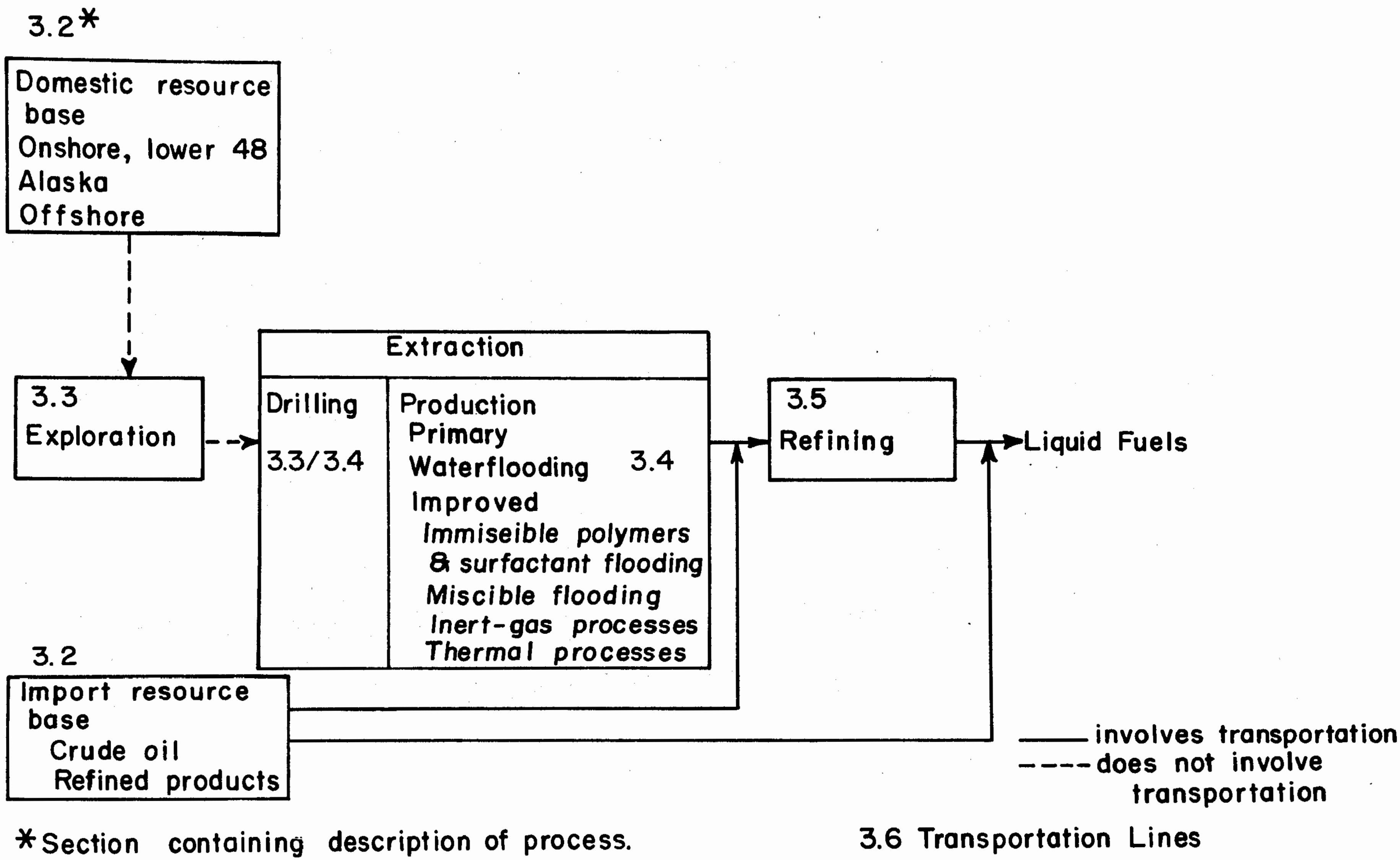


Figure 3-1. Crude Oil Resource Development

crude oils range from less than 10°API, corresponding to a very heavy tar or asphalt-like crude, to above 50°API, corresponding to a light, highly volatile crude.

Value is generally related to API gravity (the higher the API gravity, the more valuable the crude), although other factors also affect crude oil price. Most crude oil being produced worldwide at present ranges from 30 to 37°API, with the feedstocks for U.S. refineries averaging about 36°API (Peel, 1970: 161, 162).

The sulfur content of a crude is important because it has a major impact on air quality if retained in refinery products. Sulfur may be present in crude oil as dissolved gaseous hydrogen sulfide or as sulfur-containing organic compounds. As shown in Figure 3-2, the sulfur content of crude decreases with higher API gravity for crudes of a particular geographic region. However, regional variations dominate. For an API gravity of 36°, Middle East crudes contain between 1.4 and 2.1 percent sulfur, while most U.S. or Venezuelan crudes contain between 0.1 and 0.6 percent sulfur. North African, Turkish, West Texas, and California crudes have high sulfur contents, while Nigerian, Canadian, some East Indian, and the remaining U.S. crudes fall into one low-sulfur category (Peel, 1970: 163, 164). Because of the odor of hydrogen sulfide, low-sulfur crudes are termed "sweet" and high-sulfur crudes are termed "sour." Sweet crudes usually contain less than one percent sulfur.

3.2.2 Domestic Resources

3.2.2.1 Quantity of Domestic Resources

Although one 1971 estimate of total U.S. oil resources was 810 billion bbl (NPC, 1972: 72), more recent oil resource estimates are much lower. A 1974 U.S. Geological Survey (USGS) estimate put the upper limit at 400 billion bbl, while a major oil company estimated only 88 billion bbl (Gillette, 1974: 128). These estimates of the quantity of oil yet to be discovered or recovered are obviously subject to considerable uncertainty.

U.S. reserves (that portion of identified resources which can be economically extracted now) are estimated to be 50 billion bbl (NPC, 1974: 50) which, at the present levels of consumption, is at most a nine-year supply (NPC, 1972: 85). Although this appears small, U.S. reserves have never been greater than an 11- or 12-year supply, possibly because they can be considered inventory and inventories larger than 10 years may not be economically advantageous.

3.2.2.2 Location of the Resources

Oil has been found in most parts of the U.S. Information on U.S. reserves and resources is frequently divided into two categories, onshore and offshore, and two regions, the lower (coterminous) 48 states and Alaska. Estimates of oil resources in these categories and regions are shown in Table 3-1. U.S. reserves are estimated at 50 billion bbl, of which 34.2 billion bbl are onshore in the lower 48 states, 6.2 billion bbl offshore, and 9.6 billion bbl onshore in Alaska (NPC, 1974: 50).

3.2.2.3 Ownership of the Resources

In the past, ownership has had less impact on oil resource development than on coal resource development. Because of the high value of oil resources and because oil resource development has had relatively limited impact on surface land use, privately owned land has been developed with little problem. However, oil-bearing lands owned by the government are becoming increasingly significant. The federal government owns most of the offshore acreage outside the

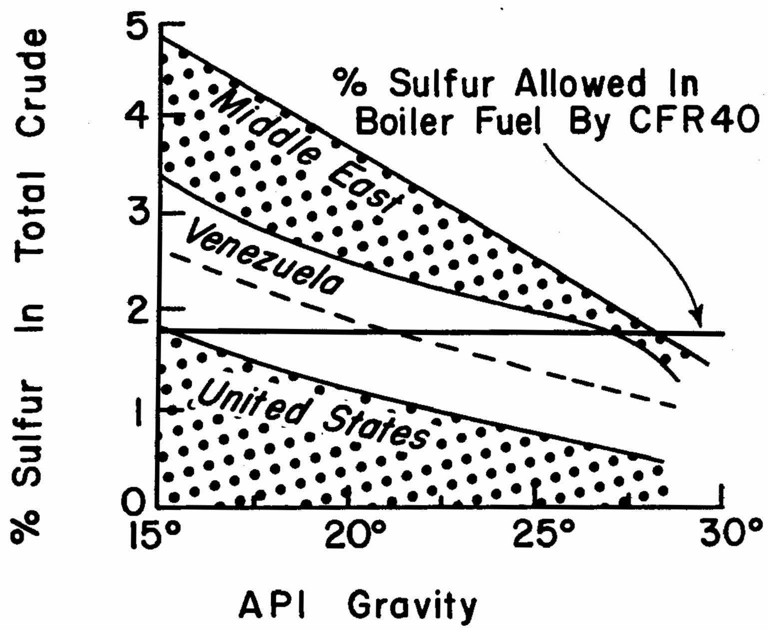


Figure 3-2. Sulfur Content and API Gravity of Crude Oils

Source: Peel, 1970: 164.

TABLE 3-1

UNITED STATES OIL RESOURCES

Location	Petroleum Liquid Resources (billions of barrels) USGS Low	High
Onshore		
Alaska	25	50
Lower 48 states	110	220
Subtotal onshore	135	270
Offshore[a]		
Atlantic	10	20
Alaska	30	60
Gulf of Mexico	20	40
Pacific Coast	5	10
Subtotal offshore	65	130
Total United States	200	400

Source: Gillette, 1974: 128.

[a]To a water depth of 660 feet.

three-mile limit,* and federal ownership onshore is significant in Alaska and the western states. The federal government is estimated to control 15 percent of domestic crude oil reserves, 11 percent on the Outer Continental Shelf (OCS) and 4 percent onshore. Federal resource ownership is estimated to be 37 percent, 30 percent on the OCS (which has not yet been extensively explored) and 7 percent onshore. The federal government owned 16 percent of all 1972 U.S. oil production (Ford Foundation, 1974: 271).

*The exceptions are Texas and Florida's west coast where state ownership extends out to nine miles. Other states' claims to ownership beyond three miles are still being adjudicated.

3.2.2.4 Regional Overview

3.2.2.4.1 Onshore, Lower 48 States

The area of the coterminous U.S. with prospects for oil discovery, either by virtue of previous discovery or promising geology, is approximately 1.7 million square miles, with a sedimentary rock volume of 3.2 million cubic miles (NPC, 1970: 1). Present production in the lower 48 states is about 11 million bbl per day (NPC, 1974: 27) from reserves of 34.2 billion bbl, and reserves are being found at about 3.4 billion bbl per year (NPC, 1974: 27). Reserve additions in the lower

48 states will come from three major sources: wells in previously undrilled areas, deeper wells, and additional recovery from known fields. As new discoveries are made, more is learned about geological formations that might contain oil resources. Other areas where such geological formations occur then become promising, and drilling activity is initiated in such areas (NPC, 1970: 3). The ability to drill deeper wells and the discovery of petroleum in rocks at extreme depths suggest that a great volume of unexplored sedimentary rock may have promise, although wells deeper than 16,000 feet will probably produce gas rather than oil (McCulloh, 1973: 488). Also, the reserves in known fields can be increased by using techniques to recover oil that remains in place after natural drive mechanisms have been depleted.

3.2.2.4.2 Alaska

The prospective area for petroleum discovery in Alaska lies under approximately 85,000 square miles and has a sedimentary rock volume of 215,000 cubic miles (NPC, 1970: 6). This area can be divided into three provinces--North Slope, Cook Inlet, and Pacific Margin--as shown in Figure 3-3. Of these, the North Slope is the most promising and is currently the subject of considerable exploratory attention (as well as political controversy because of the trans-Alaska pipeline). The Cook Inlet is now producing gas and some oil, with new petroleum expected from extensions of present fields rather than significant new finds. New areas in the Pacific Margin province are almost all offshore and thus have not yet been drilled, although geophysical and geological analyses have been made. Alaskan reserves at present are about 10.5 billion bbl, 9.6 billion of which are on the North Slope (NPC, 1974: 50). Prospective areas in Alaska have winter climates and frequent earthquakes (CEQ, 1974: 1-22).

3.2.2.4.3 Offshore

Offshore oil resources are contained almost entirely on the OCS and thus are federally owned. State-owned resources offshore include only about 10 percent of potential production on the continental shelf. Petroleum resources on the OCS to a water depth of 200 meters are estimated to be between 54 billion bbl (Gillette, 1974: 127) and 710 billion bbl (Kash and others, 1973: 315, 316). A number of specific regions of the OCS have been identified in the Bureau of Land Management (BLM) tentative lease schedule for development by 1985. These include the Gulf of Mexico, Pacific Coast, Atlantic Coast, and Alaska. Most present production is taking place in the Gulf of Mexico. Production in 1972 from the Gulf was about 1.05 million bbl per day (Kash and others, 1973: 319), with reserves of 3.2 billion bbl. Estimates are that an additional 2.5 to 5 billion bbl of reserves will be discovered (BLM, 1972: 7). Production in the Pacific region is in the Santa Barbara channel and was about 0.1 million bbl per day in 1972. Resources for the Pacific region are estimated to be about nine billion bbl, in both the Santa Barbara channel and outside the channel islands (Kash and others, 1973: 320).

No exploratory drilling has been done on the Atlantic OCS, although discoveries have been made offshore of Nova Scotia in Canadian waters. A number of areas with considerable potential have been identified, and resource estimates of 48 billion bbl have been made by the USGS (Kash and others, 1973: 320).

Areas on the Alaskan OCS with petroleum potential include Bristol Bay, Lower Cook Inlet, Prudhoe Bay, and the Gulf of Alaska. The extreme environmental conditions of the Alaskan OCS will probably preclude exploratory drilling in the near future (CEQ, 1974: 1-22). Resources on the Alaskan OCS have been estimated at 62 billion bbl (Kash and others, 1973: 320).

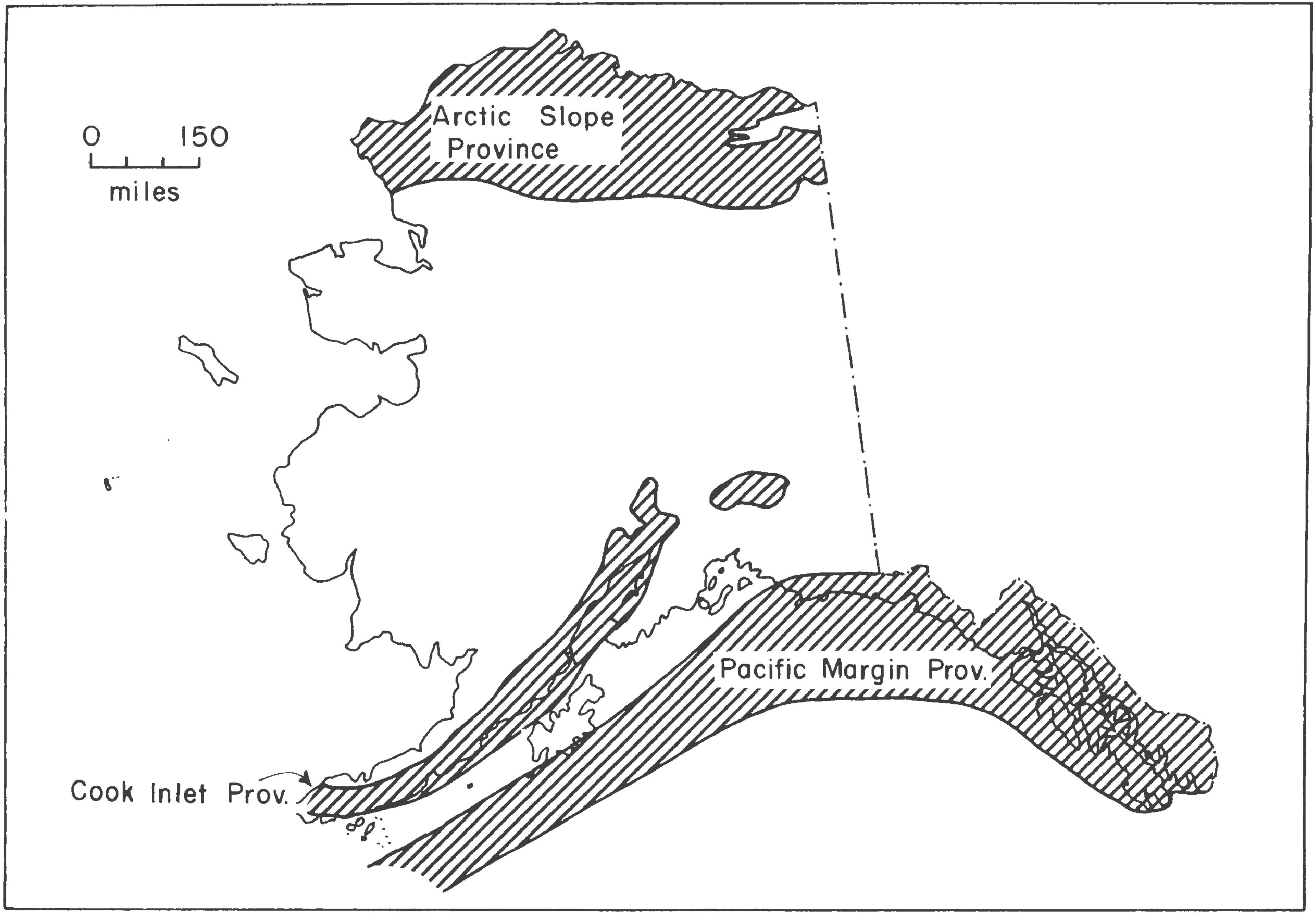


Figure 3-3. Alaskan Oil Provinces

Source: NPC, 1970: 16.

TABLE 3-2

WORLD OIL RESERVES BY COUNTRY AS OF 1970[a]

Country	Reserves (billions of barrels)
Asia-Pacific	
Australia	2
Brunei-Malaysia	1
Indonesia	10
Total Asia-Pacific	14.4
Europe	
Norway	1[b]
United Kingdom	1[b]
Total Europe	3.7
Middle East	
Abu Dhabi	11.8
Iran	70
Iraq	32
Kuwait	67.1
Neutral Zone	25.7
Oman	1.7
Qatar	4.3
Saudi Arabia	128.5
Syria	1.2
Total Middle East	344.6
Africa	
Algeria	30
Egypt	4.5
Libya	29.2
Nigeria	9.3
Total Africa	74.8
Western Hemisphere	
Argentina	4.5
Colombia	1.7
Mexico	3.2
Venezuela	14
United States	37[c]
Canada	10.8
Total Western Hemisphere	73.9
Communist Countries	
Russia	77
Red China	20
Hungary	1
Total Communist	100

Source: NPC, 1971: 46-47.

[a]Only countries with reserves exceeding one billion barrels are listed.

[b]North Sea reserves have increased dramatically since 1970.

[c]A recent (1974) estimate is 50 b million barrels (see text). (p. 3-3)

3.2.3 World Resources

World oil reserves are shown in Table 3-2. U.S. reserves are only about 11 percent of the total free world reserves (NPC, 1974: 102). In 1973, the U.S. imported about four million bbl of oil per day. Of this, two million bbl per day were from Venezuela, one million from Canada, and one million from the Mideast. Since the Mideast has 62 percent of the world's proven reserves, future increases in imports are likely to come from this area. Oil supply is international in scope because the largest consumers are unable to meet their demands from domestic sources.

3.2.4 Summary

The major conclusion with regard to U.S. oil resources is that they are inadequate to satisfy the present or anticipated needs of the country. Therefore, the U.S. must either continue importing oil for the foreseeable future, reduce average yearly energy consumption drastically, or develop alternate sources and technologies for using a different mix of fuels.

Two other conclusions can be drawn from this resource description. First, new petroleum reserves will be developed to a great extent in areas where severe environments prevail, such as Alaska, the offshore Atlantic, and on the Alaskan OCS. If these areas are to be developed, the technologies used must be adequate to meet the demands of these environments (White and others, 1973: 149).

Second, sulfur control technologies will be needed for most imported crude, and for some U.S. crude, so that fuels refined from these crudes will be acceptable under present environmental regulations.

3.3 EXPLORATION

As mentioned earlier and diagrammed in Figure 3-1, oil resource development entails a sequence of activities beginning with exploration and ending with transportation of refined products. In the following section the technologies, efficiencies, residuals, and economic costs associated with exploration will be identified and described.

3.3.1 Technologies

Exploratory activities are undertaken to locate geological formations that are potential oil reservoirs. These activities progress through three principal phases:

1. Regional surveys to identify promising geological conditions.
2. Detailed surveys on which evaluations of specific areas are based.
3. Exploratory drilling to determine whether oil is actually present in a specific area.

3.3.1.1 Regional Surveys

The oil industry is engaged almost continuously in regional surveys. Often made by air or from boats, survey methods are generally passive in nature and include measurements of changes in the earth's magnetic field and local variations in the earth's gravity. These measurements aid in identifying irregularities in subsurface geology and, thus, potential geological traps in which gas or oil may have accumulated. Regional surveys also look for natural oil seeps. The purpose of regional surveys is to identify areas where more detailed exploratory activity may be justified.

3.3.1.2 Detailed Surveys

When the decision is made to undertake a more detailed investigation of a particular area, seismic surveying and core drilling are the exploration techniques most commonly used. In a seismic survey, an energy source is used to generate sound waves which are reflected and refracted by the underlying geologic strata. The echoes are picked up on acoustic detectors and recorded on magnetic tape. These data are then digitized and computer processed to prepare cross-sectional maps of the area being surveyed.

Onshore, explosives are used as the source of acoustic waves for seismic work; offshore, explosives have been replaced by contained detonations of propane and oxygen. Another acoustic source, used both onshore and offshore, is the VIBROSEIS, which uses a high-powered oscillator whose frequency changes continuously over a period of a few seconds.

Recent advances in computer processing of seismic data may provide methods for direct detection of petroleum reservoirs (Lindsey and Craft, 1973: 23-25). Apparently, natural gas reservoirs and oil reservoirs with natural gas caps can now be located from offshore seismic data.

Core drilling of shallow holes is also employed in detailed investigations. On the OCS, core drilling is only allowed after receipt of a special permit, and depths are limited to 1,000 feet or less. Onshore, depths are usually limited by the land owner.

3.3.1.3 Exploratory Drilling

Exploratory drilling for oil is done with a rotary drill; that is, the hole is drilled by a rotating drill bit connected to the surface with a length of pipe called a drill string. Cuttings from the drill face are removed by a fluid called "drilling mud" which is pumped down through the drill pipe, out through holes in the bit, and circulated back to the surface in the annular space between the drill pipe and the bore hole (Figure 3-4). Drilling mud is a water-based slurry of chrome lignosulfate with a variable density of between 10 and 20 pounds per gallon. In addition to removing cuttings, the mud also maintains hydrostatic pressure in the hole to prevent a "blowout" (the unconstrained flow of liquids or gases from formation zones penetrated as the hole is drilled). In some wells, high pressure air is used in place of mud to remove cuttings.

In addition to drilling mud, a number of safeguards are used to minimize the

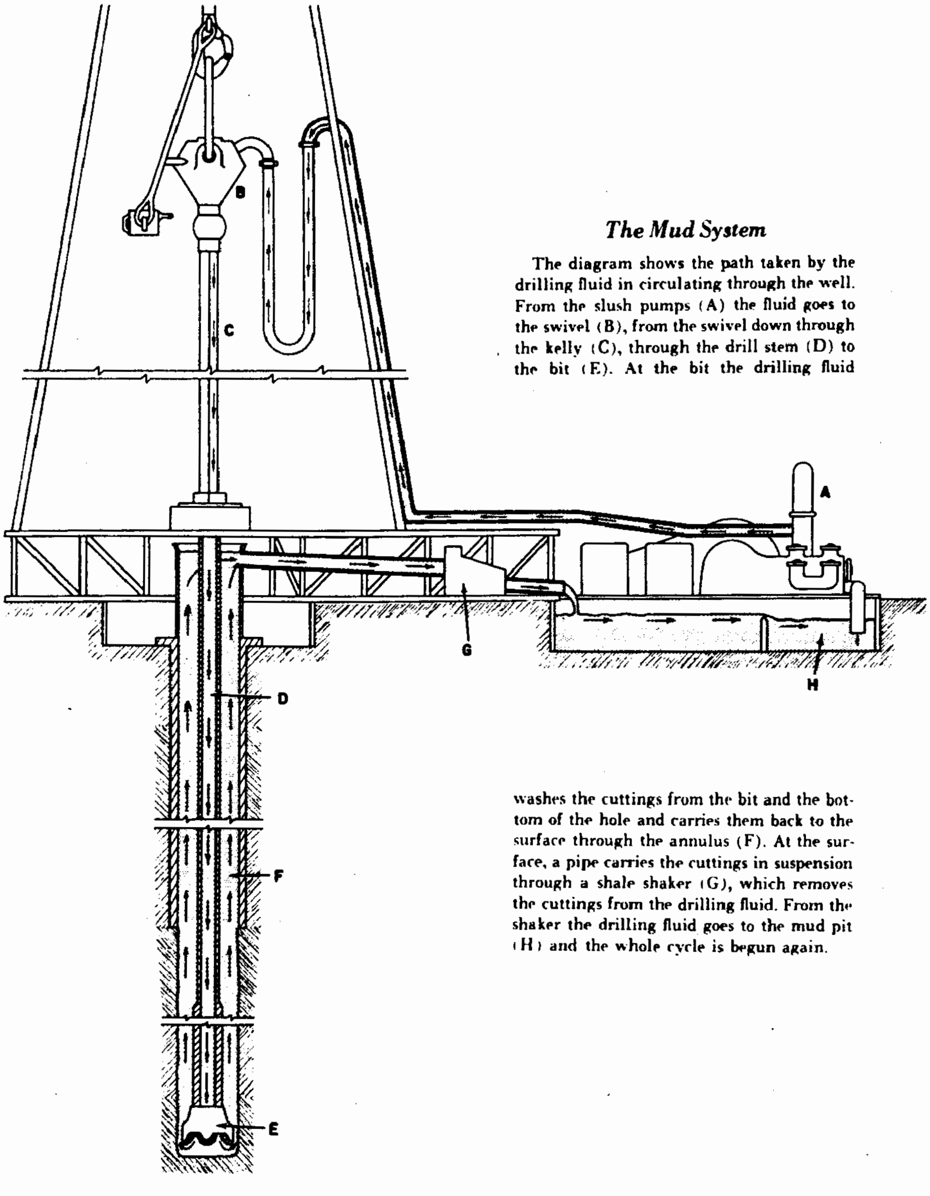


Figure 3-4. Drilling and Mud System

Source: University of Texas, 1957: 35.

likelihood of a blowout. These include setting casing and installing blowout preventer (BPO) valves. Casing is large-diameter steel pipe which is cemented in as a liner to the bore hole to prevent the loss of drilling mud into formations and to prevent communication (seepage of fluids) between formations at different depths. Casing is normally set to the total depth of the well (Figure 3-5). BOP valves are attached at the top of the casing and can close off the hole in the event control is lost. Usually, a series of these valves is used so that the hole can be sealed whether or not there is drill pipe in the hole (Figure 3-6). Drilling technology is discussed in Kash (1973: 44).

Exploratory wells are usually drilled to reach a particular geological formation that is believed to contain oil or gas. The drill cuttings taken from the hole are used to determine which formation is being penetrated and whether oil is present.

Offshore exploratory drilling uses the same techniques as onshore except that a platform must be provided to support the drilling rig and other equipment. The four basic types of offshore exploratory drilling platforms, all of which are mobile, are barges, jack-ups, drill ships, and semisubmersibles. Because of their lack of seaworthiness, barges are normally used in shallow, protected waters, although some have been built for water depths as great as 600 feet. Barges are anchored to the ocean floor. Jack-ups are platforms with retractable legs that can be lowered to the ocean floor to lift the platform out of the water (Figure 3-7). Jack-ups are limited to water depths of about 300 feet but can withstand severe weather. Drill ships (Figure 3-8) are used for exploratory drilling in deep water (as much as 2,000 feet), but they are not suitable for severe weather. Semisubmersibles are floating platforms with most of the flotation submerged (Figure 3-9). "Semis" have excellent stability in severe weather and can drill in water as deep as 2,000 feet. Semis and drill ships are either anchored or kept in position with propeller thrusters.

3.3.2 Energy Efficiencies

All the energy used in regional and detailed exploration surveys is ancillary and has not been documented in Hittman, Battelle, or Teknekron data. Energy expended in exploratory drilling is also ancillary and would be used to operate the drill rig and any associated equipment. To obtain an energy efficiency, the energy expended would have to be divided by the energy in the amount of oil found per well drilled. Data on these energies are not available.

3.3.3 Environmental Considerations

The environmental residuals from regional and detailed exploration surveys are minimal. Explosives are still used onshore, but earlier impacts due to use of explosives for offshore seismic work have been eliminated by the use of contained detonations, as mentioned in Section 3.3.1.2.

The most serious environmental residuals associated with drilling have resulted from blowouts. The number of blowouts during all drilling on land from 1960 to 1970 was 106 out of 273,000 wells or .039 percent, most of which were from high-pressure gas rather than oil wells (Kash and others, 1973: 286). Offshore, there have been 19 blowouts since 1960 (17 were gas only) which is 0.2 percent of the new wells started (Kash and others, 1973: 285).

Although the number of drilling blowouts has been small, the residuals include nondegradable organics in the form of crude oil (in amounts ranging from a few hundred to a few hundred thousand barrels per event) and, in the event of fire, air pollutants which can include hydrocarbons, oxides of nitrogen (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), and particulates. Both the

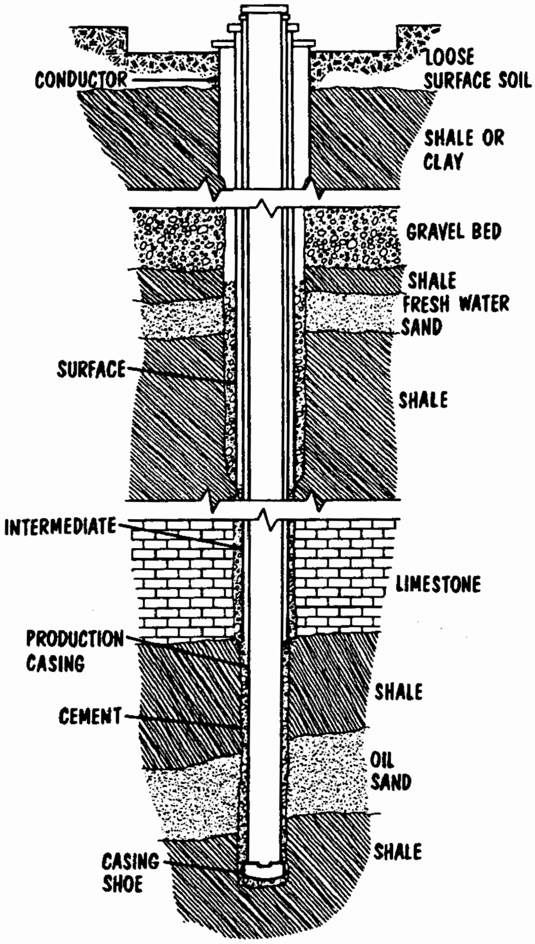
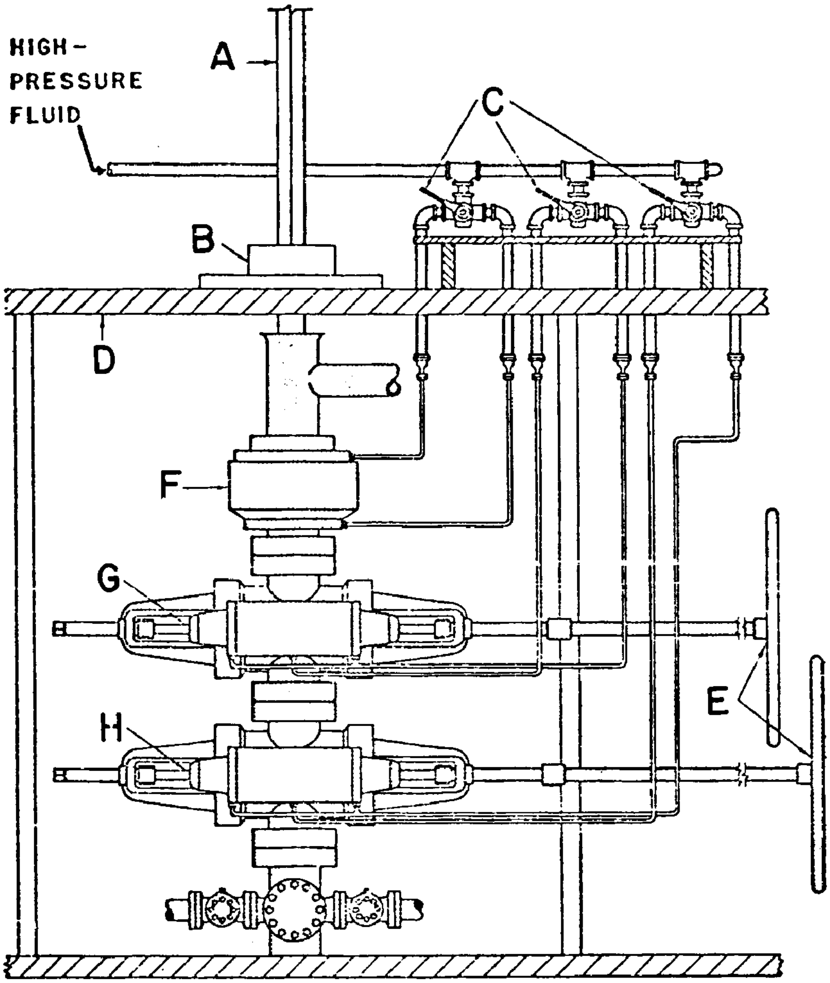


Figure 3-5. Oil Well Casing

Source: University of Texas, 1957: 48.



LEGEND

A Kelly
B Rotary table
C Hydraulic valve controls
D Drill floor
E Manual valve controls
F Bag-type preventer
G Pipe ram preventer
H Blind ram or shear ram preventer

Figure 3-6. Blowout Preventer Stack

Source: University of Texas, 1957: 45.

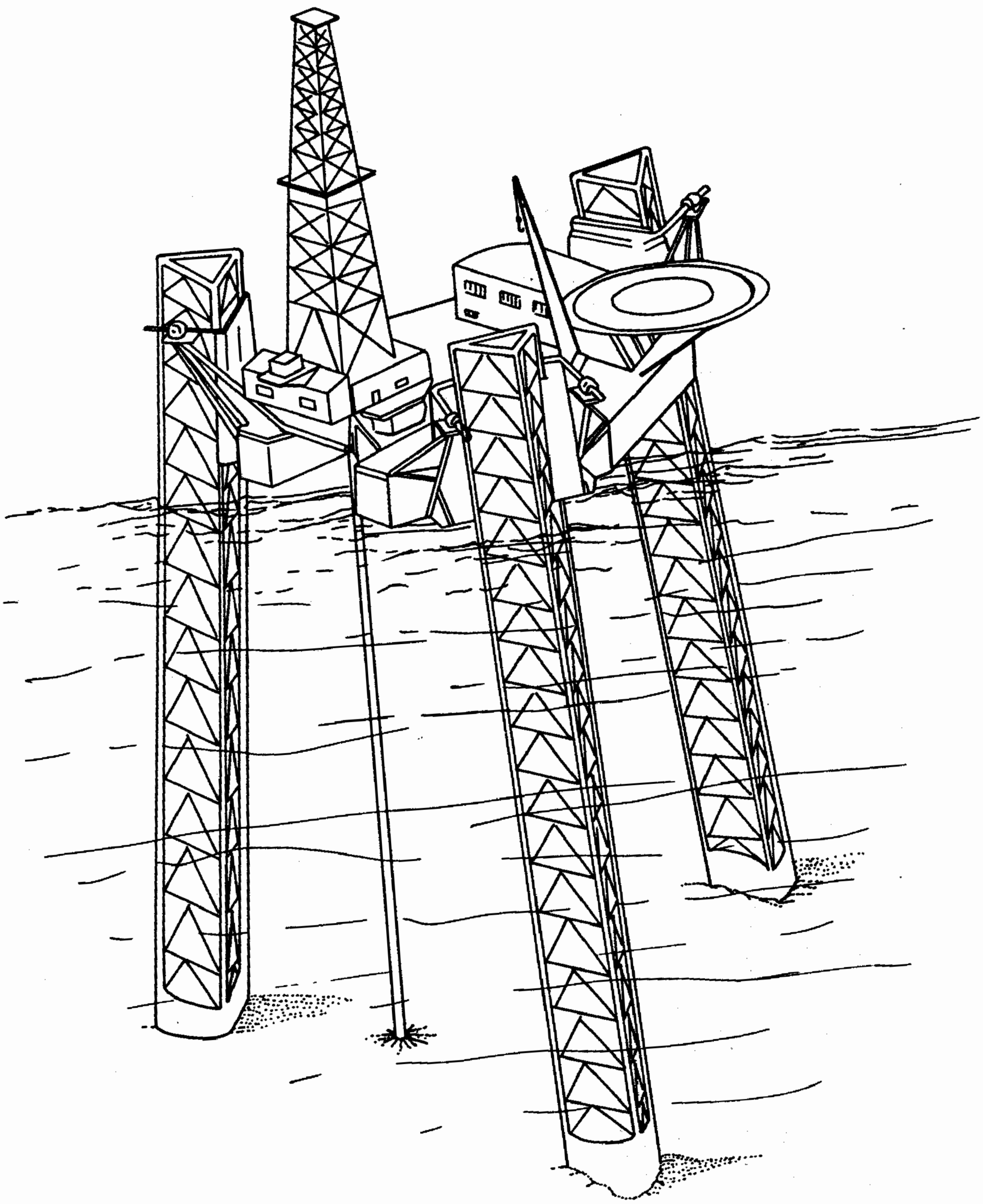


Figure 3-7. Jack-Up Offshore Drilling Rig

Source: Esso Production Research Company. Used by permission.

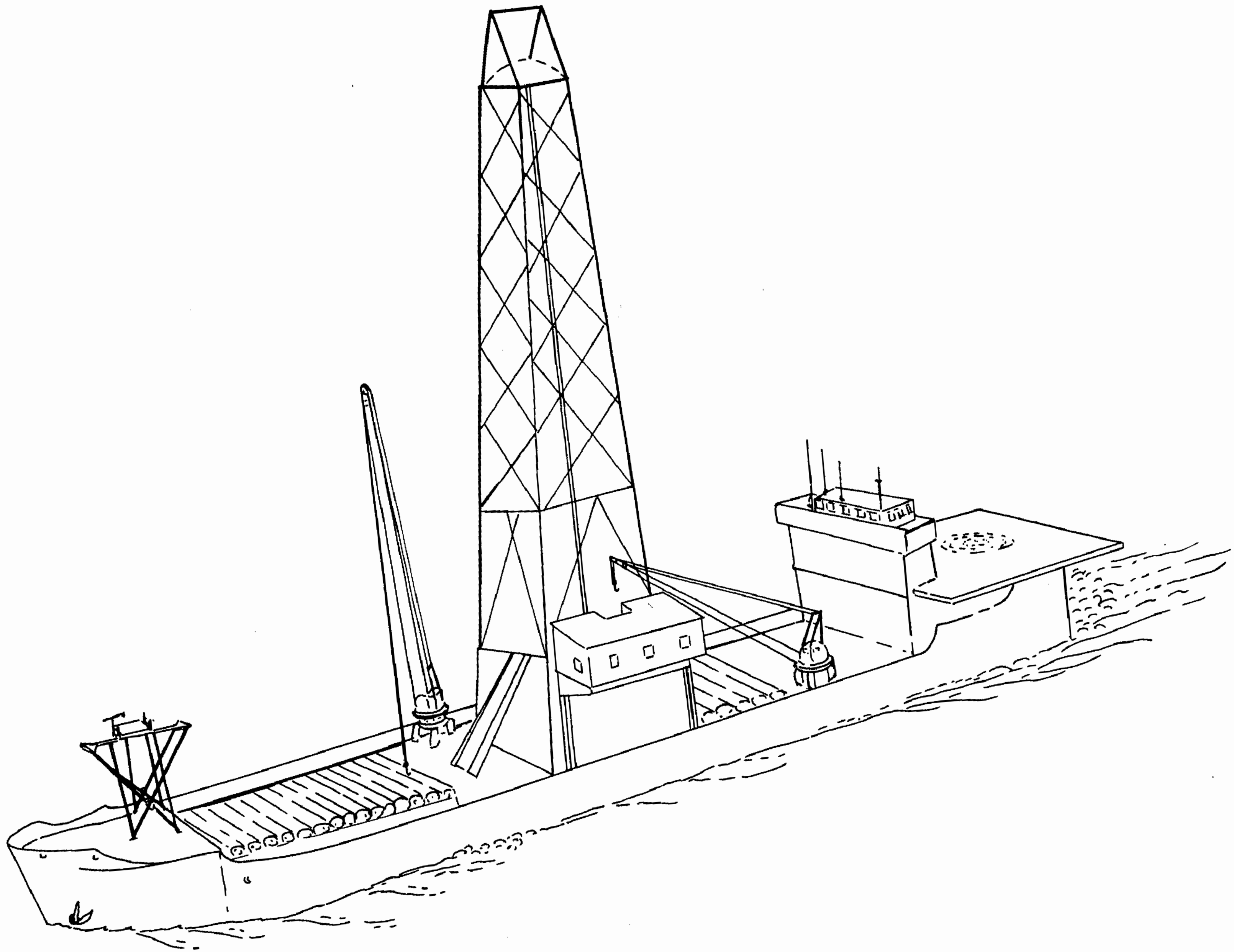


Figure 3-8. Drill Ship

Source: The Offshore Company. Used by permission.

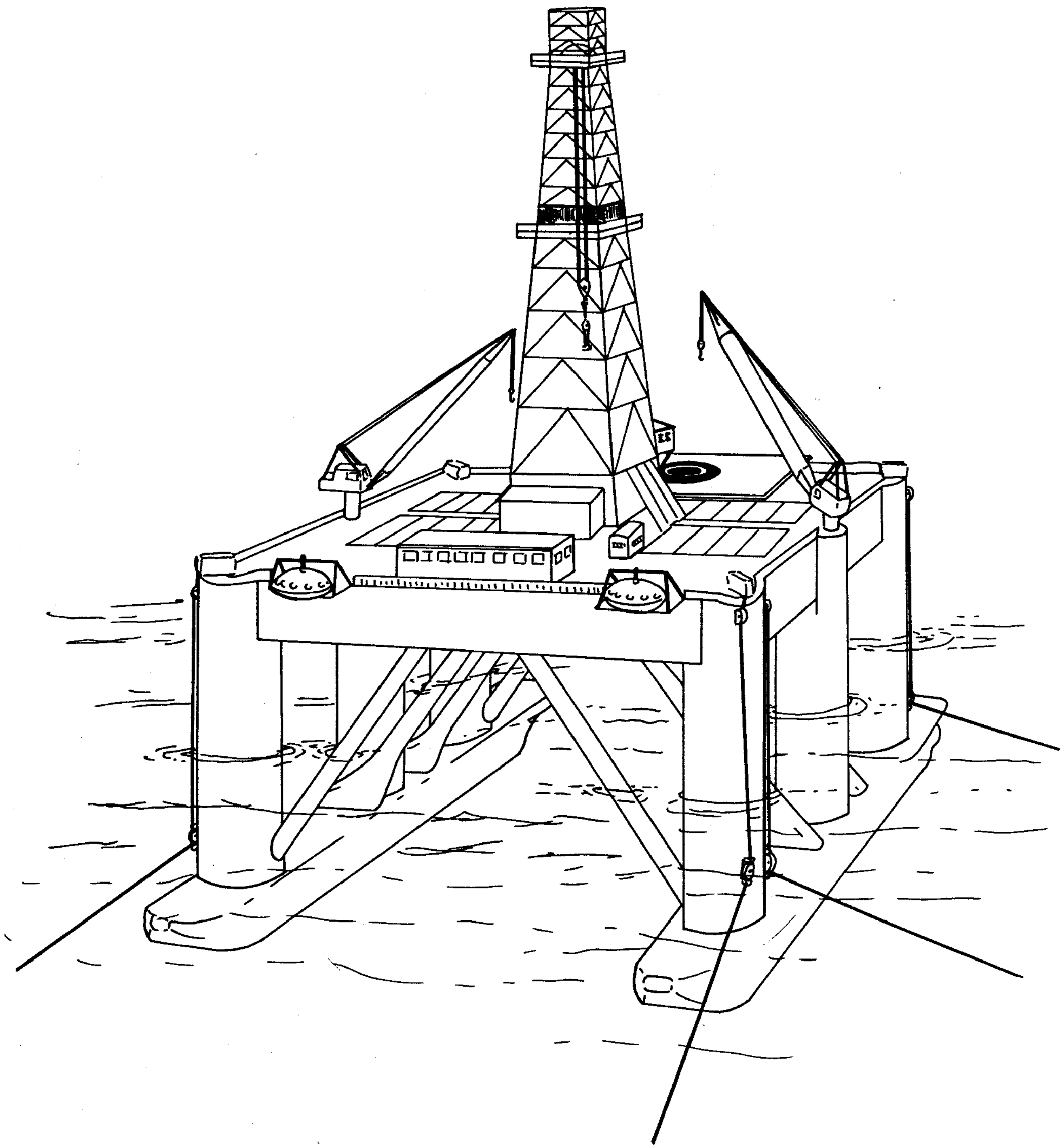


Figure 3-9. Semi-Submersible Offshore Drilling Rig

Source: The Offshore Company. Used by permission.

environmental and social impacts of these blowouts have been significant. Hittman, Battelle, and Teknekron data do not distinguish drilling blowouts from blowouts occurring during production; all blowout data are combined with chronic pollutants under oil extraction. These data are discussed in Section 3.4.

3.3.4 Economic Considerations

The total cost for regional and detailed onshore exploration surveys between 1959 and 1970 was $5.1 billion. The cost for drilling dry holes during that period was $9.1 billion (NPC, 1974: 672). Since drilling is also an exploratory activity, the minimum exploration cost for 1959 to 1970 was $14.2 billion or 15 percent of the cost of producing oil. These are minimum exploration cost figures because the cost of drilling successful wells was not included.

The total offshore exploration cost through 1968, including regional and detailed exploration surveys as well as exploratory drilling, was $1.5 billion (Kash and others, 1973: 82). Hittman, Battelle, and Teknekron do not separate exploration costs; the overall cost for oil extraction given by these sources is discussed in Section 3.4.

3.4 DEVELOPMENT

3.4.1 Technologies

The crude oil development technologies described in this section are grouped into three categories: completion, processing, and improved recovery.

3.4.1.1 Completion

Once oil is discovered by exploratory drilling, the well is tested to determine the possible oil flow rate and size of the reservoir. If the reserves calculated from these data and other geological information are large enough to warrant commercial production, the reservoir is developed. Development includes drilling a number of wells to drain the reservoir as efficiently as possible, completing these well so that flow occurs and can be controlled, installing field processing equipment, and installing pipelines.

Development drilling is carried out in the same manner as exploratory drilling, except that the spacing of wells and location of the bottoms of the holes are more carefully controlled. Offshore, development wells are usually drilled from fixed platforms rather than mobile rigs. Each platform normally contains a number of wells which are directionally drilled to different parts of the reservoir. The platforms are steel tubular truss structures with two or more decks and are attached to the ocean floor by steel pilings. Current designs have been set in water depths as great as 400 feet, and new platforms are being designed for water depths as great as 1,000 feet.

Once development wells are drilled, they are completed by setting casing in the hole with cement and installing tubing (pipe) to carry the produced oil to the surface. In offshore wells and in those onshore wells in danger of wellhead damage (such as in seismically active areas), a valve is placed near the bottom of the production tubing string. This downhole safety valve, commonly called a Storm Choke (the trade name for one brand), is designed to close when the flow through the valve exceeds a set limit. Recent modifications have made these valves much more reliable than earlier versions, which were responsible for some serious offshore accidents. A set of wellhead control valves, called a Christmas tree (Figure 3-10) controls the flow rate from the well.

Crude oil is delivered at the top of a well either by the natural pressure in the reservoir or by using some artificial lift technique. The reservoir properties, the

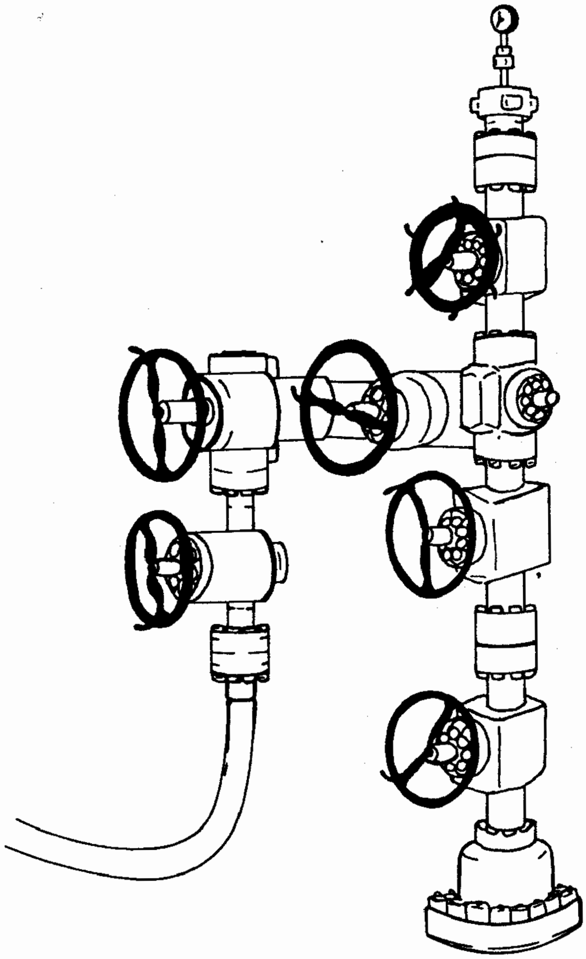


Figure 3-10. Wellhead "Christmas Tree" of Control Valves

Source: Cameron Iron Works, Incorporated, 1973: 1035.

pressure initially occurring in the reservoir, and the properties of the oil and any dissolved gas determine the percentage of oil that will be recovered by natural forces alone. Artificial lift techniques include pumps (the most common of which are sucker-rod pumps) and gas lifts (in which natural gas is injected into the oil in the well to decrease its density so that it will flow to the surface).

A new approach to completion offshore is the subsea completion. A number of prototype systems currently being tested are designed to permit well completion at the ocean floor rather than on a platform. However, because of field processing and servicing requirements, subsea completions will still require nearby surface platforms if they are far from shore. For a more complete description of subsea completions, see Kash (1973: 52).

3.4.1.2 Processing

Once out of the well, oil is processed in the field to remove natural gas, salt water (brine), sand, and/or other impurities. Although the exact field processing used depends on the impurities present, usually only one or two processing steps are required. If present, natural gas is separated from the oil by a gravity separator. The gas may then be sold if a gas pipeline is nearby. If not, the gas may be used for lift to aid recovery, may be injected back into the reservoir, may be used in lieu of ancillary energy on site, or may be mixed with air and burned in a flare. Unlike the other alternatives, flaring wastes the gas and produces air pollutants. Thus, flaring is normally used only in isolated regions, such as offshore. In 1973, the gas flared was estimated to be 3.4 percent of all the gas produced offshore (Interior, 1972: 7).

Salt water produced with the oil is removed in free water knockout processing in which the mixture sits in a large tank and is separated by gravity. If the brine is emulsified in the oil, more sophisticated processing methods (such as heaters or chemical surfactants) are required. In addition to separation, oil field brines require treatment before disposal. Offshore water treatment facilities can clean water down to about 50 parts per million (ppm) of oil by using gravity, filters, surfactants, or combinations of these techniques. Onshore, brine is usually treated by gravity separation (allowing the brine to sit for a few days in a large tank). Cleanliness is determined by tank retention time but can be as low as five ppm.

Sand is very erosive to equipment and thus, when present in the formation, is normally held in the bottom of the well by injected chemical binders or screens. When sand is produced with the oil, it is also removed in the free water knockout or oil-gas separators.

After field processing, oil quality is verified and quantity is measured before the oil enters a pipeline.

3.4.1.3 Improved Recovery

When the natural flow of oil has diminished, additional oil may be recovered from the reservoir through the use of improved recovery techniques which add supplemental energy to the reservoir. The most common method of improved recovery is waterflooding, which is sometimes called secondary recovery. This technique is so effective that, in recent years, it has been used quite early in the productive life of a reservoir to extend potential production. Waterflooding consists of pumping water down selected wells in a field to force oil up other wells in the field. Generally, waterflooding requires injection of one or more barrels of water for each barrel of oil recovered. A typical waterflooding system is shown in Figure 3-11.

Tertiary recovery, which refers to all improved recovery methods other than

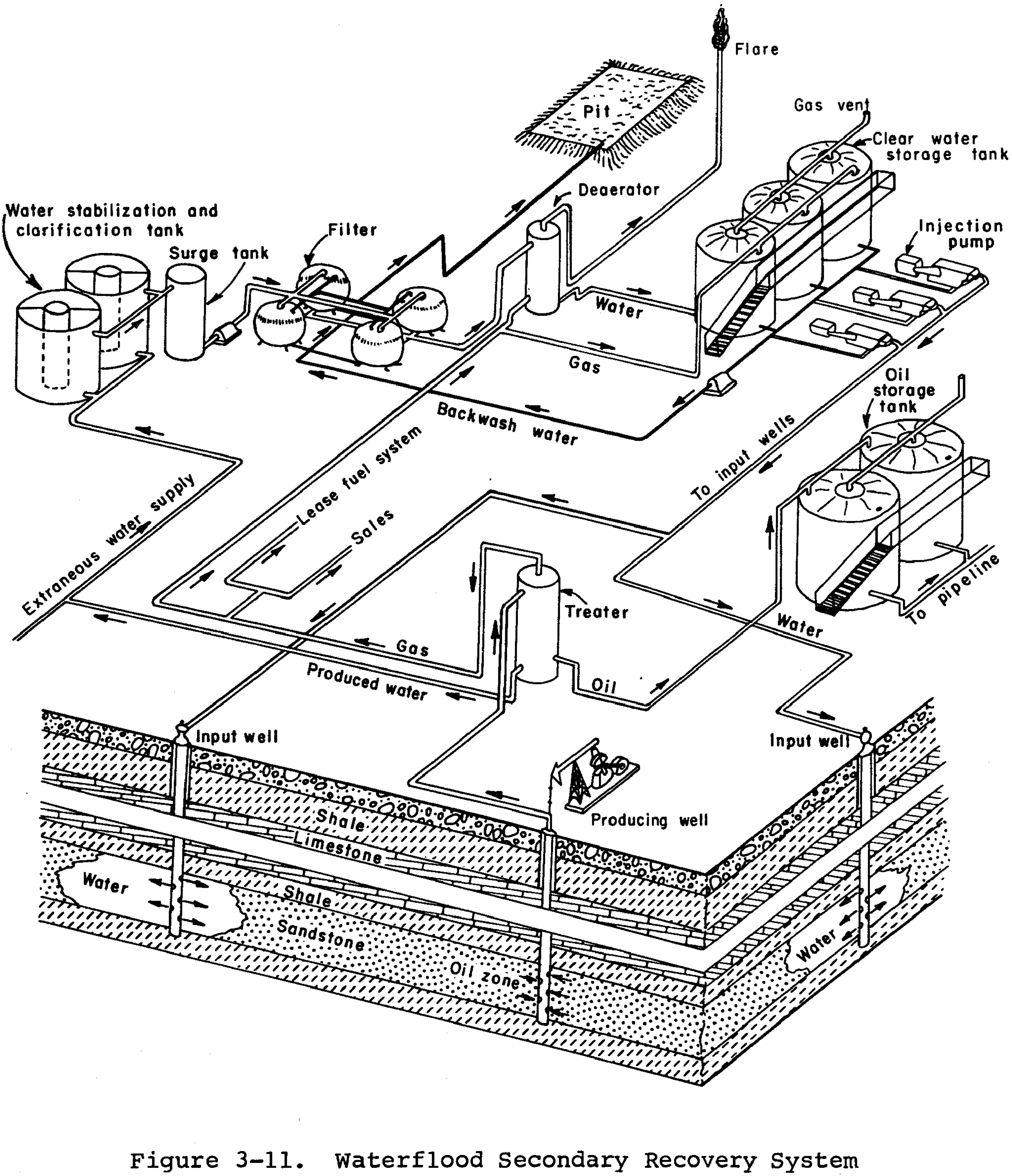


Figure 3-11. Waterflood Secondary Recovery System

Source: BuMines, 1970: 26.

waterflooding involves adding a large quantity of a liquid material (usually mixed with water) or a gas to the reservoir. The most promising tertiary technique is to inject a mobilizing material designed to release oil locked in pore spaces or the reservoir rock. The mobilized oil is then pushed to production wells by injecting either water or gas behind the mobilizing material. The five categories of tertiary recovery techniques are polymer floods; surfactants; miscible recovery processes; immiscible gases; and thermal recovery methods.

In polymer flooding, a high molecular weight polymer is dissolved into water and injected into the reservoir. The polymer increases the viscosity of the water, resulting in a thickened material that is more likely to flow within the oil-bearing zones of the reservoir and less likely to disperse into nonoil-bearing zones.

Surfactants are chemicals that act very much like soap when added to water. Injected into reservoirs, they help to wash the oil from the surface of the rock.

In miscible recovery, a fluid that will mix with the oil is injected, then water is injected to push the mixture to producing wells. The immiscible technique uses gases such as nitrogen, air, or flue gases to push the oil from the reservoir.

Thermal techniques use heat to thin the crude oil for easier recovery. Heat is most often provided by injecting steam into the reservoir, but in situ combustion of part of the oil (supported by injected air) has also been used.

Whenever a material has been added to the oil in secondary or tertiary recovery, it must be separated out after the mixture has been produced. The separation may be similar to other field processing or may take place at the refinery.

The choice among the various tertiary recovery processes as applied to a particular reservoir depends on the viscosity of the reservoir oil, reservoir properties, and the availability of injection materials. Although research and field testing are being conducted on all these techniques, tertiary recovery has limited applications at present.

3.4.2 Energy Efficiencies

The primary efficiency of oil extraction is the amount of oil extracted from the reservoir divided by the amount contained in the reservoir. This efficiency, called recovery efficiency in the industry, averages about 30 percent for onshore wells and about 40 percent for offshore wells to within an error probability of less than 50 percent. The difference between the two results from location of the reserves. More than 90 percent of offshore drilling, to the present, has been in the Gulf of Mexico where reservoir conditions are more favorable than for the U.S. as a whole.

In the future, more offshore oil will be taken from the Pacific or from previously undeveloped areas such as the Atlantic and Gulf of Alaska. Since no recovery efficiencies are available for these areas and since reservoir conditions may be less favorable than for the Gulf of Mexico reservoirs, future offshore recovery efficiencies should be estimated at about 30 percent, which is the national average.

Table 3-3 gives primary energy efficiencies for onshore and offshore extraction as estimated by Hittman, Battelle, and Teknekron. Battelle apparently defines primary efficiency differently than Hittman and Teknekron, because Battelle cites 100-percent efficiency for both onshore and offshore extraction. Such an assumption is probably not as useful as assuming that the primary efficiency for oil extraction is the same as recovery efficiency. However, estimates indicate that recovery efficiencies as high as 70 percent can be achieved, although at considerable expense. Recovery efficiency estimates for secondary and tertiary recovery are shown in Table 3-4.

Table 3-3. Efficiencies and Residuals from Crude Oil Extraction

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
EXTRACTION																					
Onshore Oil[b]	U	NA	NA	NA	U	NA	.15	NA	U	0	U	U	U	U	U	0	NA	3.03/0 3.03	8.2 $\times 10^{-5}$	.004	.137
Offshore Oil[b]	U	NA	NA	NA	U	NA	1.3	NA	U	0	U	U	U	U	U	0	NA	.35/0 .35	5.7 $\times 10^{-6}$	.0003	.009
Onshore Oil[c]	U	NC	NC	NC	3100.	0	4.	NC	NC	0	.002	.004	.03	.0002	1.5	NC	0	6.9/0 6.9	.0022	.21	35.
Offshore Oil[c]	U	NC	NC	NC	0	0	1.	NC	NC	0	.002	.004	.03	.0002	1.5	NC	0	6.9/0 6.9	.0022	.21	35.
Onshore Oil[d]	U	NC	NC	NC	U	NC	.8	NC	NC	NC	U	U	U	U	U	NC	NC	U/U 0	NC	NC	NC
Offshore Oil[d]	U	NC	NC	NC	U	NC	2.	NC	NC	NC	U	U	U	U	U	NC	NC	U/U 0	NC	NC	NC

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

[b]Hittman, 1974: Vol. I, Table 13.

[c]Battelle, 1973: Tables A-34, A-35.

[d]Teknekron, 1973: Figure 4.1.

TABLE 3-4

EFFICIENCY OF IMPROVED RECOVERY METHODS

Method	Recovery Improvement (percent)		Incremental Cost (dollars per barrel of added oil)
	From	To	
Waterflood	10	50	0.35-0.50
Steam (heavy oil)	10	60	0.75-1.25
Alternate water (polymer)	30	40	0.25-0.35
Thickened water (polymer)	30	40	0.60-0.80
Wettability reversal	45	55	0.50-0.75
Miscible-hydrocarbon	45	75	0.75-1.00
Miscible-CO_2	45	70	0.60-0.85
Miscible (micellar) water	45	80	1.00-1.50
IFT (micellar) water[a]	45	75	0.75-1.25
Thermal (COFCAW)[b]	40	70	1.25-1.50

Source: Geffen, 1973: 88.

[a]Injected Fluid Thickened (IFT) Waterflooding.

[b]Combined Forward Combustion And Waterflooding (COFCAW). This data also applies to "Huff-and-Puff" steam injection techniques.

Ancillary energy for oil extraction includes drilling and pumping requirements for primary recovery, and injection well drilling and fluid pumping requirements for secondary and tertiary recovery. Additional ancillary energy may be used in tertiary recovery if natural gas or other possible fuels are pumped into the well. The amounts of ancillary energy, particularly for secondary and tertiary recovery, will be significant; however, no data is presented in Hittman, Battelle, or Teknekron for ancillary energy use.

3.4.3 Environmental Considerations

Environmental residuals can be generated both chronically and by accidents such as blowouts. Blowouts were discussed in Section 3.3 and will not be further described here, but the residuals listed in Table 3-3 can be assumed to arise from both chronic discharges and blowouts.

3.4.3.1 Water

Water residuals from onshore oil extraction are nondegradable organics (oil) and dissolved solids (brine). As indicated in Table 3-3, estimates of oil residuals range from one to four tons per 10^{12} Btu's of oil in the ground to within a possible error of 50 percent. Estimates of dissolved solids range from 0 to 3,100 tons per 10^{12} Btu's. The Hittman oil discharges assume that 12 percent of the produced brine is discharged while Battelle assumes four percent is discharged. The dissolved solids are not discussed by Hittman except to assume that the brine is not a pollutant. And the long-term possibility of groundwater pollution from casing corrosion has not been addressed.

The only category of water residuals from offshore oil extraction is the oil contained in the discharged wastewater (brine). The range of oil discharged is from zero to two tons per 10^{12} Btu's. Without this oil, brine (produced salt water) is assumed to be nonpolluting when discharged into the ocean. Hittman estimates zero water pollution from offshore wells by assuming that all the produced brine is reinjected into the reservoir. However, complete reinjection is not practiced at all offshore wells at present, and there is no regulation requiring such reinjection. Present regulations permit discharges averaging up to 50 ppm of oil in discharged water, which implies an oil discharge of nine bbl per million bbl produced (Kash and others, 1973: 292) or 0.22 ton per 10^{12} Btu's. Battelle assumes 40 bbl of oil discharged per million bbl of oil produced.

Teknekron assumes that oil will be lost due to blowouts and spills at wells but makes no assumption concerning the amount of oil or dissolved solids in the discharged brine. Consequently, the organic pollutants from the Teknekron data are from a different source (blowouts) than the organic residuals from the Hittman and Battelle data. To obtain a reasonable estimate of total organic residuals in water due to oil extraction, the sum of chronic and blowout discharges should be used.

3.4.3.2 Air

Air-pollutant residuals include particulates, NO_x, SO_x, hydrocarbons, and CO, all of which are due to blowouts and subsequent evaporation or burning, or due to testing wells offshore in which produced oil is burned to dispose of it. Residual quantities are not significant when normalized by total oil production (on a tons per 10^{12} Btu's basis) but generate significant local impacts in the area of a spill or blowout. The air-pollutant residuals from gas flaring are not included, although they should be much larger than the residuals resulting from either testing wells or blowouts. Air-pollutant residuals are assumed to be the same offshore and onshore, although in testing wells onshore, the oil produced is loaded into tank trucks and sold.

3.4.3.3 Land

Estimates of land use from oil extraction ranges from 3.03 to 6.9 acres per 10^{12} Btu's per year (Hittman, 1974: Vol. I, Table 13; Battelle, 1973: Table A-34). These data are based on onshore land use ranging from one-quarter to one acre per well, and offshore land use from zero to one acre per well. Land use attributed to offshore wells should be much less than for onshore because the only land used will be for onshore field processing facilities near an offshore field.

3.4.4 Economic Considerations

The fixed cost estimate, within a factor of two, for an onshore well is about \$273,000 and for an offshore well is about \$125,000 per 10^{12} Btu's output. These estimates assume that offshore wells produce an average of 17 times as much oil as onshore wells but that development costs of offshore wells are almost eight times greater than onshore wells. Capital costs were assumed to be 10 percent for both types of wells (Hittman, 1974: Vol. I).

No operating costs were given for oil wells. Operating costs should include well maintenance, pumping costs, and the costs of workovers.

3.5 CRUDE OIL REFINING

3.5.1 Technologies

A petroleum refinery is a combination of processes and operations designed to convert crude oil into various products. As discussed in Section 3.2, crude may be a mixture of more than a thousand different hydrocarbons, together with trace quantities of such compounds as sulfur and nitrogen. The crude is first separated by distillation into fractions selected on the basis of boiling points; the relative volume of each fraction is determined by the type of crude used.

Since the relative volume of each fraction produced by merely separating the crude may not conform to the relative market demand for each fraction, some of the separation products are converted into products having a greater demand by splitting, uniting, or rearranging the original molecules.

The processes used in a refinery to accomplish the above conversions include distillation, sulfur removal, cracking, and reforming. Each refinery design is a unique combination of types and capacities of these processes (Hittman, 1974: Vol. I, pp. IV-1 through IV-3). A schematic of a refinery is shown in Figure 3-12. The following describes the refinery feedstocks and products, unit processes, and operation residuals.

3.5.1.1 Feedstock and Products

The feedstock for a refinery is crude oil, but there is a limited range of crudes that a particular refinery can process efficiently. Thus, early in the design of a new refinery, an effort is made to insure that feedstocks will be sufficient to allow efficient refinery operation for a maximum length of time. The important feedstock characteristics are density (API gravity), sulfur content, and the quantities of other impurities such as nitrogen and salts. If an appropriate feedstock is not available from a single source, different crudes are blended to obtain the desired characteristics. In addition to crude oil, feedstock can include natural gas liquids or synthetic crude (syncrude) from oil shale or coal liquefaction.

The principal products of U.S. refineries are gasoline, jet fuels and kerosene, and diesel and fuel oils. Lubricants, waxes and solvents, petrochemical feedstocks, and asphalt (oil) are also produced. The proportions of the principal products vary with the refinery design, location, and time of the year. For example, refineries in the northeastern U.S. produce mostly gasoline during the summer but shift to predominately fuel oil production during the winter to meet heating oil demands in that part of the country.

Gasoline production has become more difficult recently because of pollution control requirements. Tetraethyl lead, which improves the gasoline octane number,* cannot be added to gasoline for use in 1975 model cars because it destroys the effectiveness of their catalytic converters. Although low octane gasoline is compatible with the low-compression, less efficient engines in the newer cars, unleaded gasoline does not burn efficiently in older, high-compression engines. The result is lowered gas mileage (and thus increased demand) from users of both types of vehicles. Research has and is being done on nonpolluting alternatives to the use of tetraethyl lead to increase octane ratings, but the only feasible method at present is to increase the proportion of high octane hydrocarbons in the gasoline, which requires additional refining steps not available in older refineries.

Fuel oils, which are relatively low energy products, are graded from one through six, the highest number corresponding to the heaviest, least energetic oil. The two highest grades (lowest numbers) are distillate fuel oils (obtained from the distillation process in the refinery). The lowest four grades are residual fuel oils, produced by diluting the residual from the distillation process with varying amounts of kerosene to obtain the desired viscosity. Number six residual fuel oil must be heated before it will flow through a pipe or burn.

---

*Octane number is a measure of the gasoline's ability to burn smoothly.

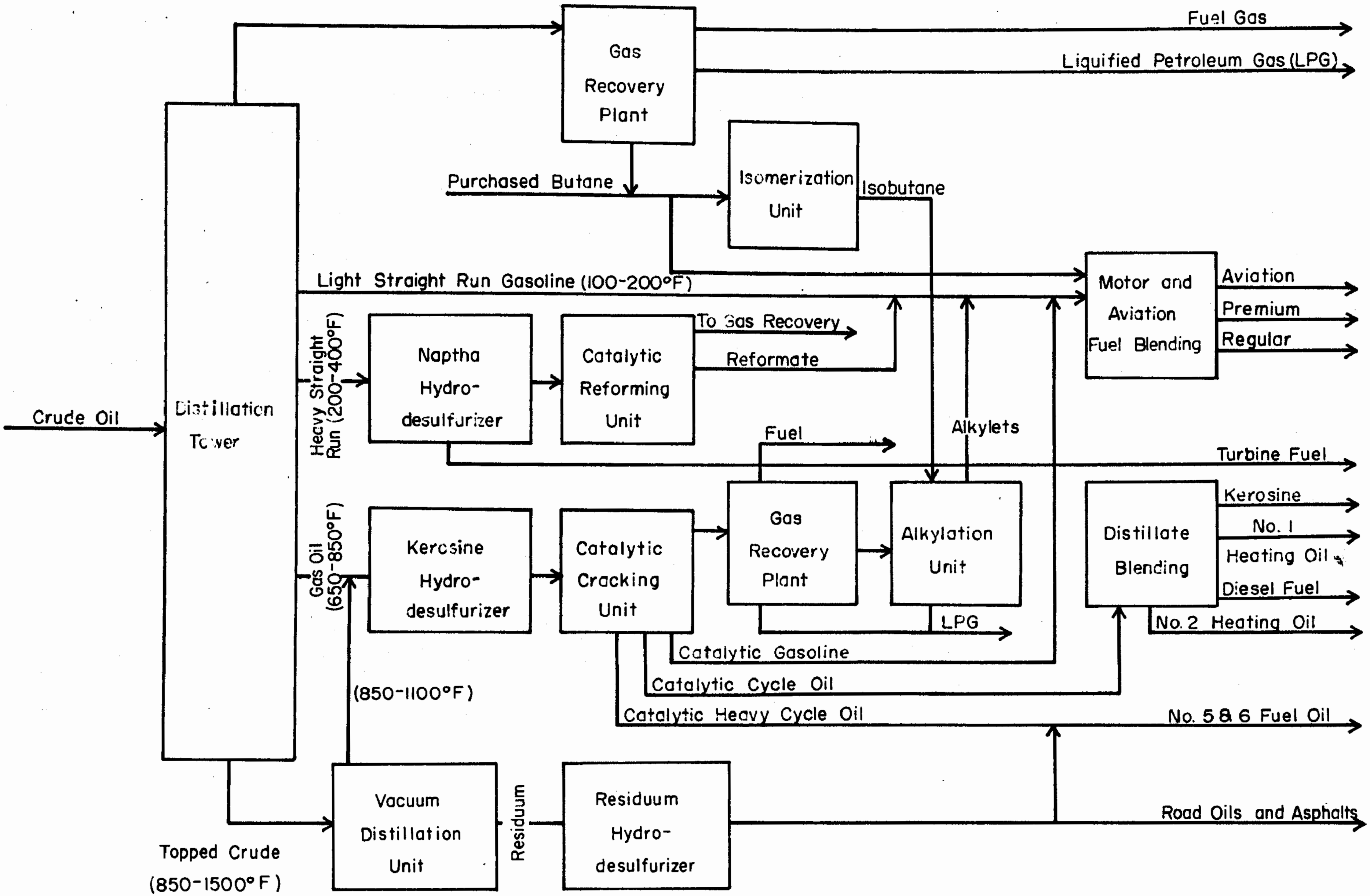


Figure 3-12. Oil Refinery

3.5.1.2 Unit Processes

As mentioned previously, a refinery complex consists of a number of unit processes that are sized and combined to produce the desired products from a given crude oil feedstock. This section describes these processes and identifies considerations necessary to combine them into a complete refinery.

3.5.1.2.1 Distillation

Distillation is a process of progressively heating crude oil in a column and drawing off various components at their different boiling points. The very light hydrocarbons, such as gasoline, boil at less than 250°F, while the boiling points of the heavy or residual fuel oils are more than 900°F. Distillation occurs in a fractionation or distillation tower which is heated at the bottom and cooled at the top (Figure 3-13). The crude goes into the column from an electrostatic desalter in which salts are removed to minimize corrosion. A typical tower will be about 15 feet in diameter and more than 100 feet high. Inside the tower, 35 or more trays are arranged so that the rising vapor must bubble through the liquid in each tray. The lower boiling point (lighter) fractions move further up the column before they condense on a tray. The residual leaving the distillation column is processed in a vacuum distillation column to separate very high boiling point fractions that could not be separated in the main tower.

The number and type of products obtainable from crude distillation is highly dependent on the design of the unit, as well as on the crude type. Changes in operating temperatures and heating rates can also affect the proportions of products, and these factors are normally the ones used to make seasonal changes in product output.

3.5.1.2.2 Sulfur Removal

The sulfur initially in the crude leaves the distillation column in the heavier fractions or as hydrogen sulfide gas. Hydrodesulfurization, the process used to remove the sulfur in the heavier fractions, reacts high-pressure (300 to 1,000 pounds per square inch [psi]) hydrogen with the sulfur-containing liquid at high temperatures (600 to 800°F) and in the presence of cobalt and molybdenum oxide catalysts (see Figure 3-14). The many different proprietary catalyst formulations account for a variety of hydrodesulfurization processes. Heavy metals, such as vanadium, will poison these catalysts so that they cannot be used or regenerated, but even without heavy metal poisoning the catalysts must be regenerated with steam twice a year. A fractionation column is used to separate the cleaned hydrocarbon from the hydrogen sulfide. A similar process for removing acid gases from natural gas is described in Chapter 4.

The hydrogen sulfide gas (whether from the distillation column or from the hydrodesulfurization process) exists in a mixture with hydrocarbon gases and must be separated to recover the hydrocarbon gases and to allow the hydrogen sulfide to be further processed. The mixture, called "sour gas," is circulated through a packed column in which an amine solvent absorbs the hydrogen sulfide (Figure 3-15). The solvent is then regenerated in a distillation column and the hydrogen sulfide removed. The hydrogen sulfide is processed in a Claus plant to recover elemental sulfur. (Claus plants are discussed in Chapter 1.)

3.5.1.2.3 Cracking Processes

Cracking is a process of breaking up large molecules in the feedstock to form smaller molecules with higher energy content. Two kinds of cracking processes, catalytic cracking and hydrocracking, are presently used in modern refineries, having replaced thermal cracking processes used earlier.

Catalytic cracking or "cat cracking" accounts for the vast majority of cracking processes in use today. Cracking catalysts are zeolites, synthetic formulations of

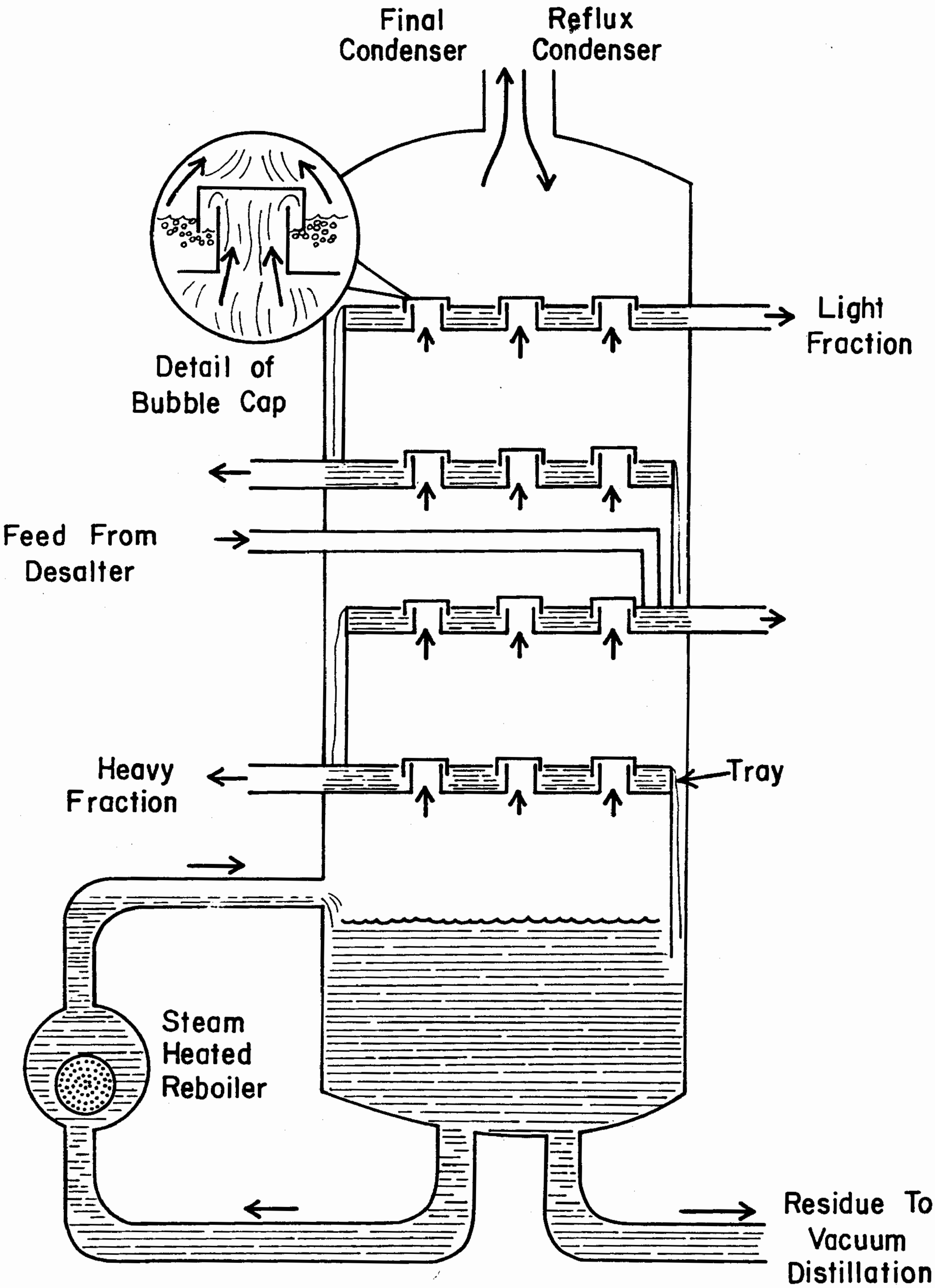


Figure 3-13. Refinery Crude Oil Distillation Column

Source: Peel, 1970: 178.

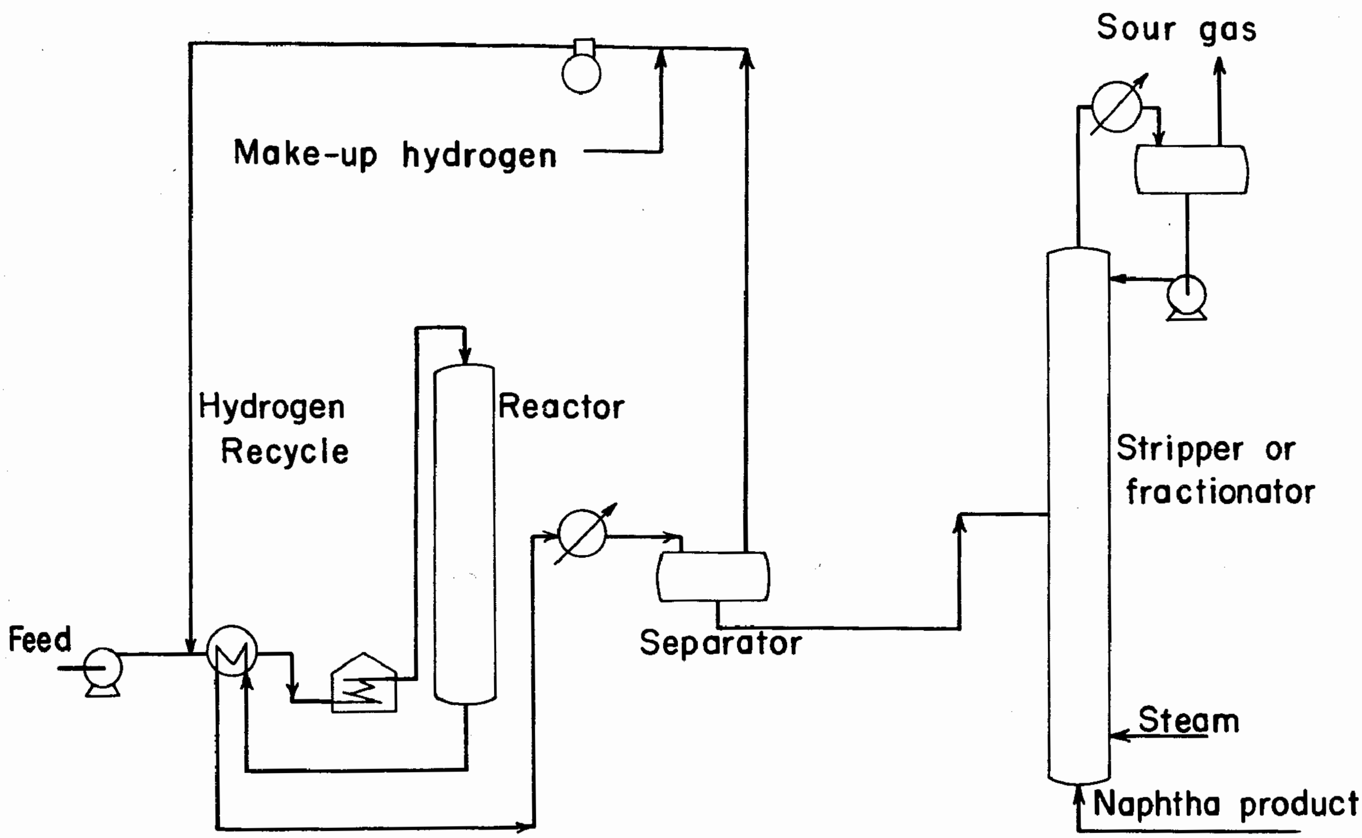


Figure 3-14. Refinery Hydrodesulfurization Process

Source: Radian Corporation, 1974: 87.

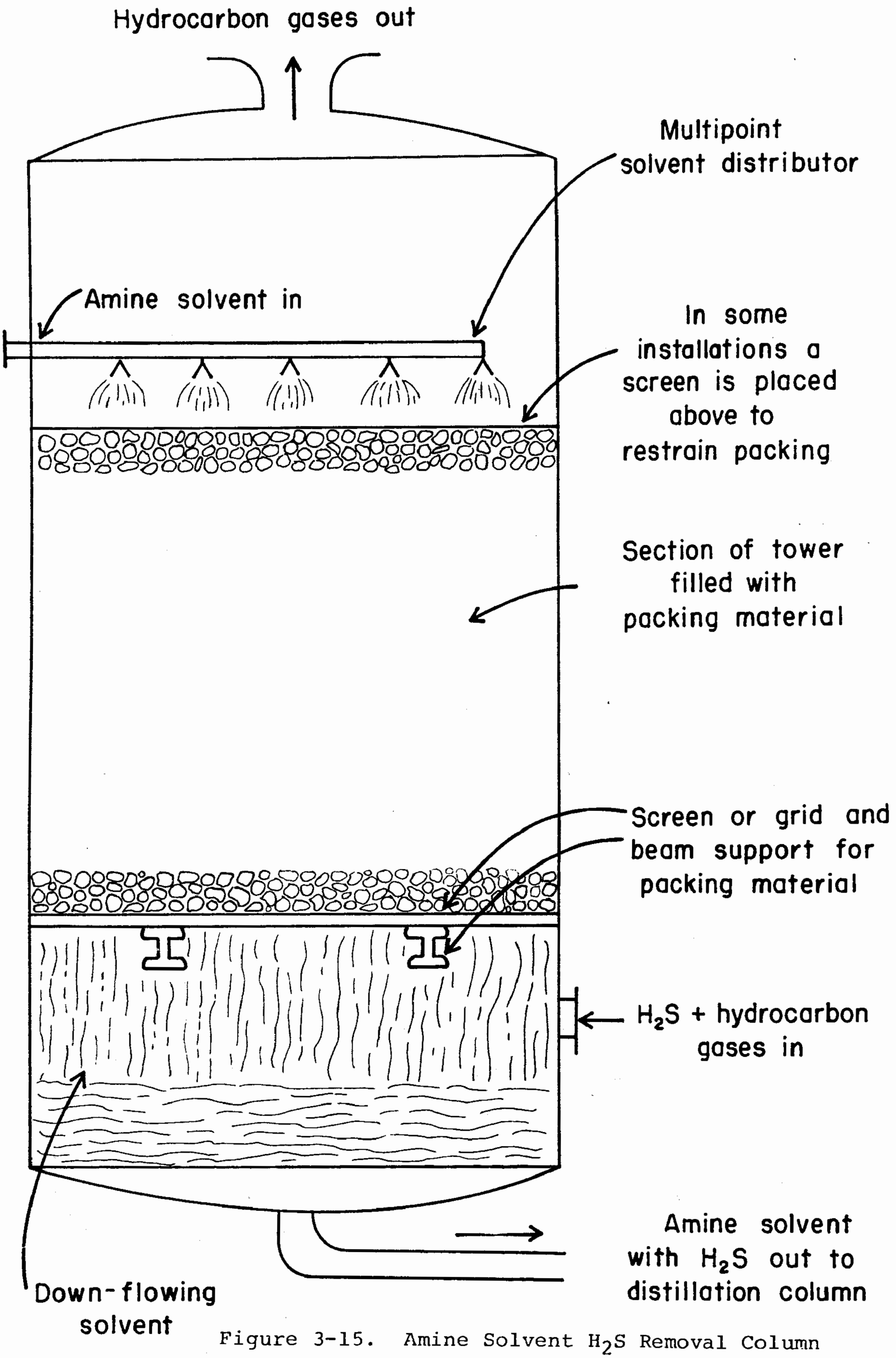


Figure 3-15. Amine Solvent H_2S Removal Column

Source: G.G. Brown and Associates, 1960: 323.

alumina in silica. Modern cat crackers use fluidized beds of catalyst. (See Chapter 1 for a description of fluidized beds.) Cat cracking catalysts rapidly become fouled with carbon and must be frequently regenerated; thus, regenerators are included as an integral part of the cat cracking reactor. The regenerator burns the carbon with air to form carbon monoxide, which is then used for refinery process heat. As with other refinery processes, the cracked hydrocarbons are separated in a distillation column. A typical catalytic cracking process is shown in Figure 3-16.

Hydrocracking carries out the cracking reactions under high pressures (2,000 to 2,500 psi) and temperatures (about 800°F) in the presence of hydrogen and a catalyst in fixed-bed reactors. Because of the high pressures and temperatures, and the hydrogen requirement, hydrocracking equipment is relatively expensive. However, hydrocracking should become more competitive in the future because it generates higher octane products and does not leave a carbon residue.

3.5.1.2.4 Reforming, Alkylation, and Isomerization

Reforming, alkylation, and isomerization processes are used to rearrange the molecular structure of hydrocarbons to form high octane number compounds for high octane gasoline manufacture. These processes differ in the technique of rearranging the molecule and, consequently, in the chemical engineering details involved. In each process, a catalyst is used. Reforming uses a platinum or rhenium catalyst in a hydrogen atmosphere at pressures of 100 to 200 psi and temperatures of 800 to 900°F. Also, the feedstock must be sulfur free because sulfur will poison these catalysts. Alkylation uses concentrated hydrofluoric, sulfuric, or phosphoric acid as the catalyst. Isomerization uses a platinum oxide catalyst at a temperature of 320°F and a pressure of 400 psi.

3.5.1.2.5 Support Facilities

In addition to the combination of basic processes identified above, a complete refinery also has support facilities that may be important in determining the quantity of residuals produced or the economics of the refinery. These include stack gas cleaning, wastewater treatment, and facilities for generating hydrogen, steam, and electrical power.

Stack gas cleaning equipment is used on processes where combustion occurs and the products do not conform to air quality standards. The technologies are the same as those used in central station power plants and are described in Chapter 12.

Wastewater from a refinery usually contains various hydrocarbons and some sulfur. Refinery wastewater treatment is the same as that used for other industrial wastewater and is described in Chapter 1.

Hydrogen, necessary for hydrodesulfurization and hydrocracking, is generated by the decomposition of methane with steam at very high temperatures (about 1,700°F) using a catalyst. This process also produces carbon dioxide which is separated from the hydrogen in an amine scrubber (see Section 3.5.1.2.2).

When electricity and steam are generated in the refinery, their production may be combined. In many cases, however, electric power is purchased and only process steam is generated on site. In either case, the technology is the same as that used for central station power generation and is described in Chapter 12.

3.5.2 Energy Efficiencies

The energy efficiencies for a national average refinery are shown in Table 3-5. The data are considered fair, with an error of less than 50 percent. They range between 88 and 96 percent when both primary efficiency and ancillary energy consumption are included. Ancillary energy consumption for refineries without residual controls is

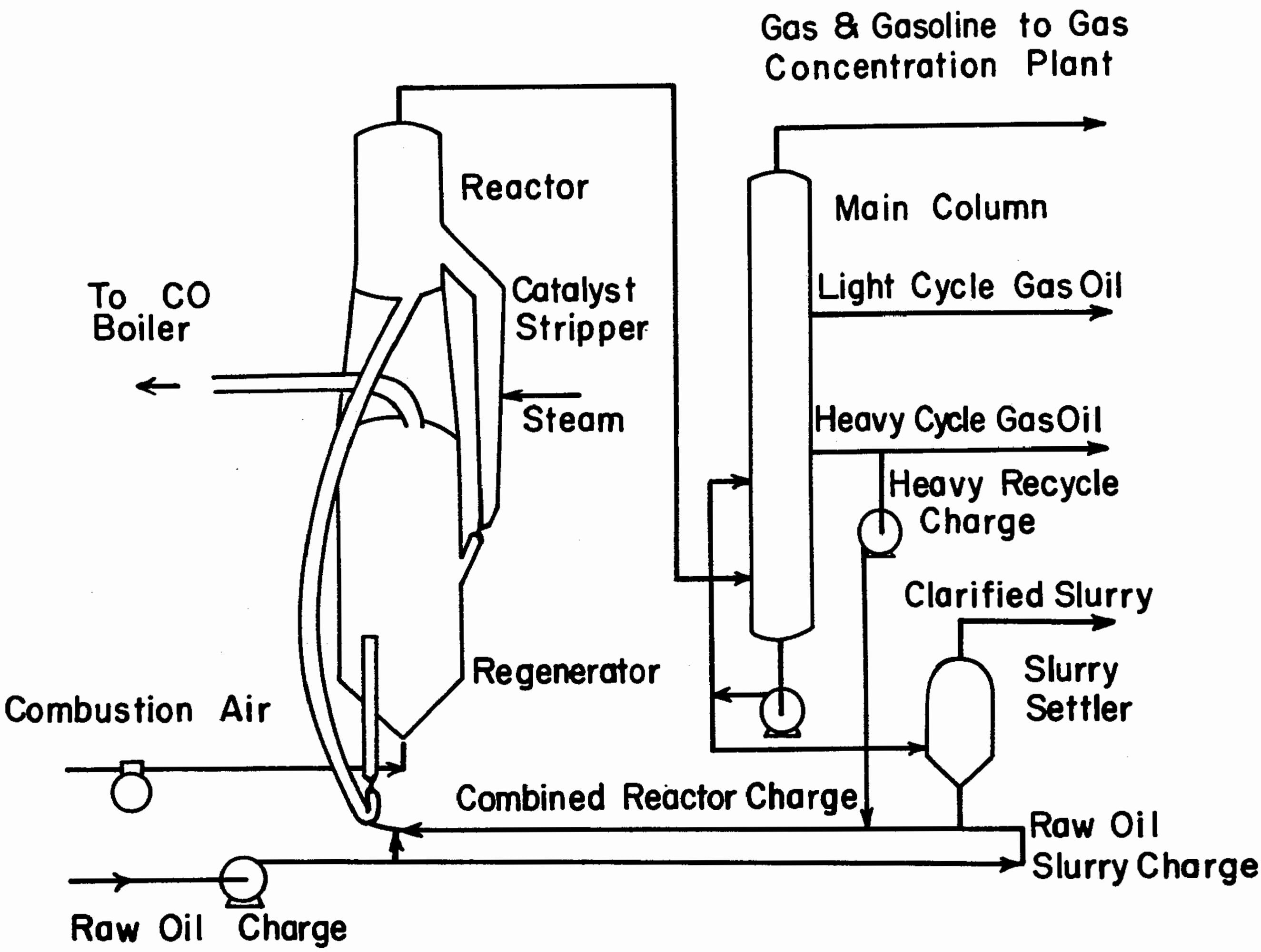


Figure 3-16. Catalytic Cracking Process

Source: Radian Corporation, 1974: 113.

TABLE 3-5

CRUDE OIL REFINING EFFICIENCIES

National Average Refinery	Primary Efficiency (percent)	Ancillary Energy (10^9 Btu's per 10^{12} Btu's)
Uncontrolled Onshore	93.2	59.8
Controlled Onshore	93.8	50.5
Uncontrolled Offshore	93.2	59.8
Controlled Offshore	93.8	50.4
Uncontrolled Imported Canadian Crude	93.2	59.8
Controlled Imported Canadian Crude	93.8	50.4
Uncontrolled Imported Middle East Crude	93.2	59.8
Controlled Imported Middle East Crude	93.8	50.7
Domestic Crude (Battelle)	90	
Imported Crude (Battelle)	90	
Domestic Crude (Teknekron)	90	4.44

Source: Hittman, 1974: Vol. I; Battelle, 1973; and Teknekron, 1973.

about 20 percent higher than for controlled refineries (59.8 as compared to 50.5×10^9 Btu's per 10^{12} Btu's of energy), but the effect on overall efficiency is insignificant.

3.5.3 Environmental Considerations

Several studies of the environmental residuals of refinery unit processes are available. In this section, the residual estimates in three studies (Hittman, 1974; Vol. I Battelle, 1973; and Radian, 1974) are compared. Rather than an exhaustive unit-by-unit analysis, the units chiefly responsible for each significant residual are cited. Environmental residual data are presented in Table 3-6.

3.5.3.1 Water

Water residuals include dissolved solids, suspended solids, nondegradable organics, and biochemical and chemical oxygen demands. The data available are fair, with a presumed error of less than 50 percent. The principal dissolved solid is salt (from electrostatic desalting prior to fractionating), which will be present in either controlled or uncontrolled refining. The range of total dissolved solids is from 1.5 to 98 tons per 10^{12} Btu's (Radian, 1974: 149), with the magnitude most likely between 34 and 50 tons per 10^{12} Btu's.

Suspended solids consist of small amounts of oily sludge not removed in oil/water separators and the dirt from runoff water and solids from biological treatment not removed by settling or flotation. Estimates are between .694 and 22.2 tons per 10^{12} Btu's depending on whether the refinery is controlled or uncontrolled. For a controlled refinery, the weight of dissolved solids is much larger than that of suspended solids.

Table 3-6. Crude Oil Refining Residuals

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)							F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (Tons/10^{12} Btu's)	Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
NATIONAL AVERAGE REFINERY																					
Uncontrolled National Oil[b]	U	U	NA	NA	35.8	22.2	6.	6.92	20.2	7.06 x10^{10}	9.1	22.8	240.	232.	611.	3.73	7.57	10.3/0 10.3	.0004	.0362	2.05
Controlled National Oil[b]	U	U	NA	NA	34.	.694	.35	.694	4.24	0	2.73	19.7	21.	23.6	.166	3.71	43.7	10.3/0 10.3	.0004	.0362	2.05
Uncontrolled Domestic Onshore[b]	U	U	NA	NA	35.8	22.2	6.	6.92	20.2	7.06 x10^{10}	9.1	22.8	246.	232.	611.	3.73	7.57	10.3/0 10.3	.0004	.0362	2.05
Controlled Domestic Onshore[b]	U	U	NA	NA	34.	.694	.35	.694	4.24	0	2.73	19.7	21.3	23.6	.166	3.71	43.7	10.3/0 10.3	.0004	.0362	2.05
Uncontrolled Domestic Offshore[b]	U	U	NA	NA	35.8	22.2	6.	6.92	20.2	7.06 x10^{10}	9.1	22.8	181.	232.	611.	3.73	7.57	10.3/0 10.3	.0004	.0362	2.05
Controlled Domestic Offshore[b]	U	U	NA	NA	34.	.694	.35	.694	4.24	0	2.73	19.7	17.9	23.6	.166	3.71	43.7	10.3/0 10.3	.0004	.0362	2.05
CONVENTIONAL REFINERY																					
Domestic Crude[c]	.2	NC	NC	NC	50.	2.2	NC	NC	NC	0	1.1	12.8	SO_2 66.7	13.9	1.7	NC	3.9	1.	.0014	.107	25.5
OIL REFINERY[d]	NC	NC	NC	1.5	1.6	7.3	1.8	6.3	NC	NC	3.3	23.7	35.5	19.1	1.4	.8	NC	NC	U	U	U

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement (Acre - year / 10^{12} Btu's) / Incremental Land Requirement (Acres / 10^{12} Btu's).

[b]Hittman, 1974: Vol. I, Tables, 13, 14, 15, 16, 17, and 18.

[c]Battelle, 1973: Table A-39.

[d]Teknekron, 1973: Figure 4.1.

There are two nondegradable organic residuals, oil and phenols. Oil is found in oily cooling and process water, and the principal source of phenols is the catalytic cracking process (Radian, 1974: 157). Estimates are between 0.35 and 8 tons per 10^{12} Btu's of total organics, determined by whether the refinery is controlled.

Biochemical oxygen demand (BOD) for refinery effluents is due primarily to sour gas treatment in the Claus plant and totals between 0.694 and 6.92 tons per 10^{12} Btu's for the controlled and uncontrolled refineries respectively. Chemical oxygen demand (COD) is due primarily to alkylation and is between 4.24 and 20.2 tons per 10^{12} Btu's for controlled and uncontrolled refineries. Whether these oxygen demands have serious impact depends on the rate of discharge. An oxygen demand of 200 ppm in discharge water would be serious.

3.5.3.2 Air

The data for air residuals given in Table 3-6 are fair, with an error probability of less than 50 percent. NO_x residuals are between 12.8 and 23.7 tons per 10^{12} Btu's and arise from the operation of fuel burning process heaters and power plant boilers. Considerable reduction in NO_x emissions can be achieved by combustion control measures on heaters and boilers (see Chapter 12). Two processes with high NO_x residuals are hydrogen production and the olefin manufacturing process which is commonly found in petrochemical refineries. Combustion control measures cannot be employed in hydrogen and olefin plants, however, because of the high temperatures involved.

SO_x residuals are between 21 and 240 tons per 10^{12} Btu's for controlled and uncontrolled refineries respectively. The SO_x residual is primarily due to the catalytic cracker, and refinery residuals would be sharply reduced with the use of hydrocracking or sulfur removal from cat cracker feedstocks.

Hydrocarbon emissions are between 13.9 and 23.6 tons per 10^{12} Btu's for controlled refineries and are 10 times larger, 232 tons per 10^{12} Btu's, for uncontrolled refineries. More than half of the hydrocarbon emissions in both controlled and uncontrolled refineries are from crude oil and product storage. Storage emissions can be reduced by a factor of 10 or more by proper control measures.

Generation of particulates, CO, and other organics is not significant.

3.5.3.3 Solids

Solid waste residuals from controlled refineries are between 3.9 and 7.57 tons per 10^{12} Btu's and up to 43.7 tons per 10^{12} Btu's for uncontrolled refineries. The most troublesome solid wastes are oily sludges from crude oil storage which cannot be disposed of in ordinary landfills. Good quantitative data on solid wastes is almost nonexistent. The Hittman data is rated "poor" or "very poor," which means that the error is within (poor) or around (very poor) an order of magnitude.

3.5.3.4 Land Use

Land use is estimated to be between 9.1 (Battelle, 1973: 307) and 10.3 (Hittman, 1974: Vol. I, Tables 13-18) acres per 10^{12} Btu's per year energy input if storage, loading areas, buffer zones, and room for expansion are included. For the refinery process alone, the land use is estimated to be one acre per 10^{12} Btu's per year of energy input. These data are considered accurate within a factor of two.

3.5.4 Economic Considerations

Energy production costs for 1972 in controlled refineries were \$85,600 per 10^{12} Btu's fixed costs and \$248,000 per 10^{12} Btu's operating cost as shown in Table 3-7. The fixed costs represent a flat fixed charge rate of 10 percent on capital which gives a total capital investment of \$2.48x10^6 per 10^{12} Btu's per year.

TABLE 3-7

CRUDE OIL REFINING COSTS (1972)

	Fixed Cost (dollars per 10^{12} Btu's input)	Operating (dollars per 10^{12} Btu's input)	Total (dollars per 10^{12} Btu's input)
National average refinery			
Uncontrolled national oil	76,800	242,000	319,000
Controlled national oil	85,600	248,000	334,000

Source: Hittman, 1974: Vol. I.

Production costs in uncontrolled refineries were \$76,800 in fixed costs and \$242,000 in operating costs per 10^{12} Btu's input. The primary value of these figures is in showing the relationship between capital and operating figures.

3.6 TRANSPORTATION

3.6.1 Introduction

Crude oil must be transported from the producing field to the refinery, and refined products must be transported from the refinery to market. This section is divided into domestic transportation of crude and products and the transportation of foreign imports.

3.6.2 Domestic Transportation Technologies

Tank trucks, railroad tank cars, tankers, barges, and pipelines are all used for domestic transportation. The choice among these alternatives depends on the distance traveled, the product being transported, and the availability of alternatives. Tank trucks are useful for small quantities carried a short distance (less than 500 miles). Railroad tank cars are competitive with tank trucks for distances of more than a few hundred miles and for quantities large enough to fill one car. Tankers and barges are used for long-distance, large quantity transportation but are limited by available ports. Pipelines are competitive with both waterborne transportation and railroads but lack any flexibility of route or destination.

Barges and tankers used for intercoastal shipping are of limited size, the largest being the 125,000-ton tankers being built for transportation of Alaskan crude from Valdez to the West Coast. The tankers should be considered part of a system that includes loading and unloading facilities as well as the vessels themselves. Current loading and unloading techniques utilize docks and loading booms that swing out over the vessel.

Pipelines onshore in the lower 48 states are laid in trenches and use welded steel construction. Oil pipelines as large as 48 inches in diameter have been laid. Pipeline right-of-ways are inspected by air regularly after a pipeline is operating to detect leaks. Because of the pressure drop due to friction along a pipeline, pumping stations must be installed each 50 to 150 miles, depending on the size of pipe and desired flow rate. The stations normally employ centrifugal pumps powered by electric motors or diesel engines. Pumping stations are not usually manned but are monitored remotely at the pipeline control station and designed to be fail-safe (Watkins, 1970: 134-136).

Offshore pipelines are difficult to lay because the pipe must be lowered to the ocean floor from a barge (Figure 3-17). After being laid, the pipe is usually buried by barges that use high pressure water jets to dig a trench under the pipe. The pipe must be inspected carefully before it is laid because of the expense and difficulty involved in repairing an offshore pipeline. Repairs can be carried out underwater using divers and special welding techniques or on the surface by lifting the pipeline with a derrick. Detection of small leaks is difficult for offshore pipelines despite aerial inspection and the use of mass flow monitors in many cases.

The trans-Alaska pipeline has presented unique problems in both its construction and use. The anticipated high temperature (135°F) of the oil and the presence of permafrost will require special insulation and even refrigeration in some segments. Corrosion protection must be provided in the form of coatings and cathodic protection, and remove control gate valves and check valves must be installed to limit the possibility of widespread pollution from leaks or ruptures. Special provisions must be taken to provide opportunities for wildlife to cross the pipeline so as not to interrupt migratory patterns. Finally, seismic faults crossed by the pipeline require design considerations for major horizontal and vertical displacements. Plans call for shutdown and inspection of the line after any earthquake within 0.3 Richter scale points of the maximum design earthquake.

3.6.3 Energy Efficiencies

The primary efficiency of all the technologies for oil transportation is very near 100 percent. Any losses of the transported product would be due to leaks or spills, and although these could have a serious environmental impact, they constitute only a fraction of one percent of the total oil transported. The efficiency data are shown in Table 3-8 and are considered good, with a possible error of 25 percent or less.

The only distinction in the efficiency data is between controlled and uncontrolled tanker transportation. The difference is that .01 percent of the oil transported in uncontrolled tankers is lost in ballast dumping, and none is lost in controlled tankers.

Ancillary energy requirements are presented in Table 3-8 and are considered accurate to within 25 percent. The data are not comparable for different modes of transportation, however, because each mode is assumed to transport the oil a different distance. Ancillary energy requirements are:

1. Pipelines: 3.59×10^9 Btu's for 10^{12} Btu's piped 300 miles.
2. Tankers and supertankers: 39.7×10^9 Btu's for 10^{12} Btu's transported 10,000 miles (assumed due to diesel engines).
3. Barges: 25.2×10^9 Btu's for 10^{12} Btu's carried 1,500 miles (assumed due to diesel-powered tugs).
4. Tank trucks: 6.15×10^9 Btu's for 10^{12} Btu's carried 500 miles (assumed due to diesel tractors).
5. Railroad tank cars: 4.59×10^9 Btu's for 10^{12} Btu's carried 500 miles (assumed due to diesel-electric locomotives).

3.6.4 Environmental Considerations

Environmental residuals for domestic crude oil and product transport are shown in Table 3-9. The data are generally good; that is, considered accurate to within 50 percent.

3.6.4.1 Water

Water pollutant residuals from domestic oil and product transportation are confined to nondegradable organics, in this case the oil or products transported.

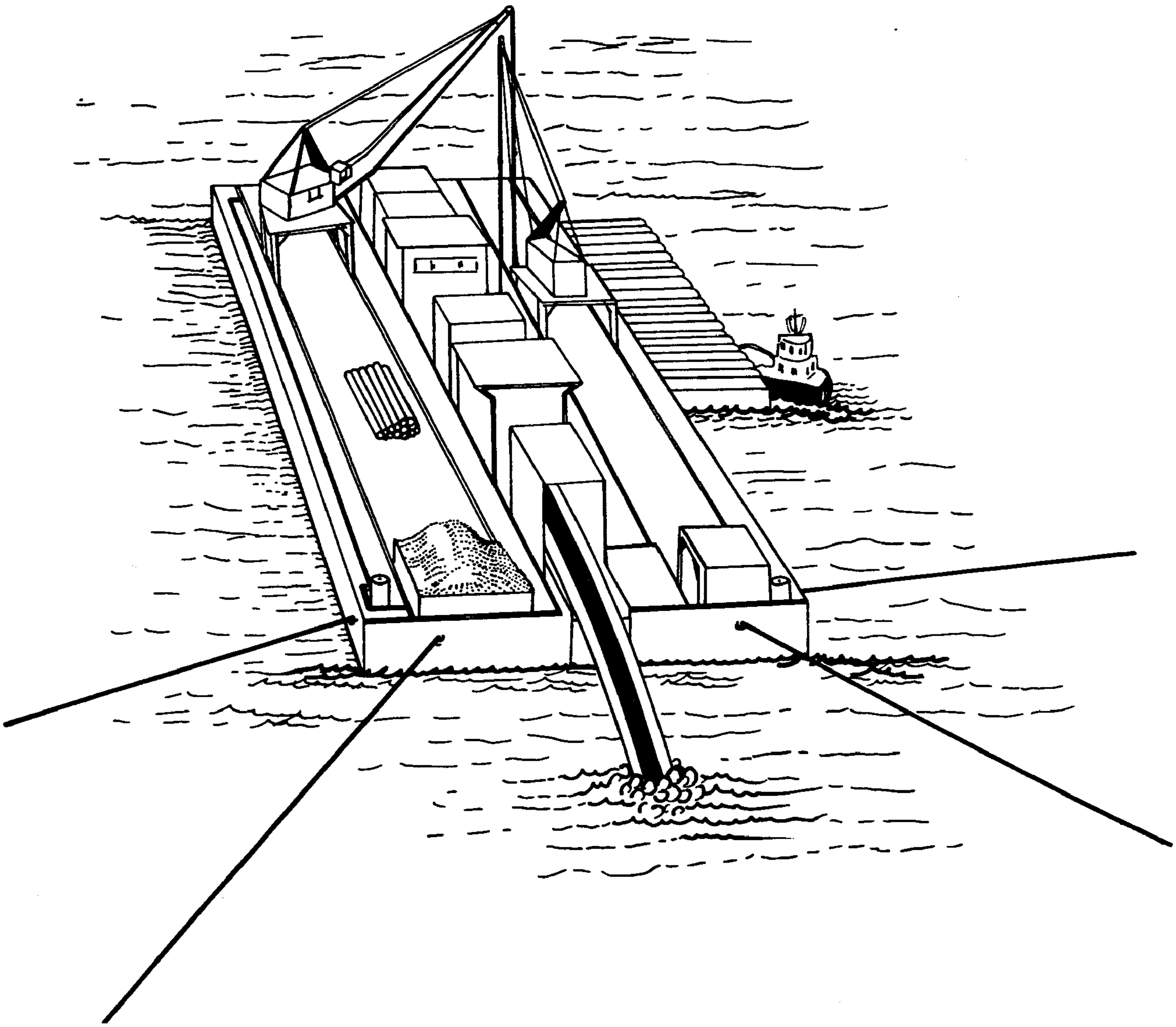


Figure 3-17. Offshore Pipelaying Barge

Source: McDermott, Incorporated.

TABLE 3-8

CRUDE OIL AND PRODUCT TRANSPORTATION EFFICIENCIES

Method	Primary Efficiency (percent)	Ancillary Energy (10^9 per 10^{12} Btu's)	Overall Efficiency (percent)	Distance for Ancillary Energy (miles)
Pipeline[a]	100	3.69	99.3	300
Tankers and supertankers[a]	99.9	40.7	95.8	10,000
Barges[a]	100	25.7	97.4	1,500
Tank trucks[a]	U	14.1	U	500
Tank cars[a]	U	14.6	U	500
Tanker transportation[b]	U	U	99.5	NA
Pipeline transportation[c]	U	U	99.1	NA
Barge transportation[d]	U	U	99.6	NA
Pipeline transportation[e]	99.96	U	U	NA

U = unknown, NA = not available

Sources: [a]Hittman, 1974: Vol. I.
[b]Battelle, 1973: Table A-36.
[c]Battelle, 1973: Table A-37.
[d]Battelle, 1973: Table A-38.
[e]Teknekron, 1973: Figure 4-1.

Residual levels are between .08 and 12.4 tons per 10^{12} Btu's transported for pipelines, with the difference arising from different assumptions about the percentage of transported oil assumed to be discharged and the amount of the discharged oil which reaches a body of water. Residuals from tankers are between 7.57 and 126 tons per 10^{12} Btu's transported with no reason provided by the sources for the wide discrepancy in the data. Both data were for approximately .03 percent of cargo assumed lost in discharges, leaks, and spills.

3.6.4.2 Air

Air-pollutant residuals from transportation include particulates, NO_x, SO_x, hydrocarbons, CO, and aldehydes. For pipelines, particulate emissions range from .172 to 1.0 ton per 10^{12} Btu's transported, NO_x from 4.5 to 4.89 tons per 10^{12} Btu's transported, SO_x from .357 to 8.1 tons per 10^{12} Btu's transported, hydrocarbons from .2 to .49 ton per 10^{12} Btu's transported, CO from .01 to 2.98 tons per 10^{12} Btu's transported, and aldehydes in trace amounts. The source of these emissions is assumed to be diesel-powered pumping stations, and the differences in residual quantities are apparently different sources of data on diesel emissions.

For tankers, particulate emissions range from .0375 to 1.1 tons per 10^{12} Btu's transported, CO ranges from 6.14×10^{-3} to

Table 3-9. Residuals for Crude Oil and Product Transport

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
CRUDE OIL																					
Pipeline[b]	U	U	U	U	U	U	.08	NA	U	NA	.172	4.89	.357	.49	2.98	.0794	0	37.9/0 37.9	6.9 x10^{-5}	4.2 x10^{-3}	1.
Pipeline[c]	U	U	U	U	U	U	0	NC	NC	0	1.	4.5	8.1	.2	.01	NC	0	U/U 34.6	.0009	.008	15.
Pipeline[d]	U	U	U	U	U	U	12.4	NC	NC	NC	NC	NC	NC	NC	NC	NC	0	NC	NC	NC	NC
Uncontrolled Tanker or Supertanker[b]	U	U	U	U	U	U	30.	NA	U	NA	.0375	.337	.515	.019	6.14 x10^{-3}	3.35 x10^{-3}	0	.166/0 .166	U	U	U
Controlled Tanker or Supertanker[b]	U	U	U	U	U	U	8.07	NA	U	NA	.0375	.337	.515	.019	6.14 x10^{-3}	3.35 x10^{-3}	0	.166/0 .166	U	U	U
Oil Tanker[c]	U	U	U	U	U	U	NC	NC	NC	0	1.1	.8	.801	.05	.7	0	0	U/U 0	.0009	.008	15.
Barges[b]	U	U	U	U	U	U	7.86	NA	U	NA	3.02	2.17	2.31	1.4	1.86	.109	0	.166/0 .166	U	U	U
Oil Barge[c]	U	U	U	U	U	U	NC	NC	NC	0	.9	.7	.7	.4	.6	NC	0	U/U 0	.0009	.008	15.
Tank Truck[b]	U	U	U	U	U	U	U	NA	U	NA	.658	18.7	1.37	1.87	11.4	.304	0	363./0 363.	U	U	U
Tank Cars[b]	U	U	U	U	U	U	U	NA	U	NA	1.28	3.84	3.33	2.56	3.59	.56	0	19.9/0 19.9	U	U	U
Product Distribution Pipeline[c]	U	U	U	U	U	U	.0822	NA	U	NA	.172	4.89	.357	.49	2.98	.0794	0	37.9/0 37.9	6.9 x10^{-5}	4.2 x10^{-3}	.1
Uncontrolled Tanker or Supertanker[c]	U	U	U	U	U	U	30.8	NA	U	NA	.0375	.337	.515	.019	6.14 x10^{-3}	3.35 x10^{-3}	0	.166/0 .166	U	U	U
Controlled Tanker or Supertanker[c]	U	U	U	U	U	U	8.07	NA	U	NA	.0375	.337	.515	.019	6.14 x10^{-3}	3.35 x10^{-3}	0	.166/0 .166	U	U	U

Table 3-9. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
Uncontrolled South American Tanker[c]	U	U	U	U	U	U	29.	NA	U	NA	.0375	.337	.771	.019	6.14×10^{-3}	3.35×10^{-3}	0	NA	U	U	U
Controlled South American Tanker[c]	U	U	U	U	U	U	7.58	NA	U	NA	.0375	.337	.771	.019	6.14×10^{-3}	3.35×10^{-3}	0	NA	U	U	U
Tanker[d]	U	U	U	U	U	U	126.	NC	NC	NC	NC	NC	NC	NC	NC	NC	0	NC	NC	NC	NC
Barges[b]	U	U	U	U	U	U	7.86	NA	U	NA	3.02	2.17	2.31	1.4	1.86	.109	0	.166/0 .166	U	U	U
Tank Trucks[b]	U	U	U	U	U	U	U	NA	U	NA	.658	18.7	1.37	1.87	11.4	.304	0	363./0 363.	U	U	U
Tank Cars[b]	U	U	U	U	U	U	U	NA	U	NA	1.28	3.84	3.33	2.56	3.59	.56	0	19.9/0 19.9	U	U	U

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement (Acre - year / 10^{12} Btu's) / Incremental Land Requirement (Acres / 10^{12} Btu's)

[b]Hittman, 1974: Vol. I, Tables 13, 14, 15, 16, 23, and 24.

[c]Battelle, 1973: Tables A-36, A-37, and A-38.

[d]Teknekron, 1973: Table 4.1.

.7 ton per 10^{12} Btu's transported, and all other air-pollutant residuals are small. The variation in residuals from different sources is due to the different assumed distances traveled in transportation, 10,000 miles for the smaller numbers and 325 miles for the larger numbers. Both sources assumed diesel-powered engines for tankers.

For barges, particulate emissions are between .9 and 3.02 tons per 10^{12} Btu's transported, NO_x emissions are between .7 and 2.17 tons per 10^{12} Btu's transported, CO emissions are between .6 and 1.86 tons per 10^{12} Btu's transported, and all other emissions are small. The emissions are assumed due to diesel-powered tugs, and the variations between sources are due to the different distances assumed.

For tank trucks, NO_x emissions are 18.7 tons per 10^{12} Btu's transported, and CO emissions are 11.4 tons per 10^{12} Btu's transported. All other emissions are small. The emissions are due to diesel-powered tractors.

For tank cars, particulate emissions are 1.23 tons, NO_x emissions are 3.84 tons, SO_x emissions are 3.33 tons, and CO emissions are 3.59 tons per 10^{12} Btu's transported. All other emissions are small. The trains are assumed powered by diesel-electric locomotives.

3.6.4.3 Land Use

Land use for pipelines is between 34.6 and 37.9 acres per 10^{12} Btu's per year transported. Land use for tankers, barges, and supertankers is between 0 and .166 acre per 10^{12} Btu's per year transported. The latter figure was obtained by assuming land used for tank farms and loading facilities. Land use for tank trucks is given as 363 acres per 10^{12} Btu's per year transported; this figure was developed by using the total area of the nation's highways and assuming that tank trucks constitute a given percentage of all vehicular traffic. Land use for railroad tank cars is 19.9 acres per 10^{12} Btu's per year transported and was developed in the same manner as the tank truck figure (tank car percentage times the total railroad right-of-way area).

3.6.5 Economic Considerations

The available data on the cost of transportation of crude oil and refined products are given in Table 3-10 and are considered accurate to within 50 percent. The total costs given are not comparable because they are based on different distances traveled. The pipeline data are based on total operating revenues and total crude or product transported for the U.S. Hittman does not specify the source of cost data for tankers and supertankers; incremental changes in cost for controlled construction and operation are cited.

The cost of the domestic transportation of crude oil and refined products does not represent a significant percentage of the total price per barrel of oil. However, with future resources predominately located in Alaska and offshore, costs for domestic transportation will rise.

3.7 FOREIGN IMPORTS

The U.S. imported 6.3 million bbl per day of crude oil in 1973 (FEA, 1974: 23) and, unless present trends are reversed, will increasingly depend on imported crude oil and refined products. The primary source of these imports will be the Middle East. This oil will be imported as crude and refined in the U.S. or will be refined in Canada, the Mediterranean, or the Caribbean. U.S. refining of Middle East crude oil entails problems because Middle East crude is primarily sour (i.e., has a high sulfur content) and present U.S. refining capacity for high sulfur oil is inadequate.

3.7.1 Import Technologies

The most economical alternative for transporting large quantities of oil to the

TABLE 3-10

TRANSPORTATION COSTS FOR CRUDE OIL AND PRODUCTS (1972)

	Fixed (dollars per 10^{12} Btu's)	Total (dollars per 10^{12} Btu's)	Distance Traveled (miles)
Crude Oil			
Pipeline	U	22,500	300
Uncontrolled Tankers	U	244,000	10,000
Uncontrolled Supertankers	U	148,000	10,000
Controlled Tankers	U	333,000	10,000
Controlled Supertankers	U	199,000	10,000
Barges	U	223,000	1,500
Tank Trucks	U	59,800	500
Tank Cars	U	96,400	500
Products			
Pipeline	U	35,900	300
Uncontrolled Tankers	U	251,000	10,000
Uncontrolled Supertankers	U	152,000	10,000
Controlled Tankers	U	343,000	10,000
Controlled Supertankers	U	205,000	10,000
Barges	U	229,000	1,500
Tank Trucks	U	61,500	500
Tank Cars	U	99,000	500

U = unknown

Source: Hittman, 1974: Vol. I, Tables 13 and 14 and footnotes.

U.S. appears to be the use of very large crude carriers (VLCC), up to 500,000 dead weight tons. The crude oil would be unloaded in deepwater ports and transshipped to refineries by tanker or pipeline. This would entail an extensive program of building deepwater ports. Currently, there is only one port in the U.S., Puget Sound in the state of Washington, which has the water depth adequate to accommodate VLCC's. However, Puget Sound does not now have a VLCC port.

There are three general types of deepwater ports: single buoy mooring (SBM) systems, sea islands, and artificial islands.

SBM systems include a deepwater area, usually far offshore, and a large buoy, 30 or more feet in diameter. The VLCC is moored by a single line to the buoy so that the ship can rotate and thus head into the prevailing sea. The crude is unloaded through a line from the ship to the buoy; from the buoy, a pipeline transports the oil to the ocean floor and then to shore. SBM's are particularly suited for rough weather operation and have been operated in seas as high as 16 to 20 feet (White and others, 1973: 74). Figure 3-18 shows an SBM.

The sea island is a platform-type structure alongside which tankers can be berthed. Sea islands consist of loading/unloading platforms with necessary pilings for absorbing the impact of ships as they come alongside. Unloading is via metal arms, and oil is transferred to shore by pipeline. Fixed berths (such as sea islands) require a more sheltered area than SBM's, and tankers can only be moored in modest waves (less than three feet generally). Tugs are required to aid in mooring. Figure 3-19 shows a sea island facility.

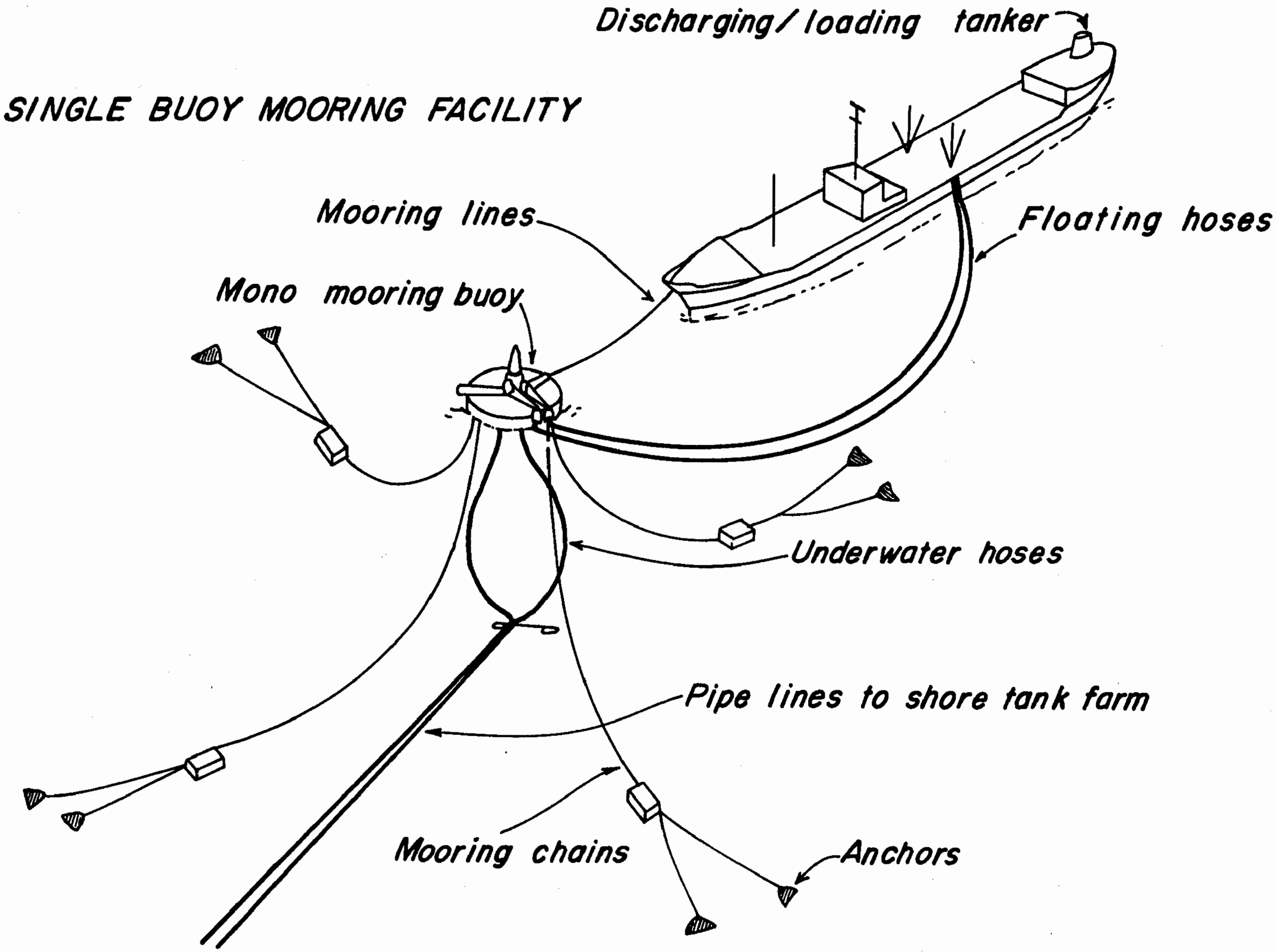


Figure 3-18. Single Buoy Mooring Facility

Source: Interior, 1973: I-6.

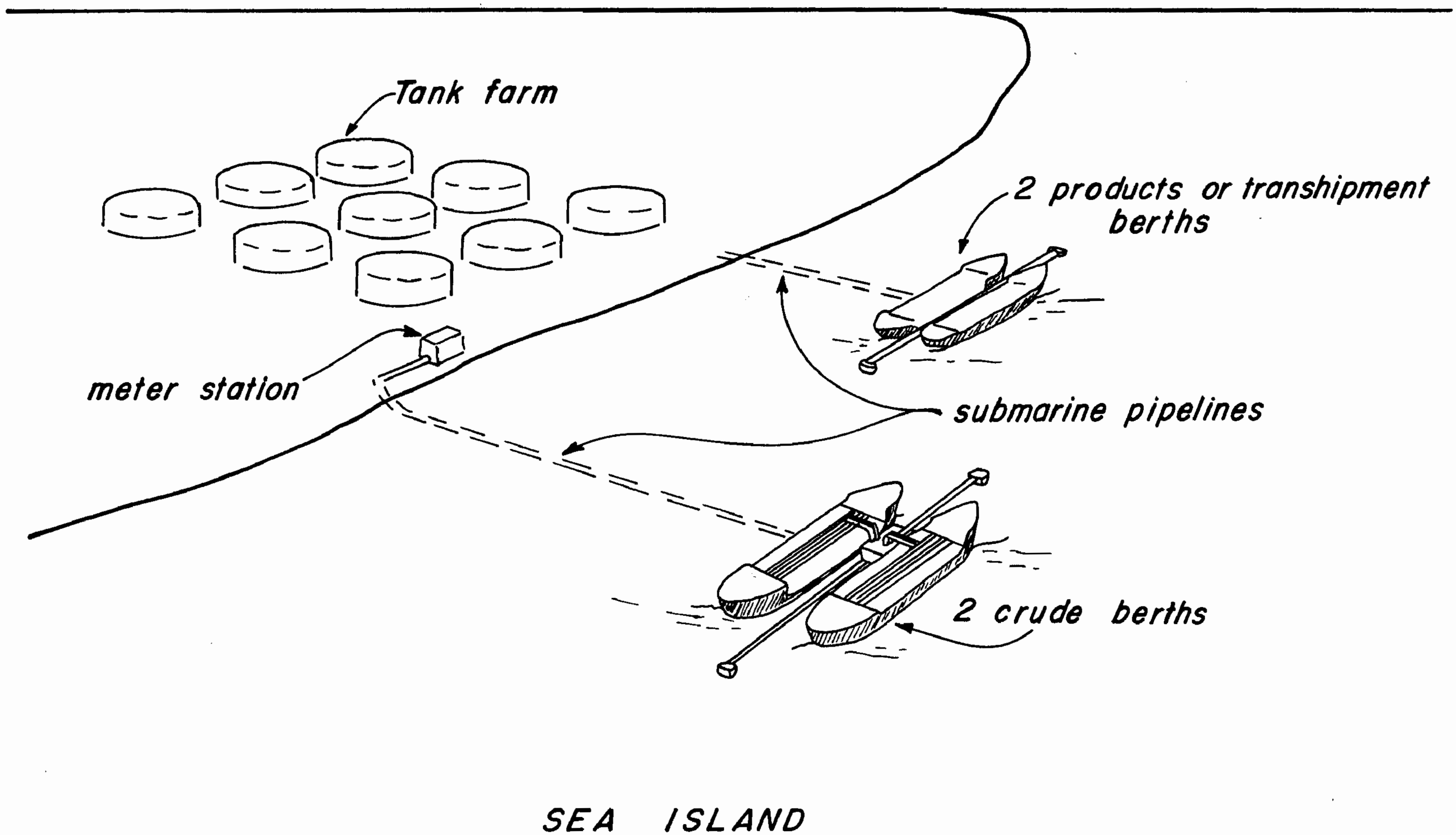


Figure 3-19. Sea Island Mooring Facility

Source: Interior, 1973: I-13.

TABLE 3-11

DEEPWATER PORT ALTERNATIVES

Single Buoy Mooring (SBM)	Sea Island	Artificial Islands
<u>Advantages</u>		
Suited to higher sea state: 10-12 feet to berth, 25 feet once moored.	Can be designed for waves: 10 feet longitudinal, 5 feet beam, while moored.	Same as sea island.
Flexible on-siting, orientation (ship swings with wind, current).	Orientation conditions by wind and wave directions.	Same as sea island
Less damage prone in poor approach (can be ducked easily and tried again).	Damage to pilings and platform are costly in time and dollars.	Damage at T-pier connections endangers pipelines.
Less costly for one berth.	Less costly than SBM for several berths.	Less costly for high loading rates and short offshore distances.
<u>Disadvantages</u>		
Access is difficult to crews and supplies.	Access somewhat easier than SBM.	No access problems.
Flexible and floating hose, risers are liable to damage (mechanical, fatigue, corrosion) and pollution (drainage difficult).	Steel loading arm better than aluminum or flexibles.	Same as sea island.
Loading rate generally lower.	Higher loading rates than SBM.	No limits on loading rates.

Source: Interior, 1973: I-18.

Artificial islands are the most expensive type of deepwater port, but they also offer the most versatility. Construction of an island would require transporting earth and rock to the site and placing the material in the sea in a manner that would insure minimum loss due to currents and waves. The island would be used for both unloading and storage, and would have berthing facilities on all four sides. Berthing would be subject to the same sea state limitations as a natural island, and a breakwater would probably be used to permit operation in heavy seas. Figure 3-20 shows an artificial island mooring facility. Table 3-11 gives the advantages and disadvantages of the alternative deepwater ports.

3.7.2 Energy Efficiencies

The energy efficiencies for importing crude by tanker or supertanker are the same as those for transporting domestic crude in the same carrier. The primary efficiency is very nearly 100 percent, and the ancillary energy requirements, primarily for ship fuel, are about four percent for the assumed 10,000-mile trip. The detailed data is presented in Section 3.6.3.

3.7.3 Environmental Considerations

Although the sulfur content of most imported crude is greater than that of domestic crude, this is not reflected in the environmental residuals for imports because the transportation of imports is

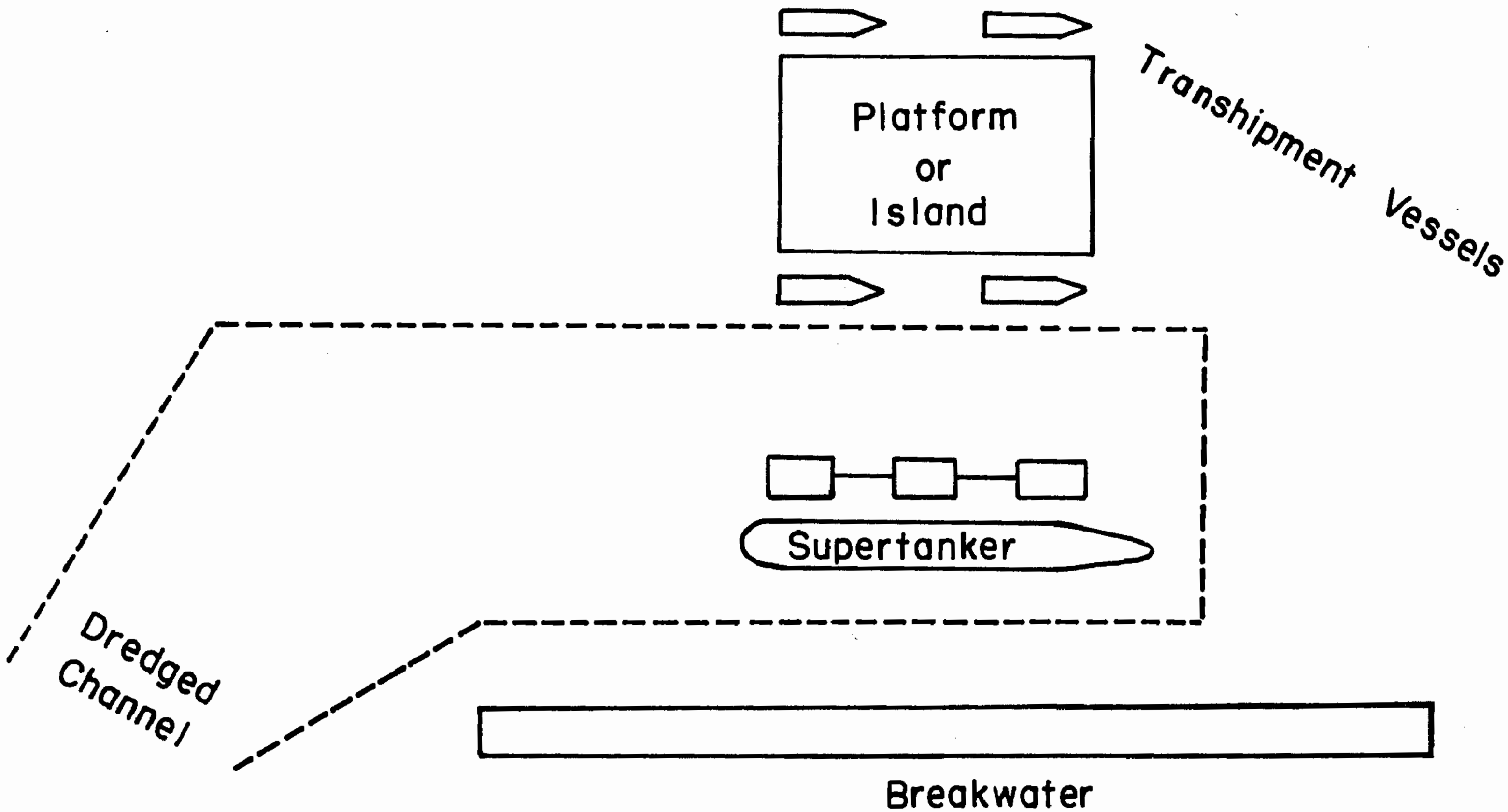


Figure 3-20. Artificial Island Mooring Facility

Source: Interior, 1973: I-17.

Table 3-12. Residuals from Refining Imported Crude Oil

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)							F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (Tons/10^{12} Btu's)	Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
Canadian Crude/Imported																					
Uncontrolled[b]	U	U	NA	NA	35.8	22.2	6.	6.92	20.2	7.06 x10^{10}	9.1	22.8	179.	232.	611.	3.73	7.57	10.3/0 10.3	4.4 x10^{-4}	.0362	2.05
Controlled[b]	U	U	NA	NA	34.	.694	.35	.694	4.24	0	2.73	19.7	17.6	23.6	.166	3.71	43.7	10.3/0 10.3	4.4 x10^{-4}	.0362	2.05
Middle East Crude/ Imported																					
Uncontrolled[b]	U	U	NA	NA	35.8	22.2	6.	6.92	20.2	7.06 x10^{10}	9.1	22.8	584.	232.	611.	3.73	7.57	10.3/0 10.3	4.4 x10^{-4}	.0362	2.05
Controlled[b]	U	U	NA	NA	34.	.694	.35	.694	4.24	0	2.73	19.7	40.3	23.6	.166	3.71	43.7	10.3/0 10.3	4.4 x10^{-4}	.0362	2.05
Conventional Refinery																					
Arabian Crude[c]	.2	NC	NC	NC	50.	2.2	NC	NC	NC	0	1.1	12.8	SO_2 66.7	13.9	1.7	NC	3.9	U/U 1.	.0014	.11	25.
Kuwait Crude[c]	.2	NC	NC	NC	50.	2.2	NC	NC	NC	0	1.1	12.8	SO_2 83.3	13.9	1.7	NC	3.9	U/U 1.	.0014	.11	25.
Topping Refinery																					
Kuwait Crude[c]	.08	NC	NC	NC	48.9	2.2	NC	NC	NC	0	4.9	16.8	SO_2 38.6	7.1	0	NC	3.8	U/U 1.	.0014	.11	25.

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement $\frac{\text{(Acre - year)}}{10^{12}\ \text{Btu's}}$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\ \text{Btu's}}\right)$.

[b]Hittman, 1974: Vol. I, Tables 19, 20, 21, and 22.

[c]Battelle, 1973: Tables A-40, and A-41.

assumed to be in the same carriers or kinds of carriers used for domestic transport. This is not likely to be the case, however, as more and more imports are being carried in supertankers. For a discussion of the residuals and problems associated with supertankers, see Mostert (1974). The detailed data are presented in Section 3.6.4. However, the presence of high sulfur levels is reflected in refinery residuals as shown in Table 3-12. The data are considered fair; that is, accurate to within 100 percent. All water and most air residuals are the same as for domestic oil, but SO_2 residuals are 17.6 tons per 10^{12} Btu's energy input for controlled refineries and 179 tons per 10^{12} Btu's energy input for uncontrolled refineries using Canadian crude. Using Middle East crude, SO_x residuals are 40.3 tons per 10^{12} Btu's energy input for controlled refineries and 584 tons per 10^{12} Btu's energy input for uncontrolled refineries (Figure 3-2). Land use residuals are unchanged from domestic oil refining.

3.7.4 Economic Considerations

The economics of tanker transportation are assumed to be the same for domestic and foreign crude with the only distinction arising from the different distances involved. Figure 3-21 illustrates the economies of scale attainable in tanker transport of crude oil by using larger vessels. Costs given are 1967 figures. Table 3-13 compares the approximate costs of crude transport from Venezuela, North Africa, and the Persian Gulf. Although the economies of scale are obvious in this data, the political considerations surrounding the construction of deepwater ports and the price of Middle East crude will have a much greater effect than the mode of transportation used.

TABLE 3-13

COST OF CRUDE OIL TRANSPORT FROM VENEZUELA, NORTH AFRICA, AND THE PERSIAN GULF (1967 DOLLARS)

Ship Size (dead weight tons)	Cost Per Barrel of Oil Transported		
	Venezuela (4,000 miles round trip)	North Africa (8,000 miles round trip)	Persian Gulf (24,000 miles round trip)
65,000	$ .28	$ .52	$1.34
250,000	.21	.37	.97
326,000	.18	.34	.91
500,000	.15	.28	.81

Source: Interior, 1973: I-41.

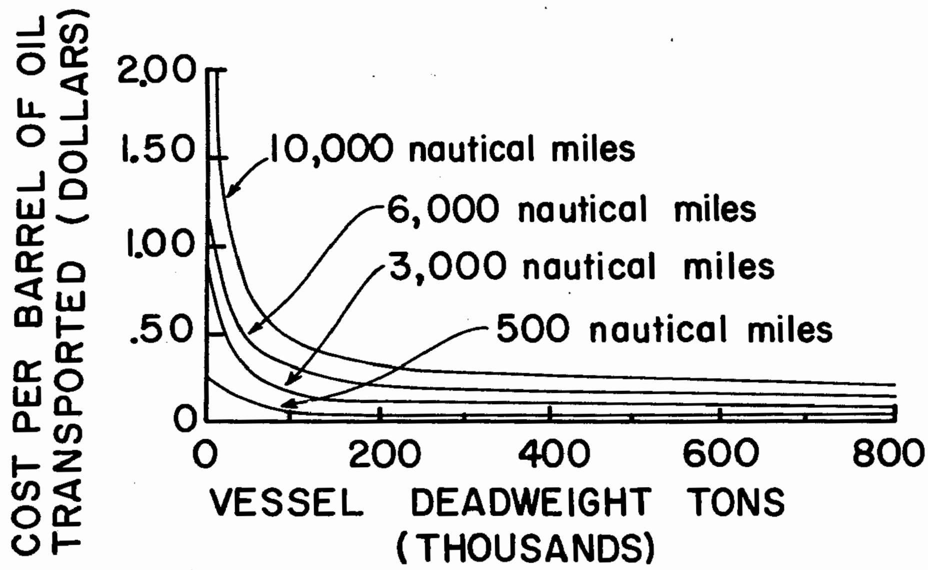


Figure 3-21. Costs of Tanker Transport

Source: Interior, 1973: I-41.

REFERENCES

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

G.G. Brown and Associates (1960) Unit Operations. New York: John Wiley and Sons, Inc.

Bureau of Land Management (1972) Final Environmental Statement: Proposed 1972 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Louisiana. Washington: Department of the Interior.

Bureau of Mines (1970) Potential Oil Recovery by Waterflooding Reservoirs Being Produced by Primary Methods, Information Circular 8455. Washington: Government Printing Office.

Cameron Iron Works, Inc. (1973) Cameron Oil Tool Products 1972-1973. Houston: Cameron Iron Works, Inc.

Council on Environmental Quality (1974) OCS Oil and Gas--An Environmental Assessment. Washington: CEQ.

Department of the Interior (1972) Statement, Questions and Policy Issues Related to Oversight Hearings on the Administration of the Outer Continental Shelf Lands Act, Held by the Senate Committee on Interior and Insular Affairs, Pursuant to S. Res. 45, March 23, 1972. Washington: Interior.

Department of the Interior (1973) Draft Environmental Impact Statement: Deepwater Ports. Washington: Interior.

Federal Energy Administration (1974) Project Independence Blueprint. Washington: Government Printing Office.

Ford Foundation, Energy Policy Project (1974) A Time to Choose: America's Energy Future. Cambridge, Mass.: Ballinger Publishing Co.

Geffen, Ted (1973) "Improved Oil Recovery Could Help Ease Energy Shortage." World Oil 177 (October 1973): 84-88.

Gillette, Robert (1974) "Oil and Gas Resources: Did USGS Gush Too High." Science, 185 (July 12, 1974): 127-130.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

Kash, Don E., Irvin L. White, Karl H. Bergey, Michael A. Chartock, Michael D. Devine, R. Leon Leonard, Stephen N. Salomon, and Harold W. Young (1973) Energy Under the Oceans: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations. Norman, Okla.: University of Oklahoma Press.

Lindsey, J.P., and C.I. Craft (1973) "How Hydrocarbon Reserves Are Estimated from Seismic Data." World Oil 177 (August 1, 1973): 24-25.

McCulloh, T.H. (1973) "Oil and Gas," pp. 477-496 in Donald A. Brobst and Walden P. Pratt (eds) United States Mineral Resources, USGS Professional Paper 820. Washington: Government Printing Office.

Mostert, Noel (1974) Supership. New York: Alfred A. Knopf.

National Petroleum Council (1970) Future Petroleum Provinces of the United States. Washington: NPC.

National Petroleum Council, Committee on U.S. Energy Outlook (1971) U.S. Energy Outlook: An Initial Appraisal, 1971-1985. Washington: NPC.

National Petroleum Council, Committee on U.S. Energy Outlook (1972) U.S. Energy Outlook. Washington: NPC.

National Petroleum Council, Committee on U.S. Energy Outlook, Oil and Gas Subcommittees, Oil and Gas Supply Task Groups (1974) U.S. Energy Outlook: Oil and Gas Availability. Washington: NPC.

Peel, D.H. (1970) "The Character of Crude Oil," pp. 154-170 in British Petroleum Co., Ltd., Our Industry Petroleum. London: BP.

Radian Corporation (1974) Final Report: A Program to Investigate Various Factors in Refinery Siting, for the Council on Environmental Quality and the Environmental Protection Agency. Austin, Tex.: Radian Corporation.

Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif.: Teknekron.

University of Texas, Division of Extension, Petroleum Extension Service (1957) A Primer of Oil Well Drilling, 2nd ed. Austin: University of Texas, Division of Extension, Petroleum Extension Service.

Watkins, R.E. (1970) "Transport of Crude Oil," pp. 130-143 in British Petroleum Co., Ltd., Our Industry Petroleum. London: BP.

White, Irvin L., Don E. Kash, Michael A. Chartock, Michael D. Devine, and R. Leon Leonard (1973) North Sea Oil and Gas: Implications for Future United States Development. Norman, Okla.: University of Oklahoma Press.

CHAPTER 4

THE NATURAL GAS RESOURCE SYSTEM

4.1 INTRODUCTION

The first recorded use of natural gas in the U.S. was in Fredonia, New York in 1821. Early usage tended to be localized and many utilities distributed gas manufactured from coal. In 1947, a major change in the character of the industry occurred when natural gas from the Southwest reached the East Coast through two converted liquid pipelines, the "big inch" (crude oil) and the "little inch" (refined crude oil products). Since then, the consumption of natural gas in all end-use classifications (residential, commercial, industrial, and power generation) has increased rapidly. This growth has resulted from several factors, including: the development of new markets; replacement of coal as a fuel for providing space and industrial process heat; use in making petrochemicals and fertilizers; and the strong demand for low-sulfur fuels that emerged in the mid 1960's.

As a result of these expanded end uses, local utility gas mains increased from 218,000 miles in 1945 to 906,925 miles in 1970 (Zareski, 1973). The high-pressure natural gas transmission network was extended into all the lower 48 states and, by 1970, included 269,610 miles of pipe and 4.0 million horsepower of compression, representing a total undepreciated, original cost investment of $18.6 billion (FPC, 1974a: 62). However, the rapid growth record and structure of the industry may soon change drastically in response to a new pattern of gas supply.

All phases of development and utilization of gas resources are provided by private industry and fall within three fairly well-defined segments: supply; transmission; and distribution. Although large corporations dominate the individual segments, the industry is not characterized by vertical integration from the gas field to the consumer. For the most part, the gas industry consists of transmission companies that buy their gas from the oil industry and distribution companies that sell the gas to the ultimate consumers.

This chapter contains a description of the natural gas resource system and a discussion of the technologies involved in exploration, extraction (including drilling and production technologies), and transportation (including transmission, storage, and distribution technologies). Because of the potential importance of imported natural gas, both the resource and technologies descriptions include portions that focus on foreign resources and import technologies.

As shown in Figure 4-1, the development of natural gas involves four major activities: exploration, drilling, production, and a substantial range of transportation or transmission alternatives. Present domestic and imported Canadian gas is transported via pipelines. Future imports (and perhaps Alaskan gas as well) will likely involve transportation in the form of liquefied natural gas (LNG). This option involves several distinct technologies which will also be covered in this chapter.

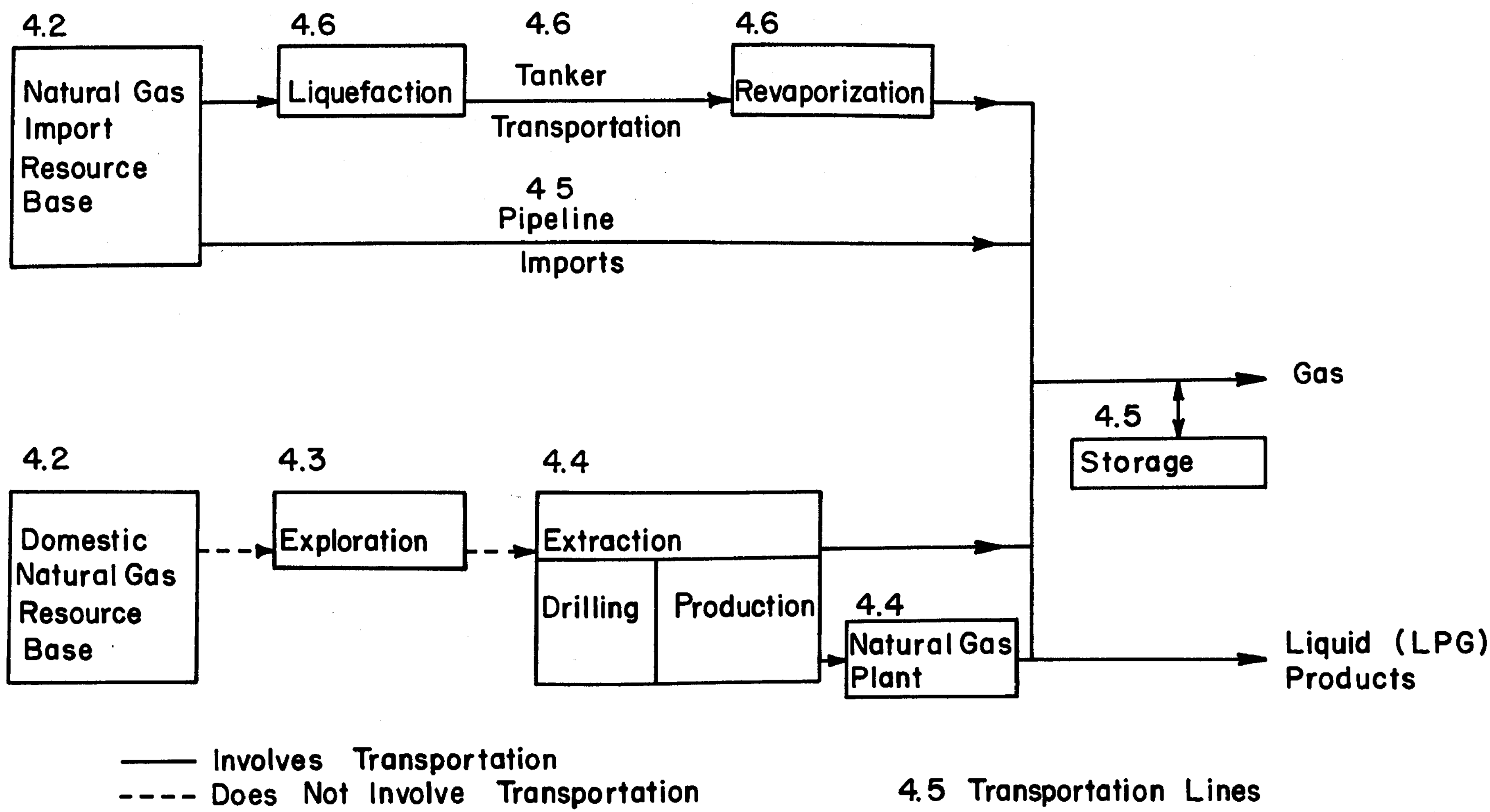


Figure 4-1. Natural Gas Resource Development

4.2 CHARACTERISTICS OF THE RESOURCE

4.2.1 Natural Gas Classifications

Although natural gas resources are classified in numerous ways, three summary classifications will be used in this chapter: proved reserves; potential supply; and ultimate supply. Proved reserves are discovered gas that can be produced under current economic and operating conditions. Potential supply is that portion of the resource that may be found and proved productive in the future. Ultimate supply is the total quantity of producible resources; it includes past production, proved reserves, and potential supply.

The potential supply classification reflects an estimate of future conditions, such as the level of exploration, state of technology, and economics. The impacts of these considerations have been central to the continuing debate over the effect of government regulation on the development of gas supplies.

4.2.2 Physical Characteristics

Dry natural gas is composed primarily of hydrocarbons (compounds containing only hydrogen and carbon). Methane (CH_4), the simplest and most basic compound of the hydrocarbon series, is the major component. Others, fractionally small but important, include ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and heavier, more complex hydrocarbons. In processing, most of the butane and heavier hydrocarbons, as well as a portion of the ethane and propane, are frequently removed from the gas in the form of liquids. Most of the water, gaseous sulfur compounds, nitrogen, carbon dioxide, and other impurities found in natural gas are also removed in various processing stages. The composition and the Btu content of unprocessed natural gas produced from different reservoirs vary widely as illustrated in Figure 4-2.

In addition to composition and Btu content, gas is commonly designated in terms of the nature of its occurrence underground. It is called nonassociated gas if found in a reservoir that contains a minimal quantity of crude oil and either dissolved or associated gas if found in a crude oil reservoir. Dissolved gas is that portion of the gas dissolved in the crude oil, and associated gas (sometimes called gas-cap gas) is free gas in contact with the crude oil. All crude oil reservoirs contain dissolved gas and may or may not contain associated gas.

Some gases are called gas condensates or simply condensates. Although condensates occur as gases in underground reservoirs, they have a high content of hydrocarbon liquids which may yield on production.

4.2.3 Domestic Resources

In the following description of the domestic gas supply, the quantities estimated for proved reserves and for potential gas supply will be presented for three regions--onshore lower 48 states, offshore lower 48 states, and Alaska--in addition to total U.S. figures.

4.2.3.1 Quantity of the Resources

The estimates of domestic ultimate supply made for the lower 48 states and Alaska since 1950 range from about 200 trillion cubic feet (tcf) to 2,995 tcf, with more recent estimates ranging from 1,000 to 2,955 tcf (FPC, 1974b: 14, 168). Table 4-1 summarizes the more widely quoted estimates (Potential Gas Committee, 1973; Interior, 1974) of potential supply presented on the basis of lower 48 states onshore, lower 48 states offshore, Alaska, and total U.S.

The variation in proved reserves from 1946 to 1973 as compiled by the American Gas Association (AGA) (AGA and others,

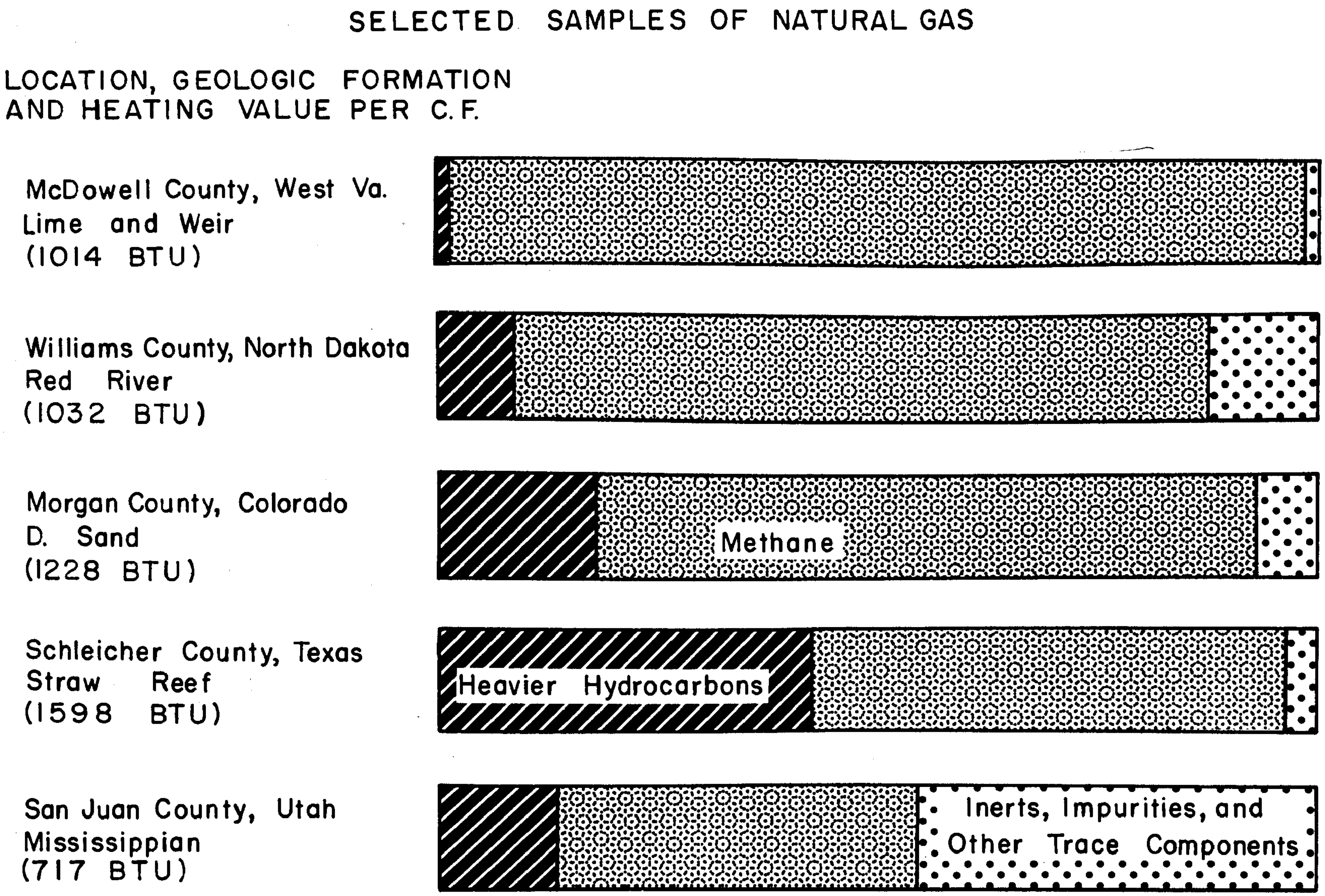


Figure 4-2. Selected Samples of Unprocessed Natural Gas

Source: FPC, 1974a: 6.

TABLE 4-1

NATURAL GAS RESOURCES (TRILLIONS OF CUBIC FEET)

Area		Proved Reserves AGA[a]	Potential Supply	
			PGC[b]	USGS[c]
Lower 48 states				
Onshore:	0 to 15,000 feet[d]	NC	413	NC
	below 15,000 feet[d]	NC	137	NC
	TOTAL	182.2[e]	550	593-1,177
Offshore:	0 to 600 feet[f]	NC	203	NC
	600 to 1,500 feet[f]	NC	27	NC
		36.1[e]	230	247- 493
Lower 48 states:	TOTAL	218.3	780	840-1,670
Alaska		31.6	366	290- 580
	TOTAL U.S.	250.0	1,146	1,130-2,250

NC = not considered.

Sources: [a]Based on year end 1973 statistics published by American Gas Association (AGA and others, 1974).

[b]Potential Gas Committee (PGC, 1973).

[c]U.S. Geological Survey (Interior, 1974).

[d]Refers to drilling or formation depth.

[e]Based on the ratio of lower 48 states offshore to lower 48 states total reserves in 1972 of 16.5 percent.

[f]Refers to water depth. Applies to PGC data only. USGS water depth limitation for undiscovered recoverable resources is 200 meters.

1974) is shown in Figure 4-3. The proved reserves as of the year ending 1973 were 218.3 tcf for the lower 48 states, with approximately 36.1 tcf offshore and 182.2 tcf onshore and 250.0 tcf for the total U.S. (Table 4-1). At the current annual production rate, the life of the reserves (i.e., the reserve-to-production [r/p] ratio) is 9.7 years with Alaska excluded and 11.1 years with Alaska included. Figure 4-3 also shows that the r/p ratio has declined steadily for the last 30 years.

The first year that more gas was produced than found in the lower 48 states was 1968. Similar deficits have been realized each succeeding year, and the overall quantity of domestic gas produced was more than twice the quantity found in the lower 48 states during the period 1968 to 1973. The accelerated decline in the r/p ratio during that period reflects both the decreasing reserves base and an increasing production rate.

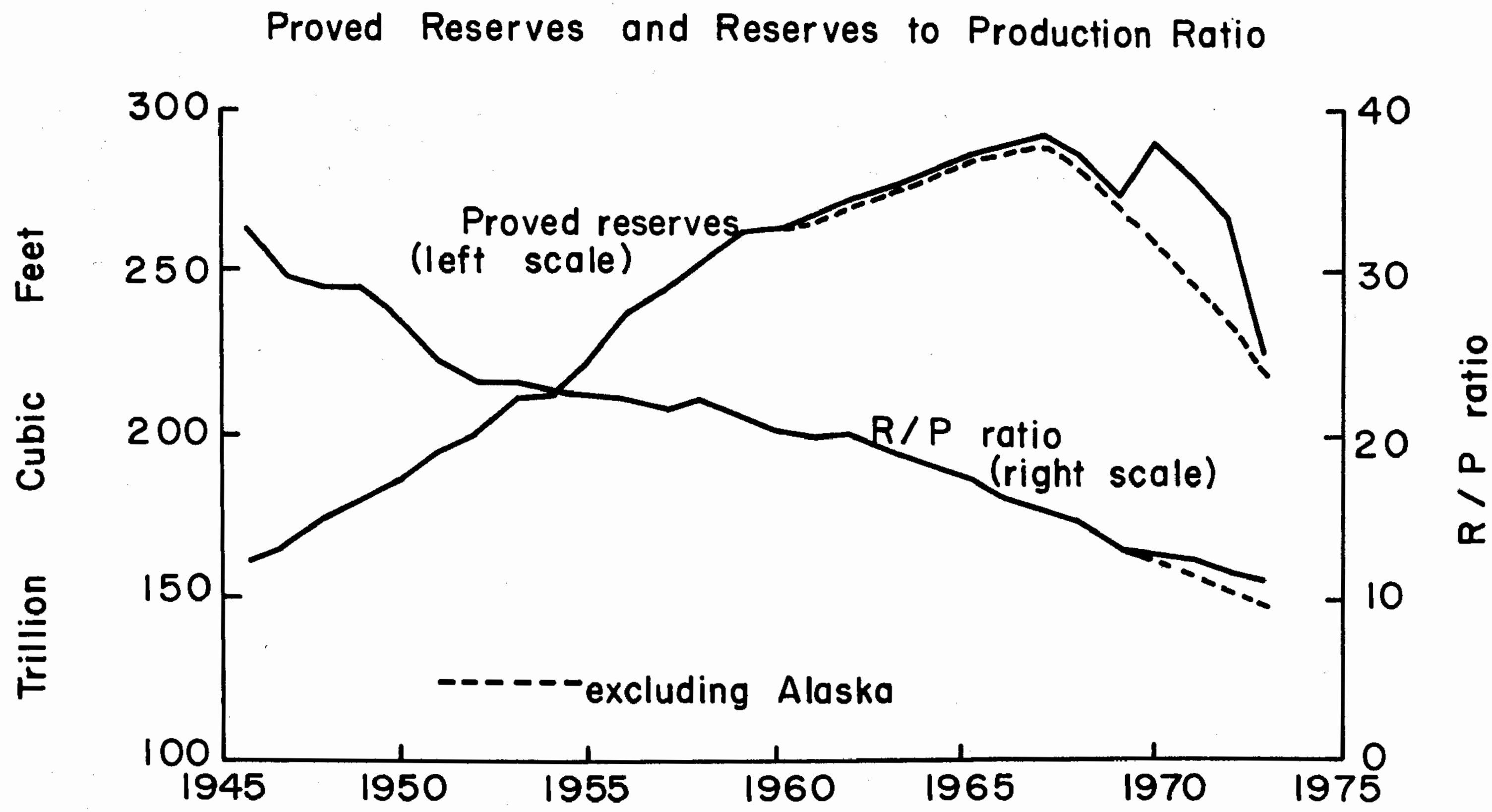


Figure 4-3. U.S. Natural Gas Proved Reserves and Reserves-to-Production Ratio

Source: FPC, 1974b: 22.

4.2.3.2 Accuracy of Resource Estimates

The variation in estimates of potential gas supply suggests that these are only order-of-magnitude figures and can serve as little more than a basis for rough, pragmatic analyses of energy policy alternatives. Similarly, ultimate supply is subject to the same degree of uncertainty because potential gas supply is one of its constituent elements.

Although proved reserves figures can be stated with greater certainty than ultimate and potential supply figures, they are also only estimates. Reserves are based on the best engineering, geological, and economic data available and the judgment of the estimator. The latter element usually accounts for the difference between evaluations. Because of the importance of having reliable reserves data, the Federal Power Commission's (FPC's) National Gas Survey conducted a National Gas Reserves Study (NGRS) (FPC, 1973a) to yield an independent estimate of the total proved gas reserves in the U.S., including Alaska and the offshore areas, as of December 31, 1970.

The NGRS estimate of 258.6 tcf was 9.8 percent lower than the corresponding AGA estimate of 286.7 tcf. However, minor variations in the results obtained by competent technical groups using recognized and accepted methods for calculating and compiling reserves estimates are to be expected. For all practical purposes, the agreement between the two total estimates is reasonable, and the reported reserve estimates seem to provide a reliable basis for short-term forecasting.

4.2.3.3 Location of the Resources

Approximately 88 percent of the natural gas reserves in the lower 48 states are located in five southern and southwestern states: Texas, Louisiana, Oklahoma, New Mexico, and Kansas (AGA and others, 1974). Of the gas moving through the interstate pipeline system, about 79 percent originates in Texas, Louisiana, and Oklahoma (FPC, 1974a: 62) as indicated by the general pattern of gas flow illustrated in Figure 4-4.

Based on data for proved reserves and USGS estimates of potential supply given in Table 4-1, 73 percent of the reserves and 52 percent of the potential gas are located in the onshore lower 48 states, 14 percent of the reserves and 22 percent of the potential gas are located in the offshore lower 48 states, and 13 percent of the reserves and 26 percent of the potential gas are located in Alaska.

Gas production in Alaska has been confined to the southern part of the state, primarily to support an LNG export project to Japan. However, the current activity on the North Slope has generated considerable public awareness. The estimate of the proved reserves for the Prudhoe Bay area of the North Slope is 26 tcf as compared to total Alaskan proved reserves of 31.6 tcf (AGA and others, 1974). The discovery of the Prudhoe Bay field has established the existence of oil and gas in a region containing a large volume of potentially hydrocarbon-bearing geological formations; nevertheless, the proved reserves of the Prudhoe Bay field alone are only slightly more than the amount of gas consumed in the U.S. in 1973.

The availability of future Alaskan gas depends on the completion of the trans-Alaska pipeline system (TAPS) as discussed in Section 4.5.1.1.1. The North Slope gas reserves consist of associated and dissolved gas, and gas production is contingent on oil production. Because of venting and flaring restrictions in Alaska, oil production is also somewhat contingent on developing an outlet for gas production as it may not be economically feasible to reinject into the reservoir the quantity of of gas produced at a specified oil production rate.

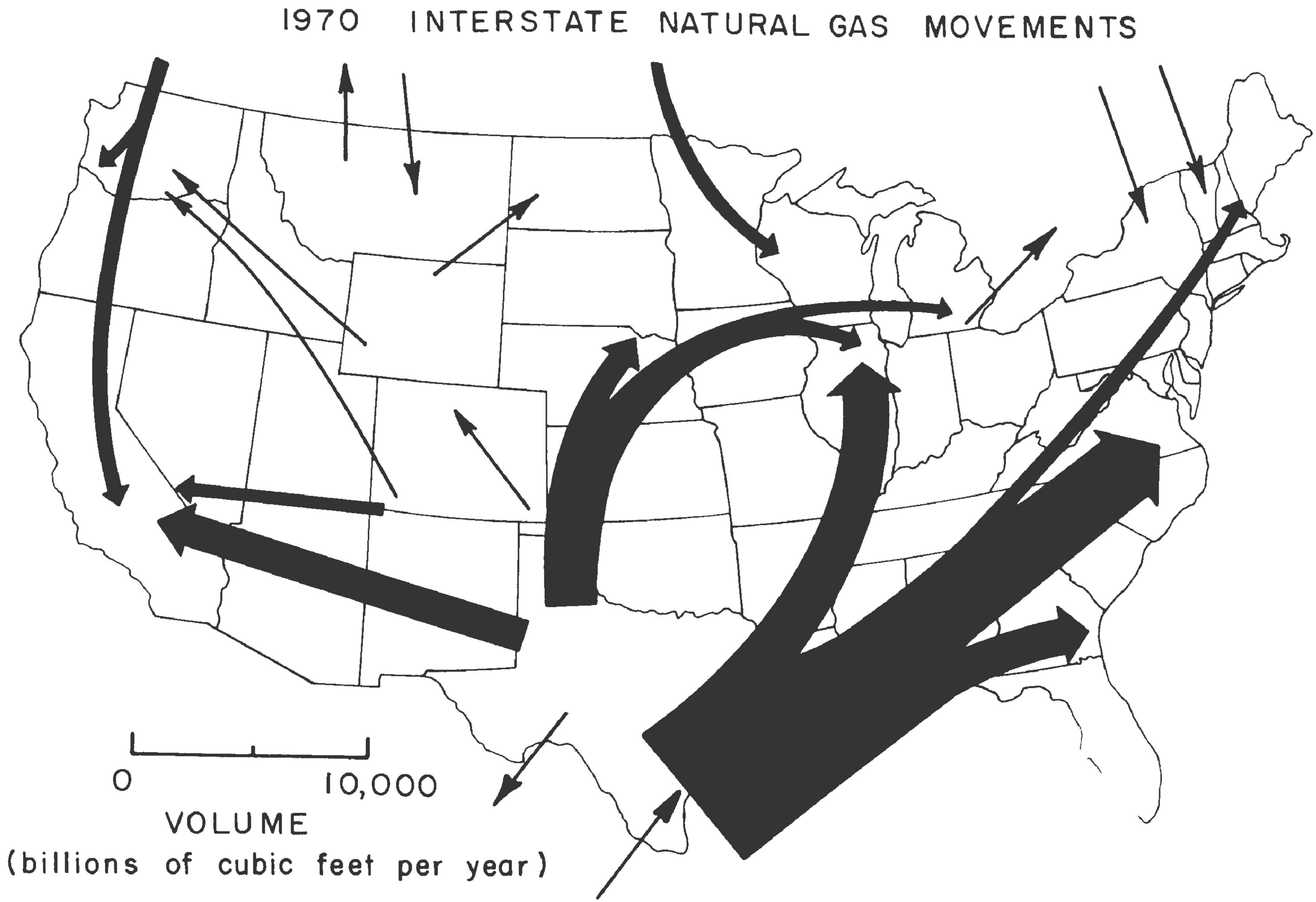


Figure 4-4. Interstate Natural Gas Movements

Source: FPC, 1974a: 63.

TABLE 4-2

FEDERAL NATURAL GAS RESOURCE OWNERSHIP
(PERCENTAGE OF DOMESTIC TOTAL)

	Reserves	Resources	Production in 1972
Offshore	15	36	16
Onshore	6	8	6
TOTAL	21	44	22

Source: Ford Foundation, 1974: 271.

4.2.3.4 Ownership/Control of the Resources

The increasing role of government ownership in the development of natural gas parallels that for crude oil as discussed in Chapter 3. This reflects, in substantial part, government ownership of Alaskan and offshore resources. The ownership of natural gas resources is clearly shown in Table 4-2.

4.2.4 Foreign Resources

As noted in the introduction, the U.S. may rely on gas imports in the years ahead. A brief summary of foreign gas resources is presented here.

4.2.4.1 Canada

Western Canada contains over 99 percent of Canada's proved reserves (FPC, 1974c: 35) but only 15 percent of Canada's potential supply (FPC, 1974c: 39). The bulk of the potential supply is attributed to the frontier provinces. Estimates are that about 31 percent of potential supply is located in the Arctic Islands, about 12 percent in the Mackenzie Delta, and about 35 percent in the Atlantic offshore (FPC, 1974c: 38). Future Canadian export authorizations will probably depend on sufficient development of the frontier gas to justify a pipeline. Potential pipeline routes for transmission of gas to the U.S. from the frontier provinces and the Atlantic offshore are shown in Figure 4-5.

4.2.4.2 Mexico

Although gas imports from Mexico averaged approximately 50 billion cubic feet (bcf) per year from 1958 to 1969, they declined to 1.6 bcf in 1973 as compared to exports of 13 bcf from the U.S. to Mexico. The relatively small natural gas resource base and the long-standing Mexican policy of "self sufficiency in energy" make it improbable that Mexico will be a major source of future U.S. pipeline imports. The impact of the recently reported discoveries on Mexican import policy cannot be assessed at this time.

4.2.4.3 World

Statistics on the reserves, production, and consumption of natural gas throughout the world were developed by members of the Supply Technical Advisory Task Force-Liquefied Natural Gas of the FPC's National Gas Survey (FPC, 1973b: 351, 352). As of the end of 1971, statistics for the countries with reported reserves in excess of 30 tcf and the world totals as adapted from the LNG Task Force report are shown in Table 4-3. However, data on foreign reserves are even less reliable than those for the U.S. Published information is often inconsistent, and various values can usually be found for a given country. This occurs in part because the definition of "reserves" varies widely throughout the world. Table 4-3 represents a choice of what was believed by members of the LNG Task Force to be the most likely estimate from the range of information available.

Table 4-3 shows that many world regions containing large volumes of developed gas reserves have limited internal markets. As indicated in the tables, world production exceeds consumption, and a significant proportion of the gas is apparently wasted.

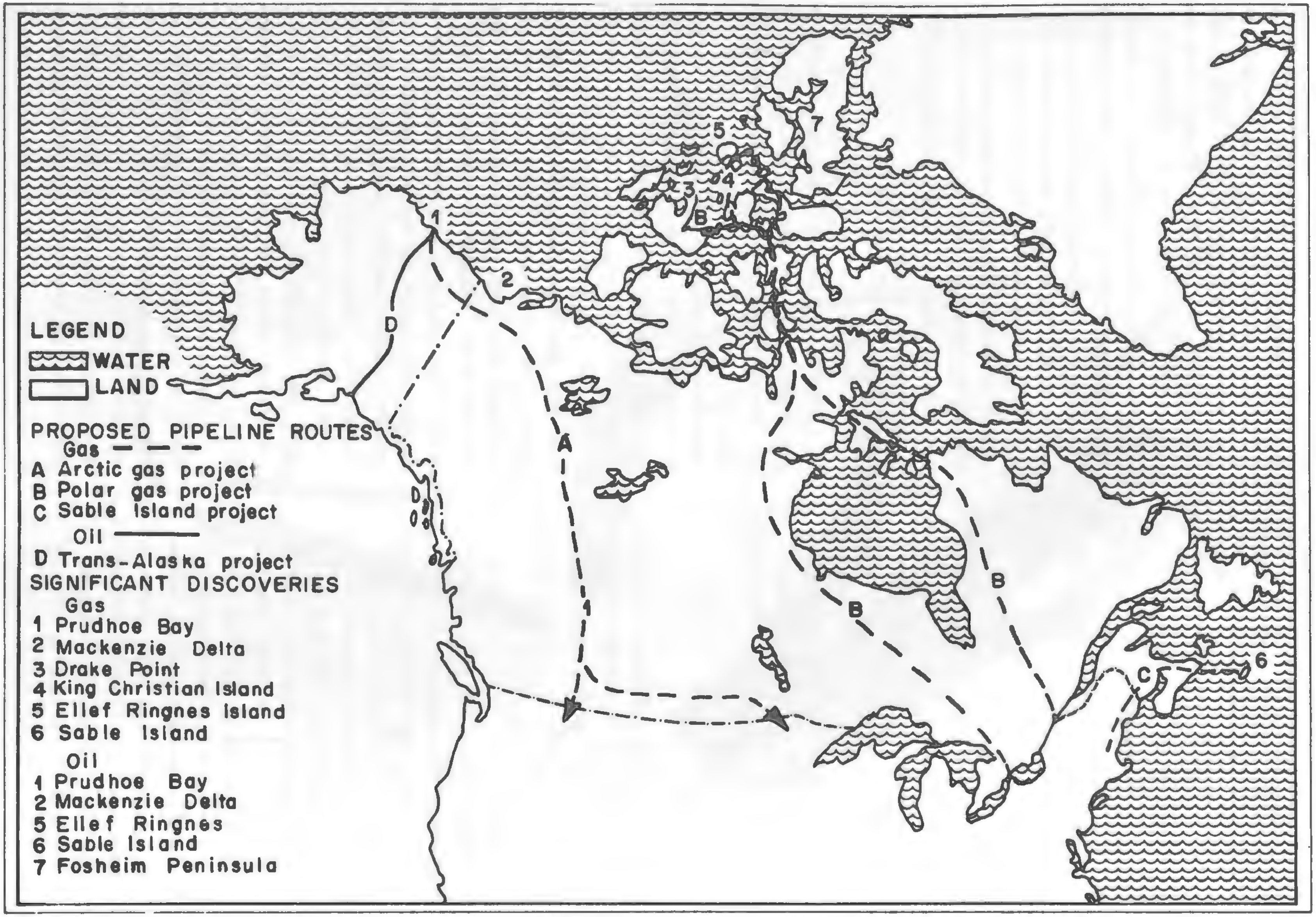


Figure 4-5. Proposed Canadian Natural Gas Pipeline Routes and Oil and Gas Discoveries

Source: FPC, 1974c: 36.

TABLE 4-3

ESTIMATED RESERVES, PRODUCTION, AND CONSUMPTION
OF NATURAL GAS BY COUNTRY
(TRILLION CUBIC FEET)

Country	Reserves (December 1971)	Production (1970)	Consumption (1970)
USSR (Russia)	547.4	7.1	7.1
United States	278.8	23.8	22.0
Iran	197.0	1.1	0.4
Algeria	106.5	0.3	0.1
The Netherlands	83.0	1.1	0.7
Canada	55.5	2.7	2.3
Saudi Arabia	50.9	0.7	0.1
Nigeria	40.0	0.3	minimal
United Kingdom	40.0	0.4	0.4
Kuwait	35.0	0.5	0.2
Venezuela	31.6	1.7	0.3
Others	279.4	6.3	4.6
WORLD TOTAL[a]	1,745.1	45.9	38.3

Source: Adapted from FPC, 1973b.

[a]Totals may not add due to rounding.

The FPC's National Gas Survey identified 21 sources of LNG with adequate reserves for supporting potential long-term import projects to the U.S. (FPC, 1973b: 344). Although operational dates for the proposed projects are uncertain and specific projects cannot be identified beyond 1980, current activity seems to indicate a pattern of long-term importation of LNG into the contiguous U.S. Table 4-4 shows various projections of long-term U.S. imports of LNG.

4.3 EXPLORATION

The following description of the technologies involved in the natural gas resource system covers both the domestic and import options identified in Figure 4-1. Since many of these technologies are the same as those used in developing crude oil, references are made, where appropriate, to Chapter 3 rather than repeating descriptions.

One new gas exploration method is the "bright spot" technique. This technique indicates the presence of both free gas reservoirs and of the nonassociated gas portions of "gas caps" at crude oil reservoirs. However, it does not respond to dissolved gas and thus cannot be used to search for crude oil reservoirs without gas caps.

The "bright spot" technique has been extremely useful in identifying potentially

TABLE 4-4

PROJECTIONS OF LIQUEFIED NATURAL GAS IMPORTS
(TRILLION CUBIC FEET)

	1980	1985	1990
Federal Power Commission[a]	2.0	3.0	4.0
Department of the Interior[b]	0.9	1.6	NC
National Petroleum Council[c]			
Low-Case	2.3	3.2	NC
High-Case	2.3	3.9	NC
Institute of Gas Technology[d]	1.1	1.6	2.1
American Gas Association[e]	1.7	2.7	3.2
National Gas Survey[f]			
Low-Case	0.4	0.4	0.4
High-Case	3.2	3.8	4.7

NC = not considered.

Sources: [a]FPC, 1972: 70.

[b]Interior, 1972a: 32.

[c]NPC, 1972: 133.

[d]Linden, 1973.

[e]Hardy, 1974.

[f]FPC, 1974b: 4, 5.

productive zones among the younger, very permeable formations in the Gulf of Mexico. However, its effectiveness may be limited to these special conditions. The technique may prove less effective for locating reservoirs in other regions or for identifying hard to find stratigraphic traps which are not normally indicated by classical geophysical techniques.

4.4 EXTRACTION

4.4.1 Technologies

4.4.1.1 Drilling

There are no substantive differences between gas drilling technologies and the oil drilling technologies described in Chapter 3.

4.4.1.2 Production

4.4.1.2.1 Well Completion

For the purposes of this report, there are no substantive differences in the equipment and techniques used to complete natural gas wells and those described in Chapter 3 for oil wells.

4.4.1.2.2 Fluid Processing

Natural gas may be produced in association with oil (associated and dissolved gas) or from predominantly gas (nonassociated gas) wells. However, once the gas is produced, processing technologies differ significantly from those for crude oil. The following sections discuss field separation of the produced fluids, compression, natural gas plants, and sulfur removal plants. Although the technologies involved in systems for gathering the produced gas and injecting it into high-pressure pipelines do not differ significantly from those used for other fluids, these are discussed in Section 4.5.

The processing method selected for a particular gas depends on factors such as its type and composition, the geographic location of the source, and the proximity of natural gas transmission lines. For example, different processing methods may be used for similar gas produced from onshore and offshore wells. Also, some processing may be done to make the gas suitable for pipeline transmission or sales, while other processing is done to recover valuable products, including a wide range of hydrocarbon liquids.

4.4.1.2.2.1 Field Separation of Produced Fluids

Processing requirements for produced gas vary widely. Natural gas produced from a nonassociated gas reservoir (i.e., one which contains little or no oil) may require minimal treatment before it is transferred to the transmission line. Conversely, associated gas, dissolved gas, and gas condensates may require full processing before they are marketable.

Generally, fluids from both oil and gas wells are first treated to remove water and sand, then passed through a single separator or a sequence of separators depending on the composition and the nature of the produced fluids. Both water and water vapor must be removed from the gas to prevent formation of hydrates (solid snow-like compounds of water and methane). Hydrates form as the result of the cooling which accompanies gas expansion and can plug wellhead valves, metering equipment, and pipelines. If formation of hydrates is a problem in a particular field, the produced fluids may be heated at the wellheads prior to flow into any gas processing equipment to deter hydrate formation before treatment.

Normally, the produced stream from a crude oil reservoir is separated in a single stage by passing it through a free water knockout separator to remove water and sand and then through a low-pressure separator to split the oil and gas streams. The separation of associated gas and condensates may be done in several stages to increase the recovery of liquid hydrocarbons. In the three-stage separation process shown in Figure 4-6, the first stage (a high-pressure separator) separates the liquid hydrocarbons from the gas by expanding the stream of well fluids. Liquid from the first stage separator is partially vaporized in the second stage (an intermediate-pressure separator) and additional gas is recovered. The remaining liquid then passes to the third stage (a low-pressure separator) for additional vaporization and gas removal. The liquid remaining after the third separation stage is transferred to storage. Three-stage separation is frequently hard to justify economically and is not as commonly used for gas wells as two-stage separation.

The type of gas produced and the processing methods required determine the amount of gas marketed. Normally, the produced fluid stream from crude oil reservoirs is processed using a single-stage, low-pressure separator. Frequently, the gas recovered from a single separator cannot be economically compressed and transmitted to shore or to an existing gas pipeline. Consequently, this gas is often vented to the atmosphere or flared. Energy losses and environmental residuals resulting from these and other operations are discussed in Sections 4.4.2 and 4.4.3.

4.4.1.2.2.2 Compression

Since pressures are normally high in the early production life of a gas reservoir, compression may be needed to transmit

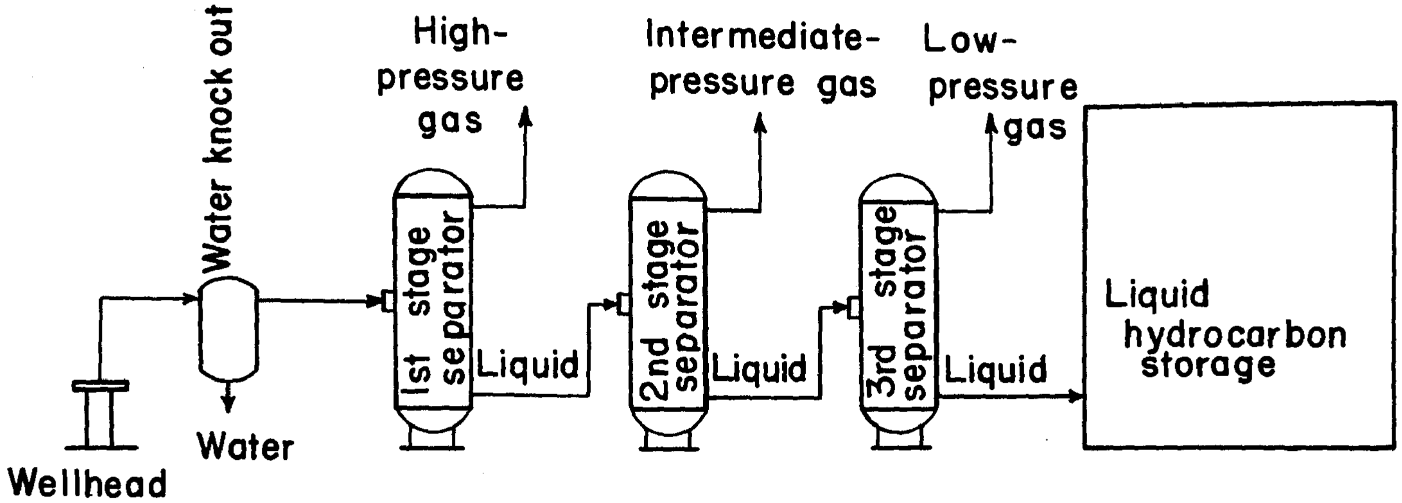


Figure 4-6. Three-Stage Wellhead Separation Unit

Source: Adapted from Handbook of Natural Gas Engineering, by D. L. Katz et al. Copyright 1959. Used with permission of McGraw-Hill Book Company.

the gas through the gathering system and into the high-pressure transmission line only in later reservoir stages. In oil-gas reservoirs, however, compression is required throughout the life of the reservoirs because all fluids are passed through low-pressure separators. Thus, depending on the type and stage of the reservoir, a range of compressor facilities from individual wellhead compressors to a central compressor station may be required. The use of individual wellhead compressors offers the advantage of flexibility, whereas the use of a central compressor station offers economy of scale. Section 4.5.1.2 gives a more detailed description of gas compression.

4.4.1.2.2.3 Natural Gas Plants

When the produced gas is very rich (i.e., has a high content of natural gas liquids), complex processing plants may be required to condition the gas and, indeed, may be economically attractive because of the value of the recovered liquids. In contrast to field separation, these natural gas plants not only separate the gases from the produced liquids but split the liquids into fractions. Separation of the liquid stream is achieved by distillation or fractionating towers as described in the refinery section of Chapter 3. The plant products are liquefied petroleum (LP) gases (including propane, butanes, and propane-butane mixtures), natural gasolines, ethane, plant condensate, and small amounts of other hydrocarbon mixtures (FPC, 1974a: 93). "Lean" gas (processed gas) is normally used to fire the boilers that provide heat to the fractionation towers and in the combustion engines that drive the plant compressors.

Natural gas plants are often used in conjunction with gas cycling projects. The lean gas is piped back to the field and reinjected into the reservoir to enhance liquid recovery. Figure 4-7 is a diagram of a typical cycling operation. In this example, the liquids are stripped from the produced gas in the oil absorber. The residue (dry) gas is returned to the reservoir. The hydrocarbon liquids are recovered from the rich oil in the separation plant, and the lean oil is returned to the absorber to contact additional produced fluids. Reservoir reinjection is used to enhance the recovery of liquids from gas condensate reservoirs or the crude oil recovery from crude oil reservoirs containing gas caps. When the economic returns from gas reinjection are no longer attractive, the reservoir is then depleted using normal production practices.

4.4.1.2.2.4 Sulfur Removal Process

Many natural gases contain hydrogen sulfide (H_2S) in amounts ranging from zero to as high as 76 percent (Battelle, 1973: 284). As with crudes, gases containing H_2S are termed "sour" and gases essentially free of H_2S are termed "sweet." Sour gases pose several problems because they are extremely toxic and corrosive and, when burned, produce either sulfur dioxide (SO_2) or sulfur trioxide (SO_3). Consequently, special grades of steel must be used in completing and equipping wells and in constructing surface facilities for the extraction and processing of sour gases. Also, because of the danger to operating personnel, field procedures for sour gases must contain precautions not required in the production of sweet gas.

Federal law does not allow more than .25 grain of H_2S per 100 standard cubic feet (cf) of natural gas (Katz and others, 1959: 612, 613), and individual states have also set H_2S limits. In addition, the toxic and corrosive characteristics of H_2S necessitate its removal in processing plants before the gas can be transported and marketed in the U.S. Desulfurization is an adjunct to other processing methods and may be used in conjunction with any combination of those covered previously.

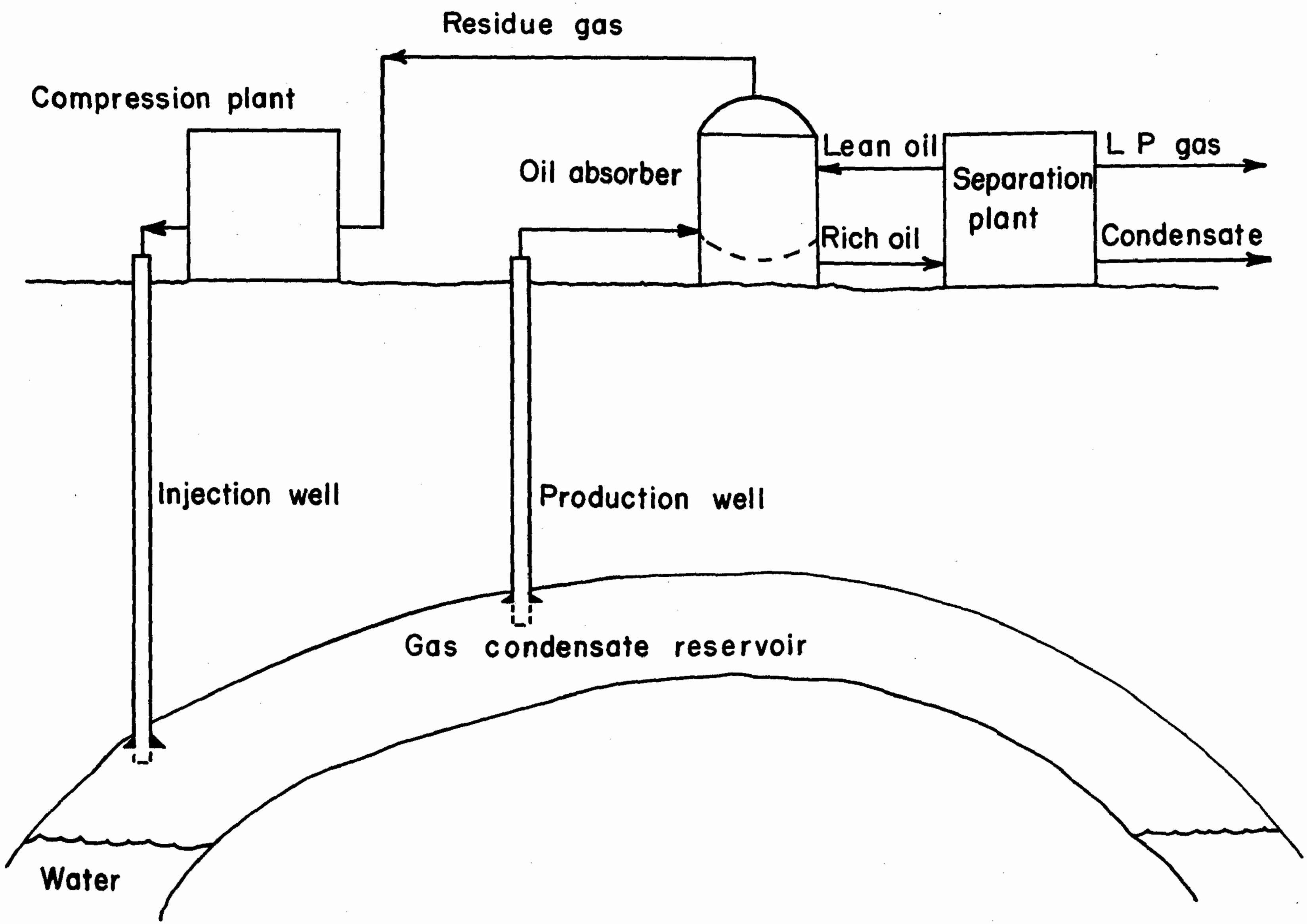


Figure 4-7. Cycling Operation

Source: Adapted from Handbook of Natural Gas Engineering, by D. L. Katz et al. Copyright 1959. Used with permission of McGraw-Hill Book Company.

Because it permits almost complete removal, the process most commonly used in these plants is reaction of the H_2S with an ethanolamine in solution or, as it is commonly called, an amine solution (Katz and others, 1959: 613, 614). This process removes both H_2S and carbon dioxide (CO_2), which are classified as acid gases, from the gas stream as shown in Figure 4-8. After removal from the gas and regeneration of the ethanolamine solution, the H_2S has often been flared, resulting in the discharge of SO_2 (a combustion product) directly to the atmosphere.

Heat is given off in the reaction between H_2S and the ethanolamine. The ethanolamine solution, which has been reacted with H_2S, is regenerated by boiling the solution to reverse the reaction and strip out the acid gases before the solution is recycled to the absorber. Natural gas must be used as fuel for regenerating the ethanolamine solution and for generating steam to drive process pumps throughout the plant.

When SO_2 discharges reach a certain limit, such as 10 tons per day from a single source in Texas, sulfur recovery is required. In current practice, 80 to 95 percent of the H_2S is converted to elemental sulfur in a conventional Claus plant,* and the remainder is vented to the atmosphere unless plant tail gases are treated. Newer techniques for treating the tail gas of a Claus sulfur plant include the Beavon, Shell, and Clean Air processes. Although an estimated 99.9 percent of the sulfur can be recovered when these processes are used, all are expensive (Battelle, 1973: 287).

Since the conversion of H_2S to sulfur gives off heat, no fuel need be consumed in the process except in start-up. In fact, under certain conditions heat from the system is used to generate steam.

*See Chapter 1 for a discussion of Claus plants.

4.4.2 Energy Efficiencies

Overall, about one percent of U.S. gas production per year is lost through flaring, venting, and production operations (FPC, 1974a: 24). Offshore losses are higher than onshore, formerly amounting to about 3.4 percent of all gas produced from both oil and gas wells on the outer continental shelf (OCS) (Interior, 1972b: 7). However, recent FPC actions establishing alternatives for setting higher wellhead prices for gas that costs more to produce (FPC, 1973c) have resulted in the marketing of some of this gas, reducing offshore losses somewhat.

A minimal amount of ancillary energy is required for natural gas drilling and production operations. The primary energy efficiencies of various natural gas extraction, gathering, and processing technologies are very high. Also, a portion of the gas cannot be recovered from the reservoir. Like the definition for oil, the primary efficiency factor for gas as given by Hittman (1974: Vol. I, Table 25) seemingly includes a reservoir recovery factor of about 35 percent. However, recovery from gas reservoirs (that portion of the total gas in the ground which is extracted) ranges from 50 to 90 percent. Thus, the primary efficiency factors given by Hittman may range from 15 to 55 percent lower than the efficiencies commonly realized in practice. Hittman claims the efficiency data has a probable error of less than 25 percent. (See Table 4-5.)

4.4.3 Environmental Considerations

The considerations involved in the environmental assessment of natural gas production differ from those involved in crude oil production. However, before these differences are described in detail, several observations should be made.

As noted in Chapter 3, accidents occur more frequently in natural gas operations than in corresponding crude oil operations,

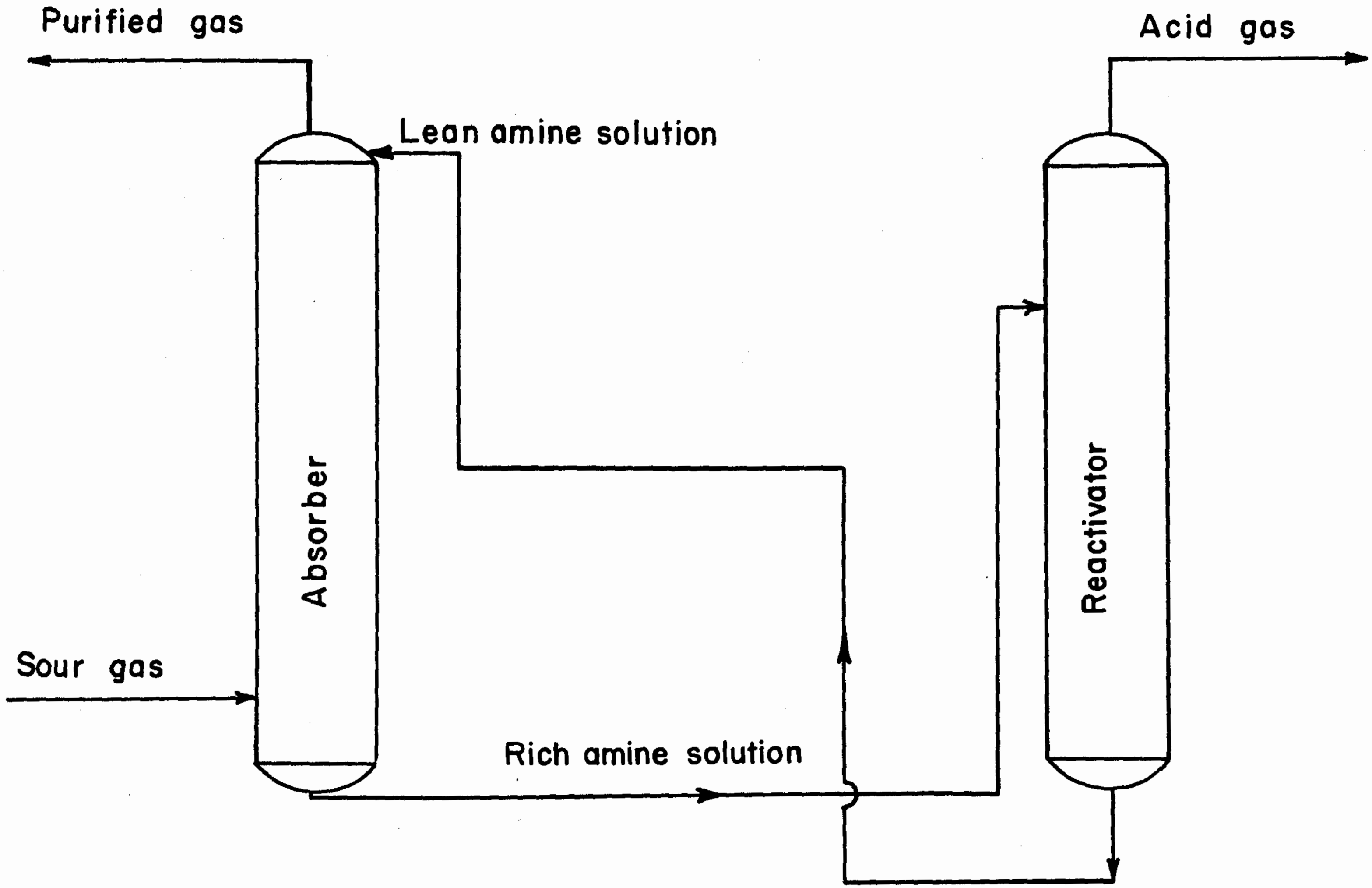


Figure 4-8. Amine Treating Process for CO_2 and H_2S Removal

Source: Adapted from Handbook of Natural Gas Engineering, by D. L. Katz et al. Copyright 1959. Used with permission of McGraw-Hill Book Company.

TABLE 4-5

EFFICIENCIES FOR EXTRACTING, GATHERING, AND PROCESSING NATURAL GAS

see p. 4-17

Activity	Primary Efficiency[a] (percent)	Ancillary Energy (Btu's per 10^{12} Btu's)	Overall Efficiency[a] (percent)
Extraction (onshore)[b]	30	0	30
Extraction (offshore)[b]	30	0	30
Gathering (pipeline)	89.2	0	89.2
Processing (natural gas liquids plant)	93.4	0	93.4
Processing (hydrogen sulfide removal)	99.7	0	99.7

Source: Hittman, 1974.

[a]Losses are due primarily to gas escaping to the atmosphere during the various activities.

[b]Energy efficiencies for wellhead separation are included.

but natural gas operational accidents generally cause far less environmental damage. For example, water pollution resulting from gas well blowouts, gas pipeline leaks, and malfunctions of gas processing equipment would be much less severe than from similar oil operations. The exception, according to Battelle, is that oxides of nitrogen (NO_x) emissions are higher for gas wells than oil wells (Battelle, 1973: 24). However, since well classifications are somewhat arbitrary (production from a "gas" well may range from a very dry gas to crude with very little gas), gas wells with relatively high liquid production rates should be viewed as oil wells in an environmental impact assessment.

Offshore, there are several significant considerations in siting well and production facilities. Examples are possible effects on commercial fishing, navigation, long-term ecosystem equilibrium, and esthetics. The debris resulting from initial construction and the drilling muds, water, sand, and chemical wastes associated with drilling and processing facilities remain possible residuals. Present federal regulations reflect these concerns in requiring that discharged sand must be free of oil and discharged water must have an average of not more than 50 parts per million (ppm) of oil (Kash and others, 1973: 62).

On land, and in marshes and estuaries, site preparation should include an analysis of the cutting and filling needed for the site, access roads, and other support activities.

The Hittman residuals for extracting, gathering, and processing natural gas are given in Table 4-6. The probable error in the data is less than 50 percent. An analysis of the more significant of these follows.

4.4.3.1 Water

No water contaminants are generated by any of the modes of extraction, gathering, or processing, although some discharge

Table 4-6. Residuals for Extracting, Gathering, and Processing Natural Gas

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
EXTRACTION																					
Offshore	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	.12/0 .12	6.9 $\times 10^{-6}$	30 $\times 10^{-4}$	.01
Onshore	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	.62/0 .62	8.1 $\times 10^{-5}$	.004	.13
GATHERING																					
Pipeline	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	2.65	0	0	0	0	NA	21.8/0 21.8	3.1 $\times 10^{-6}$	.001	.025
PROCESSING																					
Natural Gas Liquids	NA	NA	NA	NA	NA	NA	0	NA	NA	7.75 $\times 10^{9}$	.285	1.88	.0095	.63	.0063	.157	NA	.133/0 .133	4.1 $\times 10^{-5}$	.004	.097
Hydrogen Sulfide	NA	NA	NA	NA	NA	NA	NA	NA	NA	8.1 $\times 10^{8}$	.042	.28	.001	.094	9.4 $\times 10^{-4}$	.02 .0165	NA	.133/0 .133	2.1 $\times 10^{-6}$	.002	.005

NA = not applicable.

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

of contaminants such as lubricating oil and caustic wastes would occur in these operations. Although it is not a serious problem, thermal pollution may result from operation of natural gas and sulfur extraction plants. The thermal discharge for the natural gas liquids plant is considered to be 25 percent of the energy content of the gas used for plant fuel or 7.7×10^9 Btu's discharged for each 10^{12} Btu's of natural gas processed. For sulfur removal, the estimate of the thermal discharge (0.8×10^9 Btu's per 10^{12} Btu's) is based on a plant designed to treat 60 million cubic feet (mmcf) per day of gas containing one grain of H_2S per standard cubic foot of gas. If a cooling tower is used, the thermal discharge to water from either type of plant is eliminated.

4.4.3.2 Air

The magnitude of the gas discharged into the atmosphere during extraction is reported as not applicable in the Hittman analysis and no other residuals are considered to be applicable during extraction.

The estimated NO_x emission level during gas gathering (2.6 tons per 10^{12} Btu's gathered) is obtained from the consumption of 3.67 percent of the produced fuel in gas engines used to drive compressors. No other air pollutants are reported by Hittman for gas gathering. Combustion products resulting from flaring are not indicated under either the extraction or the gas gathering residuals.

Emissions from natural gas liquid separation and sulfur removal plants come primarily from the industrial steam generation boilers. In natural gas liquids plants, air emissions total about three tons per 10^{12} Btu's processed; these residuals are based on using 3.1 percent of the gas processed as plant fuel and flaring 0.1 percent. Similarly, the residuals for sulfur removal are small, totaling 0.4 ton, and are based on using natural gas as fuel to generate process steam for a 60-mmcf per day plant. On the basis of generating 6,000 pounds per hour of 40 pounds per square inch atmosphere (psia) steam with 75 percent combustion efficiency, the fuel required is 0.2 mmcf per day or 0.3 percent.

4.4.3.3 Solids

No solids are generated in the extraction, gathering, or processing of natural gas except for elemental sulfur, which is not a waste product.

4.4.3.4 Land

The land requirements given in Table 4-6 for both the offshore or onshore wells are based on the use of one acre per well. Because offshore wells tend to be larger producers and are produced on platforms, their land requirement per 10^{12} Btu's is substantially less than that for onshore wells. The average well productivities used in Hittman's calculations are based on 1963 statistics and should be updated. The gathering system land requirements assume a 62.5-foot pipeline right-of-way with compressor stations on 25-acre sites spaced 187 miles apart. These assumptions seem inappropriate for analysis of land requirements for gas gathering systems because the length of any line or any continuous path in a gas gathering system is commonly much less than 187 miles. The total requirements for either a natural gas liquids or a sulfur removal processing plant are based on an assumed value of five acres for a 100-mmcf per day plant.

4.4.4 Economic Considerations

FPC, in Opinion No. 699 (1974d), established a single uniform national base rate of \$0.42 per thousand cubic feet (mcf) at the wellhead for domestic interstate sales of natural gas commenced after January 1, 1973. This is based on the Commission's finding that \$0.3754 per mcf to

$0.4274 per mcf is a reasonable cost range for production of gas. The cost components yielding the above range are shown in Table 4-7. Provision is made for annual escalations of $0.01 per mcf and special condition allowances. Recently, in Opinion No. 699-H (FPC, 1974e), FPC concluded that a base rate of $0.50 per mcf, subject to the same price escalation and allowances that applied to the former rate, was just and reasonable. The new rate is based on an alternative method of calculating return on investment and trended 1973 cost figures.

4.5 TRANSPORTATION OF NATURAL GAS

4.5.1 Technologies

The transmission of natural gas primarily involves the technologies of pipeline construction, flow of gas within these lines, and gas compression. Secondary technologies include metering and automation.

4.5.1.1 Transmission Pipeline

Natural gas pipeline systems generally consist of one or more lines of large diameter (12 to 42 inches), thin-walled (usually .1 to .5 inch) steel pipe selected in accordance with standard pipeline codes. On land, pipelines are normally buried two to four feet below the surface in a cross-country right-of-way.

Natural gas is pushed through a pipeline by pressure obtained from compressing the gas. The capacity of a pipeline (i.e., the amount of gas that can be transmitted through it) can be increased by using

TABLE 4-7

ESTIMATED 1974 NATIONAL AVERAGE COST OF FINDING AND PRODUCING NONASSOCIATED GAS

Cost Component	Revised Update High (cents per thousand cubic feet)	10-Year Estimate (cents per thousand cubic feet)
Successful wells	5.68	4.99
Recompleted and deeper drilling	0.20	0.20
Lease acquisitions	3.83	3.36
Other-production facilities	1.28	1.13
Subtotal	10.99	9.68
Dry holes	3.77	3.32
Other exploration	2.62	2.30
Exploration overhead	0.82	0.72
Subtotal	7.21	6.34
Operating expenses	3.10	3.10
Return at 15 percent and 10½ years	17.15	15.09
Return on working capital	1.14	1.01
Net liquid credit	(3.89)	(3.89)
Regulatory expense	0.20	0.20
Subtotal	35.90	31.53
Royalty at 16 percent	6.84	6.01
TOTAL at 14.73 pounds per square inch atmosphere	42.74	37.54

Source: FPC, 1974d: Appendix B (Schedule No. 1, Columns f and g, Sheet 1 of 9).

additional compressor stations (2,500 to 20,000 or more horsepower) located about 50 to 100 miles apart along the route (FPC, 1974a: 46). Natural gas from the pipeline is normally used as fuel for the compressor engines. Valves, often called sectionalizing valves, are commonly installed every 10 to 30 miles along the pipeline. These valves make it possible to isolate a pipeline section for repairs or maintenance and frequently are equipped to close automatically in response to a rapid, large drop in pressure (Katz and others, 1959: 637, 638). Metering and regulating stations are located at gas purchase and delivery points between the transmission lines and local distribution systems.

Many major gas pipelines exceed 1,500 miles in length and cross all types of terrain, including mountains, deserts, forests, swamps, offshore, farmland, and urban areas. River crossings are constructed in various ways with some lines laid underwater and some using highway or railroad bridges.

Natural gas transmission pipelines must be operated at high pressures. Line pressures from 600 to 960 pounds per square inch gauge (psig) are common, and a few lines operate at pressures in excess of 1,000 psig. Pressures are highest at the outlet of a compressor station and drop an average of approximately three psig per mile between stations. A significant decrease in the delivery capacity of a pipeline results from a reduction in the operating pressure.

Pipelines are normally coated to protect them from corrosion. In addition, cathodic protection as discussed in Section 4.5.1.4 is used to counteract corrosion by earth currents, particularly where the pipe passes through urban areas.

4.5.1.1.1 Alaskan Pipeline

The timing of the completion of a gas pipeline from Prudhoe Bay is extremely important as discussed in Section 4.2.3.3. At present, two alternatives are being considered as shown in Figure 4-5. One calls for the construction of a pipeline through the Mackenzie Delta area in Canada to the midwestern and far western states. That pipeline might transport both Alaskan and Canadian import gas (FPC, 1974c: 41). The other alternative is the construction of a gas pipeline along the same right-of-way as the TAPS oil pipeline. The gas would be liquefied in Valdez and shipped by LNG tanker to the West Coast. This would open the possibility of additional development of onshore supplies.

4.5.1.1.2 Pipeline Construction

Offshore gas pipelines are constructed in the same manner as the offshore oil pipelines discussed in Chapter 3 and result in the same environmental residuals (excluding leaks during operation). However, because of their higher pressures, onshore gas pipelines are constructed differently than onshore oil pipelines. Preliminary operations include clearing and grading of the right-of-way, pipe stringing, welding of the strung pipe, ditching, and coating of the pipe. In the next step, sideboom tractors lower the completed continuous pipe into the ditch and backfill. Finally, clean-up crews restore the land to its former condition. In good pipelining areas, construction rates of one to three miles of completed pipe per day are normally achieved, and the distance from the front to the back of the spread (ditching to covering operations) will not exceed two to three miles. Special crews deal with road and river crossings along the route and the installation of valves, service connections, etc.

4.5.1.2 Compression

The size and characteristics of compressor stations are very significant in overall transmission efficiency, the addition of compressor horsepower being one of the options considered as a means of increasing pipeline capacity. Compressor stations on gas transmission lines may have capacities ranging from 2,500 to 20,000 horsepower or more. Each station may be equipped with a dozen or more compressors to provide the necessary flexibility for maintenance.

Since reciprocating gas compressors are long-lived and have been used since the early days of gas pipelining, they are the most commonly found units. Individual reciprocating compressors range in size up to 15,000 horsepower, and the installed unit cost decreases as the size of the unit increases. Modern units can be stopped, started, or adjusted to other loading conditions by computer or by manual control from remote locations.

Centrifugal compressors are also used in compressor stations. These compressors are easier to install and automate, and offer lower installation and maintenance costs; however, they consume more fuel and offer less operating flexibility than reciprocating compressors. The individual centrifugal compressors range in size up to 20,000 horsepower.

Gas compressors operate most efficiently when the ratio of the outlet pressure to the inlet pressure lies between certain limits: about 1.2:4 for reciprocating compressors and about 1.5:2 for centrifugal compressors.

4.5.1.3 Storage of Natural Gas

Natural gas storage facilities are developed in conjunction with long-distance pipeline systems so that the pipeline can operate at an essentially constant transmission rate throughout the year. Pipelines are designed for a delivery rate roughly equal to the average demand rate, and excess gas delivered during periods of low demand is stored for use during periods of peak demand. Operation of the pipeline near its capacity (i.e., at a high load factor) minimizes the unit transportation cost.

4.5.1.3.1 Underground

Normally, natural gas is stored underground in depleted gas reservoirs, but depleted oil reservoirs are also used. Water-bearing formations known as aquifers, dug caverns, and sealed mines have also been used for underground gas storage in areas where depleted oil or gas fields are not available.

An underground storage reservoir must have the capacity to hold large volumes of gas, must be gas tight, and must have high deliverability (i.e., it must support high production rates during withdrawal and high intake rates during injection). In addition, the storage area is normally close to the market served by the pipeline. The locations of underground gas storage reservoirs in the U.S. are shown in Figure 4-9.

4.5.1.3.2 Tanks

Aboveground storage of natural gas in tanks known as gas-holders is also common. However, since tanks cannot hold large volumes of gas, this storage mode is used primarily to meet daily peak demands in local distribution systems (such as the high demand periods in the morning and early evening).

4.5.1.3.3 Peak-Shaving Plants

Although underground storage is normally sufficient to meet the demands of ordinary winter weather, the coldest days result in extreme demand peaks which often exceed the capacities of the long-distance pipeline and the underground storage facilities. To supply the incremental gas required during these short-term periods of extreme demand, many companies operate peak-shaving plants. One type of peak-shaving plant introduces a mixture of air and a high-cost liquefied petroleum gas (LPG)

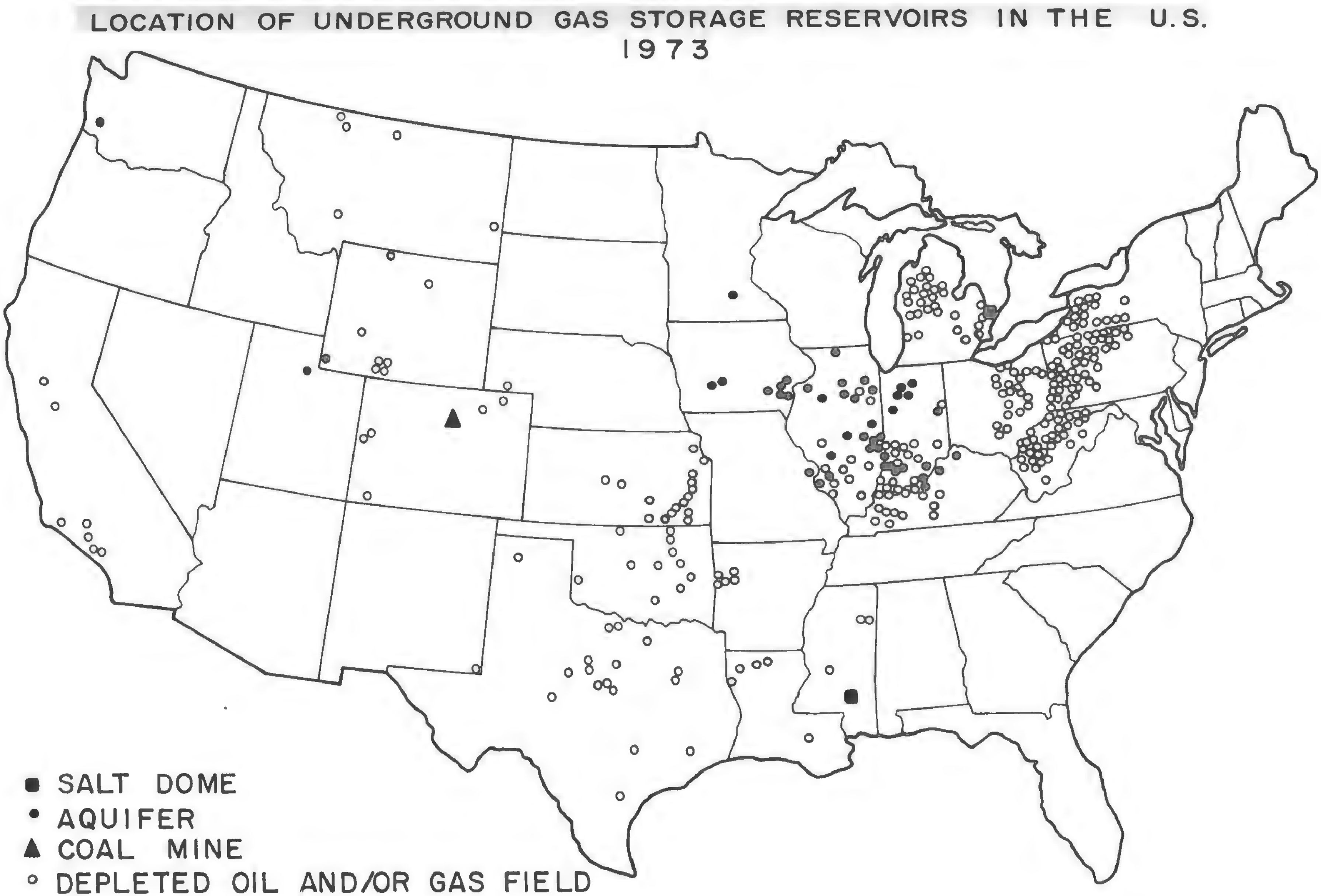


Figure 4-9. Location of Underground Gas Storage Reservoirs

Source: FPC, 1974a: 84.

(propane or, less commonly, butane) into the natural gas stream. Liquefied natural gas plants are also used to meet peak loads and offer the advantage that the revaporized LNG is more compatible with the base-load gas.

4.5.1.4 Distribution of Natural Gas

The local distribution system constitutes the means of delivering gas to the ultimate consumers. (To the residential or small commercial user, the local distribution utility is frequently seen as the natural gas industry.) A local distribution system consists basically of a system of mains, valves, regulators, meters, and other equipment and serves to transmit, control, and measure the gas flow to the individual customers. Natural gas enters local distribution systems at points called city gate stations or city border stations. Although most communities have only one city gate station, some large cities have high-pressure loops operated at 400 to 500 psig with several stations from which the gas enters the local system. Normally, the gas enters the local distribution system at a pressure between 100 and 150 psig. (The delivery pressure may be a matter of contractural obligation or merely a function of the operating pressure in the transmission line supplying the gas.)

The lines serving individual residential or commercial customers contain pressures ranging from .25 to .35 psig. Mains operating in the pressure range 25 to 35 psig are called the medium-pressure system. If pressures in street mains are maintained much above .25 psig, individual house and service regulators must be used. Because of the operating pressures in most gas distribution systems, the use of individual regulators is the common practice. The pipe carrying the gas from the street main to the regulator is usually either .75 or 1 inch in diameter. Large-volume commercial and industrial customers (2,500 cf per hour or more) are normally served by individual, direct lines from the high-pressure system or transmission lines.

In most gas distribution systems, the pipes must be coated to protect them from chemical corrosion, and measures must be taken to counteract corrosion resulting from stray electrical currents in the earth. Such currents are prevalent in cities and are the most frequent cause of corrosion in a distribution system. This type of corrosion is caused by a loss of iron ions from the point at which the current leaves the pipe. One protection technique, cathodic protection, applies a direct current to the pipe so that the current leaves the pipe, and metal is lost, at a preplanned point.

4.5.2 Energy Efficiencies

Energy efficiency data are given in Table 4-8. The data are considered fair, with a probable error of less than 50 percent. The primary efficiencies for storage and pipeline distribution reflect the use of part of the gas as fuel for compressors. The quantity of fuel used for storage is very small, averaging 0.36 percent of the fuel stored, while fuel used to drive the compressors in pipeline transmission is 3.9 percent. Truck transportation of LPG requires diesel fuel (an ancillary energy), amounting to about 0.5 percent of the energy transported.

4.5.3 Environmental Considerations

Hittman residuals for transmission, distribution, and storage of natural gas are given in Table 4-9. The data are considered poor, with a probable error of less than 100 percent.

4.5.3.1 Water

Water pollutant residuals are reported in the Hittman data as not applicable for transmission, distribution, and storage of natural gas and natural gas liquids.

TABLE 4-8

EFFICIENCY OF TRANSMISSION, DISTRIBUTION, AND STORAGE OF NATURAL GAS

Activity	Primary Efficiency (percent)	Ancillary Energy (Btu's per 10^{12} Btu's)	Overall Efficiency (percent)
Transmission and distribution			
Pipeline	97.1	0	97.1
Liquefied petroleum gas trucks	100	5.21×10^9	99.5
Storage			
Underground	99.6	0	99.6
Gas holders	99.6	0	99.6

Source: Hittman, 1974.

4.5.3.2 Air

The minimal estimated NO_x emission level during pipeline transmission is 10 tons per 10^{12} Btu's transported. This estimate assumes the consumption in compressor engines of 3.67 percent of the gas entering the pipeline. However, if a liquid hydrocarbon is used as fuel, higher NO_x levels would be realized.

The NO_x emissions during either underground or tank storage result from the use of gas engines to drive the compressors. Total amounts of NO_x emitted are small, averaging 12.2 tons per 10^{12} Btu's stored.

The air emissions generated in the truck transportation of LPG include particulates, nitrous oxides, sulfur dioxide, hydrocarbons, carbon monoxide, and aldehydes. The amounts are consistent with those normally associated with the operation of diesel tractor-trailers.

In general, the air residuals associated with transmission, distribution, and storage of natural gas do not constitute serious environmental impacts.

4.5.3.3 Solids

No solid pollutants are generated in the transmission, distribution, and storage of natural gas and natural gas liquids.

4.5.3.4 Land

The land requirements given in Table 4-9 for pipeline transmission of natural gas are based on the same parameter values as those for natural gas gathering systems. The transmission pipeline land requirements analysis, like that for the gathering system, is based on a 62.5-foot pipeline right-of-way with compressor stations on 25-acre sites spaced 187 miles apart. Because compressor stations are spaced 50 to 100 miles apart on many major pipelines, using Hittman's residuals may lead to a low estimate of pipeline land requirements.

The land required for an underground storage project is that required for a compressor station and related equipment, which was estimated to be 10 acres per project. The land needed for high-pressure storage tanks was based on 1.25 acres per mmcf of gas storage capacity. Storage capacity equivalent to 25 percent of the daily flow rate was assumed.

Table 4-9. Residuals for Transmission, Distribution, and Storage of Natural Gas

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	$^F/_I$[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
TRANSMISSION AND DISTRIBUTION																					
Pipeline	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	103.	0	0	0	0	NA	91.1/0 91.1	4. $\times 10^{-5}$	.0138	.324
Liquefied Petroleum Gas Trucks	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	.245	6.95	.509	.695	4.23	.113	NA	122./0 122.	U	U	U
STORAGE																					
Underground	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	12.2	0	0	0	0	NA	1.75/0 1.75	U	U	U
Gas Holders	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	12.2	0	0	0	0	NA	.33/0 .33	U	U	U

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement (Acres - year / 10^{12} Btu's) / Incremental Land Requirement (Acres / 10^{12} Btu's).

The Battelle report states, relative to onshore gas pipelines, that "other than the need to clear and maintain an overland easement, the pipelines in the continental U.S. present a minimal impact on the surroundings they traverse (after initial installation)" (Battelle, 1973: 240).

4.5.4 Economic Considerations

The average costs for major pipelines from 1956 to 1970 are shown in Figure 4-10 (FPC, 1973d: 111). The costs range from \$0.19 to \$0.24 per mcf and indicate an overall downward trend over the 14-year interval. The Hittman report lists the following cost data (probable error less than 50 percent) for natural gas transmission by pipelines (Hittman, 1974: Vol. I, Table 25):

Fixed cost:	$\$1.69 \times 10^5$ per 10^{12} Btu's
Operating cost:	$\$0.62 \times 10^5$ per 10^{12} Btu's
Total cost:	$\$2.31 \times 10^5$ per 10^{12} Btu's

Clearly, the natural gas transmission industry is highly capital intensive. About 90 percent of the costs of gas transmission by pipeline are fixed costs (taxes, depreciation, and return associated with the physical plant), and 10 percent are operating and maintenance costs which are partly constant and partly variable depending on the throughput volume of gas. The costs of pipeline transmission are so sensitive to load factor that the cost per mcf of gas transmission at 50-percent load factor is almost double the cost of transmission at 100-percent load factor (FPC, 1974a: 66). For a typical 30-inch diameter, 1,000-mile pipeline operating during 1973 at an average pressure of 800 pounds per square inch (psi) and at 95-percent load factor (i.e., at 95 percent of its capacity), the total cost of transporting gas is about \$0.02 per mcf per 100 miles, of which fixed charges represent over 90 percent (FPC, 1974a: 51).

4.5.5 Other Constraints and Opportunities

Intrastate distribution companies are regulated by the individual states, but the FPC regulates interstate pipelines (under the authority granted in the Natural Gas Act) and establishes the rates at the city gates of the distribution companies. Other federal responsibilities for the regulation and administration of pipelines are not as clearly defined. Four agencies--the Federal Power Commission, Bureau of Land Management, United States Geological Survey, and Office of Pipeline Safety--have jurisdiction over some aspect of offshore natural gas pipelines. Natural gas pipeline operations are also subject to provisions of the Natural Gas Act of 1936, National Environmental Policy Act, Federal Water Pollution Control Act, Clean Air Act of 1970, Occupational Safety and Health Act, and regulations issued pursuant to these statutes as well as various safety laws and regulations.

4.6 IMPORTED NATURAL GAS

Gas imports into the U.S. are from Canada by pipeline and from Algeria by LNG tankers. In 1973, net imports from Canada were in excess of one tcf. Since reserves from which this gas was drawn were not in excess of Canadian requirements under current guidelines established by the Canadian National Energy Board, it seems unlikely that additional gas will be available to the U.S. from this source.

Except in the Canadian pipeline, importation of natural gas first requires its reduction to a liquid so that useful amounts can be transported. Liquefaction of methane, the primary constituent of natural gas, occurs at atmospheric pressure when the temperature of the gas is reduced to $-259^{o}F$. The resulting volume reduction is more than 600:1.

Past use of LNG has been primarily for peak load service in gas distribution

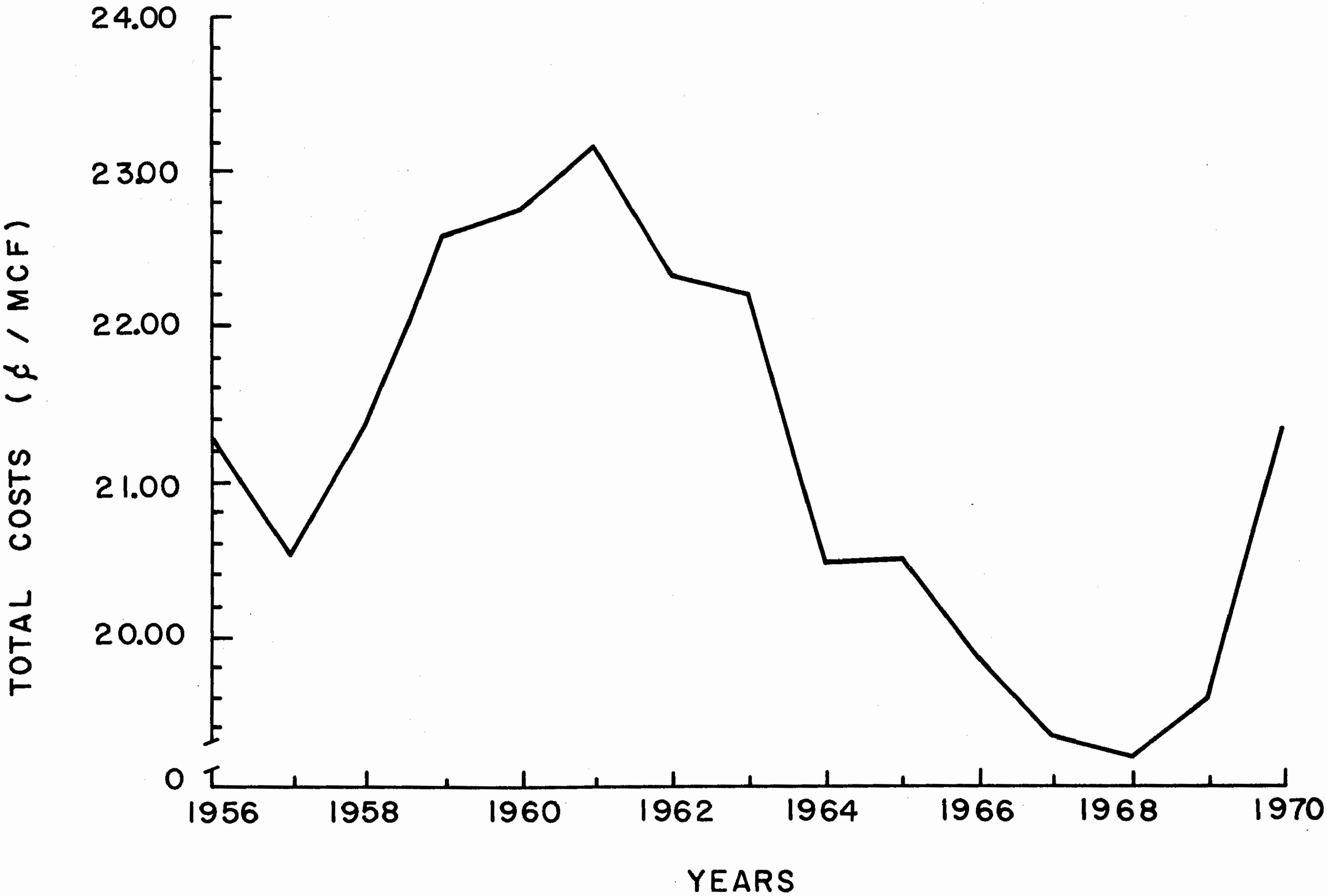


Figure 4-10. Major Pipeline Costs

Source: Adapted from FPC, 1973d: 111.

operations. However, the development of technology for marine transportation of LNG has made new sources of supplemental natural gas available for baseload service in the U.S. Current interest centers on initiating long-term (usually 20 to 25 years) baseload projects; that is, projects which would supply a significant portion of the average load of a transmission system. Two such projects have been approved and one conditionally approved by the FPC; in addition, applications for four others have been filed with the FPC (FPC, 1974f). Other prospective and possible projects have been reported in the press.

4.6.1 Liquefied Natural Gas Technologies

An LNG export-import system as illustrated in Figure 4-11 would include the following components: a source of natural gas; transportation from the source to the liquefaction plant; the liquefaction plant; storage, loading, and port facilities at the exporting site; transportation by ocean tanker; unloading and storage facilities at the importing site; a regasification plant; and transmission facilities from the regasification plant to a major pipeline. For most LNG projects, some components of the system would have no environmental impact on the U.S. and, for purposes of this report, could be ignored. However, the environmental impact of all components of the system for shipping the LNG from Alaska to the West Coast must be considered.

4.6.1.1 Pretreatment

Prior to liquefaction any gas constituents that would solidify at the low temperatures involved must be removed or reduced to insignificant amounts. Some of the more critical of these constituents are carbon dioxide, water, hydrogen sulfide, lubricating oils, dust, and odorants. The conditioning process includes cleaning, dehydration, and purification.

4.6.1.2 Liquefaction

The liquefaction complex at the export point consists of several major components including the refrigerator or "coldbox" in which the gas cooling occurs, the source of refrigeration power, the means of delivering the power, and the cooling system. The plant will also normally contain facilities for pretreatment of the gas, fluid transfer within the plant (i.e., pumps and piping), storage of LNG, and docking and loading of tankers. Figure 4-11 illustrates the role of the liquefaction plant in the overall LNG system.

Basically, liquefaction is achieved by using a refrigerant to remove heat from a gas at a low temperature and transfer it to some other medium (cooling water or atmospheric air) called a heat sink. Using a single refrigerant, the temperature of natural gas can only be reduced to approximately $-150^{\circ}F$. Thus, liquefaction of natural gas requires the use of more than one refrigerant. Three types of refrigeration systems are commonly used to liquefy natural gas: the cascade cycle; mixed refrigerant cycle; and single fluid expander cycle.

The cascade cycle uses a sequence of refrigerants to obtain progressively lower temperatures. As illustrated in the flow diagram of Figure 4-12, cooling is accomplished by reducing the gas temperature to $-31^{\circ}F$ in the propane-cooled exchangers, to $-142^{\circ}F$ in the ethelene-cooled exchangers, to $-240^{\circ}F$ in the methane-cooled exchangers, and finally to $-259^{\circ}F$ by reducing the pressure to 20 psia in the flash drum. This cycle has lower horsepower requirements, fewer distribution problems because single component fluids are circulated, more rapid plant start-up and shutdown, and normally simplified plant operation. It is generally believed to be the most reliable, especially in remote areas.

The mixed refrigerant cycle is a variation of the cascade cycle and involves the

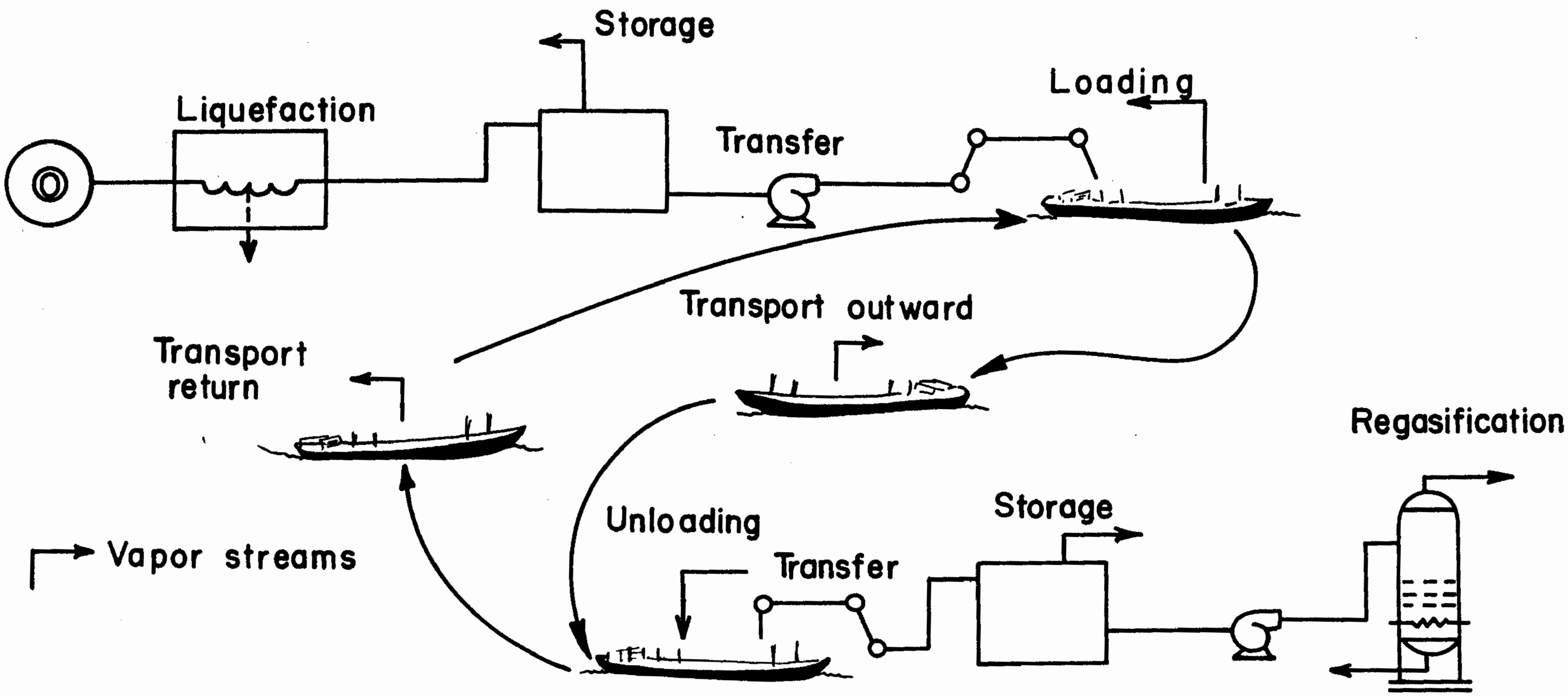


Figure 4-11. Integrated Liquid Natural Gas Operation

Source: Bodle and Eakin, 1971: 5.

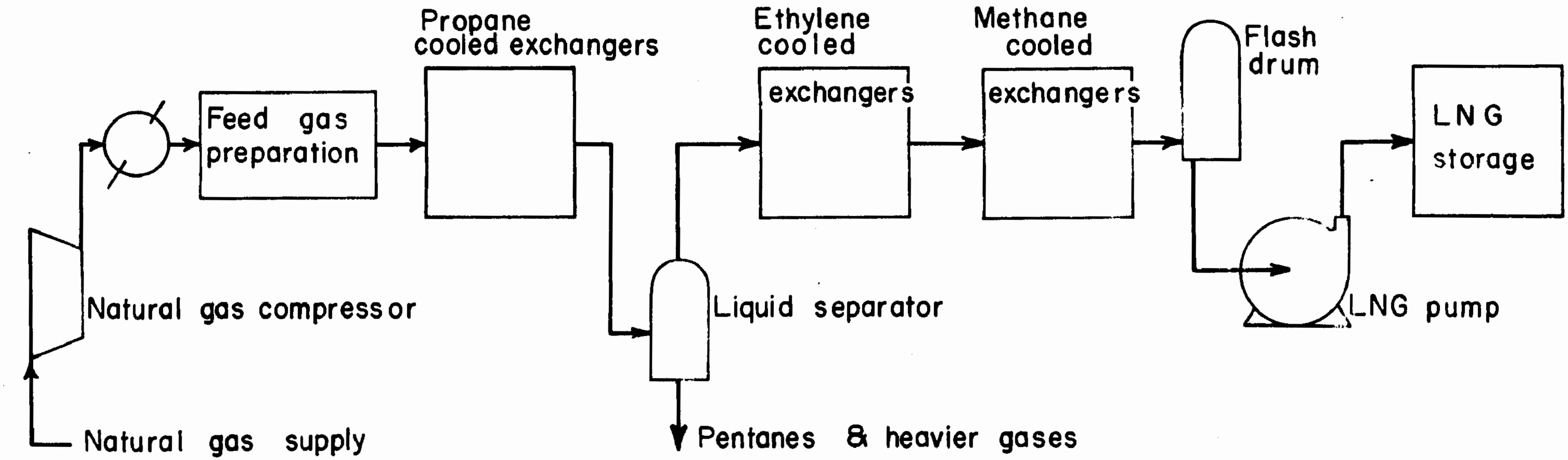


Figure 4-12. Cascade Cycle Liquefaction Plant

Source: J.F. Pritchard and Company.

circulation of a single refrigerant stream. In this process, the natural gas is also chilled, condensed, and subcooled in a series of heat exchangers. The refrigerant is first compressed to a high pressure, then partially condensed and flashed in successive steps until the lightest component is condensed and flashed. The contents of the mixed refrigerant stream are usually constituents of the natural gas such as butane, propane, ethane, methane, and nitrogen. This cycle has fewer compressor types and simpler piping and refrigerant process-vessel requirements. Because the compression and heat exchange systems are simpler, a mixed cycle plant may, under certain circumstances, require lower capital expenditures than a conventional cascade plant.

The single-fluid expander cycle uses the cooling effect obtained by expanding a stream of compressed gas through a turbine or engine and is of primary application in distribution system peak-shaving plants rather than baseload export-import systems.

4.6.1.3 Storage

Continuous operation of liquefaction plants requires the use of storage to accommodate gas liquefied when tankers are not being loaded. Normally, storage capacity of two to three million barrels (bbl) is required per bcf per day of processing. Aboveground, double-wall metal tanks are most commonly used. The space between the walls contains various types of insulation, a partial vacuum, or a combination of both. Other cryogenic fluids have been stored in prestressed concrete tanks, and this type of tank may be suitable for LNG storage as well. Such storage techniques as the use of frozen holes or pits in the earth and mined caverns have been tested or investigated, but there are no reported successful applications.

4.6.1.4 Tankers

Of the variety of LNG tanker configurations either in operation or proposed, two basic systems are used to contain and insulate the LNG. The first uses self-supporting (free-standing) tanks that rest inside the ship's hold and are independent of and insulated from the hull of the ship. The second uses a membrane tank in which the ship's hull serves as the outer tank wall. The inside of the hull is insulated, and a thin membrane covering the insulation serves as a liquid barrier. The membrane tank system offers more efficient utilization of cargo space; however, differences which may be significant in an environmental sense have not been reported.

Generally, the ship's engines can use either boil-off from the cargo or conventional fuel. Boil-off gas is always available to furnish a portion of the ship's fuel requirements because some LNG is carried on the return trip to keep the tanks cold.

Equipment supporting the loading, transportation, and discharging of LNG includes cargo pumps, gas compressors, heat exchangers, inert gas generators, and piping. As reported by the FPC's National Gas Survey (1973b: 377), the largest carrier in operation (75,000 cubic meters) was delivered in late 1972, but there are several ships currently on order with 125,000-cubic-meter capacities and LNG carriers of 160,000-cubic-meter capacities and larger are under consideration.

In terms of the total Btu content of the cargo, a 160,000-cubic-meter LNG tanker delivers about 70 percent as much energy per trip as a 125,000-ton crude oil tanker (the largest size oil tanker that can be accommodated in most U.S. ports). Typical ranges for the dimensions of LNG tankers are: length, 750 to 950 feet; beam, 120 to 150 feet; and draft, 35 to 40 feet.

TABLE 4-10

ENERGY EFFICIENCY OF LNG[a] OPERATIONS

Activity	Primary Efficiency (percent)	Ancillary Energy (Btu's per 10^{12} Btu's)	Overall Efficiency (percent)
LNG[a] liquefaction	83	0.00	83
LNG[a] tanker	96.4	$2.43x10^{10}$	94.1
LNG[a] tank	100	$2.81x10^{9}$	99.7
LNG[a] vaporization	98	$7.11x10^{8}$	97.9

Source: Hittman, 1974.

[a]Liquefied natural gas.

4.6.1.5 Port and Transfer Facilities

The FPC's National Gas Survey (1973b: 404) identified 19 potential receiving ports as shown in Figure 4-13. This map contains a tabulation of the water depths and remarks pertinent to the suitability of each location. In some cases, substantial dredging and/or fill and foundation building may be necessary. The list was compiled on the basis of the physical dimensions of the port with the assumption that suitable plant sites are available. Receiving sites need not be limited to those shown in Figure 4-13. At Cove Point, Maryland, for example, a mile-long pipeline will connect the unloading buoy in the Chesapeake Bay to the onshore facilities.

Facilities for transfer of LNG to or from the tankers or storage area are required. These facilities are similar at both the export and import points; thus, only the import case is described here.

For unloading either at a dock or through a pipeline, LNG ships connect to liquid unloading arms and the LNG is moved from the ships to stainless steel or aluminum storage tanks. A schematic diagram of the facilities at the receiving site is shown in Figure 4-14. The LNG is unloaded by submerged pumps in the ship's cargo tanks and flows into the LNG storage tanks. During the unloading period, vapor is physically displaced from the storage tanks; part of this vapor flows into the pipeline, while the remainder must flow through the vapor return line to the ship to prevent the ship's tanks from either taking in air or collapsing.

4.6.1.6 Regasification

The LNG is regasified (vaporized) by passing it through heat exchangers, which are tubes heated by either the surrounding air or water, or by the combustion of either a fuel or some of the gas itself. Regasification occurs at pressures up to 1,200 psig, which is sufficiently high for direct introduction into a conventional natural gas pipeline.

4.6.2 Energy Efficiencies

The liquefaction, transportation, storage, and vaporization of natural gas requires about 23 percent of the energy of the gas. Liquefaction alone consumes 17 percent of the overall energy expended. The available quantified data for energy efficiencies as given by Hittman (1974: Vol. I, Table 25) are shown in Table 4-10.

LIQUEFIED NATURAL GAS IMPORTS
POSSIBLE PORTS OF ENTRY

AREA	WATER DEPTH (feet)	TIDE RANGE (feet)	REMARKS
1. Penobscot Bay, Maine	40	9.7	Substantial distance from major gas transmission lines.
2. Portland, Maine	40	9.0	Substantial distance from major gas transmission lines.
3. Boston, Massachusetts	40	9.5	Densely populated.
4. Conanicut Island, R.I.	40	3.2	Good location for receiving LNG. Low demand area.
5. New York, New York	35-37	5.0	High marine traffic density. Densely populated.
6. Delaware River	40	6.0	Several possible sites. High demand area. Near major gas transmission lines.
7. Chesapeake Bay, Va.	45	3.0	Several possible sites. Heavy Navy traffic.
8. Savannah, Georgia	40	7.0	Near major gas transmission line.
9. Mobile, Alabama	40	6.0	Near major gas transmission lines.
10. New Orleans, La.	40	3.0	Near major gas transmission lines.
11. Lake Charles, La.	40	2.0	Near major gas transmission lines.
12. Sabine, Texas	40	6.0	Near major gas transmission lines.
13. Galveston-Houston, Texas	40	6.0	Near major gas transmission lines.
14. Tacoma, Washington	45	6.8-11.8	Good location for receiving LNG. Near major gas transmission line.
15. Portland, Oregon	35-40	2.4	Near major gas transmission line.
16. San Francisco-Oakland, California	40	3.2-6.0	High demand area--Near major gas transmission line.
17. Hueneme, California	40	2.8-5.4	Near major gas transmission line. 120,000 cubic meter ships.
18. Los Angeles-Long Beach, California	40-50	2.8-5.4	High demand area--Near major gas transmission line.
19. San Diego, California	40	3.0-5.7	Near major gas transmission line. Heavy Navy traffic.

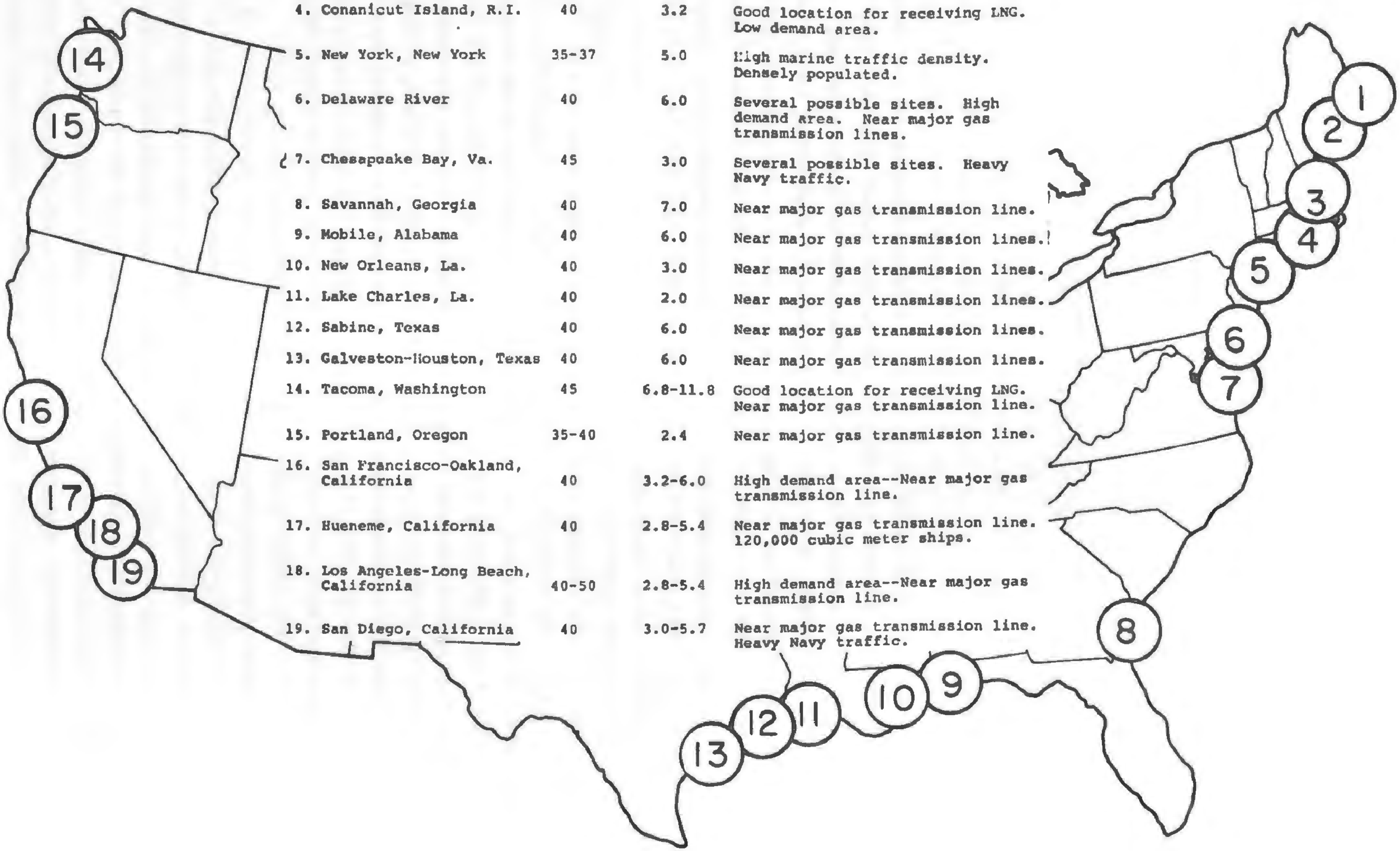


Figure 4-13. Potential Receiving Ports

Source: FPC, 1973b: VI-4.

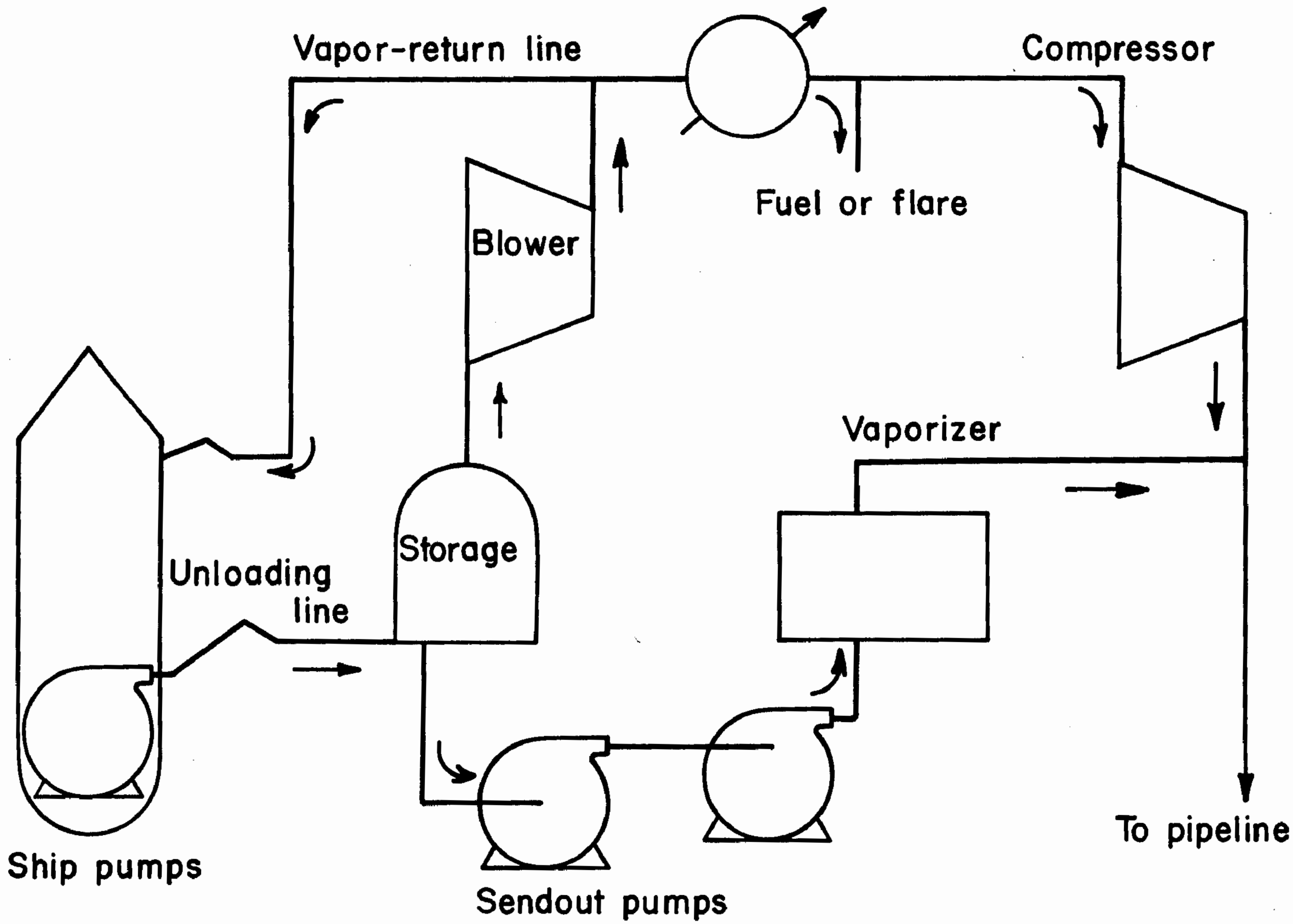


Figure 4-14. Liquid Natural Gas Receiving Terminal

Source: The Oil and Gas Journal, 1974: 60.

These data have a probable error of less than 25 percent.

4.6.3 Environmental Considerations

The Hittman residuals for the components of an LNG export-import system are shown in Table 4-11. These data have a probable error of less than 100 percent.

4.6.3.1 Water

No water pollutant data are given for any of the liquefaction, storage, or vaporization operations. For tanker operations, the nondegradable organics residual is 0.212 ton per 10^{12} Btu's shipped, based on a discharge of 12 gallons of LNG per day per vessel while in U.S. coastal waters or berthed. Although there is always the possibility of an LNG spill on land or water, any such spill would immediately begin to vaporize. Two studies (Wilcox, 1971; Enger and Hartman, 1972) dealing with the release of LNG and the subsequent dispersions of the resulting vapor both reached the conclusion that the environmental stress stemming from large and sudden releases to either land or water surfaces are short-lived and minor when compared to the safety hazard involved (FPC, 1973b: 411). Water residuals for LNG tankers are essentially the same as those for normal shipping operations, and the environmental impact of an LNG spill, in contrast to a crude oil spill which might occur in the transportation of crude oil by tanker, would be minimal.

Any dredging required to prepare and maintain channels and turning basins at the exporting and importing terminals causes turbidity of the water and disturbance of bottom-dwelling marine animals and organisms. In addition, movement of LNG carriers in shallow and restricted areas may result in disturbance of bottom and shore life both from the turbulence generated by propellors and the ship's wake (FPC, 1973b: 411). Although such disruptions would be temporary in most cases, import-export facilities should not be placed near commercial fishing areas if possible (BLM, 1973: 336, 337).

Plants using water in the regasification step will discharge water at a lowered temperature. In the case of the Savannah plant, water temperature will be lowered $5^{o}F$ before being returned to the river. The possible use of the potential cooling in conjunction with another process requiring dissipation of heat may represent a process benefit.

A level of discharge of shipboard wastes and engine exhaust fuel consistent with other comparable marine carriers would be anticipated.

4.6.3.2 Air

As given in Table 4-11, the NO_x emissions (the only residual listed for the liquefaction plant) are 354 tons per 10^{12} Btu's processed and are based on the consumption by compressor motors of 13 percent of the feedstock.

The tanker emissions are based on a 294,000-bbl LNG tanker traveling 100 miles per trip in coastal waters and spending two days in port. The total includes emissions from the tanker while in coastal waters and in port as well as emissions from the required tugboats.

No residuals are generated in storing LNG. The residuals attributable to vaporization are based on the use of two percent of the LNG input as fuel for the heat exchanger.

4.6.3.3 Solids

No solid pollutants are generated in LNG operations.

4.6.3.4 Land

A total of 1,000 acres is needed for the fuel storage depot, dock, port facilities, and vaporization system required for a 1,000-mmcf-per-day receiving terminal;

Table 4-11. Residuals for Liquefied Natural Gas Operations

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
LIQUEFIED NATURAL GAS																					
Liquefaction	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.03 x10^{11}	0	354.	0	0	0	0	NA	.0125/0 .0125	U	U	U
Tanker	NA	NA	NA	NA	NA	NA	.212	0	NA	0	.0315	.437	.336	.0154	.0062	.0044	NA	.49/0 .49	U	U	U
Tank	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	2.04/0 2.04	U	U	U
Vaporization	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	.187	1.00	.0059	.0785	.196	.108	NA	.133/0 .133	U	U	U

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement $\left(\frac{\text{Acres - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

this corresponds to 2.66 acre-years per 10^{12} Btu's. Allocation of land usage to the components of the receiving site storage, vaporization, and port facilities is made on the basis that the acreage is approximately proportional to the corresponding investment values.

For the liquefaction operations, the land requirements are assumed to be equal to those for vaporization of LNG. However, the land requirement figures given in the Hittman data for both the vaporization and liquefaction sites are misleading because a part of the land requirements for each has been reported as LNG tanker land requirements. The land requirements for a liquefaction site should actually include the Hittman values for the liquefaction site and one-half of the value for the tanker. Although the sum of the three residuals (liquefaction site, tankers, and vaporization site) may be representative of a complete LNG system, the indicated residual would not represent the full impact of the facility if an environmental assessment of either a liquefaction plant or a revaporization plant was being prepared. For example, the plant proposed for Cove Point, Maryland would initially produce 650 mmcf per day and require a 1,022-acre tract of land. The plant proposed for Savannah, Georgia would initially produce 335 mmcf per day and require 860 acres (BLM, 1973: 337, 338). Expressed in terms of acre-years per 10^{12} Btu's, the land usage at Cove Point would be 4.18 and that at Savannah would be 6.82, while the corresponding value for land usage given in the Hittman data is 0.130.

4.6.3.5 Major Accident

The potential for fire or explosion is always present during LNG operations. In 1944, an early LNG plant was destroyed by a disastrous fire, resulting from a storage tank failure, that killed 100 people. Since then, the technology of LNG operations has been improved and greater attention has been given to proper safety precautions. Nevertheless, the recent explosion of a Staten Island storage tank, killing more than 40 men, shows that there is still an element of danger involved in storing and handling LNG (BLM, 1973: 337).

In 1969, the U.S. Bureau of Mines reported on several instances of violent reactions resulting from the contact of LNG and water. No fire or ignition of vapor was observed, but there was a rapid upward movement of gas accompanied by a loud "bang" (Burgess and others, 1970). A later study concluded that there was little likelihood of a violent reaction between normal LNG and water and that such a reaction could result only after the methane content of the LNG had dropped to 40 percent. Since the normal methane content of LNG is 80 to 90 percent or more and the boil-off rate is about 0.2 percent per day, a reduction to 40 percent is not likely under current shipping practices (Enger, 1972). Although, in the case of a large spill, the quantity of LNG remaining after weathering (or methane boil-off) into the critical composition range could be significant, the weathering period would be of sufficient duration that the LNG would have spread on the surface and the chance of a single large reaction would be relatively small. Also, the energy available for the reaction is limited because it is not a chemical reaction (BLM, 1973: 336).

4.6.4 Economic Considerations

Although costs for individual components of an LNG importation system are listed in the Hittman report (1973: Table 25), the delivery price into the sales pipeline is more meaningful for the purposes of this report. The delivery price includes: the gas price, royalties, taxes, and other payments in the exporting country; production, transmission, liquefaction, storage, and loading costs in the exporting country; tanker transportation costs from the exporting country to the U.S.; and unloading, storage, revaporization, and some transmission costs in the U.S.

In approving the application by El Paso Natural Gas to import LNG, the FPC limited prices to $0.77 per million Btu's delivered to Cove Point, Maryland and to $0.83 at Savannah, Georgia (FPC, n.d.). (On the basis of a heating value of 1,032 Btu's per cf, these prices are approximately $0.80 per mcf and $0.86 per mcf respectively.) The company has indicated that these prices may not be sufficient. The current uniform national rate for sales of interstate natural gas established by the FPC is $0.50 per mcf (FPC, 1974e). While the prices approved by the El Paso project offer some guidance, the magnitude of price increases for future projects is difficult to predict because prices for a given project are markedly influenced by freight-on-board (f.o.b.) prices in the exporting country in addition to the usual capital and operating cost escalations.

Based on component costs given by the National Petroleum Council (1972: 294) for a project in which LNG is shipped from Algeria to Cove Point, Maryland, approximately 40 percent of the capital requirements are for ships, 41 percent for the liquefaction plant, and 19 percent for the revaporization plant. Clearly, the major capital costs are incurred in liquefying and shipping the LNG. The regasification facilities are the only capital cost in the importing country, and this cost is normally less than 20 percent of the total capital requirements. The above distribution of operating costs in the categories of regasification, shipping, and liquefaction would be expected to be typical of all LNG projects; however, the cost of the gas in the exporting country will undoubtedly be a dominant component of the total operating costs.

Other capital expenditures would include the development of marine facilities and the construction of two pipelines: one to the liquefaction plant and one from the regasification plant to the major transmission line. Pipeline construction for the Cove Point, Maryland plant will require $89 million, while pipelines for the Savannah plant will cost $25 million (FPC, n.d.).

4.6.5 Other Constraints and Opportunities

The impact of LNG imports on the U.S. balance of payments is difficult to assess at this time. The construction of liquefaction plants will certainly involve capital from the U.S. For example, some of the funds for construction of an Algerian plant are being provided by the Export-Import Bank. However, the amounts of U.S. capital that will flow to exporting countries and the amounts that will return through the purchase of U.S. equipment have not been established. In addition, the past methods of financing such projects may undergo changes because of the increased flow of money into the oil producing countries. The use of foreign or domestic tankers is another factor in the balance of payments.

Undoubtedly, the most significant effect on the balance of payments will be the price of the gas in the exporting country. One estimate of the f.o.b. price of gas is $0.38 to $0.53 per mcf (Khan and Bodle, 1972). On this basis, a long-term project for importing two tcf of LNG would result in an outflow of $760 million to $1.06 billion.

REFERENCES

American Gas Association, American Petroleum Institute, and Canadian Petroleum Association (1974) Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada and United States Productive Capacity, as of December 31, 1973. Washington: FPC.

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

Bodle, W.W. and B.E. Eakin (1971) "Predicting Properties for LNG Operations," p. 99 in Proceedings; 50th Annual Convention, Technical Papers, National Gas Producers Association, Houston, Texas, March 17-19, 1971.

Bureau of Land Management (1973) Energy Alternatives and Their Related Environmental Impacts. Washington: Government Printing Office.

Burgess, D.S., J.N. Murphy and M.G. Zabetakis (1970) Hazards Associated with Spillage of Liquefied Natural Gas on Water, Bureau of Mines Report of Investigations 7448. Washington: Government Printing Office.

Department of the Interior (1972a) United States Energy Through the Year 2000, by Walter G. Dupree, Jr. and James A. West. Washington: Government Printing Office.

Department of the Interior (1972b) Statement, Questions and Policy Issues Related to Oversight Hearings on the Administration of the Outer Continental Shelf Lands Act, Held by the Senate Committee on Interior and Insular Affairs, Pursuant to S. Res. 45, March 23, 1972.

Department of the Interior (1974) "USGS Releases Revised U.S. Oil and Gas Resource Estimates," News Release, March 26, 1974.

Enger, T. (1972) "Rapid Phase Transformation During LNG Spillage on Water." Paper presented at the Fluid International Conference and Exhibition on Liquefied Natural Gas, September 1972.

Enger and Hartman (1972) "Mechanism of LNG-Water Interactions." Paper presented at AGA Distribution Conference, Atlanta, Ga., May 18, 1972.

Federal Power Commission, Bureau of Natural Gas (1972) Natural Gas Supply and Demand, Staff Report No. 2. Washington: FPC.

Federal Power Commission (1973a) National Gas Reserves Study. Washington: FPC.

Federal Power Commission (1973b) National Gas Survey, Vol. II, Supply Technical Advisory Task Force Report: Liquefied Natural Gas. Washington: Government Printing Office.

Federal Power Commission (1973c) "Order Adopting and Amending Proposed Section 2.77 of General Rules of Practice and Procedure." Order No. 482, Docket No. R-459, issued April 12, 1973.

Federal Power Commission (1973d) National Gas Survey, Vol. III, Transmission-Technical Advisory Task Force Report: Operations. Washington: Government Printing Office.

Federal Power Commission (1974a) National Gas Survey, Vol. I, Chapter 2: The Resource and the Industry, preliminary draft issued in advance of Commission approval.

Federal Power Commission (1974b) National Gas Survey, Vol. I, Chapter 9: Future Domestic Natural Gas Supplies, preliminary draft issued in advance of Commission approval.

Federal Power Commission (1974c) National Gas Survey, Vol. I, Chapter 10: Future Gas Supplies from Alternate Sources, preliminary draft issued in advance of Commission approval.

Federal Power Commission (1974d) "Opinion and Order Prescribing Uniform National Rate for Sales of Natural Gas Produced from Wells Commenced on or After January 1, 1973, and New Dedications of Natural Gas to Interstate Commerce On or After January 1, 1973." Opinion No. 699, Docket No. R-389-B, issued June 21, 1974.

Federal Power Commission (1974e) "Opinion and Order on Rehearing Affirming in Part and Modifying in Part Opinion No. 699 and Granting in Part and Denying in Part Petitions for Rehearing," Opinion No. 699-H, Docket No. R-389, issued December 4, 1974.

Federal Power Commission (1974f) "Liquefied Natural Gas Applications Filed with the FPC," July 18, 1974. Washington: FPC.

Federal Power Commission (n.d.) Docket No. CP71-68, et al.

The Ford Foundation, Energy Policy Project (1974) A Time to Choose: America's Energy Future. Cambridge, Mass.: Ballinger Publishing Co.

Hardy, E.F. (1974) "The Emergence of U.S. Gas Utilities as a Factor in World Petroleum Economics." Paper presented at the Annual Meeting of the AIChE, Tulsa, Ok., March 10-13, 1974.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

IGT Highlights (1974) IGT Highlights 4 (June 24, 1974).

J.F. Pritchard and Co. (n.d.) CAMEL: A Proud Engineering Achievement. Kansas City: J.F. Pritchard and Co.

Kash, Don E., Irvin L. White, Karl H. Bergey, Michael A. Chartock, Michael D. Devine, R. Leon Leonard, Stephen N. Salomon, and Harold W. Young (1973) Energy Under the Oceans: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations. Norman, Ok.: University of Oklahoma.

Katz, D.L. and others (1959) Handbook of Natural Gas Engineering. New York: McGraw-Hill Book Co., Inc.

Khan, A.R. and W.W. Bodle (1972) "Supplementing United States Gas Supplies with Imported LNG." Journal of Petroleum Technology (May 1972).

Linden, H.R. (1973) "The Role of SNG in the U.S. Energy Balance." Special report for the Gas Supply Committee of the American Gas Association, May 15, 1973.

National Petroleum Council, Committee on U.S. Energy Outlook (1972) U.S. Energy Outlook. Washington: NPC.

Oil and Gas Journal (1974) Oil and Gas Journal (May 13, 1974): 60.

Phillips, J.G. (1974) "Energy Report/Congress Nears Showdown on Proposal to Decontrol Gas Prices." National Journal Reports 6 (May 25, 1974): 761-775.

Potential Gas Committee (1973) Potential Supply of Natural Gas in the United States, As of December 31, 1972. Golden, Colorado: Colorado School of Mines, Potential Gas Agency.

Wilcox, D.C. (1971) "An Empirical Vapor Dispersion Law for LNG Spill." AGA Project 15-33-4, Arlington, Va., April, 1971.

Zareski, G.K. (1973) "The Gas Supplies of the United States--Present and Future," in Pollution Control and Energy Needs, Advances in Chemistry Series No. 127. New York: American Chemical Society.

CHAPTER 5

THE TAR SANDS RESOURCE SYSTEM

5.1 INTRODUCTION

Tar sands are deposits of porous rock or sediments that contain hydrocarbon oils (tar) too viscous to be extracted by conventional petroleum recovery methods (NPC, 1972: 225). Large deposits of tar sands were identified in North America at the end of the 19th Century, and efforts to extract the tar sands were undertaken early in the 20th Century (Camp, 1969: 690). Some of these efforts achieved intermittent commercial operation. In Canada, commercial ventures for producing energy products from tar sands are being developed on a large scale, but in the U.S., only relatively small-scale development efforts have been made on selected deposits in Utah (Kilborn, 1964: 247).

The tar sands resource development system is described in this chapter as a sequence of activities starting with exploration, continuing with the recovery, upgrading, and refining, and ending with transportation of the finished products. As diagrammed in Figure 5-1, this system can involve several transportation steps, depending on the location of facilities.

Most information on tar sands technologies comes from Canadian developments. Future technologies that might be employed in the U.S., and the impacts sustained, may differ from those indicated by Canadian information. No data on tar sands were available from the Hittman, Battelle, and Teknekron studies that provide much of the quantitative data for other chapters. The similarities between certain activities in the tar sands system and oil shale, coal, and crude oil technologies suggest that those technologies may be useful references for understanding tar sands.

5.2 RESOURCE QUANTITY

Few quantitative estimates of tar sands resources have been made, and the existing estimates are based on limited information. The total world deposits are estimated to be equivalent to one to two trillion barrels of tar (NPC, 1972: 225). Large deposits occur in Columbia, Venezuela, and especially Canada, where the Athabascan deposit in Alberta contains a total resource of 700 billion barrels (BLM, 1973: 366; Camp, 1969: 682).

The U.S. possesses two to three percent of the world tar sands, an estimated resource* of about 30 billion barrels of oil (Cashion, 1973: 100). These resources should not be counted as energy reserves because they are not known to be economically recoverable at the present time.** However, the Department of the Interior believes that in 15 to 30 years it may be feasible to begin recovery of about 30 to 50 percent of the resource, resulting in the production of 10 to 16 billion barrels of oil. Estimates of recoverable U.S. tar sands made by the Bureau of Mines (based

*A resource is an identified or undiscovered (but surmised to exist) deposit that is currently or potentially feasible to extract.

**A reserve is an identified deposit that can be extracted, processed, and sold on a profitable basis under current market conditions.

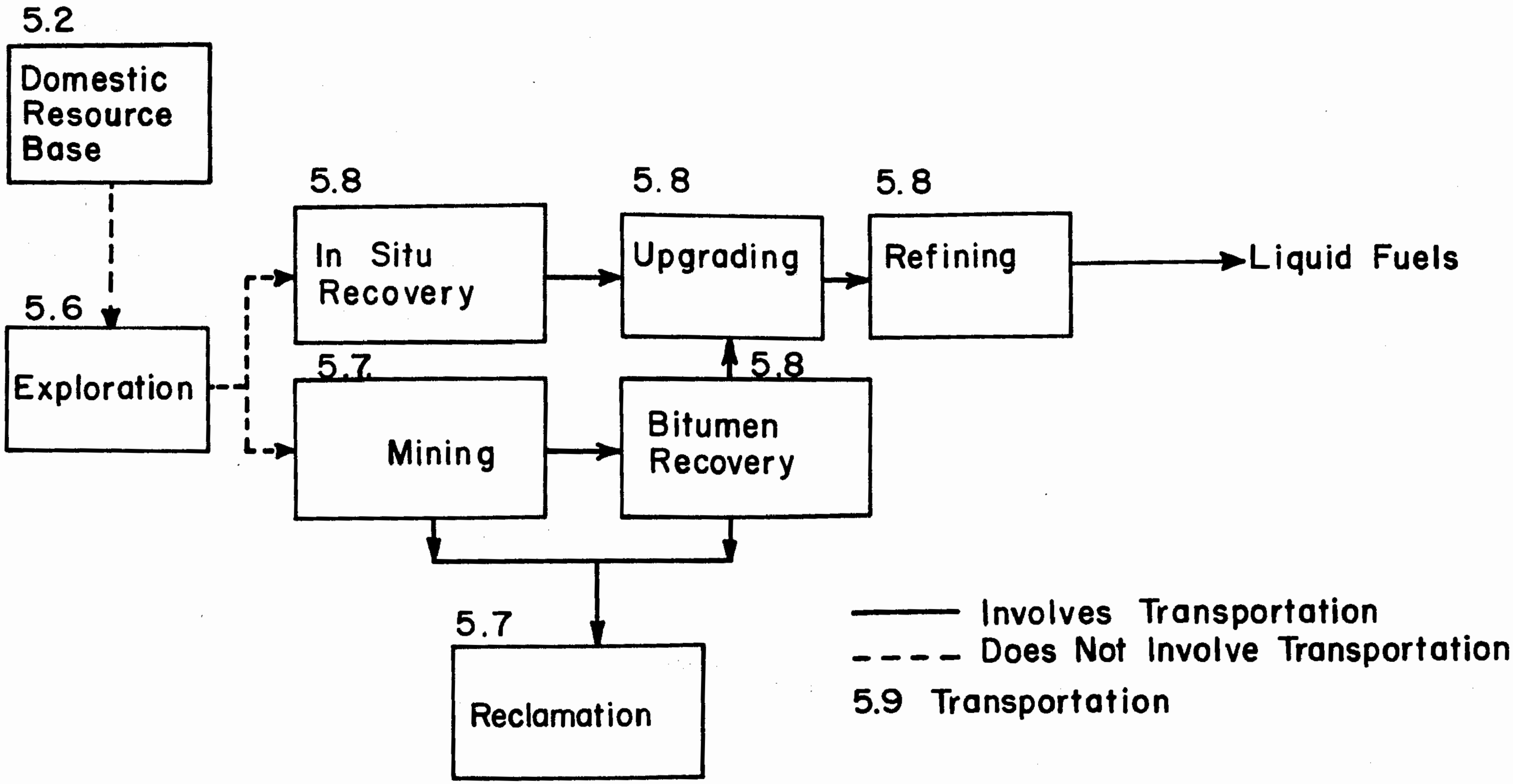


Figure 5-1. Tar Sands Resource Development

on shallow occurrences only) are lower, ranging from 2.5 to 5.5 billion barrels of recoverable oil (BLM, 1973: 364).

5.3 CHARACTERISTICS OF THE RESOURCE

Tar sands are composed of an organic hydrocarbon fraction occupying pore space in a rock such as sandstone or dolomite (Spencer and others, 1969: 5). Porous space consists of 26 to 39 percent of rock volume in most U.S. tar sands, and this space can be occupied by water or tar. Water is frequently the largest fraction, and tar content varies between 13 and 33 percent of the pore volume* (Spencer and others, 1969: 6).

The tar, which consists of many hydrocarbon compounds, is frequently referred to as bitumen by geologists. Thus, tar sands are often referred to as bituminous sands. The bitumen content of most U.S. tar sands deposits varies between 9 and 16 percent of the total weight. A deposit with about 14 percent bitumen is considered rich. About 1.5 tons of rich tar sands yield about one barrel of bitumen, the equivalent of about 6.3×10^6 Btu's (AEC, 1974: A.2-95). A few deposits in Utah are very high in bitumen and are distinguished from other deposits by being labeled gilsonite. The viscosity or resistance to flow of the bitumen varies greatly, but all tars are by definition more viscous than petroleum. Some bitumen-bearing rocks are solid with the tar softening only on heating.

The sulfur content of U.S. tar varies considerably between different geographic locations, but the major Utah deposits have a low sulfur content (about 0.5 percent as indicated in Table 5-1). The overburden of specific deposits also differs greatly; some are covered by as much as 2,000 feet of rock while others emerge at the surface as the data in Table 5-1 indicate.

5.4 LOCATION OF THE RESOURCES

About 550 deposits of tar sands have been identified in 22 states, but only California, Kentucky, New Mexico, Texas, and Utah have individual deposits of over a million barrels (Cashion, 1973: 101). Table 5-2 summarizes reserve and resource

TABLE 5-1

SULFUR CONTENT AND OVERBURDEN DEPTH OF SOME MAJOR U.S. TAR SANDS DEPOSITS

Location	Size of Identified Resource (million barrels)	Sulfur Content (percentage by weight)	Overburden Depth (feet)
Asphalt Ridge, Utah	900	0.5	0-2,000
Sunnyside, Utah	500	0.5	0 - 150
Whiterocks, Utah	250	0.5	nil[a]
Edna, California	165	4.2	0 - 600

Source: Camp, 1969: 685.

[a]Specific overburden depths are not available but deposits are very shallow.

*Canadian tar sands have oil in 40 to 98 percent of the pore volume.

TABLE 5-2

SIZE OF U.S. TAR SANDS DEPOSITS
(KNOWN DEPOSITS OF AT LEAST
ONE MILLION BARRELS)

State	Reserves	Resources (millions of barrels)
California	2	270 - 320
Kentucky	U[a]	30 - 40
New Mexico	U[a]	60
Texas	U[a]	120 - 140
Utah	1,000-5,000[b]	19,000 - 29,000

Source: Cashion, 1973: 101; AEC, 1974: A.2.95-98.

[a]U = unknown.

[b]These "reserves" are apparently not presently recoverable. They could be appropriately termed paramarginal reserves.

estimates in these states. Widespread thin occurrences of tar sands underlie areas in the central U.S. as indicated in Figure 5-2. The vast majority of the identified resource, estimated at up to 29 billion barrels of oil, is located in Utah. One deposit alone, the Tar Sand Triangle west of the confluence of the Green and Colorado rivers in the eastern portion of Utah, is estimated to contain between 10 and 20 billion barrels of oil (Cashion, 1973: 101). The major Utah deposits are in an arid setting that has been described more completely in Chapter 2.

5.5 OWNERSHIP OF THE RESOURCES

The major tar sands deposits in Utah are owned by the federal government.* Several of the tar sands deposits are on lands that contain other minerals, such as oil shale. Private claims to mineral rights on these lands are being challenged by the federal government. Most of the deposits located outside Utah are on private land.

*Apparently extensive deposits occur in the Uinta and Ouray Indian Reservations.

5.6 EXPLORATION

5.6.1 Technologies

Exploration for tar sands has largely been confined to visual observation of surface outcrops or tar seeps and the examination of core drillings. Little use has been made of the sophisticated exploration tools, such as seismic exploration and the introduction of electrical instrumentation into well bores, that are used in the petroleum industry. If the need arises for more intensive tar sands exploration, petroleum industry tools (including seismic, well logging, and aerial reconnaissance devices) will be employed (Cashion, 1973: 102). In the near future, however, efforts will most likely be confined to coring and more carefully describing known tar sands deposits.

5.6.2 Energy Efficiencies

The ancillary energy expended in discovering tar sands deposits has been a small fraction of the energy recovered in the Canadian operations. U.S. exploration expenditures should be similar.

5.6.3 Environmental Considerations

Environmental residuals from exploration are limited to surface and subsurface physical disturbances associated with drilling and support facilities for geologists. These are confined to small areas and the overall residuals are small.

5.6.4 Economic Considerations

Data on tar sands exploration costs are not available. Because seams are thick and many of the deposits have already been identified, exploration activities in support of mining operations are likely to be a very small portion of the overall costs of mine development.

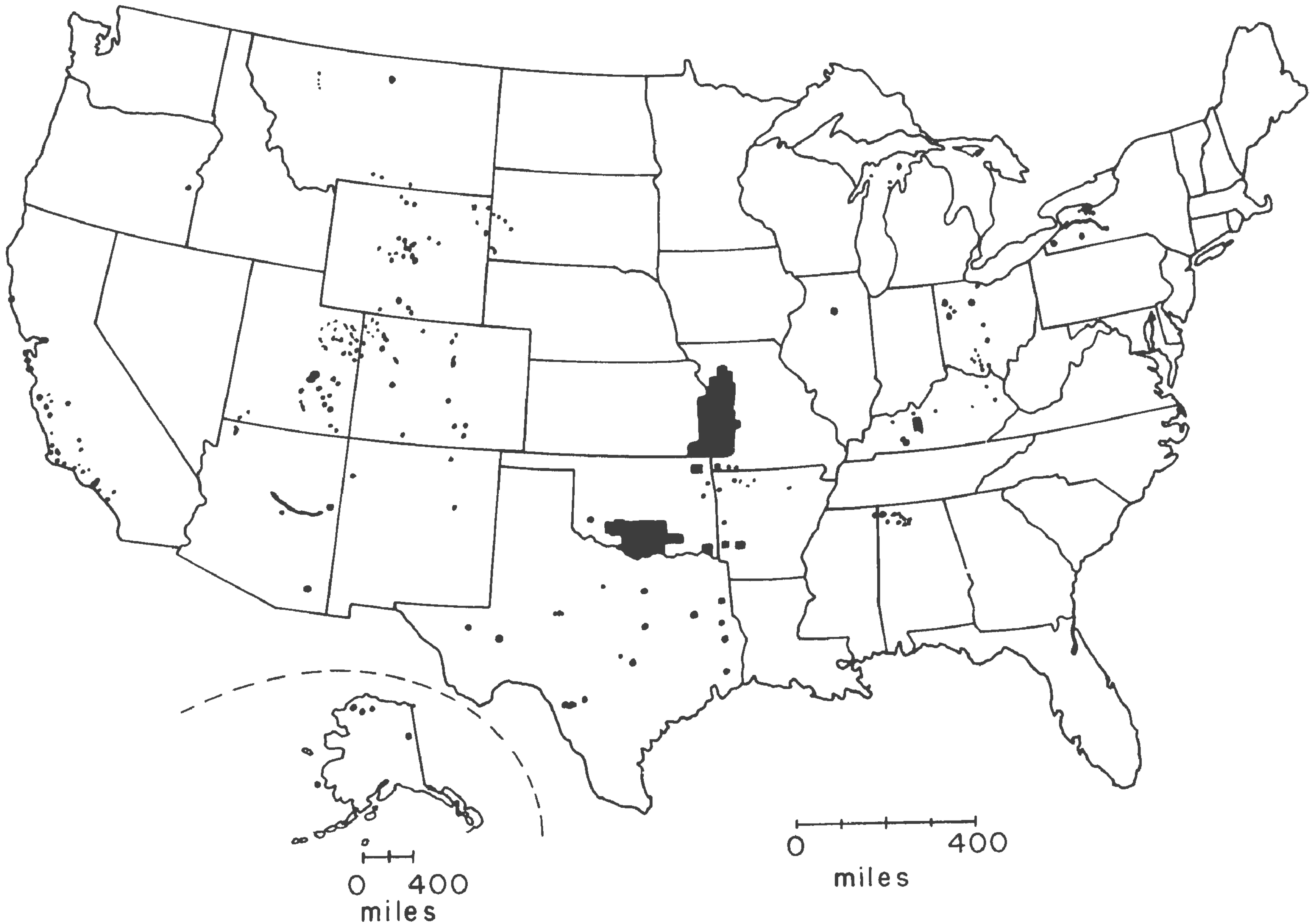


Figure 5-2. Distribution of U.S. Tar Sands Resources

Source: Spencer, Eckhard, and Johnson, 1969: 7.

5.7 MINING AND RECLAMATION

The bitumen can be recovered either by mining the tar sands and transporting them to the surface for processing or by underground extraction of the oil without mining or removing the overburden. The underground extraction method is called in situ recovery. Mining and reclamation procedures are described in this section; in situ extraction is described in Section 5.8.

5.7.1 Technologies

5.7.1.1 Mining

As with coal and oil shale, tar sands can be mined from the surface or underground, depending primarily on economic considerations. Most deep deposits, including many of those occurring in Utah, await development of in situ recovery methods (BLM, 1973: 365). Underground mines have only been used to recover high quality consolidated tar deposits, such as the thick veins of gilsonite in Utah. Although rudimentary hand excavation and loading techniques have been used in the past, more recent methods have employed jetted water streams to fracture and excavate the gilsonite, a process called hydraulic mining. The largest such operation produced about 1,000 tons of gilsonite a day (Kilborn, 1964: 247).

Shallow deposits (an overburden roughly as thick as the resource seam) can be mined from the surface. In surface mining, the vegetation is cleared from the area to be mined, the overburden is fractured (if necessary) by blasting, and the material is then removed by standard excavation techniques. With the overburden removed, the tar sands are mined and carried by conveyor or truck to the processing facility.

Two methods of excavating the overburden and tar sands have been proposed: one uses several large pieces of excavating equipment, as in surface coal mines, and the other uses a number of smaller mining units (Camp, 1969: 702). The large-scale units can be either bucket wheel excavators or draglines, and the smaller-scale units can be either shovels or motorized scrapers. (Chapter 1 includes descriptions of these techniques and machines.)

A consortium of oil companies has proposed a system employing a number of excavating scrapers for one tar sands operation. These scrapers will remove the overburden, then the tar sands, discharging the mineral onto a conveyor for transportation to the processing plant (Camp, 1969: 703).

5.7.1.2 Reclamation

Reclaiming lands disturbed by tar sands development through mining primarily involves the disposal of spent sand from the processing plant and restoration of the mined area. For surface mining, satisfactory reclamation procedures will integrate the mining and disposal operations, returning the spent sand to the mine or to other suitable areas as described in the mine reclamation sections of Chapters 1 and 2. Complete reclamation will also require recontouring the material and revegetating the area. For underground operations, subsidence could be minimized if processed sands could be returned to the mine.

5.7.2 Energy Efficiencies

Few data are available on the efficiency of surface mining tar sands. The recovery efficiency should be about 80 percent, based on other surface mining operations (e.g., coal surface area mines recover 80 to 98 percent of the seams) (Hittman, 1974: Vol. I, Tables 1 through 12). Ancillary energy requirements could be about the same as in oil shale mining or about one billion Btu's per 10^{12} Btu's excavated from the mine, not including energy used in reclamation. Efficiency data on possible underground operations are not available.

5.7.3 Environmental Considerations

Surface mining produces substantial residuals, including: gross modification of surface topography; disposal of large amounts of overburden (and spent tar sands returned from processing facilities); dust and vehicle emissions into the atmosphere; and water pollution from mining and processing activities, erosion, watershed modification, and disturbances to groundwater (BLM, 1973: 370). In Canada, about 3.3 tons of tar sands and overburden must be excavated to produce one barrel of oil. The weight of overburden is about one-half that of the tar sands. In a typical day's mining operation in support of a 50,000-barrel-per-day processing facility, a total of about 165,000 tons of material is moved (Spencer and others, 1969: 10).

Depending on seam thickness, several acres of surface lands per day could be affected by surface mine operations. Quantification of other residuals from hypothetical mining operations in the U.S. has not been attempted. The use of controlled technologies, including revegetation and irrigation in arid areas (if water is available), would substantially minimize the impact of surface mining, and as previously mentioned, returning the processed sands to underground mines could minimize the extent of subsidence.

Residuals from both types of mining operations could be similar to those described in Chapters 1 and 2.

5.7.4 Economic Considerations

Current information on all aspects of the cost of tar sands operations is limited and is usually based on Canadian operations. These operations differ greatly in such areas as geology, scale of operations, and environment, and it should not be assumed that possible activities in the U.S. will be similar.

In Canadian operations, mining averages about 41 percent of the total costs of producing synthetic oil from tar sands (Hottel and Howard, 1971: 193). However, the mining costs vary with the overburden-to-seam thickness ratio, which is normally 1:1 or less. One 1969 estimate of costs of supplying raw tar sands to a processing facility was 15 to 25 cents per ton under relatively good conditions (Cameron, 1969: 256). The 41-percent cost figure and the 25-cents-per-ton figure do not agree well (if 1.5 to 2 tons are required for a barrel of oil), and extraction costs are probably closer to $1.00 per ton.

5.8 PROCESSING

5.8.1 Technologies

Following the mining operation, the first processing step is bitumen recovery and removal of the inorganic mineral sands. If the tar sands are too deep for economic mining operations, in situ bitumen recovery could be employed, although this technology is only in developmental stages. Whether recovery of the bitumen is accomplished in surface facilities or in situ, the next step is upgrading the bitumen to a product that resembles crude oil. This upgrading step can then be followed by a refining operation if products such as gasoline or jet fuel are desired.

5.8.1.1 Bitumen Recovery

Once the tar sands have been mined, three general processes for recovering the bitumen have been suggested: hot water extraction, solvent extraction, and pyrolysis.

The bitumen extraction technique used in Canada heats the tar sands with steam, hot water, and sodium hydroxide in separation tanks where the sands fall to the bottom and the tar floats to the top.[*] The bitumen is then skimmed off and centrifuged to remove the water and any dissolved minerals before being mixed with a naphtha to reduce viscosity and allow pumping to the upgrading facilities (Spencer and others, 1969: 11). Figure 5-3 diagrams this hot water extraction process.

Figure 5-4 delineates the steps in the solvent extraction process. In this method, the bitumen is dissolved by mixing a solvent (such as naphtha) with the tar sands, and the resulting mixture is drained from the inorganic mineral sands (Camp, 1969: 706). This mixture is then pumped to a vessel where the solvent is recovered (e.g., by distillation) and recycled. Recovery of all the solvent is important because even small losses of solvent can make this system costly.

The pyrolysis method (Figure 5-5) consists of partial combustion or "coking" of the tar sands to decompose the complex bitumen molecules into gases and liquids. One method first heats the tar sands (Camp, 1969: 705) in a vessel called a coker to drive off most of the volatile matter. The remaining hydrocarbons in the coked sands are then burned to provide process heat for the coker. The volatile matter is driven out of the sands in the coker and then condensed and recovered for gases and liquids. This system has only operated on a pilot-plant basis in Canada (Camp, 1969: 706). A more complete description of pyrolysis extraction technologies is given in Chapter 2.

5.8.1.2 In Situ Recovery

Two basic methods have been suggested for recovering the hydrocarbons from tar sands without mining the deposits: applying heat in various forms to lower viscosity, and using emulsifiers or organic solvents to dissolve the tar from the sands. By definition, tar sands are too viscous to be recoverable by petroleum secondary recovery methods, and simple waterflooding of the tar sand formation is not sufficient for in situ removal of the hydrocarbons. However, some of the tertiary petroleum recovery practices described in Chapter 3 are applicable (such as thermal recovery and injection of emulsifiers).

A number of heat application methods have been proposed, including injection of hot liquids or gases such as water or steam, combustion in place, and nuclear explosions. Steam injection can either be cyclic or continuous. In a cyclic process, steam is pumped down a wellbore drilled into the formation for several days or weeks. After the tar sands are sufficiently heated, the steam system is disconnected and the tar is pumped from the well. This method has been used to recover several million barrels of tar from sands in California. In continuous steam drive, two or more wells are used, with one of the wells supplying steam while the other is used for material extraction. Experimental steam drive operations have taken place in California and Canada. Like other in situ heating processes, lack of permeability and heat losses in the formation tend to limit the success of the steam extraction method (Spencer and others, 1969: 9-11).

Combustion of the tar sands to reduce viscosity and volatilize the hydrocarbons can be accomplished by drilling wells, fracturing the formation, injecting air, and establishing a combustion zone (Spencer and others, 1969: 9). The resulting materials are then produced from a downstream well. This method can be modified by adjusting the relative location of the combustion zones, type of air injection, and extent of fracturing, or by introducing additional materials such as steam. Similar in situ combustion processes have been described in Chapters 1 and 2.

---

[*]The caustic sodium hydroxide facilitates separation of the tar from the sand.

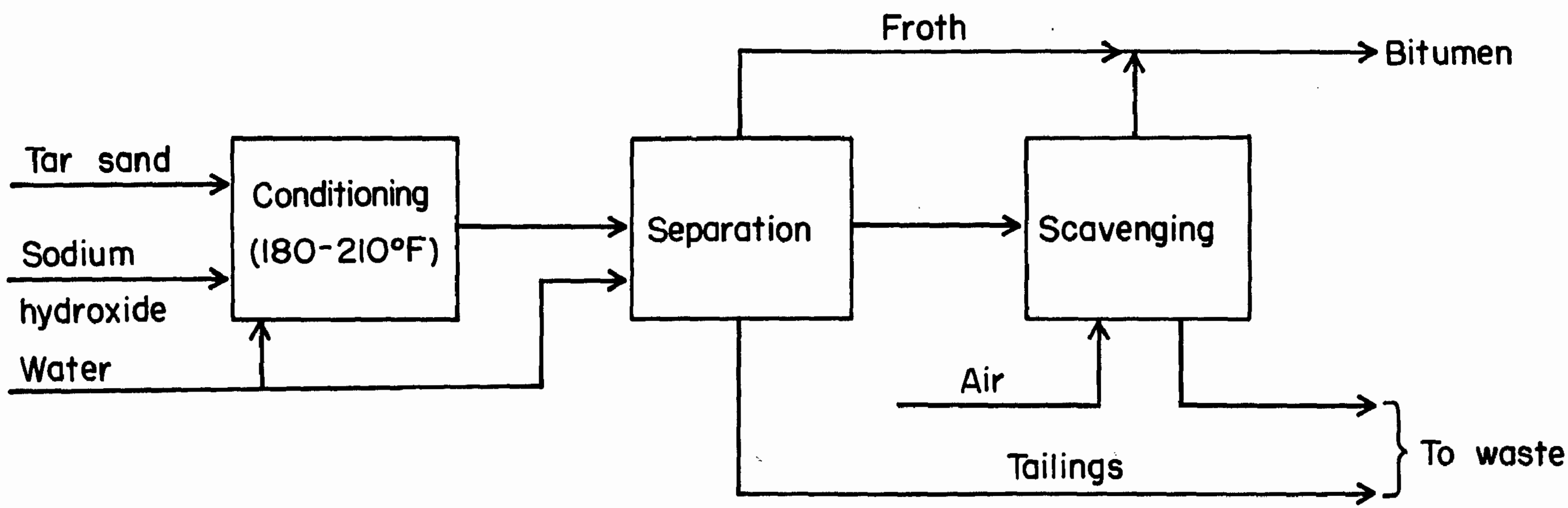


Figure 5-3. Hot Water Extraction Process

Source: Camp, 1969: 710.

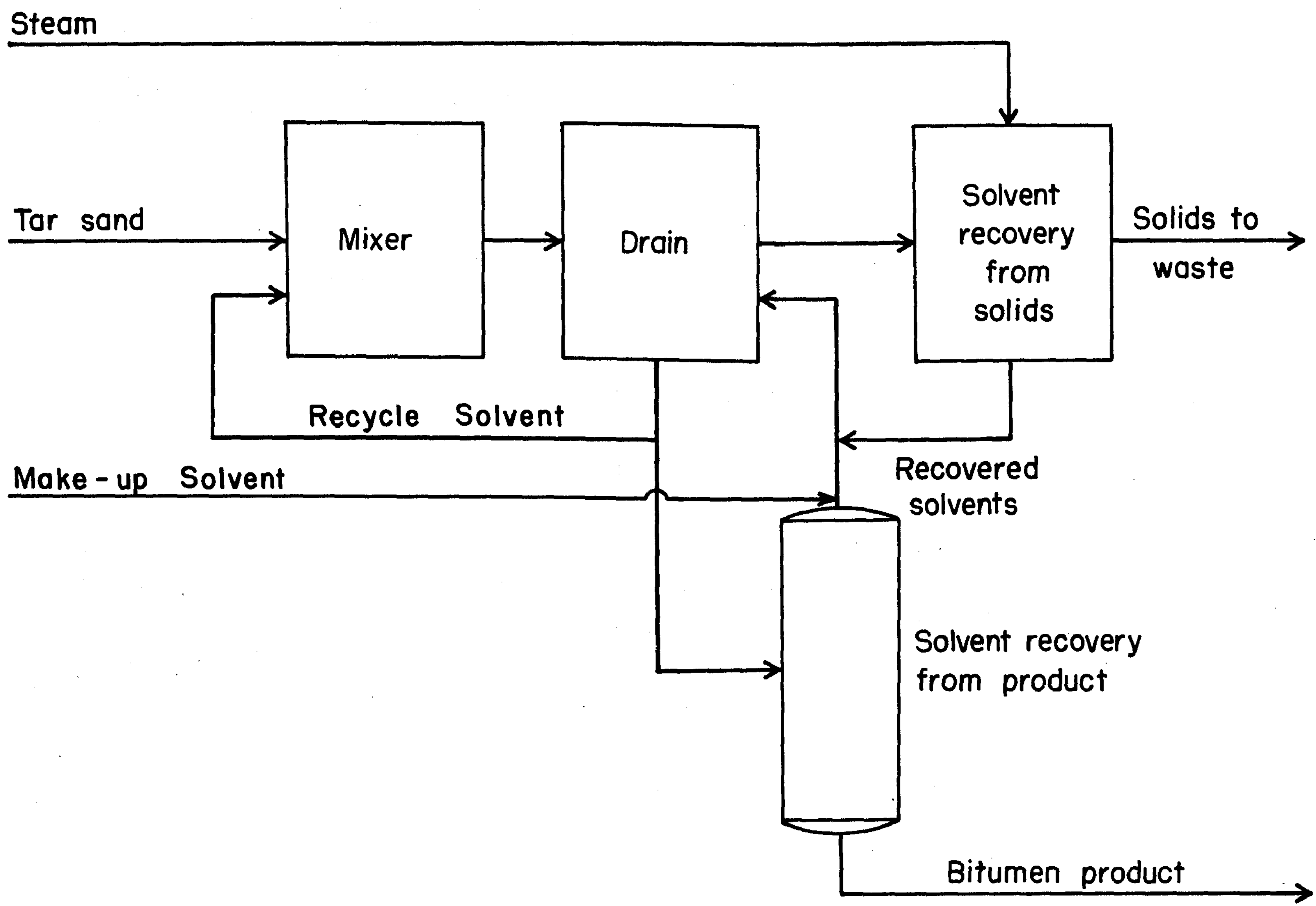


Figure 5-4. Solvent Extraction Process

Source: Camp, 1969: 707.

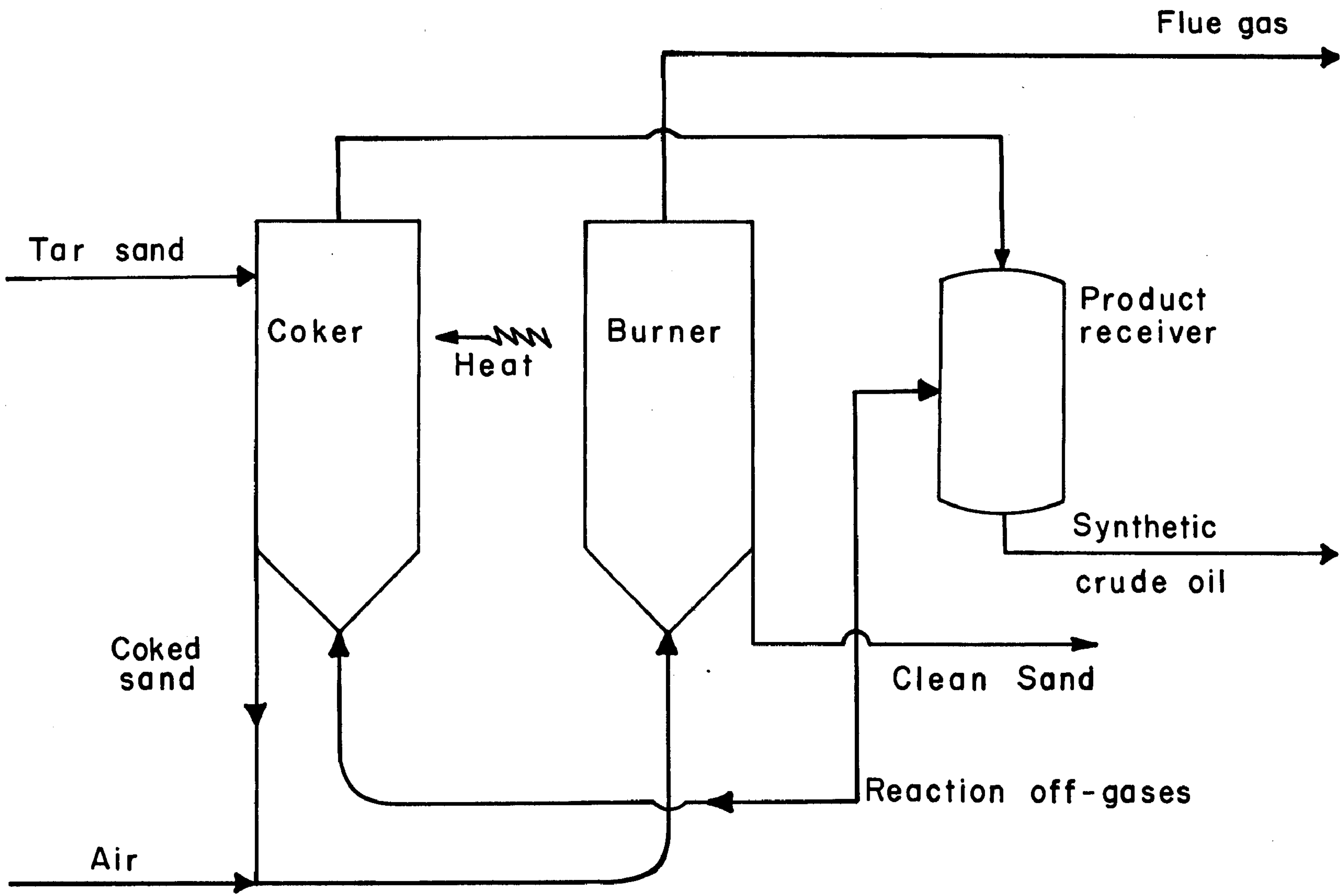


Figure 5-5. Pyrolysis "Coking" Extraction Process
Source: Camp, 1969: 706.

Several groups have suggested that a nuclear device could be used to heat tar sands. One effort, advocated for use in Canada during the 1960's, would have employed a nine-kiloton device (Camp, 1969: 701). However, some spokesmen have suggested that nuclear fracturing and heating would be less controlled and more expensive than conventional steam injection (Spencer and others, 1969: 10).

Solvent extraction methods also use injection wells for introduction of the dissolving agents. Three types of dissolution systems have been applied: emulsifiers, such as detergents; organic solvents, such as naphthene; and caustic agents, such as sodium hydroxide. All three types require removal of the additive after the tars are produced.

The detergent systems dissolve the tar in water and are much less expensive than the organic solvents. Although detergents usually penetrate only a portion of the tar sands reservoir, almost all the bitumen is removed from the area "swept" (Spencer and others, 1969: 10). Emulsifiers have also been successfully tried in conjunction with steam injection.

Organic solvent extraction has been attempted but is not as economical as methods that heat the reservoir.

Caustic agents, such as sodium hydroxide, have been used in conjunction with steam. Tests in Canada during the 1960's have produced generally favorable results, but steam requirements were high (Camp, 1969: 701).

Whichever <u>in situ</u> method or combination of methods is employed, the extracted bitumen must be piped a short distance to upgrading facilities.

5.8.1.3 Upgrading

The bitumen extracted <u>in situ</u> or by surface processing facilities must be upgraded to a synthetic crude oil (syncrude) for handling and pipeline transport. Two basic methods can be used: thermal breakdown and direct hydrogenation.

In the thermal process the bitumen is heated to between 800 and 1,000°F to break down the chemicals and drive off the volatile matter. A part of this process may involve a coking unit similar to that used for the pyrolysis extraction of bitumen from tar sands. The leftover material (coke) is a carbon residue that can be burned for process heat within the plant (Camp, 1969: 712-717).

The gases and liquids from the coking unit are fractionated into oils of different weight, and these are pumped into a pressure vessel and mixed with hydrogen. The hydrotreating step removes the sulfur by forming hydrogen sulfide and also reduces the viscosity of the oil. One proposed alternative method of refining would involve direct hydrogenation of bitumen under high temperatures and pressures, without the coking step. However, direct hydrotreating will require more hydrogen and catalysts (Camp, 1969: 719). A simplified diagram of the sequence of these basic upgrading steps is shown in Figure 5-6.

5.8.1.4 Refining

Processes for refining the syncrude are the same as for crude oil and are described in Chapter 3.

5.8.2 Energy Efficiencies

Only limited data are available on energy efficiencies for processing tar sands, and these are primarily from prototype facilities tested in Canada. The following describes some efficiencies for <u>in situ</u> recovery, bitumen recovery following mining, and upgrading.

The <u>in situ</u> extraction method employing both steam and emulsifiers has been tested by Shell Canada, Ltd. (Camp, 1969: 700). Shell reports an overall recovery of 50 to 70 percent of the bitumen in

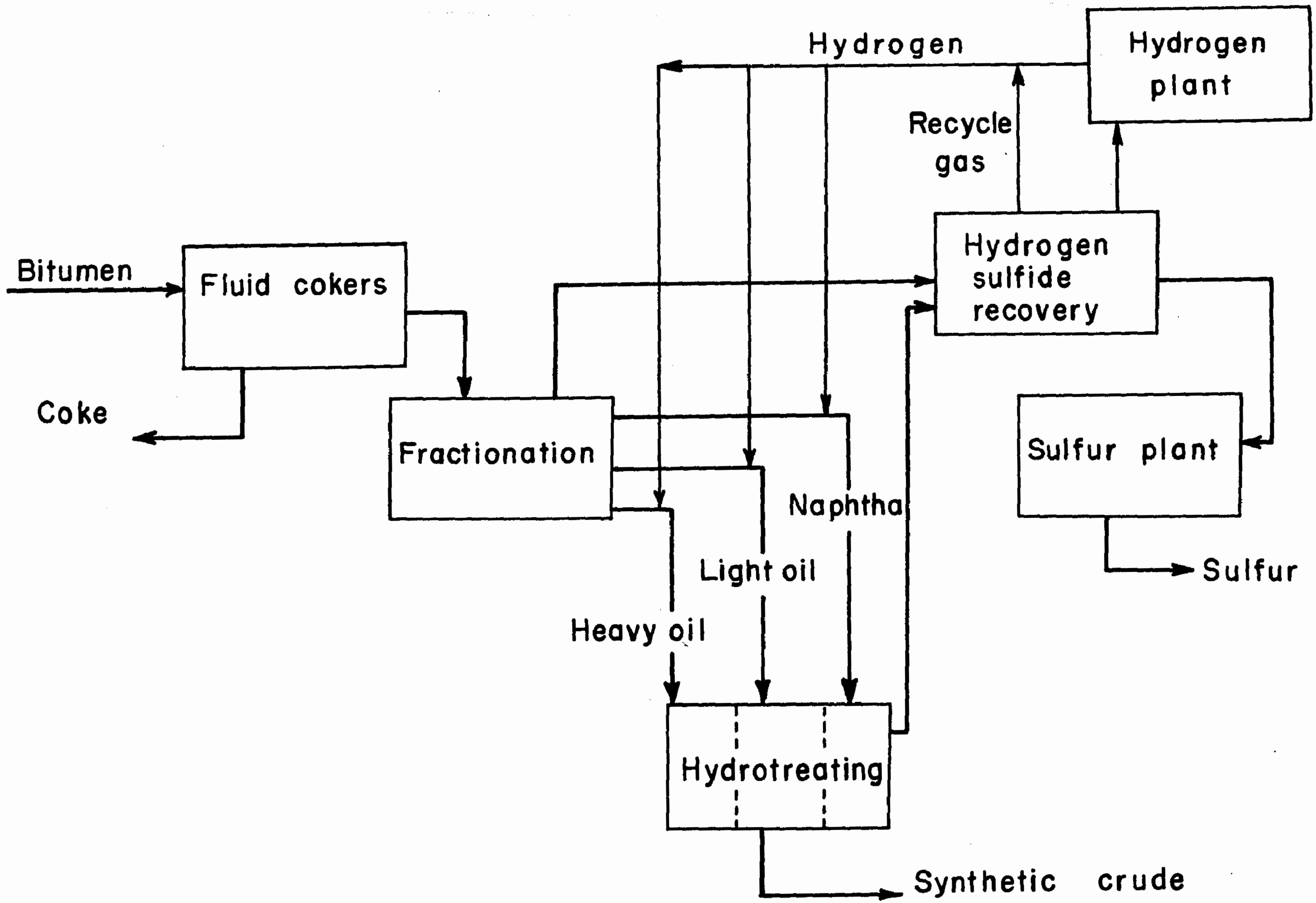


Figure 5-6. Steps Involved in Upgrading Bitumen to Synthetic Crude Oil

Source: Camp, 1969: 710.

place. However, this process has high heating requirements and ancillary energy for steam injection represents 160×10^9 Btu's per 10^{12} Btu's of bitumen produced. Also, this 16-percent energy subsidy is sensitive to the thermal efficiency of heat transfer in the tar sands, and if this efficiency is impaired, ancillary energy requirements would be much greater.

Primary efficiency for removal of bitumen following mining ranges between 81 percent and 95 percent for some coking type processes. Ancillary energy requirements are about 1,400 kilowatts or 3.4×10^8 Btu's per day for a 10,000-barrel-per-day (6.3×10^{10} Btu's) plant.* Most of the product losses result from material consumed during combustion, and the energy is dissipated as heat. Solvent recovery systems can operate with primary efficiencies of about 90 percent; losses result primarily from incomplete stripping of the bitumen from the sand and in the recovery of solvent. The hot water bitumen removal process has achieved primary efficiencies of 90 to 96 percent. The 90-percent efficient operation was on Utah tar sands (Camp, 1969: 712).

Upgrading efficiencies are not available on a detailed basis, although the primary efficiency of the Canadian operations is about 78 percent in transforming bitumen to syncrude (not including by-products that could be sold or used for process heat, such as plant fuel oil, fuel gas, and coke). Efficiencies for refining are described in Chapter 3.

5.8.3 Environmental Considerations

Surface processing plants have a number of process streams that involve potential discharges to air, land, and water. Although these discharges are similar to oil shale upgrading facilities or petrochemical and refinery operations, quantitative data are not available. Perhaps the most significant potential discharges are: solid tailings from the extraction operations; cooling water and blowdown streams; thermal discharges; and off-gases from the refinery, cokers, and process heat plants. Under controlled conditions, a number of these residuals could be minimized. For example, tailings could be returned to the mine and reclaimed, process streams could be equipped with suitable particulate and gas removal devices, water streams could be purified and sent to evaporative ponds, and thermal discharges could be vented to the air via cooling towers.

In situ recovery can result in residual discharges including: thermal additions to the atmosphere, water, and ground in association with steam or combustion methods; possible contamination of aquifers with chemicals; surface spills and accidents from machinery or human failure; possible surface earth movements associated with subsurface disturbances that could affect large areas; noise pollution; and emission of gases to the air, especially from combustion for steam generation processes (BLM, 1973: 370). Residuals from hypothetical *in situ* tar sands operations have not been quantified.

5.8.4 Economic Considerations

Current information on the economics of tar sands processing is not available. One 1970 study found that the Canadian tar sands operation had an overall cost of $270 million (Hottel and Howard, 1971: 190). Assuming a depreciation over 15 years and a discounted cash flow rate of return of 5.8 percent, the value of tar sands syncrude would be $2.90 a barrel. This is certainly a low figure by present standards. The distribution of total production costs was about 22 percent for extraction of bitumen from sands and 37 percent for upgrading (41 percent was for mining) (Hottel and Howard, 1971: 193).

---

*Calculated on the basis of 33 percent efficiency and 3,413 Btu's per kilowatt hour. Each barrel of bitumen is equivalent to 6.3×10^6 Btu's.

TABLE 5-3

ANNUAL 1970 OPERATING COST AND INCOME FOR A 50,000-BARREL-PER-DAY TAR SANDS OPERATION

Category	Millions of Dollars
Mine operations	10.9
Labor, supervision	3.2
Maintenance	5.8
Catalysts and chemicals	2.6
Process royalty	0.5
Overhead, taxes, insurance	3.6
Alberta product royalty	5.9
Total operating costs	31.7
Syncrude income at $2.90 per barrel	50.8
Sulfur income at $20.00 per ton	2.3
Total annual income	53.1

Source: Hottel and Howard, 1971: 191.

The operating costs and income from the plant are listed in Table 5-3.

Extraction costs using <u>in situ</u> methods are not available. If steam heating is applied, an important variable appears to be the cost of ancillary energy in producing the steam. This energy would probably be supplied by burning a portion of the produced bitumen. Although <u>in situ</u> methods negate the mining and processing plant costs, they do require substantial outlays for well development, field expansion, and injection and recovery equipment.

A number of tar sands development costs are difficult to predict, thus making U.S. cost projections questionable. Factors contributing to this include: government royalty and taxation policies; impact of adverse weather on material handling problems; distance to market; and competition with other energy forms (Hottel and Howard, 1971: 193). Other factors may also impact on costs; for example, the U.S. export and import policies are of special importance to Canadian tar sands development.

5.9 TRANSPORTATION

Transportation of tar sands and materials would generally take place following the upgrading or refining steps. One exception is gilsonite, which is slurried and then piped several miles to a refinery in Utah. If demand and supply were sufficient, gilsonite could probably be transported longer distances economically. Liquid transportation technologies used for synthetic crudes are more completely described in Chapters 1 and 2.

REFERENCES

Atomic Energy Commission (1974) <u>Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program</u>; Vol. I, <u>Alternative Technology Options</u>. Washington: Government Printing Office.

Bureau of Land Management (1973) <u>Energy Alternatives and Their Related Environmental Impacts</u>. Washington: Government Printing Office.

Cameron, R.J. (1969) "A Comparative Study of Oil Shale, Tar Sands and Coal as Sources of Oil." <u>Journal of Petroleum Technology</u> 21 (March 1969): 253-259.

Camp, Frederick W. (1969) "Tar Sands," pp. 682-732 in <u>Encyclopedia of Chemical Technology</u>, Vol. 19 (2nd edition). New York: Interscience.

Cashion, W.B. (1973) "Bitumen-Bearing Rocks," pp. 99-103 in Donald A. Brobst and Walden P. Pratt (eds.) <u>United States Mineral Resources</u>, USGS Professional Paper 820. Washington: Government Printing Office.

Hittman Associates, Inc. (1974 and 1975) <u>Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use</u>, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

Hottel, H.C., and J.B. Howard (1971) New Energy Technology: Some Facts and Assessments. Cambridge, Mass.: M.I.T. Press.

Kilborn, George R. (1964) "New Methods of Mining and Refining Gilsonite," pp. 247-252 in Edward F. Sabatka (ed.) Guidebook to the Geology and Mineral Resources of the Uinta Basin: Utah's Hydrocarbon Storehouse. Salt Lake City: Intermountain Association of Petroleum Geologists.

National Petroleum Council, Committee on U.S. Energy Outlook (1972) U.S. Energy Outlook. Washington: NPC.

Spencer, George B., W.E. Eckard, F. Sam Johnson (1969) "Domestic Tar Sands and Potential Recovery Methods--A Review," pp. 5-12 in Interstate Oil Compact Commission Committee Bulletin 11 (December 1969).

CHAPTER 6

THE NUCLEAR ENERGY--FISSION RESOURCE SYSTEM

6.1 INTRODUCTION

6.1.1 History of Nuclear Energy

Commercial use of nuclear fission as an energy source has a history of less than 20 years; the first electric power generating plant went into operation at Shippingport, Pennsylvania in 1957. The use of nuclear power as an energy source grew out of nuclear weapons development during World War II. With the creation of the Atomic Energy Commission (AEC) following the war came an explicit effort by the government to fund and develop the commercial use of nuclear energy. The major rationale behind this development has been the assumption of a large supply of nuclear resources that could one day be substituted for the more limited fossil fuel sources.

The development of nuclear fission as an energy source has been strongly influenced by the complex technologies and the hazards from radioactivity. The complexity of the technologies has required continuous research and development, and as a result, development costs have been higher than the private sector has been willing to bear. Together with the need for regulating radioactive materials, the level of cost has resulted in a major role for the federal government in the development of nuclear energy.

6.1.2 Basics of Nuclear Energy

Nuclear fission is the process whereby certain heavy atoms split into two dissimilar atoms and, in doing so, release energy and one or several neutrons (a basic nuclear particle). The neutrons can then react with other atoms, causing them to fission, and thus create a "chain reaction." The term "nuclear criticality" is used to describe a sustaining chain reaction; that is, the chain reaction will continue until conditions are altered to make the reaction cease. In a nuclear reactor, the controlled chain reaction creates heat, which can be converted to electrical energy.

Three isotopes* fission readily and are usually referred to as fissile** fuels: U-235, Pu-239 (Plutonium-239), and U-233. When an atom fissions, the two newly formed atoms are called fission products or fission fragments. Since the splitting can occur in a variety of different ways, various fission products are formed; for example, strontium, cesium, iodine, krypton, xenon, etc. The nuclear fuels and most of these fission products are radioactive, thereby creating fuel and fuel by-product handling problems that are unique to the nuclear power industry.

Radioactivity (or "radioactive decay") can be described as the spontaneous

---

*Isotopes are atoms that contain the same number of protons but a different number of neutrons. Two or more isotopes of an element exhibit similar chemical properties but different physical properties because of their different atomic weight. For example, uranium has three isotopes, Uranium-233, Uranium-235, and Uranium-238. All contain 92 protons but a different number of neutrons.

**Fissile is a term that describes nuclear fuels that will fission when bombarded with low-energy neutrons. Fertile is a term that describes a material which, when bombarded by a neutron, becomes fissile.

transformation of an atom into either a new atom or a different form of the original atom with the concurrent release of energy in the form of highly energetic alpha particles, beta particles, or gamma rays. The term "half-life" indicates how rapidly a material will decay. In the time equal to a half-life, the amount of radioactive material decreases by one-half. In addition to a number of beneficial uses (including several in medicine), these particles and rays can have significant adverse effects on the cells of biological organisms. The effect of radioactivity on biological organisms is determined by the rate of decay and by the type of particles and rays that are released. Two units for describing radioactivity that will be used throughout this chapter are "curies" and "rems." A curie measures the rate of decay of a substance; that is, it is a measure of a number of unstable nuclei that are undergoing transformation in the process of radioactive decay. One curie equals the disintegration of 3.7×10^{10} nuclei per second. A rem is a unit to measure the radiation received by organisms in the form of the particles and rays.* The natural background dose, not including medical x-rays, is approximately 125×10^{-3} rem. In many cases the notation "mrem" (or millirem) will be used, where one millirem equals 10^{-3} rem. Thus, natural background dose levels may be expressed as 125 mrem.

Two generations of nuclear fission technology are either available or under development: conventional fission reactors and breeder reactors. Conventional fission reactors are commercially available and represented approximately 6.1 percent of the nation's electrical generating capacity as of May 1974, or 27,800 megawatts-electric (Mwe) (INFO, 1974: 7). These reactors are expected to be the major source of nuclear-generated electric power for the next 20 years. Two types of conventional fission reactors are presently available in the U.S.: the light water reactor (LWR) (43 of these are licensed) and the high temperature gas reactor (HTGR) (two of these are licensed). The AEC expects conventional fission reactors to provide 16 percent of total U.S. electric power consumption by 1980 (INFO, 1974: 5). Three factors should be noted with regard to conventional fission reactors:

1. Although they are commercially available, engineering problems are still being solved.
2. The rate at which these reactors have been brought into operations has been slower than projected.
3. A controversy exists over the amount of uranium that is available for conventional reactor use.

The last factor, the projected scarcity of uranium, has driven the development of the liquid metal fast breeder reactor (LMFBR). The breeder reactor is attractive because it produces plutonium, which may be used to fuel other LMFBR's, and therefore reduces the amount of uranium required per reactor per year. The AEC is presently carrying on a major development program for the LMFBR, but commercial LMFBR's are not expected to be available until around 2000.

6.1.3 Organization of Chapter

The remainder of this chapter is organized into three major sections. Section 6.2 covers the LWR, Section 6.3 covers the HTGR, and Section 6.4 covers the LMFBR. Each section begins with a description of the resource base and then sequentially describes the entire fuel cycle for that system, beginning with exploration and ending with transportation. As with the other chapters, each technological process

*The conversion from curies to rems for a certain type of radiation can be made when the biological damage caused by that radiation is known. The received dose is determined by the curie value and the damage.

described, including information on energy efficiencies, environmental impacts, and economics.

The presentation of the environmental residual data differs from the presentations in other chapters. In the LWR section, the amount of residuals for each process is based on a 1,000-Mwe nuclear plant operating for one year at a load factor of 80 percent. Each process (such as milling, enrichment, etc.) must produce a certain "quantity" of product material to be used by the model 1,000-Mwe plant. The residuals listed in the tables are based on this "quantity." Another difference is that the LWR tables include the residuals from secondary power sources. For example, the majority of the sulfur oxides (SO_x) residuals listed for the enrichment process are emissions from the Tennessee Valley Authority coal-fire plants.

The residual assumptions used in the HTGR and the LMFBR sections differ from those used in the LWR. The necessary information to understand these residuals is given in the appropriate HTGR and LMFBR sections.

6.2 LIGHT WATER REACTOR (LWR) SYSTEM

6.2.1 Introduction

The light water reactor gets its name from the use of ordinary water (terms light water*) to transfer heat from the fissioning of uranium to a steam turbine. The primary energy sources for the LWR is U-235, and there are 10 major activities in the LWR fuel cycle as indicated in Figure 6-1: exploration for uranium; mining of uranium ore and reclamation; milling of uranium ore to produce yellowcake (U_3O_8);** production of uranium hexaflouride (UF_6); enrichment to produce a higher concentration of U-235; fuel fabrication; use of the LWR to produce electricity; reprocessing of used fuel to recover the remaining U-235 and Pu-239; radioactive waste management; and transportation of radioactive materials at various stages in the LWR system.

*Light water is pure H_2O (two hydrogen atoms plus one oxygen atom). Heavy water is deuterium oxide, D_2O (two deuterium atoms plus one oxygen atom). Deuterium is a heavy isotope of hydrogen.

**The product of a milling process that converts ore containing 0.2-percent U_3O_8 into "yellowcake" containing approximately 80-percent U_3O_8.

6.2.2 Resource Base

6.2.2.1 Characteristics of the Resource

Uranium is one of the elements and occurs in nature as a compound. About 95 percent of the uranium mined in the U.S. exists as uranium oxide (known as uraninite or pitchblende). Most of the remaining five percent exists in uranium hydrous silicate compounds (known as coffinite) or potassium uranium vanadate (known as carnotite) (Singleton, 1968:11). Uranium consists of three naturally occurring isotopes in the following proportions: 99.29 percent U-238, 0.71 percent U-235, and a trace of U-234. U-235 is used to fuel the LWR. A ton* of uranium-bearing ore contains, on the average, four to five pounds of uranium oxide from which 0.024 to 0.030 pound of U-235 can be obtained.

Most of the uranium mined in the U.S. is found in three types of deposits: petrified rivers, veins, and ancient conglomerates. Ancient conglomerates are old stream channel deposits that were formed more than one-half million years ago (Singleton, 1968:22). The difference between petrified rivers and veins is that the host sandstone containing the uranium lies horizontally in the first and vertically in the second. These sandstone formations provide 95 percent of the ore mined in the U.S.

6.2.2.2 Quantity of the Resources

Uranium resources and reserves are normally discussed in terms of quantities

*Unless preceded by "metric," "ton" will refer to a short ton (2,000 pounds). A metric ton is 2,205 pounds.

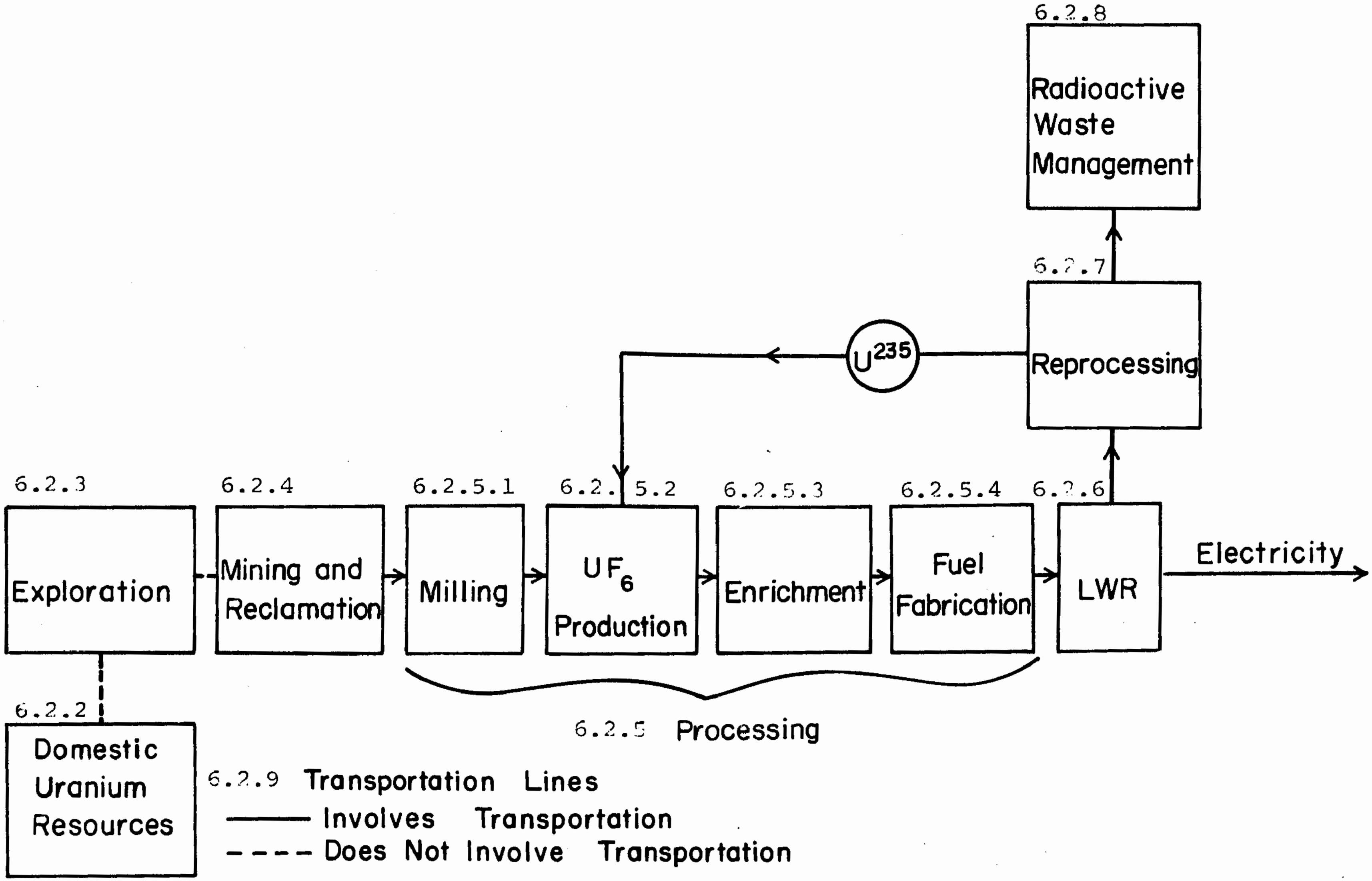


Figure 6-1. Light Water Reactor Fuel Cycle

TABLE 6-1

URANIUM RESOURCES

Cutoff Costs (1974 dollars per pound)	Resources (thousands of tons of U_3O_8)	
	Reserves	Potential
8	227	450
10	340[a]	700[b]
15	520[a]	1,000[b]

Source: AEC, 1974a.

[a]Includes lower cost reserves.

[b]Includes lower cost potential resources.

available at three cost-of-recovery levels: \$8, \$10, and \$15 per pound of U_3O_8. Table 6-1 gives the AEC's estimates of uranium resources at each of these price levels in 1974 dollars. The prices include the cost of exploration, mining, and milling. The resources are divided into reserves (that amount currently known to be recoverable at the given price level) and potential resources (that amount estimated to be ultimately recoverable at the given price level). The estimated reserve of 520,000 tons at \$15 per pound represents approximately 47 percent of the free world reserves.

To indicate the energy represented by these reserves, a typical 1,000-Mwe LWR requires 200 tons of yellowcake per year. Therefore, the presently licensed capacity of approximately 28,000 Mwe would exhaust the nation's \$8-per-pound reserves in about 49 years. If the nation achieves the 250,000-Mwe capacity projected by the AEC for 1985 (INFO, 1974: 5), existing \$15-per-pound reserves would last only 10 years.

Table 6-2 presents estimates of the relationships between generating capacity, uranium needs, and years of supply to 1985. These projections make the accuracy of uranium reserve estimates a critical issue. Part of the debate revolves around the government's procedures for estimating reserves. Responsibility for these estimates rests with the AEC which publishes a yearly estimate (AEC, 1974b). The data base for the estimate is proprietary reserve information provided on a voluntary basis by private companies. The AEC makes its own reserve estimates based on the company-supplied

TABLE 6-2

U_3O_8 NEEDS FOR PROJECTED LIGHT WATER REACTOR CAPACITY

Date	AEC Projected Nuclear Capacity (Mwe)[a]	Tons of U_3O_8 Needed per Year	Number of Years the Proven Reserves Will Last at the Given Nuclear Capacity		
			\$8 per pound	\$10 per pound	\$15 per pound
1974	28,183	5,367	49	60	92
1980	102,000	20,400	13.5	16.5	25.5
1985	250,000	50,000	5.5	6.8	10.4

Source: [a]INFO, 1974: 5.

information. The AEC judges the reasonability of the company's estimates by a comparison with the AEC's own estimates. However, no uniform data collection method or reserve estimate method exists in the uranium industry.

In an effort to provide more reliable reserve estimates, the AEC undertook the National Uranium Resource Evaluation program for a comprehensive assessment of U.S. uranium resource potential (AEC, n.d.). However, the inherent problems in arriving at generally accepted estimates are illustrated by the AEC's preliminary study of the San Juan Basin in New Mexico. The AEC estimated that this basin contained 740,000 tons of U_3O_8 at a price of $30 per pound. When the AEC had 36 independent geologists review its study and their estimates were averaged, reserves were calculated to be 290,000 tons less than the AEC estimate, or a total of 450,000 tons of U_3O_8.

Conversely, some industry critics contend that the overall domestic resource estimates of the AEC are low. These differing conclusions reflect both the difficulties inherent in judging the quantity of resources and those associated with judging the impact of differing prices. There does, however, appear to be general agreement that only a small portion of potential ore-carrying formations has been explored (NPC, 1973: 6).

6.2.2.3 Location of the Resources

As indicated in Table 6-3, two states (New Mexico and Colorado) contain more than 84 percent of the proven reserves at $8 per pound. The Colorado plateau (which covers parts of Utah, Colorado, Arizona, and New Mexico) contains 63 percent of the proven reserves at $15 per pound (Senate Interior Committee, 1973: 34).

Fifty-eight percent of the $8-per-pound reserves are located at depths that require underground mining; the rest can be

TABLE 6-3

URANIUM ORE RESERVES BY STATES

State	Percent of Total Ore Reserves At $8 Per Pound
New Mexico	49.5
Wyoming	35.0
Utah	2.8
Colorado	3.1
Others	9.6

Source: AEC, 1974b: 34.

surface mined. The higher cost of underground mining; generally requires that the deep ores have a higher concentration of uranium before they can be classified as reserves.

6.2.2.4 Ownership of the Resources

In January 1974, approximately 19 million acres of land were classified as being held for uranium exploration and mining. Of that amount, approximately 31 percent was private land and the rest was held by the federal government or by the states. Private access to public lands varies, depending on their particular legal classification. Access to the largest portion of the federal land, public domain, may be had by the relatively simple process of filing a claim.

6.2.3 Exploration

Exploration for uranium divides into three principal phases (preliminary investigations, detailed geologic studies, and detailed physical exploration) and eight specific activities as illustrated in Figure 6-2. Full exploration of an area requires, on the average, from four to five years. The following technical description is organized around the three principal phases.

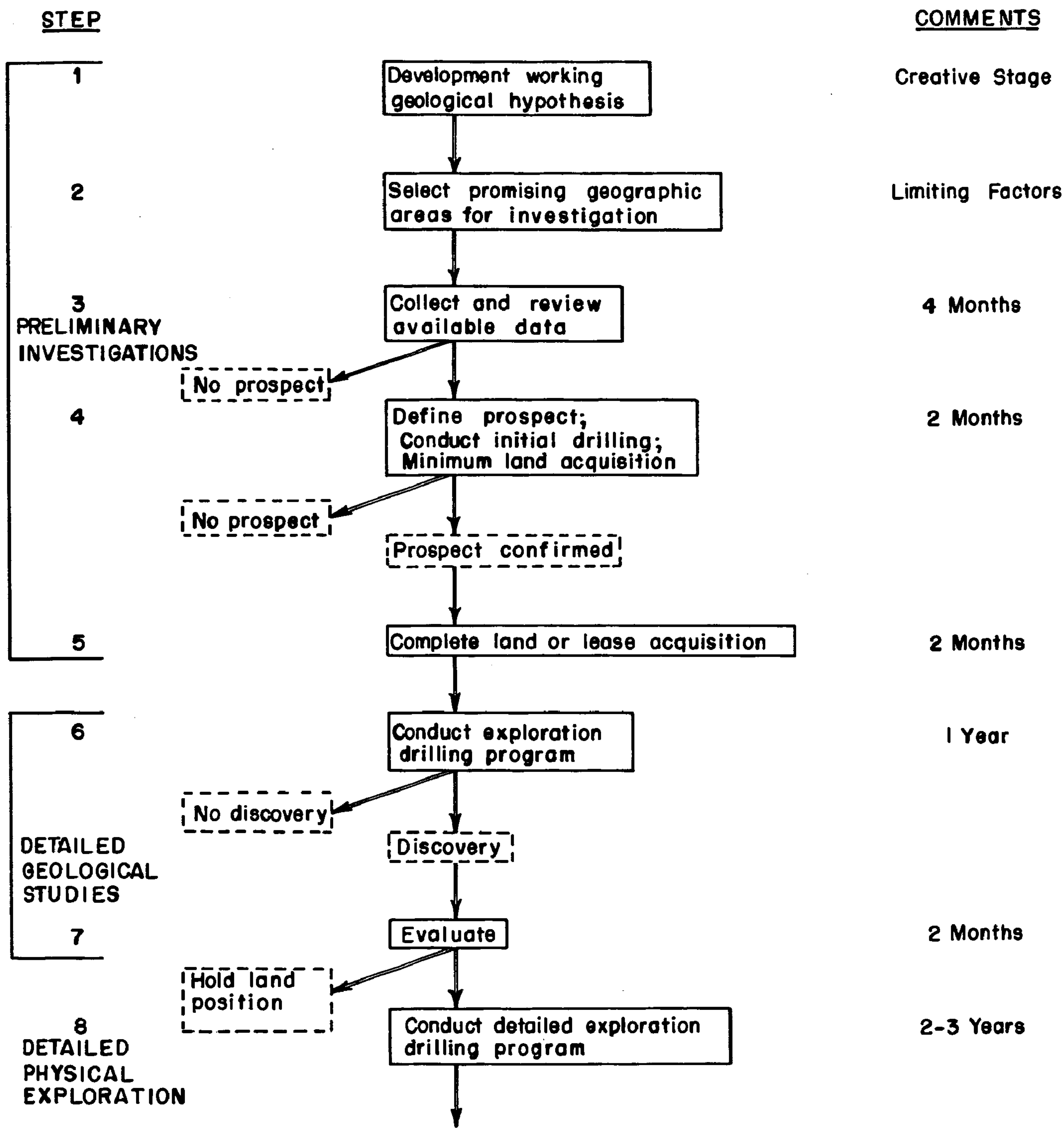


Figure 6-2. Uranium Exploration
Source: NPC, 1973: 51.

6.2.3.1 Technologies

6.2.3.1.1 Preliminary Investigations

Preliminary investigations are characterized by data collection and review based on available reports and aerial photographs for a selected area. This initial phase seeks to identify a uranium host rock, usually sandstone.

6.2.3.1.2 Detailed Geological Studies

Phase two includes all or part of the following activities: surface mapping, sampling, preparing subsurface maps, and performing geochemical, geophysical, and aerial surveys. Although these activities generally parallel those used in prospecting for other minerals, some uranium prospecting techniques rely on the ore's radioactivity to aid in its location. The uranium in the ore emits gamma rays that can be detected. One such detection technique is airborne radiometric prospecting, which uses either Geiger-Muller tubes (Geiger counters) or scintillometers. Although both of these instruments are sensitive to gamma rays, the scintillometer is more effective and is more frequently used.

Radiometric prospecting is most effective in locating uranium deposits that are older and close to the surface. Where the deposit is recent (less than 500,000 years old) or where there is a thick overburden, radiometric prospecting is less reliable. Additionally, such prospecting sometimes identifies radiation from thorium and potassium rather than uranium. Therefore, deposits found by radiometric prospecting must be confirmed by some type of geophysical or geochemical technique (Youngberg, 1972).

Another prospecting technique involves monitoring for radon gas. Radon gas is a radioactive element naturally produced from the uranium that can be identified either by scintillometers or sensitive film. Radon gas monitoring must be carried out on the surface.

6.2.3.1.3 Physical Exploration

The final phase of exploration involves drilling into the suspected ore deposit. Drilling is usually done with rotary or pneumatic percussion equipment. Drilling allows two types of final assessments: scintillometer measurements at various depths in the borehole and geochemical analyses of the materials brought to the surface. Data from these two measures are correlated to determine uranium concentrations at various depths.

Drilling is one measure of the rate of exploration and has remained relatively constant for the last three years at approximately 17 million feet per year. This rate is slightly more than half the rate of the peak year, 1969, when approximately 30 million feet were drilled (AEC, 1974b). In 1973, about one-half of all exploratory drilling for uranium was located in Wyoming and one-quarter in New Mexico.

The discovery rate of uranium per foot drilled has averaged 3.8 pounds of U_3O_8 contained in the ore, and, with the exception of a period in the 1950's, the addition to proven reserves has fluctuated in direct proportion to the drilling rate.

6.2.3.2 Energy Efficiencies

The energy required in exploration is classified as ancillary. While the amounts of ancillary energy required have not been calculated, they are apparently quite small compared to the energy content of the uraium found. The overall efficiency is probably above 99 percent.

6.2.3.3 Environmental Considerations

Data on environmental residuals resulting from exploration are not available but appear small. The main environmental impact is land disturbance associated with drilling.

6.2.3.4 Economic Considerations

Exploration represented about 13 percent of the total cost of yellowcake production in 1970, as given in Table 6-4. Since yellowcake production represented only six percent of the 11 mills per kilowatt-hour (kwh) nuclear electric generation cost that year, exploration costs were only about 0.8 percent of the power generation costs. Thus, even if exploration costs rise, as some observers expect, nuclear power costs should not be appreciably affected.

6.2.4 Mining and Reclamation

Uranium mining techniques depend on the depth, size, assay, and host formation of the ore body, but the basic technologies are similar to those used in coal mining (Chapter 1). Of the 175 uranium sources being worked in 1973, 70 percent were underground mines, 19 percent were open pit mines, and the remaining 11 percent consisted of other sources (e.g., low-grade stock piles, etc.) In terms of total 1973 ore production, however, underground mines provided 36 percent, open pit mines provided 62 percent, and other sources provided about 1.5 percent (AEC, 1974b: 22). Thus, although small in numbers, open pit mines produced a majority of the yellowcake mined in 1973, the reason being that daily production rates from underground mines are much lower than the rates from open pit mines.

As noted earlier, a 1,000-Mwe model reactor requires approximately 200 tons of yellowcake per year. Assuming a U_3O_8 concentration in the ore of 0.2 percent, 100,000 tons of ore must be mined each year to supply one 1,000-Mwe reactor. For comparison, a 1,000-Mwe coal-fired plant would require approximately three million tons of coal per year (assuming coal with a heating value of 10,000 Btu's per pound).

TABLE 6-4

COSTS OF U_3O_8 PRODUCTION (CONSTANT 1970 DOLLARS)

Production Task	Dollars Per Pound of U_3O_8 Recovered	Percent of Total
Exploration		13
Land cost	0.10	
Exploration drilling	0.60	
Development drilling	0.20	
Mine/Mill		87
Capital	1.59	
Operating	4.35	
TOTAL	6.84	

Source: NPC, 1973: 10.

6.2.4.1 Technologies

6.2.4.1.1 Open Pit Mining

Open pit uranium mining techniques are quite similar to the surface coal mining techniques described in Chapter 1. (The primary difference between "open pit" and "surface" mines is that open pit mines are deeper and do not cover as broad an area as surface mines.) One significant difference is that each truckload of uranium ore is graded (measured for radioactivity) as it leaves the pit. The truck then delivers the ore to one of several stockpiles maintained near the mine. The purpose of separating ore by grades is to control the feed to the mill and thereby insure the most efficient and economical processing of each grade.

6.2.4.1.2 Underground Mining

As in open pit mining, underground uranium mining techniques are similar to underground coal mining techniques. The two major differences are related to seam sizes and mine ventilation systems. Most uranium ore bodies are long, thin, and quite erratic in occurrence, and thus require special adaptations of routine coal mining techniques. Since the seam at any one site is often quickly mined, both the working equipment and total mining operations must be highly mobile.

Special ventilation systems are required in underground uranium mines because of the radon gas created by the uranium. To maintain radon radioactivity in the air at acceptable levels, large-capacity air circulation pumps are used in conjunction with special exhaust shafts at tunnel extremities to provide adequate ventilation throughout the mine. Fresh air enters the main shaft, travels through the various tunnels and passageways, and exits through the vent holes.

6.2.4.2 Energy Efficiencies

No data is available for calculating the energy efficiencies of uranium mining. The primary energy efficiency in the mining step would be equivalent to the percentage of in-place uranium ore that is recovered. The ancillary energy is that required to power the equipment used in mining and reclamation. In coal mining, the ancillary energy requirements represent less than one percent of the energy of the coal extracted (Chapter 1). Presumably, the ancillary energy requirements would be even smaller for uranium mining because, as noted earlier, much smaller amounts of uranium ore than coal must be mined to provide an equivalent amount of energy.

6.2.4.3 Environmental Considerations

6.2.4.3.1 Open Pit Mining

Table 6-5 lists the residuals associated with open pit mining; the data are normalized to the requirements of a typical 1,000-Mwe LWR (AEC, 1974c). Generally, the major impact categories are the same as coal, with impacts differing depending on location (Chapter 1). However, the scale of the impacts is generally much less for uranium because of the difference in the quantities of material mined to provide an equivalent amount of energy. Approximately 55 acres are temporarily committed and two acres are permanently committed per model 1,000-Mwe LWR per year. The overburden represents the most significant environmental residual associated with open pit mining. About 2.7 million metric tons of overburden per year is moved for each 1,000-Mwe LWR plant. The overburden is used for backfilling the pit, although in the past the pit normally has never been completely filled because of economic considerations. Present and future land reclamation laws may require, as in Colorado and Wyoming, that the land be properly reclaimed and restored.

TABLE 6-5

SUMMARY OF ENVIRONMENTAL RESIDUALS FOR URANIUM MINING (NORMALIZED TO 1,000-Mwe LWR ANNUAL FUEL REQUIREMENT)

Natural Resource Use	Quantity
Land (acres)	
Temporarily committed	55
Undisturbed area	38
Disturbed area	17
Permanently committed	2
Overburden moved (millions of metric tons)	2.7
Water (millions of gallons)	
Discharged to ground	123
Effluents	
Chemical (metric tons)	
Gases[a]	
Sulfur oxides	8.5
Nitrogen oxides	5.0
Hydrocarbons	0.3
Carbon monoxide	0.02

Source: AEC, 1974c: A-2.

[a]Estimated effluent gases based upon combustion of coal to supply power, together with combustion of diesel fuel for mining equipment operation.

The AEC estimates that 123 million gallons of water per year (per model 1,000-Mwe LWR) are pumped out of the mine and discharged to the ground. If this water contains suspended solids, the pollutants can enter local water supplies unless control procedures (such as settling ponds) are used. Another effect is the probable lowering of the local water table. However, water levels usually return to former levels once the pumping has ceased.

The gaseous residuals include chemical and radioactive effluents. The sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrocarbons and carbon monoxide (CO) emissions are from the operation of the mining machinery.

The major radioactive effluent is radon gas, a naturally occurring radioactive element that is a decay product of uranium. However, this effluent is readily diluted in the atmosphere and has a short half-life (defined in Section 6.12), and thus its concentrations in unrestricted areas near the mine are expected to be undetectable (AEC, 1974c: A-3). Therefore, radon gas is not shown in Table 6-5.

6.2.4.3.2 Underground Mining

Data on environmental residuals for underground mining are not available at present. The disturbed surface area is much less for underground mines than for open pit mining. Unlike open pit material, the rock removed from underground mines is stockpiled because it is generally not econically feasible to refill the "rooms." Since, on the average, underground ore must contain 0.27-percent uranium to make mining economical (as opposed to 0.17-percent uranium in open pit mines) (AEC, 1974b: 33), less ore needs to be extracted from underground mines to produce a given quantity of uranium.

A controversial aspect of underground uranium mining has been the exposure of miners to radioactivity, primarily radon gas as described earlier. Currently, the EPA is responsible for establishing guidelines for exposure limits, but the industry has protested the current limits as being too strict.

No data are available on land subsidence resulting from underground uranium mining. However, any such subsidence should be less than that from either underground coal or oil shale mining because of the smaller extraction areas.

6.2.4.4 Economic Considerations

Table 6-4 presents cost data for the combined uranium mine/mill operation; separate data for just mining and reclamation are not available. As indicated in Table 6-4, the mine/mill costs (including both

TABLE 6-6

ESTIMATED INCREMENTAL COST OF U_3O_8 TO MEET NEW SAFETY STANDARDS

Pounds of U_3O_8 Recovered Per Ton of Ore	Incremental Cost[a] of U_3O_8 Under Given Mine Conditions (dollars per pound)		
	Favorable	Average	Severe
2.6	0.40	0.63	1.12
4.0	0.26	0.41	0.73

Source: NPC, 1973: 81.

[a]Costs are in 1972 dollars.

capital and operating costs) are 87 percent of the cost of a pound of U_3O_8. However, the cost of U_3O_8 in the complete production of electric power is only 0.66 mill per kwh out of a total power generation cost of 9 to 11 mills per kwh. Therefore, the mine/mill costs represent only about six percent of the total nuclear power generation costs.

The Federal Metal and Non-Metallic Mines Safety Act of 1966 has had an important effect on the underground mining of uranium (NPC, 1973: 79) due to the strict regulations on radiation exposure limits. Table 6-6 gives an estimate of the increase in the cost of U_3O_8 due to these new safety and radiation regulations (NPC, 1973: 81). For ore containing only 2.6 pounds of recoverable U_3O_8 per ton, the increase in the cost of a pound of U_3O_8 would be 63 cents in an average mine.

Although the act will have a negligible effect on open pit mines, the cost of surface reclamation for an open pit mine is expected to range from $0.07 to $2.90 per ton of ore (or from $0.03 to $1.15 per pound of U_3O_8 assuming 2.6 pounds of U_3O_8 per ton of ore), depending on the degree of reclamation desired.

6.2.5 Processing

Processing consists of a variety of different physical and chemical steps in which the raw uranium ore is converted into uranium fuel pellets encased in long metal tubes that are ready to be inserted into the reactor. As shown in Figure 6-1, the steps in processing are usually divided into milling, UF_6 production, enrichment, and fuel fabrication.

6.2.5.1 Milling

The basic purpose of the milling process is to convert the uranium ore (which contains about 0.2-percent U_3O_8) into a compound called "yellowcake" (which contains 80- to 83-percent U_3O_8).

In 1973, 16 yellowcake mills were operating or on standby (Table 6-7). These mills vary in processing capacity from 400 to 7,000 tons of ore per day. Operating at 79 percent of their capacity in 1973, approximately 6,800,000 tons of ore were milled for an annual U_3O_8 production of 13, 13,200 tons. A typical 1,000-Mwe LWR needs 200 tons of U_3O_8 per year.

6.2.5.5.1 Technologies

Figure 6-3 is a flow chart for the typical milling plant in the U.S. The steps in the milling process are:

1. Crushing and Grinding: The basic purpose of this step is to reduce the particle size so that chemical reactions can be accomplished more rapidly.

TABLE 6-7

U.S. URANIUM ORE MILLS OPERATING OR ON STANDBY (DECEMBER 1973)

Company	Location	Nominal Capacity (tons ore per day)
Anaconda Company	Grants, New Mexico	3,000
Atlas Corporation	Moab, Utah[a]	1,500
Conoco and Pioneer Nuclear, Incorporated	Falls City, Texas	1,750
Cotter Corporation	Canon City, Colorado	450
Dawn Mining Company	Ford, Washington	400
Federal-American Partners	Gas Hills, Wyoming	950
Exxon Company	Powder River Basin, Wyoming	2,000
Kerr-McGee Nuclear Corporation	Grants, New Mexico	7,000
Petrotomics Company	Shirley Basin, Wyoming	1,500
Rio Algom Corporation	La Sal, Utah	500
Union Carbide Corporation	Uravan, Colorado	1,300
Union Carbide Corporation	Natrona County, Wyoming	1,000
United Nuclear-Homestake Partners	Grants, New Mexico	3,500
Utah International, Incorporated	Gas Hills, Wyoming	1,200
Utah International, Incorporated	Shirley Basin, Wyoming	1,200
Western Nuclear, Incorporated	Jeffrey City, Wyoming	1,200
TOTAL		28,450

Source: AEC, 1974b: 62.

[a]Uranium production facility on standby at end of 1973.

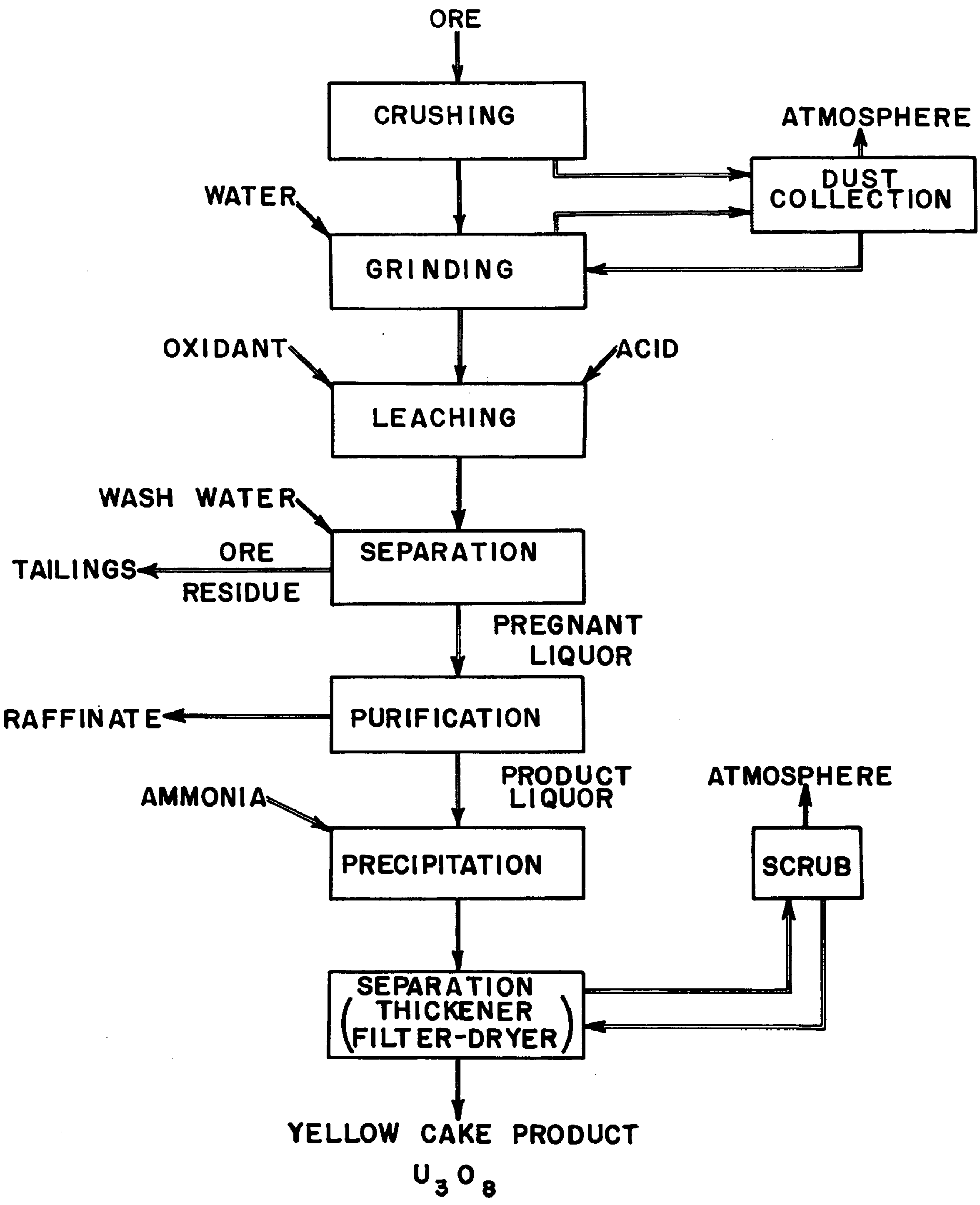


Figure 6-3. Milling Plant
Source: AEC, 1974c: B-8.

2. Leaching. After the physical grinding, the uranium minerals are dissovled (or "leached") from the host rock. The type of chemical used in this process is determined by the composition of the uranium in the ore and by the other types of minerals present. The two primary leaching agents used in the U.S. are sulfuric acid and either sodium carbonate or sodium biocarbonate. Eighty percent of all yellowcake is produced using sulfuric acid. Acids will react with the uranium more quickly than carbonate but also will react with the other dissolved minerals, which are removed during later steps.
3. Washing (Separation). Regardless of the leaching method, the leached solution is then "washed" with water to remove the sand and slime.
4. Purification. Uranium is separated from all the other leached minerals by sending the washed solution through a "purification" step. The purification process selectively removes the uranium from the water solution and leaves the unwanted metals in solution.
5. Precipitation. The product from the purification step enters the precipitation stage where ammonia, air, and heat are used to cause the uranium to become insoluable.
6. Separation. The solution containing suspended uranium particles proceeds to a thickener, and the resulting product from the thickener, yellowcake, is further washed and dried. The yellowcake is packaged in 55-gallon drums for shipment.

6.2.5.1.2 Energy Efficiencies

The ancillary energy requirement is the energy required to run the milling process. The ancillary energy requirement for the milling operation to supply a 1,000-Mwe plant for one year is equivalent to 68.5 million cubic feet (mmcf) of natural gas and 970 metric tons of coal (AEC, 1974c: B-2). Assuming an energy content of 1,000 Btu's per cubic foot (cf) for natural gas and 10,000 Btu's per pound of coal, the ancillary energy requirement for just the milling operation is approximately 0.09×10^{12} Btu's (thermal). Since the annual output of such a model LWR is equivalent to approximately 23×10^{12} Btu's (electric), the ancillary energy requirement for milling is quite small.

The primary efficiency is equivalent to the recovery efficiency in the milling process, which was approximately 93.5 percent during 1973. From 1964 to 1970, the recovery efficiency was about 95 percent (AEC, 1974b: 67). The main factors that affect the recovery rate are the contact time in the leaching tank and the concentration of the leaching agent that is used. The time and concentration can both be increased, but at a sacrifice of product throughput and economics.

6.2.5.1.3 Environmental Considerations

Table 6-8 contains the chronic environmental residuals associated with the typical yellowcake milling operation normalized to the annual requirement for a 1,000-Mwe LWR (AEC, 1974c: B-2, B-3). The table was derived under the following assumptions:

1. Acid leaching is used.
2. The mill is located in an arid, isolated region.
3. Several mines are close to the mill.

The main residuals associated with the milling process are the solid and liquid tailings. Since the percentage of U_3O_8 in the ore is always low (i.e., about 0.2 percent), essentially all the processed ore becomes a residual known as solid tailings. The solid ore residuals are 91,000 metric tons of ore per year per model 1,000-Mwe LWR, but this quantity will vary inversely with the ore assay. If the percentage of U_3O_8 in the ore increases, a smaller quantity of ore is mined and milled to supply the 1,000-Mwe reactor. The 240,000 metric tons of liquid tailings are discharged into the tailings pond. All the radioactive effluents are low-level emissions, about 2 to 24 percent of current AEC standards (AEC, 1974c: 8-4), and present no known health problems.

If the mill uses the sodium carbonate leaching process, several of the chronic residuals given in Table 6-8 will change.

TABLE 6-8

SUMMARY OF ENVIRONMENTAL RESIDUALS FOR URANIUM MILLING (NORMALIZED TO 1,000-Mwe LWR ANNUAL FUEL REQUIREMENT)

	Quantity
Natural Resource Use	
Land (acres)	
Temporarily committed	0.5
Undisturbed area[a]	0.2
Disturbed area	0.3
Permanently committed (limited use)	2.4
Water (millions of gallons)	
Discharged to air	65
Effluents	
Chemical	
Gases[b] (metric tons)	
Sulfur oxides	37
Nitrogen oxides (40 percent from natural gas use)	15.9
Hydrocarbons	1.3
Carbon monoxide	0.3
Liquids (thousands of metric tons)	
Tailings solutions	240
Solids (thousands of metric tons)	
Tailings solutions	91
Radiological (curies)	
Gases (including airborne particulates)	
Radon-222	74.5
Radium-226	0.02
Thorium-230	0.02
U natural	0.03
Liquids	
U and daughters	2
Solids	
U and daughters	600
Thermal (billions of Btu's)	69

Source: AEC, 1974c: B-2, B-3.

[a]Major portion of undisturbed area for mills is included in mine land use.

[b]Estimated effluent gases based upon combustion of equivalent coal and natural gas for power and heat.

The sodium carbonate or alkaline leaching process uses 3.5 times less water than the acid leaching process and thus releases a smaller volume of discharge (containing less radium) to the tailings pond.

Two possible major accidents in a uranium milling plant are a failure of the tailings pond dam and a fire in the building where the purification step is performed. Either incident would produce additional residuals not included in Table 6-8, but the effect on the environment in both cases is expected to be negligible because the materials at this step are neither toxic nor highly radioactive.

6.2.5.1.4 Economic Considerations

Data are not available on just the milling operation. The costs of the combined mining/milling operation were discussed in Section 6.5.4

6.2.5.2 Uranium Hexafluoride (UF_6) Production

The purpose of UF_6 production is to convert the uranium in the yellowcake to a gaseous compound (UF_6) that can be used in the uranium enrichment step. Two processes of producing UF_6 are currently being used: the dry hydrofluor process and the wet solvent extraction-fluorination process. At present, two plants are in operation (one of each type) and produce about equal quantities of UF_6 (AEC, 1974c: C-1). The capacity of these two plants is currently sufficient, but their capacity will have to be doubled to meet the projected 1980 demand.

6.2.5.2.1 Technologies

Simplified flow diagrams for the dry hydrofluor process and the wet solvent extraction-fluorination process are given in Figures 6-4 and 6-5 respectively. Common steps in the two processes are the hydrofluorination step and the fluorination step.

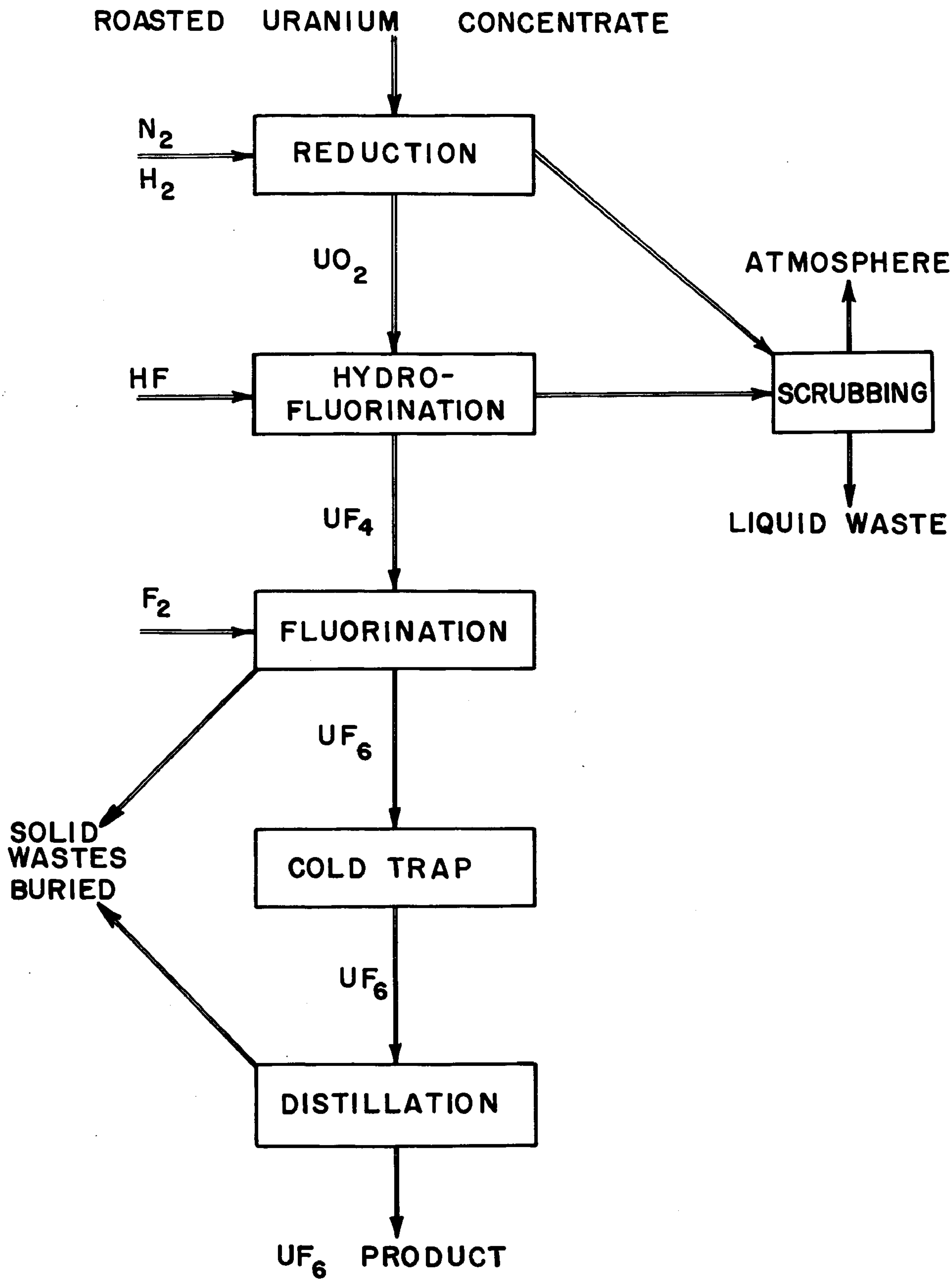


Figure 6-4. UF_6 Production--Dry Hydroflour Process
Source: AEC, 1974c: C-7.

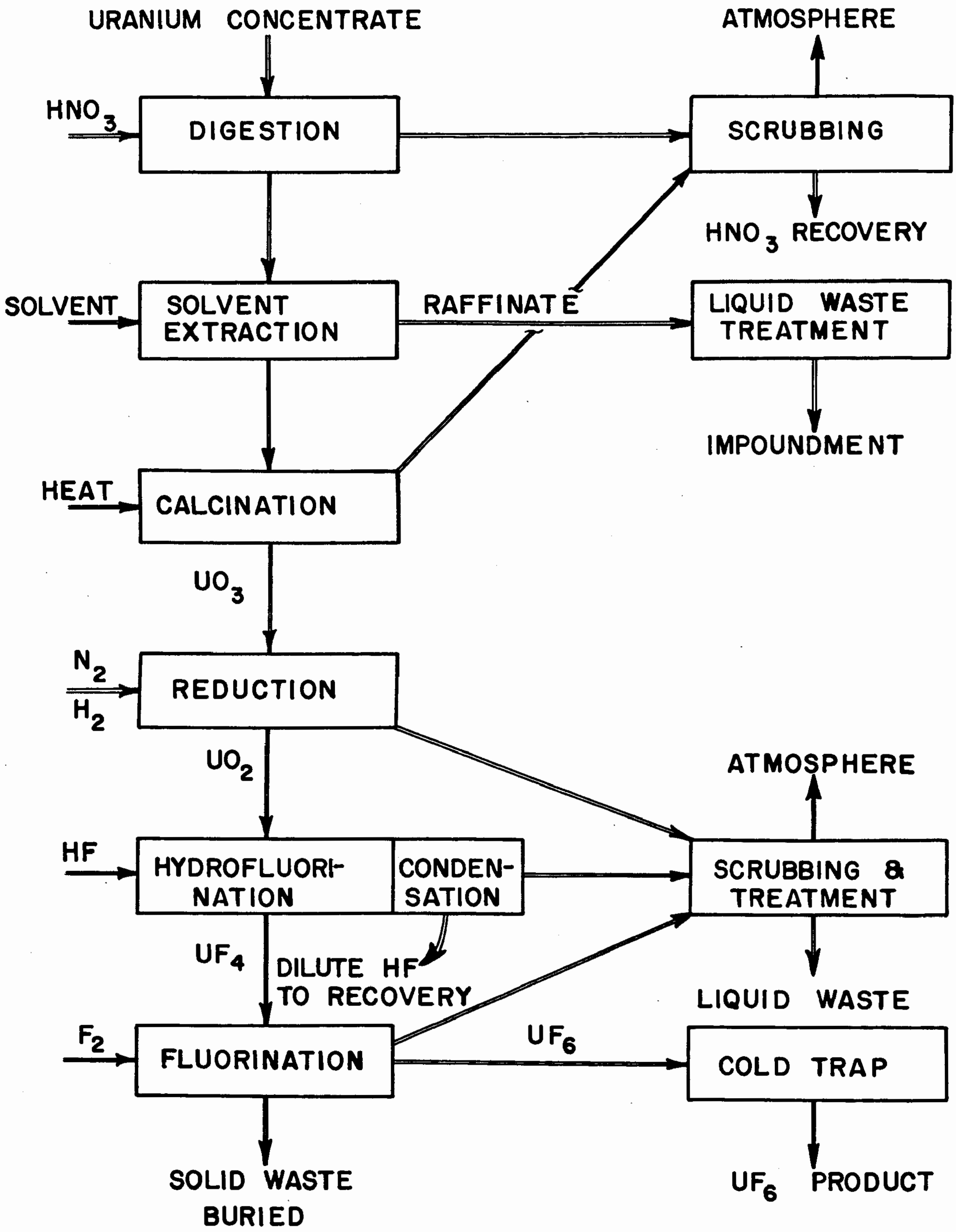


Figure 6-5. UF_6 Production--Wet Solvent Extraction-Flourination
Source: AEC, 1974c: C-9.

In essence, the two processes differ at the point where impurities are removed. The dry method produces the gas, then removes the impurities by distillation. The wet method removes impurities from the yellowcake before the gas is made (AEC, 1974c: Section C).

6.2.5.2.1.1 Dry Hydrofluor Process

The dry hydrofluor process consists of the following steps:

1. Reduction. The yellowcake is roasted with cracked ammonia (N_2 and H_2) to change the U_3O_8 into uranium dioxide (UO_2).
2. Hydrofluorination. Hydrogen fluoride (HF) is used to change the UO_2 into uranium tetrafluoride (UF_4).
3. Fluorination. Reaction of the UF_4 with fluorine gas (F_2) results in the "crude" UF_6 product. The term "crude" refers to the purity of the UF_6 gas, which at this point contains other volatile fluorides of such elements as molybdenum and vanadium that are impurities found in the original ore.
4. Cold trap. The cold trap removes molybdenum and vanadium impurities.
5. Distillation. Fractional distillation separates the UF_6 from the remaining impurities in the gas to produce a "refined" UF_6.

6.2.5.2.1.2 Wet Solvent Extraction-Fluorination Process

The wet solvent extraction process contains the following steps:

1. Digestion. The yellowcake is first dissolved in nitric acid to prepare it for extraction.
2. Solvent Extraction. This step selectively removes the uranium. The impurities, such as molybdenum and vanadium, remain in the aqueous solution called raffinate. The uranium is in a uranyl nitrate solution.
3. Calcination. The uranyl nitrate is heated to form uranium trioxide (UO_3).
4. Reduction. The UO_3 is reduced to UO_2 by chemical reaction with N_2 and H_2.
5. Hydrofluorination. This step is the same as in the dry process.
6. Fluorination. This step is the same as in the dry process.
7. Cold trap. This step is the same as in the dry process.

6.2.5.2.2 Energy Efficiencies

The primary energy efficiency of UF_6 production is quite high, as both processes recover nearly 100 percent of the uranium in the yellowcake (AEC, 1974c: C-17). The ancillary energy requirement to produce enough UF_6 for the model 1,000-Mwe reactor for one year is reported as equivalent to 620 metric tons of coal plus 20 mmcf of natural gas (AEC, 1974c: C-2). Assuming an energy content of 10,000 Btu's per pound for coal and 1,000 Btu's per standard cf for gas, the ancillary energy requirement is 0.033×10^{12} Btu's (thermal). Comparing this with the annual energy output of a 1,000-Mwe plant of approximately 23×10^{12} Btu's (electric), the ancillary energy requirement for UF_6 production is quite small.

6.2.5.2.3 Environmental Considerations

Table 6-9 lists the chronic environmental residuals from UF_6 production for the model 1,000-Mwe LWR. In deriving this table, the assumption was that one-half of the necessary UF_6 comes from each of the two processes (AEC, 1974c: C-2, C-3). Again, these residual data are somewhat inconsistent with the residual data of other chapters because Table 6-9 includes residuals from the electric power plant that supplies electricity to the UF_6 production plant.

The gaseous fluoride from the two fluorination steps used in UF_6 production is emitted at a rate of 0.11 metric ton per year per model 1,000-Mwe LWR. Measurements of the fluoride concentration in the vicinity of a wet solvent extraction plant have indicated levels below those expected to cause deleterious effects on humans or grazing animals (AEC, 1974c: C-4).

TABLE 6-9

SUMMARY OF ENVIRONMENTAL RESIDUALS FOR URANIUM HEXAFLUORIDE PRODUCTION (NORMALIZED TO MODEL LWR Annual Fuel Requirement)

	Quantity
Natural Resource Use	
Land (acres	
Temporarily commited	2.5
Undisturbed area	2.3
Disturbed area	0.2
Permanently committed	0.02
Water (millions of gallons)	
Discharged to air	3.3
Discharged to water bodies	23.0
TOTAL	26.3
Effluents	
Chemical	
Gases (metric tons)	
Sulfur oxides[a]	29
Nitrogen oxides[b]	10
Hydrocarbons[b]	0.84
Carbon monoxide[a]	0.2
F^-	0.11
Liquids	
F^-	17.5
SO_4-	4.5
NO_3	.1
F^-	8.8
Cl^-	.2
Na^+[c]	3.4
NH_3^+	1.6
Fe	.04
Solids (metric tons)	40
Radiological (curies)	
Gases	
Uranium	0.00015
Liquids	
Radium-226	0.0034
Thorium-230	0.0015
Uranium	0.044
Solids (buried)	
Other than high-level	0.86
Thermal (billions of Btu's)	20

Source: AEC, 1974c: C-2, C-3.

[a]Effluent gases from combustion of equivalent coal for power generation.

[b]From the combustion of coal and natural gas and process vents, hydrocarbons include 0.2 metric ton per year of hexane from wet process portion of model plant.

[c]Contains 80-percent potassium.

Three radioactive materials--uranium, radium-226 (Ra-226), and thorium-230 (Th-230--are emitted as liquid residuals in the UF_6 production. The natural uranium in the exhaust gases is quite small, and calculations of natural uranium concentrations at the site boundary indicate concentrations less than 0.1 percent of the federally established limit (AEC, 1974c: C-15). Radioactive elements in the liquid effluents released to the river near the plant are approximately four percent of maximum permissible concentrations (AEC 1974c: C-15). The raffinate stream in the wet process is impounded, and plans call for disposal of the sludge either by burial or reprocessing at a mill to recover the uranium. Solid wastes from the dry process contain radioactivity and will require burial.

The amount of water used is approximately 2.4 million gallons per day. Most of this is used as cooling water, and about 90 percent of this cooling water is returned to the source (e.g., a river) from which it came at a slightly higher temperature. The rest is lost by evaporation. The wet process uses about 1.5 million gallons per day in the wet solvent extraction step (AEC, 1974c: C-4).

6.2.5.2.4 Economic Considerations

The cost in 1972 of the UF_6 production step has been calculated as $2.52 per kilogram, which is equivalent to 0.08 mill per kwh out of a total generation cost of 9.0 to 11.0 mills per kwh (NPC, 1973: 28). Thus, the UF_6 production step represents a very small portion (about four percent) of the total fuel cost and only about 0.8 percent of the total power generation cost.

6.2.5.3 Enrichment

Naturally occurring uranium consists of approximately 0.7-percent U-235 and 99.3-percent U-238. Enrichment is the process by which the percentage of the desired fissile fuel, U-235, is increased. LWR's require a fuel that is approximately three-percent U-235, while the high temperature gas reactor will require a U-235 concentration of 95 percent. There are currently three operational enrichment plants in the U.S.: Portsmouth, Ohio; Paducah, Kentucky; and Oak Ridge, Tennessee.

6.2.5.3.1 Technologies

There are currently one extant and two proposed enrichment technologies. The proposed techniques are ultracentrifuge and laser enrichment. The operational process is known as gaseous diffusion.

Basically, a gaseous diffusion plant consists of a large number of pumps to move UF_6 through a large amount of piping and separate enrichment stages. As shown in Figure 6-6 (Elliot and Weaver, 1973: 114), each enrichment stage produces two outgoing streams of UF_6, one which has a higher percentage of U-235 than the input feed stream and one which has a lower percentage than the input.

Each stage operates in the following manner. A high-pressure feed stream of UF_6 gas enters the stage. Since a very slight weight difference exists between the $U\text{-}235F_6$ and $U\text{-}238F_6$ molecules, the lighter molecules containing the U-235 move at a slightly higher velocity than the molecules containing U-238. The high-pressure input stream flows by a porous membrane known as a barrier, and, since the lighter U-235 molecules are moving faster, they strike and pass through the membrane at a higher rate than the heavier U-238 molecules. Therefore, the stream of UF_6 that has passed through the barrier will contain a higher percentage of the light U-235 molecules.

By combining a series of stages, the gas can be further enriched. However, the mass difference between the light and heavy molecules is small, and a large number of stages in series are necessary to produce enriched uranium that can be used in an LWR. For example, about 1,500 stages are necessary to produce UF_6 that contains four percent U-235.

As shown in Figure 6-7, the three government-owned diffusion plants work as a complex, each plant producing different enrichments (Elliot and Weaver, 1972: 116). The Paducah plant produces UF_6 gas at one-percent enrichment for input to the Oak Ridge or Portsmouth plant. The Oak Ridge plant typically produces enrichments from one to four percent while Portsmouth can produce 98-percent enriched gas. The depleted streams of gas from Portsmouth or Oak Ridge can be used as input to the Paducah plant. All three plants were built between 1943 and 1955.

In 1972, any of the three existing plants had the capacity to satisfy the total U.S. demand for enrichment. However, given the existing projections, additional plant capacity will be needed by the early 1980's (House Interior Committee, 1973: 10). These new plants may use the gaseous diffusion method or may use the ultracentrifuge separation or laser enrichment techniques if they are commercially feasible by the time plant construction is begun.

As a result of government urging, two U.S. industrial consortia for enrichment have been formed. Bechtel, Union Carbide, and Westinghouse constitute one group, and the other group consists of Exxon Nuclear and General Electric (INFO, 1973: 14). At present, both groups are leaning toward the ultracentrifuge method, which consumes far less electricity than the gaseous method, although the technology for this method has not yet been proved (House Interior Committee, 1973: 10). (A British-Dutch-West German combine has decided to use this method.) Laser enrichment will probably not be feasible before 1985 but classified enrichment work with

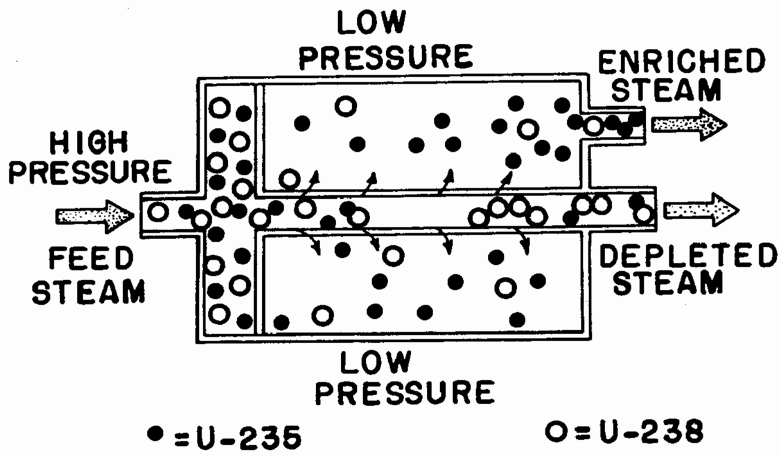


Figure 6-6. Gaseous Diffusion Stage
Source: Elliot and Weaver, 1972: 114.

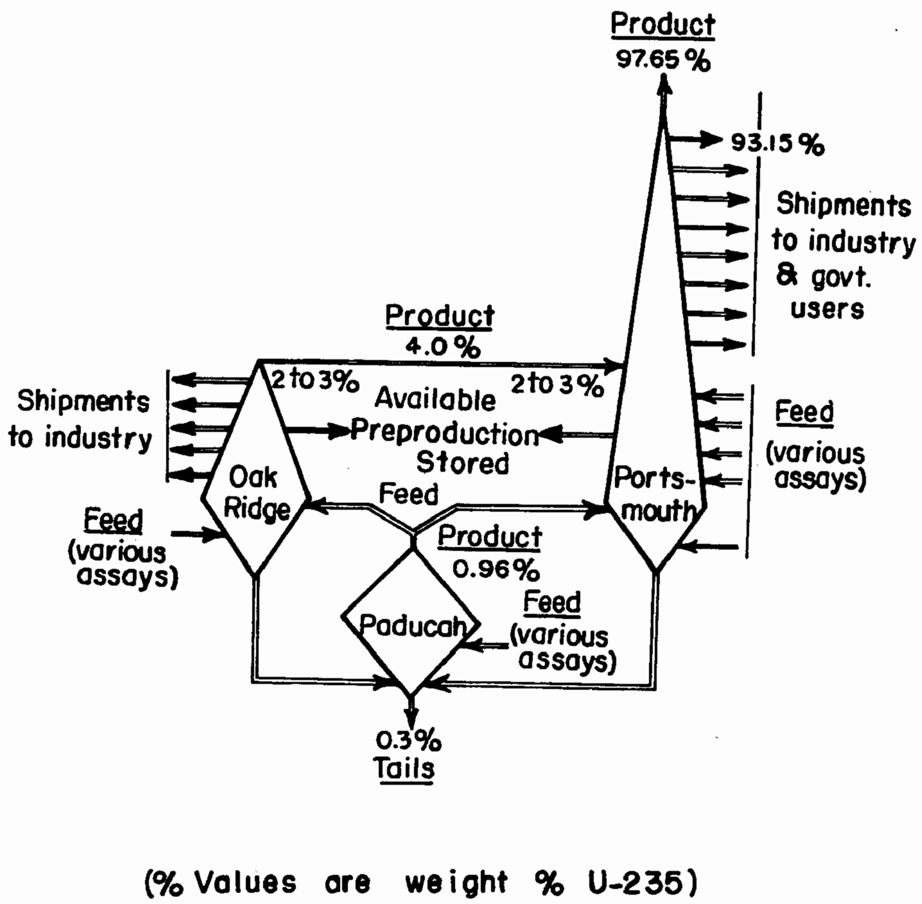


Figure 6-7. Mode of Operation for Gaseous Diffusion Plant
Source: Elliot and Weaver, 1972: 116.

lasers at a number of locations (primarily at the Los Alamos Scientific Laboratory) could change the entire uranium enrichment picture if successful (Weekly Energy Report, 1973: 1).

6.2.5.3.2 Energy Efficiencies

The ancillary energy required to enrich enough UF_6 to supply a model 1,000-Mwe plant (80-percent load factor) for one year is 310,000 megawatt-hours (Mwh) (AEC, 1974c: D-4). The annual output from the 1,000-Mwe plant would be 7,008,000 Mwh; thus, the ancillary energy in the enrichment step represents 4.4 percent of the final electrical power output.

The primary efficiency losses for the enrichment process would be the U-235 that remains in the depleted stream and is stored for possible future uses. A facility which provides three-percent enriched U-235 fuel leaves 22.9 percent of the total amount of naturally occurring U-235 isotopes in the depleted stream (Westinghouse, 1968: 18). Therefore, the primary efficiency for the enrichment step would be 77.1 percent.

6.2.5.3.3 Environmental Considerations

6.2.5.3.3.1 Chronic

Table 6-10 contains a summary of the environmental residuals normalized to the yearly requirement for a 1,000-Mwe LWR (AEC, 1974c: D-2, D-3). Again, the residual data include those from the ancillary energy source, in this case a coal-fired power plant. However, the residuals can be placed into two categories: primary residuals are those associated with the actual operation of the gaseous diffusion plant; and secondary residuals are associated with the operation of the supporting coal-fired plants that supply electricity for the diffusion plants.

TABLE 6-10

SUMMARY OF ENVIRONMENTAL RESIDUALS FOR URANIUM ENRICHMENT (NORMALIZED TO MODEL LWR ANNUAL FUEL REQUIREMENT)

	Quantity
Natural Resource Use[a]	
Land (acres)	
Temporarily committed	0.8
Undisturbed area	0.6
Disturbed area	0.2
Permanently committed	0.0
Water (millions of gallons)	
Discharged to air (at gaseous diffusion plant)	84
Discharged to water bodies (at gaseous diffusion plant)	6
Discharged to water bodies (at power plants)	11,000
Effluents	
Chemicals (metric tons)	
Gases (from coal-fired power plants)	
Sulfur oxides[b]	4,300
Nitrogen oxides[b]	1,130
Hydrocarbons[b]	11
Carbon monoxide[b]	28
F^-	0.5
Particulates[b]	1,130
Liquids (from gaseous diffusion plant)	
Ca^{++}	5.4
Cl^-	8.2
Na^+	8.2
$SO_4^=$	5.4
Fe	0.4
NO_3^-	2.7
Radiological (curies)[c]	
Gases	
Uranium	0.002
Liquids	
Uranium	0.02
Thermal (10^{12} Btu's) (from coal-fired power plants and gaseous diffusion plants)[d]	3,200

Source: AEC, 1974c: D-2, D-3.

[a]Based on 20-year life of gaseous diffusion plant.

[b]Estimated effluent gases based on combustion of equivalent coal for power generation, assuming 100-percent load factor.

[c]Based on four-percent isotopic enrichment.

[d]Approximately 67 percent of this heat is discharged by the electric generating plants servicing the model enrichment plant, assuming 100-percent load factor coal-fired plant.

The primary residuals consist of discharged water, a small amount of elemental liquid effluents, and a small amount of radioactivity. About one-third of the total waste heat is at the enrichment plant, which requires that approximately 84 million gallons of water be discharged to the atmosphere from the cooling towers and another six million gallons be returned to its source. All the liquid effluents listed in Table 6-10 were emitted at concentrations less than current standards. The radioactivity emissions are small, and no significant increase in the natural background radiation levels near the diffusion plants is expected (AEC, 1974c: D-5).

Secondary residuals are greater than primary residuals. About 11 billion gallons of water are needed for once-through cooling at the coal-fired plants that supply the electricity to the diffusion plant. The gaseous chemical effluents are combustion products from the coal. The coal plants also dissipate 2.1×10^{12} Btu's of heat to the environment.

6.2.5.3.3.2 Major Accidents

The AEC has considered the possibilities and impacts of enrichment plant accidents such as fires, explosions, and a nuclear criticality incident (AEC, 1974c: D-6). The conclusions were that while fires and explosions could release gaseous and liquid chemicals to the environment, plant design would limit the quantities that could be involved in one accident. As far as nuclear criticality, the AEC concluded that (1974c: D-6) a criticality incident in the low-enrichment portions of a diffusion plant is highly improbable and that handling U-235 concentrations above 1.0 percent requires special safety criteria. In the event of a highly improbable nuclear incident, most of the materials, if releases occurred, would be contained in the equipment or the building with only minor contamination and clean-up required beyond the section where the incident occurred.

6.2.5.3.4 Economic Considerations

The cost of enrichment is reported as 0.8 mill per kwh, compared to a total fuel cost of 1.93 mills per kwh and a total generation cost of 9.0 to 11.0 mills per kwh. Thus, enrichment is a relatively large portion (41 percent) of the nuclear fuel cost but represents only about eight percent of the total generation cost.

However, the price for enrichment work has increased from $32 per separative work unit* to $39.80 as of July 1974. But the government increased the rate to about $48.00 as of December 1974, and private industry proposed enrichment facilities will probably charge at least $74 per separative work unit when operative (Nuclear News, 1974: 65). If the rate increased to $74, the total generation cost would increase from 11.00 to 11.66 mills per kwh or a six-percent increase.

6.2.5.4 Fuel Fabrication

The fuel fabrication step converts the enriched UF_6 into UO_2 pellets and then encases them in long metal tubes known as

*A separative work unit is a measure of the effort expended in the enrichment plant to separate a quantity of uranium into enriched and depleted components.

cladding. From 50 to 200 of the cladding tubes are positioned in a grid to form a fuel assembly. Several of these fuel assemblies are shipped to an LWR each year.

Ten plants are licensed by the AEC to perform all or part of the necessary steps of converting the UF_6 to the UO_2 assemblies. Three plants perform the complete process, four produce only the UO_2, and the remainder produce assemblies from the UO_2.

6.2.5.4.1 Technologies

The production of the fuel assemblies requires a substantial number of chemical and mechanical processes, the basic techniques of which are the same for all U.S. plants. The process of fuel fabrication can be subdivided into: the chemical conversion of UF_6 to UO_2; mechanical processing, including pellet and fuel element fabrication; and processing of all the scrap. Figure 6-8 is a flow diagram of the complete fuel fabrication process.

6.2.5.4.1.1 Chemical Conversion of UF_6 to UO_2

The currently dominant method for UF_6 to UO_2 conversion is a wet process that involves an intermediate ammonium diuranate (ADU) compound and is thus termed the ADU process. The six steps in the ADU process are:

1. The UF_6 is received as a frozen solid in a high-pressure cylinder and is heated to change it to a gas.
2. The gaseous UF_6 reacts with water to form UO_2F_2.
3. Ammonium hydroxide is used to convert the UO_2F_2 into ADU.
4. The ADU slurry is concentrated by centrifuging or filtering.
5. The ADU is converted to U_3O_8 by heating (calcined).
6. The U_3O_8 is heated in a hydrogen atmosphere to form UO_2 (AEC, 1974c: E-9).

6.2.5.4.1.2 Mechanical Operations

The purpose of mechanical processing is to produce UO_2 pellets (approximately one-half inch in diameter and one inch in length) and to insert these pellets into the cladding. The seven steps in the process are:

1. The UO_2 powder is ground to reduce the particle size.
2. The powder is pressed into pellets.
3. The pellets are baked, known as sintering, in a furnace.
4. The hard pellets are ground to the needed dimensions (the accuracy needed is typically ± 0.0005 inch.
5. The pellets are cleaned (washed and dried).
6. The pellets are loaded in the cladding and the ends of the tubes are sealed.
7. The tubes are used to form a fuel assembly (AEC, 1974c: E-9).

6.2.5.4.1.3 Scrap Processing

The purpose of scrap processing is to recover the uranium left in any of the scrap material; the uranium is quite valuable at this point because it has undergone a large number of processing steps. The scrap processing cycle involves three basic steps (not shown in Figure 6-8):

1. The scrap is dissolved in nitric acid, which produces uranyl nitrate.
2. A solvent extraction process is used to recover the uranium from the nitric acid solution.
3. The uranium is converted into a suitable form for return to the UO_2 production phase.

6.2.5.4.2 Energy Efficiencies

To fabricate the annual fuel requirement for a model 1,000-Mwe LWR requires 1,700 Mwh of electricity and 3.6×10^9 Btu's of heat energy from natural gas (assuming a heat content for gas of 1,000 Btu's per cf) (AEC, 1974c: E-2). Since the annual output from the model LWR would be approximately

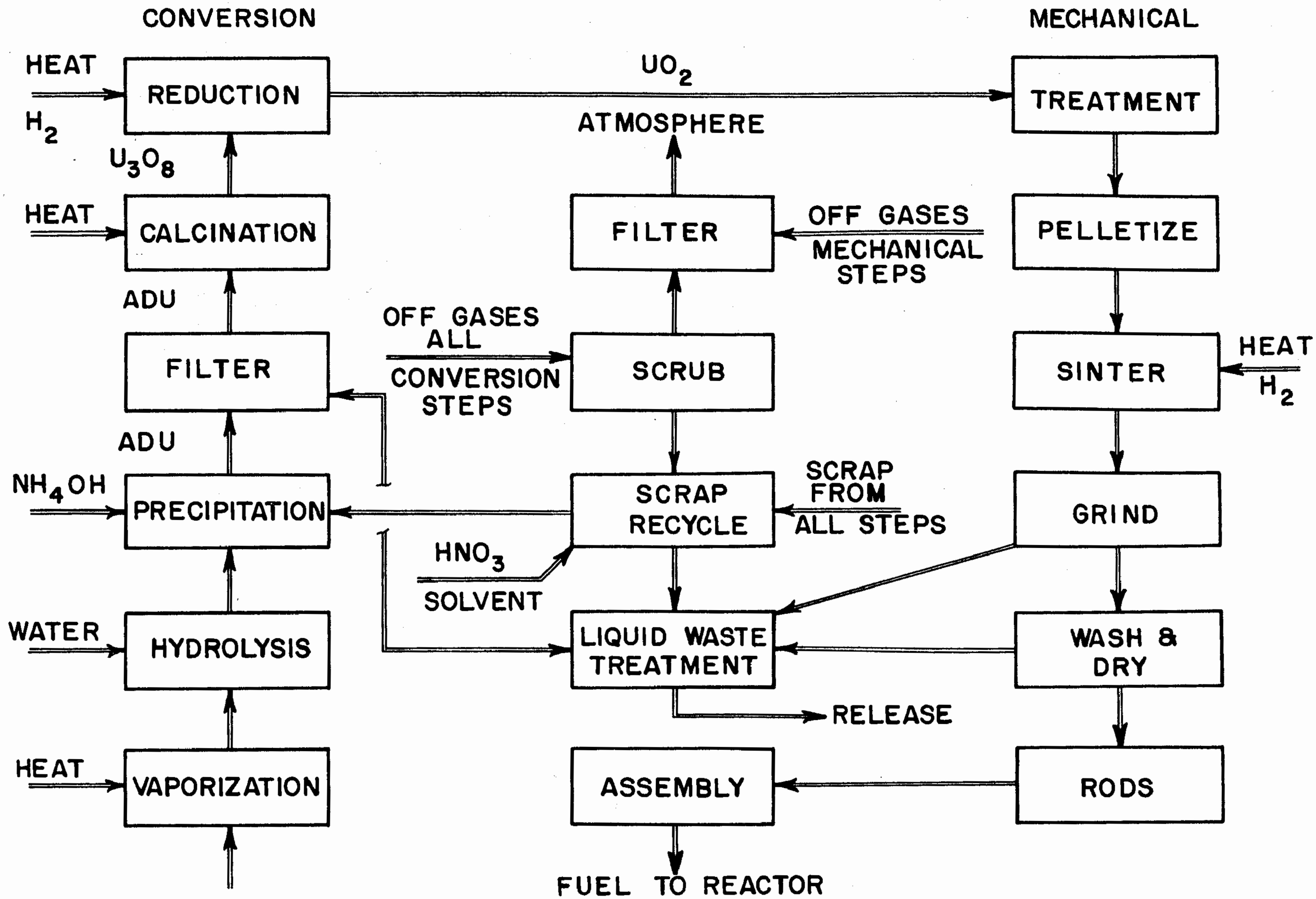


Figure 6-8. Fuel Fabrication--ADU Process
Source: AEC, 1974c: E-10.

7,008,000 Mwh (or $23x10^{12}$ Btu's electric), the ancillary energy requirement for fuel fabrication is relatively small.

The primary efficiency loss would be equivalent to the percent of uranium lost in the fuel fabrication process. No data on these losses are available, but presumably they are quite small.

6.2.5.4.3 Environmental Considerations

6.2.5.4.3.1 Chronic

Table 6-11 lists the chronic residuals for a fuel fabrication plant, normalized to the annual fuel requirements for a model 1,000-Mwe LWR (AEC, 1974c: E-2). Again, these data include the emissions at the electric power plant (secondary residuals).

The main residuals are associated with the chemical processing steps; that is, the conversion to UO_2 and the scrap recovery. The mechanical processing produces few residuals. The important primary residuals (those associated directly with the fuel fabrication plant) are the 10 metric tons of ammonia and 23 metric tons of NO_3 emitted into waste holding ponds. These two emissions are generated when the ammonium hydroxide and nitric acid are used in the processing. The significant primary gaseous residuals are fluorides; approximately 0.0055 ton of fluorides is emitted each year. A radioactive residual is thorium-234 (Th-234); however, the small amount released would present no known health hazards (AEC, 1974c: E-4).

The most important secondary residuals are the SO_x, NO_x, hydrocarbons, and CO from the fossil-fueled plants that supply the electricity from the fabrication plants.

6.2.5.4.3.2 Accidents

A variety of accidents can be postulated (and have occurred) in the fabrication plants. However, experience has shown that the impact of these minor accidents is confined to the plant. The postulated accidents that could have significant off-site effects are rupture of a hot UF_6 cylinder, a criticality accident, and a furnace explosion. The AEC has analyzed these accident possibilities and, in essence, concluded they have a very low probability of

TABLE 6-11

SUMMARY OF ENVIRONMENTAL RESIDUALS FOR FUEL FABRICATION (NORMALIZED TO 1,000-Mwe LWR ANNUAL FUEL REQUIREMENT)

	Quantity
Natural Resource Use	
Land (acres)	
Temporarily committed	0.2
Undisturbed area	0.16
Disturbed area	0.04
Permanently committed	0
Water (millions of gallons)	
Discharged to water	5.2
Effluents	
Chemical (metric tons)	
Gases	
Sulfur oxides[a]	23
Nitrogen oxides[a]	6
Hydrocarbons[a]	0.06
Carbon monoxide[a]	0.15
F^-	0.005
Liquids	
N as NH_3	8.4
N as NO_3	5.3
Fluoride	4.1
Solids	
CaF_2	26
Radiological (curies)	
Gases	
Uranium	0.0002
Liquids	
Uranium	0.02
Thorium-234	0.01
Solids (buried)	
Uranium	0.23
Thermal (billions of Btu's)	9

Source: AEC, 1974c: E-2.

[a]Effluent gases from combustion of coal for power supply.

occurring and would have very little effect if they did (AEC, 1974c: E-4 and E-5).

6.2.5.4.4 Economic Considerations

The cost of fabricating the fuel assemblies was estimated in 1972 to be approximately $70 per kilogram of contained uranium. This cost represents approximately 0.4 mill per kwh, about 20 percent of the total fuel processing costs of 1.93 mills per kwh or only four percent of the total power generation costs of 9.0 to 11.0 mills per kwh (NPC, 1973: 28).

6.2.6 Light Water Reactors

6.2.6.1 Technologies

A nuclear-electric power plant is similar in nature to the fossil-fueled power plants described in Chapter 12 except that the nuclear steam supply system replaces the conventional fuel boiler and the nuclear fuel core replaces the fossil fuel supply. In LWR's, the heat energy comes basically from the fissioning of U-235 atoms, with a small contribution from the fissioning of U-238 atoms. However, as the reactor operates, a fissile atom (Pu-239) is produced from U-238. For each gram of U-235 consumed in LWR fuel, as much as 0.6 gram is formed. Generally more than half of the plutonium formed undergoes fission in the core, thus contributing significantly to the energy produced in the power plant (AEC, 1974d: Vol. IV, p. A.1.1-2). LWR's typically employ partial refueling annually, with somewhere between one-fourth and one-third of the fuel assemblies being removed and replaced with fresh fuel each year. Spent fuel assemblies are stored underwater at the power plant for a period of five to six months to allow their radioactivity level to decrease prior to shipment to a fuel reprocessing plant (AEC, 1974d: Vol. IV, p. A.1.1-15). Since the historical origin of nuclear power is from nuclear weapons, it is important to point out that a nuclear reactor cannot explode like a bomb. A different type of fuel and different fuel configuration are used in a reactor.

There are currently two different types of U.S. LWR's: the boiling water reactor (BWR) manufactured by General Electric and the pressurized water reactor (PWR) manufactured by Babcock and Wilcox, Combustion Engineering, and Westinghouse.

6.2.6.1.1 Boiling Water Reactors

Figure 6-9 is a simplified schematic of a boiling water reactor. In this type of reactor, water is pumped in a closed cycle from the condenser to the nuclear reactor. In the reactor core, heat generated by the fissioning uranium pellets is transferred through the metal cladding to the water flowing around the fuel assemblies. The water boils and a mixture of steam and water flows out the top of the core and through steam separators in the top of the pressure vessel. The separators clean and "dry" the steam before it is piped to the turbine-generator(s). The turbine exhaust is condensed and returned to the reactor pressure vessel to complete the cycle. (See Chapter 12 for a more complete description of steam power plants).

Because the energy supplied to the water from the hot fuel is transported directly (as steam) to the turbine, the BWR system is termed a "direct cycle" system The pressure in a typical BWR is maintained at about 1,000 pounds per square inch (psi), with a steam temperature of 545°F (AEC, 1974d: Vol. IV, p. A.1.1-18). Neutron-absorbing control rods, operated by hydraulic drives located below the vessel, are used to control the rate of the fission chain reaction (and thus the heat output).

One major concern with light water reactors is an accidental depressurization or coolant loss (e.g., resulting from a high-pressure steam pipe rupture). If no safety measures were in effect, such events would cause the core to overheat and melt, and

Boiling water reactor (BWR)

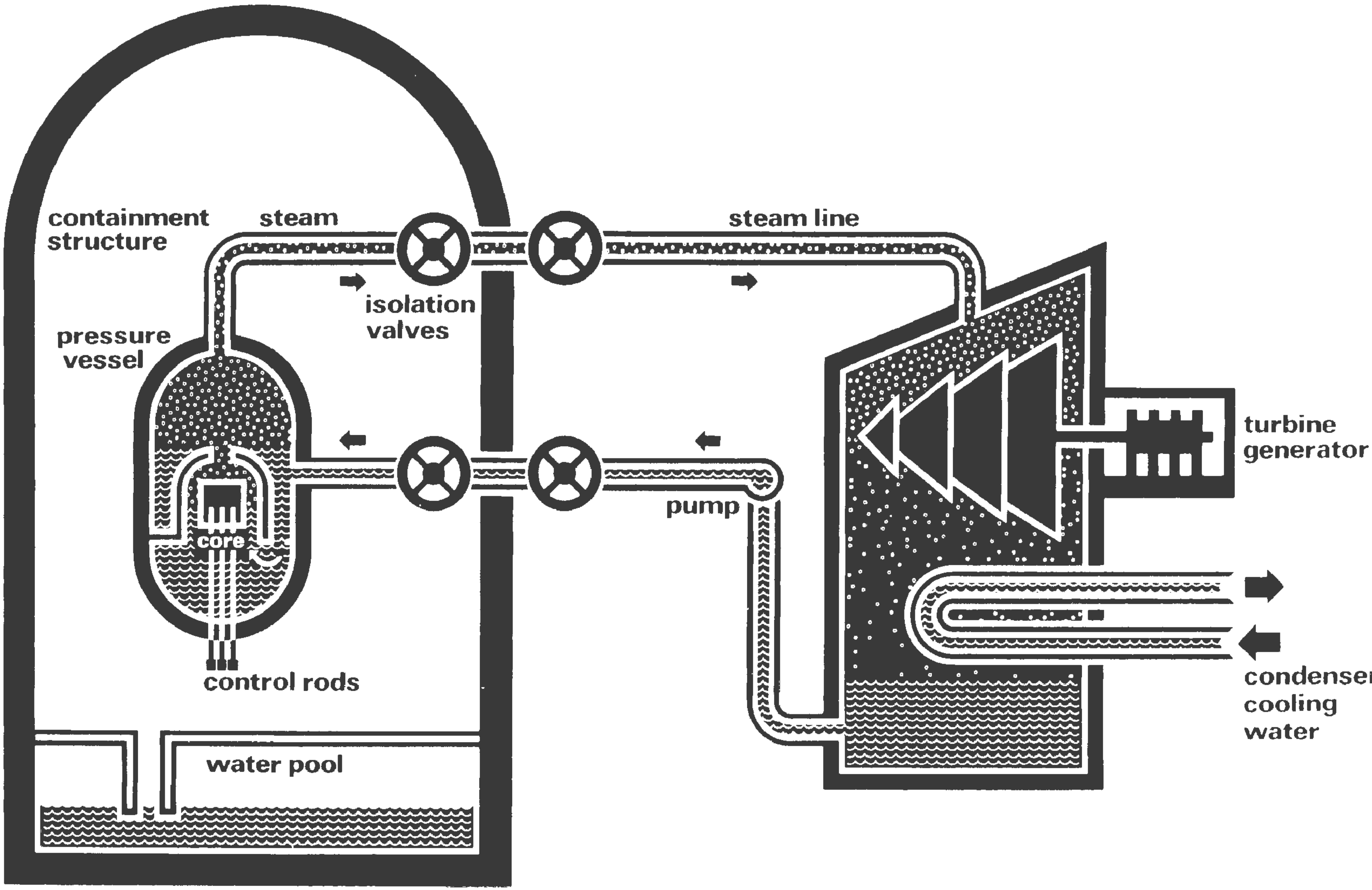


Figure 6-9. Boiling Water Reactor
Source: Atomic Industrial Forum, Incorporated.

large amounts of high-level radioactivity might be released to the environment. To prevent such catastrophes, reactor systems include emergency core cooling systems (ECCS's) to prevent meltdowns and containment systems for preventing the release of radioactivity in the event of any type of accident.

Although provisions differ from plant to plant, all BWR's have multiple provisions for cooling the core fuel in an emergency. Typical ECCS's involve either a high-pressure core spray system (early BWR's) or both core sprays and a high-pressure coolant-injection system (latest BWR's) to assure adequate cooling of the core in the event of reactor system depressurization (AEC, 1974d: Vol. IV, pp. A.1.1-20).

To prevent such accidents from releasing radioactivity and other pollutants to the environment, BWR designs generally provide both "primary" and "secondary" containment. The primary containment system, shown in Figure 6-9 as the "containment structure," is a steel pressure vessel surrounded by reinforced concrete and designed to withstand the peak transient pressures that might occur in the most severe of the postulated loss-of-coolant accidents. The primary containment system employs a "drywell," which encloses the entire reactor vessel and its recirculation pumps and piping. The drywell is connected to a lower-level, pressure suppression chamber in which a large pool of water is stored. In the event of an accident, valves in the main steam lines from the reactor to the turbine-generators (the "isolation valves" in Figure 6-9) would close automatically and any steam escaping from the reactor system would be released into the drywell. The resulting increase in drywell pressure would force the air-steam mixture in the drywell down into and through the large pool of water where the steam would be completely condensed, thereby preventing any large pressure buildup. This pressure injection pool also serves as a potential source of water for the emergency core spraying system (AEC, 1974d: Vol. IV, p. A.1.1-21).

The "secondary" containment system is the building that houses the reactor and its primary containment system (not shown in Figure 6-9). Reactor buildings are constructed of poured-in-place, reinforced concrete and have sealed joints and interlocked double-door entries. Under accident conditions, the normal building ventilation system would shutdown, and the building would be exhaust-ventilated by two parallel standby systems. These ventilating systems incorporate effluent gas treatment devices, including high-efficiency particulate cleaners and solid absorbents for trapping radioactive halogens (particularly iodine) that might have leaked from the primary containment system (AEC, 1973: 1-24).

6.2.6.1.2 Pressurized Water Reactors

Figure 6-10 is a simplified schematic of a pressurized water reactor. The primary difference between a PWR and a BWR is that all PWR's employ a dual coolant system for transferring energy from the reactor systems. In the dual coolant system, the primary loop is water that is pumped through the core and the heat exchanger. The secondary loop is water that is pumped through the heat exchanger and the turbine. The water is heated to about 600°F by the nuclear core in the pressure vessel, but pressure is sufficiently high (about 2,250 psi) to prevent boiling. The high-pressure water is piped out of the reactor vessel into usually two or more "steam generators" that form a basic heat exchanger. The primary heat is transferred to the secondary stream. The secondary stream boils, providing steam for the turbine. The secondary stream is then condensed and the water is pumped back to the

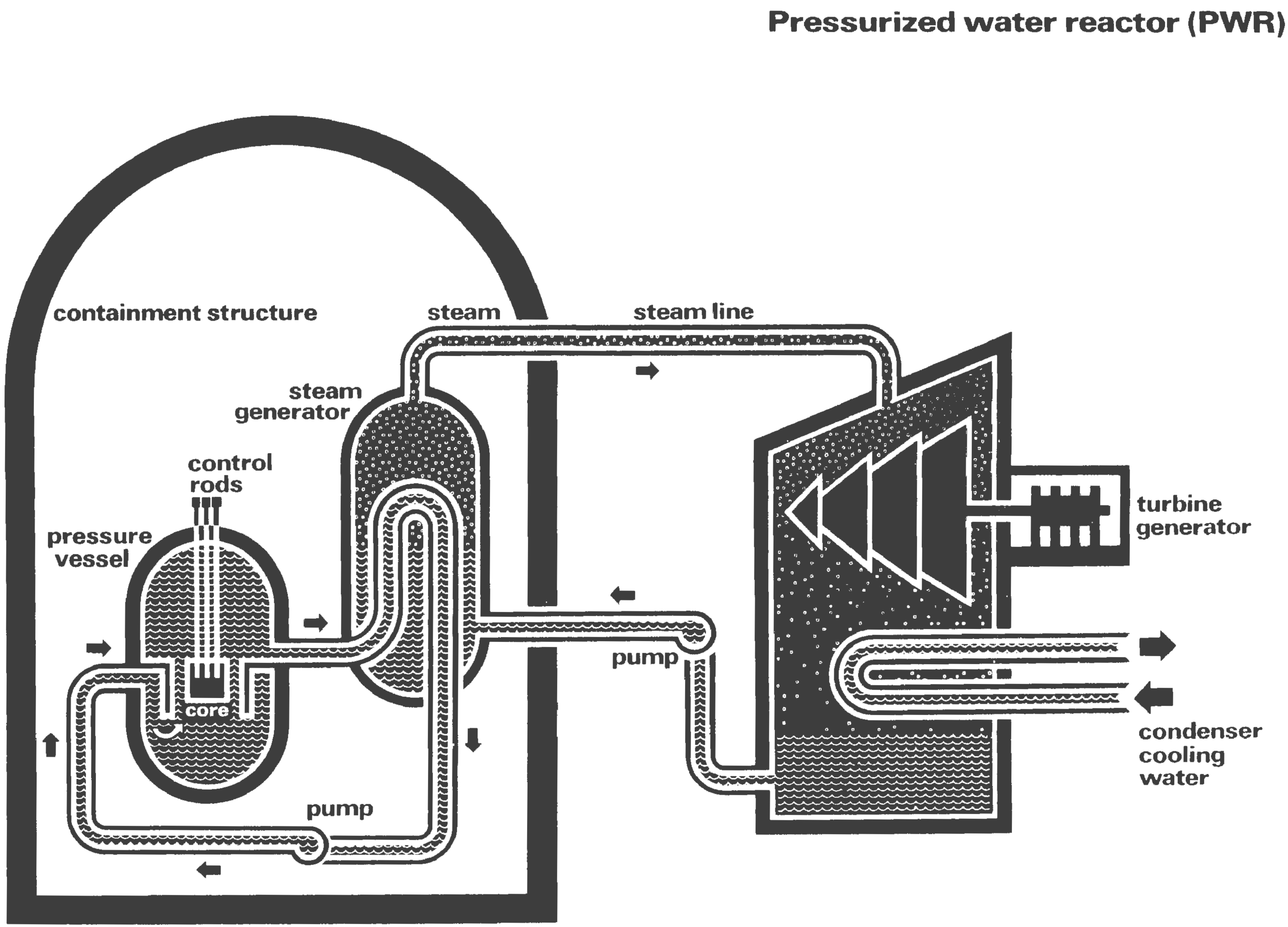


Figure 6-10. Pressurized Water Reactor
Source: Atomic Industrial Forum, Incorporated.

steam generator to begin the cycle over. No steam is generated in the primary loop and the water is returned to the core from the steam generator to start the primary cycle over. As in BWR's, the nuclear chain reaction is controlled through the use of neutron-absorbing rods; however, in PWR's, additional control can be obtained through the dissolution of such variable-concentration neutron-absorbing chemicals as boron (which may also serve other purposes) in the primary system coolant.

The PWR ECCS's consist of several independent subsystems, each characterized by redundancy of equipment and flow path. Although the arrangements and designs of PWR ECCS's vary from plant to plant (depending on the vendor of the steam supply system), all modern PWR plants employ both accumulator injection systems and pump injection systems. Accumulator injection systems are called passive systems because they operate automatically without activation of pumps, motor driven valves, or other equipment. The systems consist of pressurized tanks of cool borated water which are connected through check valves to the reactor vessel. Should the primary coolant system lose pressure, the check valves would open and a large volume of water would be rapidly discharged into the reactor vessel and core. Two pump injection (active) systems are also incorporated in PWR ECCS's. One is a low-pressure system to provide coolant after the above mentioned accumulator tanks are empty, and the other is a high-pressure system designed to function if the break is small and the primary coolant pressure remains too high to activate the passive systems (AEC, 1973: 1-14).

The containment structure for PWR's is of reinforced concrete with a steel liner and is stressed to withstand the maximum expected temperature and pressure if all the water in the primary system was expelled into the containment. However, containment system designs vary widely from plant to plant. For example, in some plants, the containment space is kept slightly below atmospheric pressure so that leakage through the containment walls would, at most times, be inward from the surroundings. Other systems have double barriers against escape of material from the containment space. In addition, to condense the steam resulting from a major break of the primary system, either cold-water sprays or stored ice is provided (AEC, 1973: 1-17).

6.2.6.2 Energy Efficiencies

The overall energy efficiency for the power plant is the ratio of electric energy output to total heat energy produced. LWR's (both BWR's and PWR's) have energy efficiencies around 32 percent, as compared to 38 to 40 percent for modern fossil-fueled plants (see Chapter 12). The reason for this lower efficiency is that LWR plants can only operate at a maximum steam temperature of around $600^{\circ}F$ while fossil plants can operate at $1,000^{\circ}F$ or higher.

6.2.6.3 Environmental Considerations

6.2.6.3.1 Chronic Residuals

The main residuals from LWR's are waste heat and radioactive emissions. For a 1,000-Mwe plant operating at a 75-percent load factor, a 32-percent efficient nuclear plant would emit 47.6×10^{12} Btu's of waste heat annually. For comparison, a 38-percent efficient fossil plant would emit 36.5×10^{12} Btu's of waste heat. For a description of the cooling mechanisms and water required to dissipate this waste heat, see the section on cooling in Chapter 12.

Table 6-12 gives the annual chronic radioactive emissions for both types of LWR's. These data are based on a 1,000-Mwe plant operating at a 100-percent load factor.

The PWR emits a larger quantity of tritium (the heaviest hydrogen isotope which is radioactive) than does the BWR. The tritium is created as a direct product of

TABLE 6-12

ANNUAL RADIOACTIVE EMISSIONS FOR A 1,000-Mwe LWR[a]

Radioactive Gas	BWR[b] (curies)	PWR[c] (curies)
Tritium (H_3)	10	50
Iodine (I_{131})	0.3	0.8
Noble gases (Kr+Xe)	50,000	7,000

Source: Teknekron, 1973: Figure 2.1.

[a]Based on 32-percent thermal efficiency, 8.8×10^9 kwh produced.

[b]Boiling water reactor.

[c]Pressurized water reactor.

some fission events in both types of reactors and may then diffuse out of the fuel rods into the coolant water. In addition, tritium is also formed from the boron used in the coolant water of the PWR. Noble gases (i.e., inert gases, primarily krypton and xenon) are fission fragments. These too can diffuse out of the fuel rods into the coolant water. The radioactive gases may leak out of the coolant water or are removed from the coolant water during the coolant purification operation. If trapped in the purification operation, the gases are held in tanks to allow decay to reduce the radioactivity level. The radioactivity emission from noble gases is higher for BWR's because the gas is held a much shorter time than for PWR's (AEC, 1974d: A.1.1-35). All emission levels are below AEC standards and have no known adverse health effects.

6.2.6.3.2 Major Accident

As mentioned in Section 6.2.6.1, the history of nuclear power is interwined with the image of nuclear weapons. A nuclear reactor cannot explode like a bomb because different fuels and fuel configurations are used in a reactor. However, a reactor can experience a core meltdown if the primary coolant is lost. To prevent such a meltdown, the reactors (BWR's and PWR's) are equipped with ECCS's described in Sections 6.2.6.1.1 and 6.2.6.1.2. The possibility exists that the ECCS may not function and the core would melt.

In a recent reactor safety study, estimates were made of the frequency of core meltdowns and the danger to the public (AEC, 1974h: 18). The risk of a public fatality per year from 100 nuclear plants (1,000-Mwe) is one chance in 300,000,000. This compares to one chance in 4,000 of a fatality from a motor vehicle accident. The probability of a core meltdown is one chance in 17,000 per reactor per year. This means that an operating reactor is likely to have one core meltdown every 17,000 years. Of the core melt accidents, only 1 in 10 might produce measurable health effects.

6.2.6.4 Economic Considerations

The economics of the two types of LWR's are very similar and thus no distinction is made between BWR's and PWR's. Table 6-13 gives an estimate for electric power costs in 1980 from LWR's (1980 dollars). For comparison, average U.S. electric power costs from all sources in 1980 are expected to be near 12 mills per kwh. Obviously, the plant capital costs constitute the majority of nuclear electric generation costs and dictate that the plants be used as base load units. However, fuel accounts for only 18 percent of nuclear generation costs, whereas in 1968 fuel accounted for 32 percent of fossil-fuel generation costs (see Chapter 12).

The capital costs for an LWR have been projected as between \$411 and \$472 (1974 dollars) per kw installed capacity for a plant to begin operation in 1981 (Nuclear News Buyers Guide, 1974: 23). For comparison, this same source estimated the capital

TABLE 6-13

ANTICIPATED 1980 ELECTRICITY COSTS FOR LWR

Expense	Mills per kwh (in 1980 dollars)
Capital	8.50
Operation and maintenance	0.73
Fuel	2.10
Abatement costs such as land reclamation	0.60
TOTAL	11.93

Source: AIF, 1974.

costs for a coal-fired plant at $386 to $444 per kw and for an oil-fired plant at $280 to $332 per kw.

6.2.7 Fuel Reprocessing

Instead of being discarded, used fuel from LWR's is reprocessed to recover the unused uranium and the created Pu-239. Reprocessing enables use of the recovered fuel to partially allay the need for mining and processing new fuel. At present, the plutonium is being stored, with the expectation that it will be used for LWR fuel or for liquid metal fast breeder reactors in the future. The reprocessing step is unique to nuclear power production; fossil fuel forms (such as coal, oil, gas, etc.) are discarded when oxidation is complete.

Although three nuclear fuel reprocessing plants are either being constructed or modified, none are presently operating. One plant, operational since 1966, is shut down for modifications. A second plant was expected to begin operation in 1974, but economic and operational problems have caused the company to undertake the study to consider how (or even whether) to attempt to overcome these problems (Nuclear News, 1974: 65). The third plant is under construction and is scheduled to begin operation in late 1976. As a result, the fast approaching glut of irradiated fuel has caused some concern in the industry. When these plants are operational, they will have a combined capacity of 2,700 metric tons of fuel per year. Since each 1,000-Mwe LWR requires that 33 tons of fuel be reprocessed each year, the combined capacity should be sufficient until the later 1970's.

6.2.7.1 Technologies

The three plants will all use the same process, with some slight variations. The used fuel elements are stored under water for 150 days before processing begins to allow the radioactivity levels to decrease, then a mechanical cutter chops the elements into short pieces, and the resulting pieces are put in a nitric acid bath which reacts with the fuel and leaves the metal tubing behind. The acid solution is then altered chemically so that a solvent extraction process can be used. The solvent extraction recovers the plutonium and uranium. The uranium is converted to UF_6 and returned to the enrichment plant. As stated earlier, the plutonium is presently being stored (AEC, 1974c: F-10).

6.2.7.2 Energy Efficiencies

The ancillary energy requirement to reprocess the annual fuel requirement for the model 1,000-Mwe reactor is 450 Mwh, which is quite small compared to the total power output from this reactor. Essentially all the unused U-235 and created Pu-239 is recovered in the fuel reprocessing step; therefore, the primary efficiency is approximately 100 percent.

6.2.7.3 Environmental Considerations

6.2.7.3.1 Chronic

Table 6-14 lists the residuals associated with reprocessing. The items listed include both the primary and secondary residuals emitted during reprocessing; high-level wastes that are moved to the burial

TABLE 6-14

SUMMARY OF ENVIRONMENTAL RESIDUALS FOR IRRADIATED FUEL REPROCESSING (NORMALIZED TO 1,000-Mwe LWR ANNUAL FUEL REQUIREMENT)

	Quantity
Natural Resource Use	
Land (acres)	
Temporarily committed	3.9
Undisturbed area	3.7
Disturbed area	0.2
Permanently committed	0.03
Water (millions of gallons)	
Discharged to air	4.0
Discharged to water	6.0
TOTAL	10.0
Effluents	
Chemical	
Gases (metric tons)	
Sulfur oxides[a]	6.2
Nitrogen oxides[b]	7.1
Hydrocarbons[a]	0.02
Carbon monoxide[a]	0.04
F^-	0.11
Liquids	
Na^+	5.3
Cl^-	0.2
$SO_4^=$	0.4
NO_3^- (as N)	0.2
Radiological (curies)	
Gases (including entrained matter)	
Tritium (thousands)	16.7
Krypton-85 (thousands)	350
Iodine-129	2.4×10^{-3}
Iodine-131	2.4×10^{-2}
Fission products	1.0
Transuranics	4×10^{-3}
Liquids	
Tritium (thousands)	2.5
Ru-106	0.15
Cs-137	0.075
Sr-90	0.004
Thermal (billions of Btu's)	61

Source: AEC, 1974c: F-3.

[a]Estimated effluent gases from combustion of equivalent coal for power generation.

[b]23 percent of total is estimated effluent gas from combustion of equivalent coal for power generation.

site are not included. Obviously, reprocessing reduces the total residuals associated with mining, milling, and conversion to UF_6 because the recovered uranium replaces uranium that otherwise must be supplied by mining and processing uranium ore.

The quantity of released radioactive effluents in this step is large in comparison with other steps in the LWR fuel cycle. Reprocessing is a source of emitted tritium, krypton-85 (Kr-85), iodine, fission products, and transuranium elements. The estimates in Table 6-14 assume that 100 percent of the Kr-85 and 87 percent of the tritium originally contained in the incoming fuel elements are emitted to the environment. The data are based on the operating experience of the Nuclear Fuel Services Plant near Buffalo, New York. Air and land surveys have indicated that emissions are a small percentage of the maximum permissible concentrations as specified by the AEC (Shleien, 1970; Cochran and others, 1970).

Another residual is the casks of high-level wastes. These wastes are initially stored in the form of a liquid for a period of up to five years. After being converted to inert solids, the wastes are shipped to a storage facility (see Section 6.2.8).

6.2.7.3.2 Major Accidents

The most significant accident would be an accidental criticality of the used fuel. Calculations have indicated that a person at the site boundary could receive a dose of 50 mrem to the thyroid, an important organ indicating accumulation of radioactive and stable iodine. Other accidents of lesser importance could result in a dose of 10 mrem to the bones of individuals at the site boundary. It is interesting to note that no accident has resulted in any significant release of radioactivity in 25 years of operating experience at commercial and government reprocessing facilities using similar processes (AEC, 1974c: F-5, F-6).

6.2.7.4 Economic Considerations

The reprocessing and shipping of fuel to be reprocessed costs about $45 per kilogram of uranium, or approximately 0.14 mill per kwh (NPC, 1973: 14). This represents only about 1.4 percent of the total power generation costs. As the prices of raw ore, milling, and conversion processing steps increase, reprocessing will become even more important. After subtracting the necessary associated costs, the reclaimed U-235 and plutonium have a net worth of about $1.75 million per model LWR per year.

6.2.8 Radioactive Waste Management

Radioactive waste management is another unique and necessary process for nuclear power generation. The purpose of the management program is to insure that nuclear wastes do not enter the environment until their radioactivity is below harmful levels. Certain types of waste must be isolated from the environment for thousands of years. Radioactive waste management is concerned with the manipulation and storage of all radioactive materials produced in the nuclear fuel cycle.

6.2.8.1 Technologies

Radioactive wastes are classified as either "high-level" or "other than high-level," the distinction being based on the radioactive content of the waste. High-level waste, which contains hundreds of thousands of curies, is produced from the reprocessing plant and contains the fission products. Low-level waste consists of residuals from UF_6 production, fuel fabrication, reactor operation, and fuel reprocessing.

New regulations regarding high-level liquid wastes require that the inventory at the reprocessing plant be limited to the amount processed in the prior five years and that the waste be converted into a solid form and be transferred to a federal repository within 10 years of its separation from the irradiated fuel. Until a long-term storage facility is available, the government will provide a retrievable surface storage facility (RSSF) as a temporary holding facility. Federal control over this facility will be maintained as long as waste is being stored in the facility.

The "other than high-level" wastes are buried in shallow trenches, usually in the containers in which they are shipped. There is no intent to recover the waste once they are buried. These wastes are currently being buried at six commercial sites (AEC, 1974c: G-1). The land is controlled by the host state, which must maintain care and surveillance of the site if the commercial operator defaults. In future years, the burial site cannot be used for any other purpose.

Proposals for dealing with radioactive wastes consist of either using the wastes or disposing of the wastes. Since high-level radioactive wastes generate significant amounts of heat, various means of using these wastes as heat sources in remote locations have been proposed. Some of the wastes are used as sources of radioactive isotopes for medical purposes. However, current and future applications for these purposes will not use sufficient material to alleviate the waste disposal problem. A variety of disposal methods have been proposed (Kubo and Rose, 1973). Storage in salt vaults, further chemical separation of the waste to reduce the necessary surveillance time, near-surface storage in mausoleum-type structures, burial in antarctic rocks, and storage in a large cavity beneath the reprocessing plant are some of the proposals.

6.2.8.2 Energy Efficiencies

The ancillary energy requirement for radioactive waste management cannot be calculated because a long-term solution for disposal of these wastes has not been found

However, any energy used in radioactive waste management represents an ancillary energy and should be subtracted from the reactor output to calculate actual net energy.

6.2.8.3 Environmental Considerations

6.2.8.3.1 Chronic

The residuals of the actual operation are small and negligible. To bury the residuals (both high-level and other than high-level) resulting from the various steps in the fuel cycle requires approximately 0.2 acre per year per model 1,000-Mwe LWR (AEC, 1974c: G-2). Typical quantities of residuals to be buried per 1,000-Mwe LWR per year are 114 cf of fission products containing 18,300,000 curies and 72 cf of cladding containing 167,000 curies. The total low-level waste is approximately 14,000 cf per model 1,000-Mwe LWR.

6.2.8.3.2 Major Accidents

Possible accident effects at other than high-level waste burial facilities would normally be confined to the immediate area and would not release any significant amounts of radioactivity to the environment.

The most severe accidents would involve high-level radioactive wastes. Two types of such accidents have been analyzed: a handling accident and catastrophic failure of the cooling system. The handling accident would result in a bone dose of 0.1 rem per year at the site perimeter. The loss of cooling could result in a meltdown of the waste, but even if the cooling system failed the waste would not begin to melt within the first week. Because of the many safety precautions and the long time period for corrective action, a waste meltdown is highly unlikely (AEC, 1974c: G-2, G-3).

6.2.8.4 Economic Considerations

The economics of radioactive waste management cannot be properly estimated at present. The dollar costs associated with the burial of low-level waste at the six commercial burial sites, and the extra costs involved for containing and packaging this waste at each step in the fuel cycle, can probably be estimated, but no data are available at this time. Also, the economics of storing and securing high-level waste for thousands of years cannot be estimated, especially since the RSSF has not yet been built.

6.2.9 Transportation

In Figure 6-1, the solid arrows indicate the necessary transportation steps in the LWR system. Because of the unique radioactive nature of the material being transported, special regulations are necessary. These regulations have three purposes: to protect the general public and workers from radiation, to insure no release of radiation in all types of accidents, and to insure the security of the material. Two agencies, the AEC and the Department of Transportation (DOT), are responsible for writing the regulations and setting standards. A recent memo of understanding between the two agencies has delineated each agency's area of jurisdiction (AEC, 1974e: 70). In this section, a general description is given of the regulations concerning the transport of radioactive materials (both fissile and nonfissile). In addition, a brief description of the specific transportation steps in the LWR system is presented.

6.2.9.1 Nuclear Material Transportation Regulations

All radioactive materials must conform to certain packaging requirements as outlined in Table 6-15. There are two broad classes of radioactive materials: "normal form," which has seven classifications based on radiotoxicity of the material, and "special form." The type of container required for each of these material groups depends on the amount shipped, as indicated in Table 6-15. For example, Pu-239 can be shipped as "exempt" if it contains less than 10^{-5} curies; it is shipped

TABLE 6-15

CONTAINER REQUIREMENTS ACCORDING TO QUANTITY OF RADIOACTIVE MATERIALS

Radioactive Materials	Transport Group	Examples	Exempt Quantity (less than Curies)	Type A Container (up to Curies)	Type B[a] Container (up to Curies)
Normal Form	I	Pu-239, Cm-242, Cf-252	10^{-5}	10^{-3}	20
Normal Form	II	Bi-210, Pi-210, Sr-90	10^{-4}	$5x10^{-2}$	20
Normal Form	III	Cs-137, Ir-192, Ir-131	10^{-3}	3	200
Normal Form	IV	As-76, C-14, Cr-45	10^{-3}	20	200
Normal Form	V	Noble gases, Kr-85	10^{-3}	20	5,000
Normal Form	VI	Ar-37, Xe-133, Kr-85 uncompressed	10^{-3}	1,000	50,000
Normal Form	VII	Tritium - as a gas or in luminous paint	25	1,000	50,000
Special Form		Co-60 radiography source, Pu-Be neutron source	10^{-3}	20	5,000

Source: AEC, 1972: 12.

[a]A "Large Quantity" is defined as any quantity in excess of a Type B quantity.

in Type A containers if it contains less than 10^{-3} curies; and it is shipped in Type B containers if it contains less than 20 curies. Any Pu-239 in excess of 20 curies would be designated as a "Large Quantity" and is subjected to special requirements. Exempt quantities can be shipped in strong industrial packages and are exempt from labeling regulations. The Postal Service will ship exempt quantities if they are packaged in leakproof containers. The container standards for Type A packages require that they prevent loss or dispersal and retain shielding efficiency under "normal" transport conditions. However, Type B containers must meet the following tests in sequence without leakage:

1. A drop from 30 feet onto the container's most vulnerable area.
2. A drop from four feet onto a six-inch diameter spike.
3. Exposure to a fire of 1,475°F for 30 minutes.
4. Immersion for 24 hours in three feet of water.

"Large Quantities" (usually nuclear fuel assemblies that contain millions of curies) have special packaging and shipping requirements, depending on the characteristics of the specific fuel assembly.

In addition to the above general radioactive materials packaging requirements, certain quantities of fissile materials (i.e., U-233, U-235, and plutonium) require additional control to prevent accidental criticality. Safety in transport is provided by the container design so that criticality cannot occur under any conditions to be encountered, including accidents. All fissile material must be shipped in containers capable of meeting the accident test conditions listed earlier for Type B containers.

TABLE 6-16

SUMMARY FOR ENVIRONMENTAL RESIDUALS FOR FUEL CYCLE TRANSPORTATION STEPS
(NORMALIZED TO MODEL LWR ANNUAL FUEL REQUIREMENT)

Step - Material Transported	Assumed Method	Shipments	Travel Miles
Mine to mill - ore	Truck - mostly private land	3,350	16,800
Mill to UF_6 production - yellowcake	Truck - public highway and rail	12	12,000
UF_6 production to enrichment - natural UF_6	Truck - public highway and rail	22	11,000
Enrichment to UO_2 enrichment - enriched UF_6	Truck - public highway and rail	5	3,750
UO_2 Plant to fabrication - enriched UO_2	Truck - public highway	9	6,750
Low-level wastes to commercial land burial sites	Truck - public highway	58	29,000
Solid wastes to federal storage - fission products	Rail	1	2,000
TOTALS - public highway and truck shipment		106	62,000
TOTALS - Truck shipments		3,450	80,000

Source: AEC, 1974c: H-3.

6.2.9.2 Technologies

Table 6-16 lists the characteristics of the transportation steps in the LWR fuel cycle (excluding steps to and from the reactor), and Table 6-17 lists the characteristics of the transportation steps to and from the reactor. The procedures involved in these steps are:

1. Ore from Mine to Mill

Uranium ore is usually in the form of low-level radioactive sandstone. The mined ore is normally moved in open trucks with capacities of up to 30 tons. The economics of moving ore dictates that the transportation distances be short, typically five miles or less, and in general do not involve public highways.

2. Yellowcake from Mill to UF_6 Production

Yellowcake is low in radioactivity and must be transported from mills in the western U.S. to the two UF_6 production sites. An average shipment travels 1,000 miles. Yellowcake is transported in 55-gallon steel drums, each containing about 0.42 ton of yellowcake, and each truck can carry about 40 drums or 17 tons per load.

3. Natural UF_6 from Production to Enrichment Plant

Natural UF_6 is shipped as a solid from the UF_6 production center to the enrichment facility. Natural UF_6 is low in radioactivity and, typically, one of two types of containers is used. One container is

TABLE 6-17

CHARACTERISTICS OF SHIPMENTS TO AND FROM REACTOR
(NORMALIZED TO REQUIREMENTS TO TYPICAL 1,000-Mw REACTOR)

Step	Type of Shipment	Mode of Transportation	Estimated Weight (metric tons)	Heat Generated by Shipment (kilowatts)	Number of Shipments per 1,000-Mw Reactor Year	Estimated Average Shipping Distance (miles)	Total Shipping Distance per Reactor Year (miles)
Fuel fabrication to reactor	unirradiated fuel	truck	24	negligible	6[a] (18 initial)[a]	1,000	12,000[b]
Reactor to reprocessing	irradiated fuel	truck	35	10	60[a]	1,000	120,000[b]
		rail	100	70	10[a]	1,000	20,000[b]
		barge	150	140	5[a]	1,000	10,000[b]

Source: AEC, 1972.

[a]Plus an equal number of shipments for return of empty packagings.

[b]Only half of this distance involves shipments of radioactive material. The other half involves return of empty packagings.

about 4 by 10 feet and carries 11 tons of UF_6; the other container is 4 by 12.5 feet with a capacity of approximately 14 tons. The average shipment is by truck over a distance of 500 miles.

4. Enriched UF_6 from Enrichment to UO_2 Plant

   Enriched UF_6 is a fissile material and is shipped as a solid. The shipping package consists of a 2.5-ton cylinder with a protective outer covering. Each package will hold about 2.2 tons of UF_6. The shipments are made by truck over an average distance of 750 miles, and each truck can carry a maximum of five cylinders.

5. Enriched UO_2 from the UO_2 Plant to Fuel Fabrication

   If the plant receiving the enriched UF_6 does not have the capability to perform the complete operation of producing the fuel assemblies, this transportation step is necessary. The enriched UO_2 is a fissile material and is shipped as a powder. The UO_2 is packaged in 55-gallon steel drums with each container holding about 0.12 ton of UO_2. The shipments are made by truck over an average distance of 750 miles, and each truck carries 40 drums or about 4.8 tons.

6. Fuel Assemblies from Fuel Fabrication to Reactor

   Approximately 30 metric tons of new fuel must be supplied to an LWR reach year. Because of nuclear criticality safety requirements, the new fuel arrives in six separate truck shipments during the year. The shipping container is a long cylindrical device in which the fuel assemblies are cradled. The average transit distance is 1,000 miles (AEC, 1972: 22).

7. Used Fuel from Reactor to Reprocessing Plant (AEC, 1972: 32; Elliot and Weaver, 1972: 140).

   Since the radioactivity and heat levels of used fuels are much higher than unused fuels, irradiated fuels require special shipping containers to dissipate the heat and to contain the radioactivity. As of December 1972, only one design had been approved for transportation of future fuel assemblies.

   The shipment is made by either truck or rail. The containers are similar in their cylindrical appearance, but the rail cask weighs from 77 to 110 tons and a truck cask weights a maximum of 39 tons. The weight of the irradiated fuel is only two to three percent of total cask weight. Approximately 30 metric tons of used fuel must be transported from each 1,000-Mwe reactor each year; this amount of used fuel would require either 60 trucks or 10 rail car shipments.

8. High-Level Radioactive Waste from Reprocessing Plant to Disposal Site

   The high-level waste consists of the radioactive fission products. These products will be solidified and shipped to the RSSF when it is completed. At present, the solid wastes are accumulating at the reprocessing plant. The shipping containers for these wastes will resemble those used in transporting irradiated fuel. Approximately 100 cf, the amount generated per model 1,000-Mwe LWR per year can be moved in one shipment by rail an average distance of about 2,000 miles (AEC, 1974c: H-13).

9. Low-Level Wastes to Commercial Burial Sites

   Low-level wastes are generated at the UF_6 production plants, fuel fabrication plants, and fuel reprocessing plants, and must then be shipped to a commercial burial site. The total waste per year per model 1,000-Mwe reactor is about 14,000 cf and requires about 58 truckloads, shipped an average distance of 500 miles.

6.2.9.3 Energy Efficiencies

The primary efficiency for each of the transportation steps should be 100 percent. The ancillary energy is the fuel required for the trucks or trains. No data are available on these energy requirements.

6.2.9.4 Environmental Considerations

6.2.9.4.1 Chronic

The two categories of chronic residuals are the combustion emissions from the trucks and trains, and the radioactive exposure. The truck and rail traffic due to the transportation of materials for the LWR system is so small, compared to total U.S. transportation, that the impact of the additional combustion residuals should be negligible.

Under normal conditions, some radioactive exposure will be received by handlers, truck drivers, and onlookers. The highest dose that might be received under normal conditions is about 0.5 rem per year (AEC, 1974c: H-4) as compared to a natural background radiation dosage of 0.125 rem per year. The AEC's facility regulations specify a maximum worker dosage of 5 rems per year.

6.2.9.4.2 Accidents

An accidental criticality could result in significant amounts of radiation exposure, but the AEC believes that such an accident is not possible because of the safety precautions that are undertaken (AEC, 1974c: H-4). The only other type of accident that would release significant quantities of radioactivity to the environment would be one in which a high-level waste container is breached. However, considering the low probability of a serious vehicle accident and the construction standards of the Type B containers, the AEC believes that the likelihood of a high-level waste container being breached is small (AEC, 1974c: H-22).

6.2.9.5 Economic Considerations

No separate data are available on the cost of the various transportation steps and their effect on total power generation costs.

6.3 HIGH TEMPERATURE GAS REACTOR (HTGR) SYSTEM

6.3.1 Introduction

The HTGR derives its name from the use of helium (as opposed to water in a LWR) as a coolant and heat transfer medium. In addition, to this characteristic, the HTGR differs from the LWR in efficiency and fuel characteristics. The capacity to heat helium to high temperatures at high pressures allows the HTGR to achieve efficiencies of 40 percent. Its fuels are Th-232, U-233, and U-235 which are formed into microspheres and loaded in graphite blocks.

A distinctive characteristic of current HTGR development is its limited support by the federal government when compared to support for the LWR or the LMFBR. The development of the HTGR is mainly a commercial venture by Gulf General Atomic.

Although the HTGR is commercially available, only the 40-Mwe Peach Bottom facility in Pennsylvania that began operation in 1966 is currently producing electricity. The 330-Mwe Fort St. Vrain facility in Colorado has received its operating license and is expected to begin commercial operation in late 1974 or early 1975. Ten additional plants have been ordered (Nuclear Task Force, 1974: 10), but the future role of the HTGR is unclear. Projections of HTGR growth made in 1969 indicated total capacities of 23,000 Mwe by 1985, 54,000 Mwe by 1990, and 100,000 Mwe by 2000 (AEC, 1974d: A.1.2-24). More recent estimates are that the HTGR will not be a major producer of electrical power until the year 2000 (Battelle, 1973: 470).

The resource system diagram for the HTGR is given in Figure 6-11 and includes seven major activities:

1. Exploration for both uranium and thorium.
2. Mining of both uranium and thorium.
3. Processing of both uranium and thorium.
4. Energy production in the reactor.
5. Fuel reprocessing.
6. Waste management.
7. Transportation.

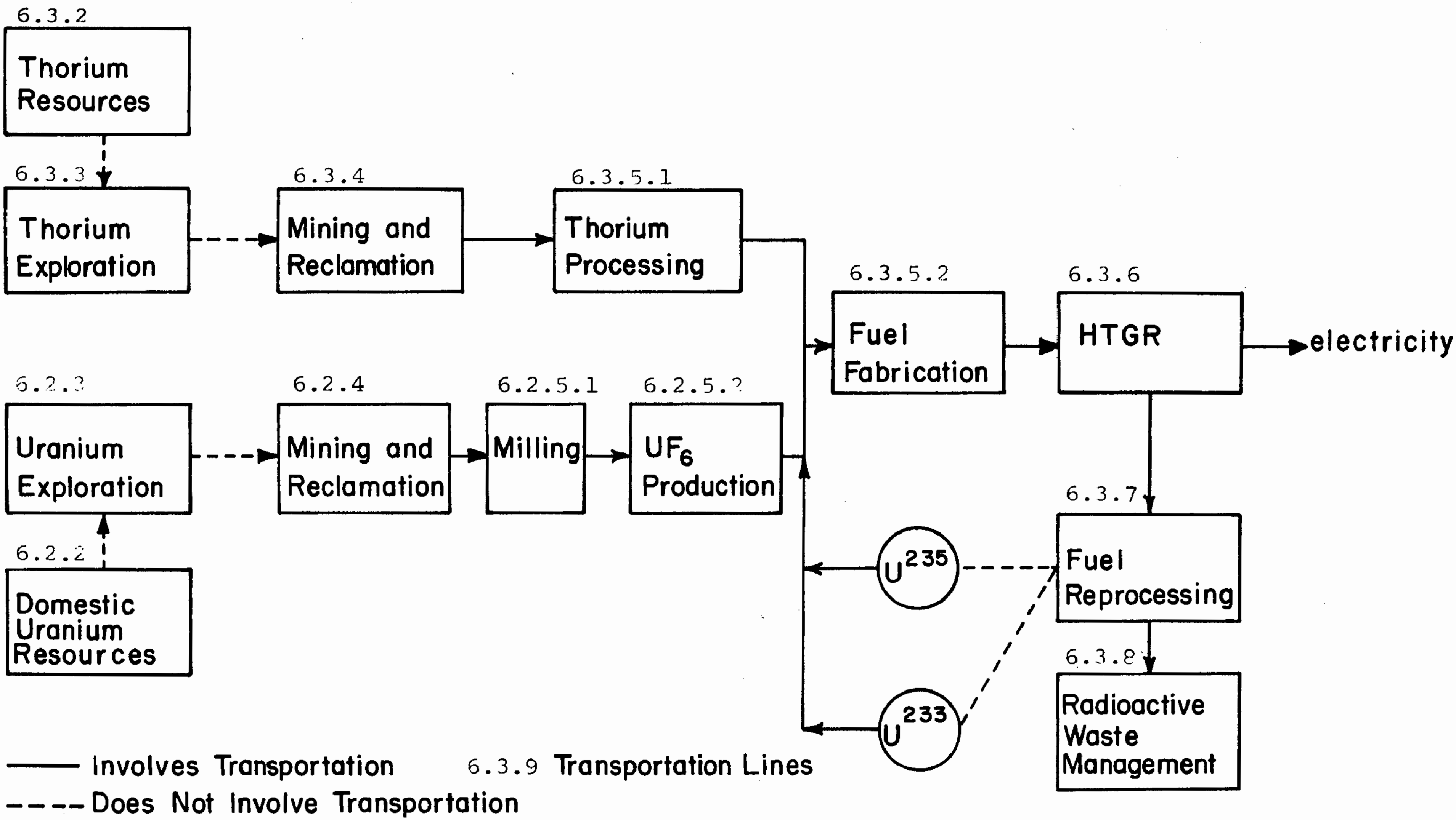


Figure 6-11. High Temperature Gas Reactor Fuel Cycle

As the flow diagram indicated the reactor's three fuels come from different sources, and the mix of fuels changes between the start-up period and regular operation. A summary of these characteristics is necessary to understanding the following descriptions.

The initial fuel loading of the reactor core will consist of U-235 and Th-232. In the reactor, the Th-232 will be converted into U-233. The used fuel will be reprocessed and the U-233 recovered and recycled to be used as fuel in the HTGR. The annual fuel requirements for a 1,000-Mwe HTGR are 13 tons of U_3O_8 and about eight tons of thorium dioxide (ThO_2) (AEC, 1974d: A.1.2-15).

U-235 is obtained by using the same fuel production steps, through enrichment, as as described in the LWR section, the difference being that uranium for the HTGR must be enriched to 95 percent versus three to four percent for the LWR. Th-232 comes from natural sources that are described in Section 6.3.2. Also, mining and processing of thorium are described. The production of U-233 is covered in Section 6.3.7. The three fuel sources are then developed as HTGR fuel in a specialized step that involves fuel microsphere production and fuel fabrication as indicated in Figure 6-11.

The following description of the HTGR system is divided between thorium resources and HTGR technologies. This description will not repeat material covered in the LWR description. Further, the limited experience with commercial HTGR's is reflected in the lack of available data on many of the activities.

6.3.2 Resource Base (Thorium)

Following is a description of domestic and Canadian thorium resources. Thorium by-products of Canadian uranium mining are included because their low cost makes them a major factor in the resource base for the HTGR.

6.3.2.1 Characteristics of the Resource

Thorium, one of the basic elements, is a heavy, silvery metal. Estimates of the thorium content in the earth's crust range from 5 to 13 parts per million (ppm) (Brobst and Pratt, 1973: 471) with the element being widely distributed in small quantities. Thorium occurs naturally in a variety of chemical forms, the most common of which are $ThPO_4$ (the chemical form found in monazite), ThO_2, and thorite ($ThSiO_4$).

Thorium is obtained from three main sources: monazite, a mixture of rare metals often found in sand or gravel deposits (Brobst and Pratt, 1973: 471); as a by-product of uranium mining; and from veins containing thorite. Prior to 1953, monazite was the major source of thorium (Brobst and Pratt, 1973: 469); since 1953, uranium deposits containing commercial amounts of thorium have been found in Malagasy and, more importantly for the proposed U.S. HTGR program, at Elliot Lake, Canada. These locations are now the major sources of thorium for the U.S.

6.3.2.2 Quantity of the Resources

Thorium resource quantities are not well identified mainly because the demand is small in relation to the available supply. Table 6-18 lists the identified thorium resources for the U.S. and Canada. The presently known resources are about 10,000 times greater than the amount used in 1968 (Brobst and Pratt, 1973: 473). The amount of thorium available in Canada as a by-product of uranium will be sufficient to fuel all of the HTGR's to be built in the U.S. during the century, a projected capacity of 100,000 Mwe (AEC, 1974d: A.1.2-6). At present, obtaining thorium from Canada is considered to be less expensive than developing U.S. resources. If U.S. thorium resources were developed and used for the HTGR's projected to be operating by the year 2000, the

TABLE 6-18

U.S. AND CANADIAN THORIUM RESOURCES

Locality[a]	Type of Deposit	Thousands of Short Tons ThO_2: Recoverable Primarily as By-Product or Coproduct	Recoverable Primarily for ThO_2 of grade--: Less Than 0.1 Percent	Recoverable Primarily for ThO_2 of grade--: Greater Than 0.1 Percent
U.S.:				
Atlantic Coast	Beach placer	16	NA	NA
North and South Carolina	Fluviatile placer	NA	NA	56
Idaho and Montana	Fluviatile placer	2	NA	38
Lemhi Pass District, Idaho and Montana	Veins	NA	100	NA
Wet Mountains, Colorado	Veins	NA	4.5	NA
Powderhorn District, Colorado	Veins	NA	1.5	NA
Mountain Pass District, California	Veins	NA	0.5	NA
Mountain Pass District, California	Carbonatite	28	NA	NA
Palmer Area, Michigan	Conglomerate	NA	NA	NA
Bald Mountain, Wyoming	Conglomerate	NA	NA	2
TOTAL U.S.		46	106.5	142
Canada:				
Elliot Lake, Ontario	Conglomerate	580		

NA - not applicable

Source: Brobst and Pratt, 1972: 474.

[a]Includes some hypothetical resources, which are undiscovered mineral deposits, whether of recoverable or subeconomic grade, that are geologically predictable as existing in known districts.

3.2 million tons of reasonably assured ThO_2 at $50 per pound would last for 400 years (see Table 6-19).

6.3.2.3 Location of the Resources

The major sources of U.S. thorium are monazite-containing beach placers on the Atlantic coast and thorite-containing vein deposits in the Lemhi Pass, Idaho. The only U.S. resources presently being mined are the Atlantic coast beach placers, where monazite is produced as a by-product of titanium mining.

Approximately 16,000 tons of ThO_2 are thought to be available in the Atlantic coast beach placers and about 100,000 tons may be present in the Lemhi Pass area.

Table 6-19 lists U.S. thorium reserves (those resources economically recoverable at present). Like uranium, thorium resources are categorized according to amounts recoverable at different per-pound costs.

6.3.3 Exploration

Thorium exploration has been minimal because the amount of thorium available as a by-product from titanium and uranium mining has been sufficient to meet the small demand (Brobst and Pratt, 1973: 475).

TABLE 6-19

U.S. THORIUM RESERVES

Cost (dollars per pound ThO_2)	Reserves (thousands of tons)		
	Reasonably Assured	Estimated Additional	Total
10	65	335	400
30	200[a]	400[a]	600[a]
50	3,200[a]	7,400[a]	10,600[a]

Source: AEC, 1974d: A.1.2-6.

[a]Includes lower cost resources.

6.3.3.1 Technologies

Thorium exploration methods are similar to those used for uranium as described in the exploration section of the LWR. In general, exploration methods rely on the radioactivity of thorium; also, more traditional methods are used for examination and sampling.

6.3.3.2 Energy Efficiencies

Although existing data are insufficient for ancillary energy calculations, these values should be negligible compared to ancillary energy requirements in other portions of the HTGR fuel cycle. The primary energy efficiency is not applicable for exploration.

6.3.3.3 Environmental Considerations

The residuals associated with exploration should be similar to those described in Chapter 1 or in the LWR description.

6.3.3.4 Economic Considerations

Specific economic data on thorium exploration are not available; however, the dollar costs should be similar to uranium exploration.

6.3.4 Mining (Battelle, 1973: 467)

6.3.4.1 Technologies

Mining techniques for monazite deposits and thorite veins differ. Since the water-insoluble monazite accumulates with other minerals on river bottoms and ocean beaches, placer mining methods are normally used. In essence, the material is simply gathered by shovel, dragline, or dredge.

The extraction of thorite (as from the Lemhi Pass veins) would be done by conventional mining methods, either open pit or underground, as described in Chapter 1.

6.3.4.2 Energy Efficiencies

Present information is insufficient to calculate either the primary or ancillary energy requirements for thorium mining. However, the ancillary energy use should be minimal in comparison to ancillary energy used at other points in the fuel cycle.

6.3.4.3 Environmental Considerations

The residuals associated with placer mining are unknown. The conventional mining techniques to be used on the Lemhi Pass veins should produce residuals similar to those for other minerals mined by these techniques.

6.3.4.4 Economic Considerations

Costs for extracting and converting ore into ThO_2 are divided into cost-per-pound categories as shown in Table 6-19. These range from \$10 to \$50 per pound for the ore presently classed as reserves.

As shown in Table 6-20, the mining costs associated with a 1,000-Mwe HTGR are $\$1.1 \times 10^6$ per year or 0.19 mill per kwh.

6.3.5 Processing

The processing of fuel for the HTGR is characterized by three major steps. First, thorium ore is processed to produce a powder, ThO_2. (This step is unnecessary for ThO_2 shipped from Canada.) Second, raw uranium is processed in the manner described in the LWR section to produce UO_2. (As mentioned earlier, HTGR uranium must be 95-percent enriched.) The third step, fuel fabrication, makes the ThO_2, enriched U-235, and reprocessed U-233 into microspheres and inserts the spheres into channels in graphite blocks that measure 14 inches by 31 inches.

Uranium processing has been covered in the LWR description. A discussion of the thorium processing and fabrication steps follows.

6.3.5.1 Processing of Thorium Ore to Produce ThO_2

Since the Canadian thorium is delivered to the fabrication plant as ThO_2, and the Lemhi Pass thorite is unlikely to be exploited in the near future, only the description of monazite processing will be presented.

6.3.5.1.1 Technologies

Processing monazite consists of two main phases, separating the monazite from its host material (primarily sand) and producing the ThO_2.

After the host material has been mined from placers or sand beaches, water is added and the mixture is sieved. Because monazite occurs in fine particles, it passes through the larger screens which retain and reject coarse material. The fine material resulting from the sieve operation is approximately 60-percent monazite (Yemel'vanov and Yevstyukhin, 1969: 377). After drying, this material is passed through a strong magnetic field. The monazite collects on one pole of the magnet in concentrations of 95 to 98 percent (Yemel'vanov and Yevstyukhin, 1969: 377).

ThO_2 production from the concentrated monazite is normally done by a three-step process. The initial step uses a hot caustic to dissolve and strip away unwanted portions of the monazite. The second step is a series of chemical treatments that start by dissolving the thorium and other remaining materials in acid. Through solvent extraction, the thorium (in the form of thorium nitrate) is then separated from other materials. The final step involves milling the thorium nitrate to produce ThO_2 (Battelle, 1973: 468).

6.3.5.1.2 Energy Efficiencies

Although a lack of data prevents energy efficiency calculations for thorium ore processing, the primary efficiency will be large because only an estimated 0.1 percent of the thorium is lost in the processing. The ancillary energy requirement should also be small.

6.3.5.1.3 Environmental Considerations

6.3.5.1.3.1 Chronic

As shown in Table 6-21, the primary radioactive elements to be discharged from thorium milling are thorium, radium, and uranium isotopes. Estimated 1990 emissions vary from 3.0 to 2.3 curies per 1,000 Mwe. All these estimated discharges will be ejected into a settling pond. Additional residual data for the combined milling-fabrication step are given in Table 6-20.

The total land area needed for the milling plant and the settling pond is not known.

TABLE 6-20

ANNUAL EFFECTS OF A 1,000-Mwe HTGR AND ITS FUEL CYCLE
(BASED ON 75 PERCENT LOAD FACTOR)

	Mining	Milling Fabrication[a]	Reactor Power Plant	Reprocessing Transportation[b]	Totals
Conventional Costs					
10^6 dollars 1980 dollars					
Fuel	1.1 (.19)[c]	7.5 (1.26)[c]	3.5 (.59)[c]	1.5 (.25)[c]	15 (2.3)[c]
Plant capital			57		57 (8.9)[c]
Operating and maintenance			4.8		4.8 (.7)[c]
Abatement cooling towers			2.4		2.4 (.4)[c]
TOTAL COSTS			67.7		79.4 (12.3)[c]
Occupational Accidents					
Deaths	0.05	0.003	0.01	0.002	0.07
Non-fatal injuries	1.8	0.75	1.3	0.06	3.9
Man-days lost	383	47	110	14	354
Mining and Milling Impacts					
Strip mining of uranium and mill tailings (acres)	2.7	1.2	NA	NA	3.9
Tailings produced at mill (10^3 metric tons)		43			43
Public Accidents in Transportation of Nuclear Fuels (excluding exposure to radioactivity)					
Deaths	0	0	0	0.009	0.009
Non-fatal injuries	0	0	0	0.08	0.08
Man-days lost	0	0	0	60	60
Occupational Health					
Miners' radiation exposure (miner-WLM)	58	0	0	0	58
Other occupational exposure (man-radiation)	0	15	300	12	327

TABLE 6-20 (Continued)

	Mining	Milling Fabrication[a]	Reactor Power Plant	Reprocessing Transportation[b]	Totals
Solid Radioactive Waste Disposal					
Volume (10^2 cubic feet)	0	31	22	10	63
Burial area (acres)	0	0.06	0.04	0.26	0.4
Effects at the Power Plant					
Thermal discharge (10^{10} kilowatt hour [thermal])	0	0	1.1	0	1.1
Net destruction of uranium (metric tons)	0	0	0.3	0	0.3
Net destruction of thorium (metric tons)	0	0	0.5	0	0.5
Routine Radioactive Releases to the Atmosphere (curie)					
H-3	0	0	4	16,000	16,000
Kr-85	0	0	9	570,000	570,000
I-129	0	0	0	0.0003	0.0003
I-131	0	0	0	3	3
Xe-131m	0	0	0	0	0
Xe-133	0	0	0	0	0
Cs-137	0	0	0	0.002	0.002
Rn-220	0	23	0	0	23
Rn-222	0	23	0	0	23
U-232	0	0.4	0	0	0.4
U-233	0	0.2	0	0	0.2
Total U	0	0.7	0	0	0.7
Others	0	0	0	0	2
Routine Radioactive Releases to Waterways (curies)					
H-3	0	0	0	350	350
I-129	0	0	0	0.0002	0.0002
I-131	0	0	0	0.02	0.02
Cs-137	0	0	0	0.004	0.004
U-232	0	9	0	0	9
U-233	0	4	0	0	4
Total U	0	14	0	0	14
Other	0	0.1	4	2	6

TABLE 6-20 (Continued)

	Mining	Milling Fabrication[a]	Reactor Power Plant	Reprocessing Transportation[b]	Totals
Population Exposure from Routine Releases of Radionuclides					
Global model: All-time commitment, long-lived nuclides					
World (whole body man-radiation)					
Kr-85	0	0	0	256	256
H-3	0	0	0	21	21
TOTAL WORLD					277
U.S. (whole body man-radiation)					
Kr-85				12.0	12.0
H-3				2.3	2.3
TOTAL U.S.					14.3
Local model: Airborne short-lived noble gases and tritium					
Total man-rem within 50 miles					
High population assumption					48
Medium population assumption					4.8
Low population assumption					0.69

Source: AEC, 1974d: A.1.2-32.

[a]Milling, conversion, enrichment, and preparation and fabrication.

[b]Includes all transportation steps.

[c]Units are in mills per kilowatt hour.

[d]Working capital charges.

6.3.5.1.3.2 Major Accidents

A major accident associated with thorium ore processing has not been analyzed; however, the residuals should be comparable to the residuals given in the LWR uranium milling section.

6.3.5.1.4 Economic Considerations

Table 6-20 gives a combined cost of milling and fabrication of $7.5 million per year (1980 dollars) or approximately 1.26 mills per kwh for a 1,000-Mwe reactor.

TABLE 6-21

SUMMARY OF THORIUM MILLING EMISSIONS

	Radioisotope Discharge to Receptors Total Curies of Th-232, Th-228, Ra-228, U-238, and Ra-226 per 1,000-Mwe			
	1975[a]	1980	1985	1990
Air[b]	0	0	0	0
Land	0	3	2.5	2.3
Water	0	0	0	0

Source: Modified from Battelle, 1973: 469.

[a]No residuals are included in 1975 because it was assumed there would be no thorium milling for reactor use until 1980.

[b]The actual distribution of the short-lived gas Ra-220 throughout the milling industry is not known, particularly since the ore is mined in a pulverized state and is mechanically concentrated at the mine site to chemical milling procedures. Thus, the contribution of radon to the air receptor is not included in this study.

6.3.5.2 Fuel Element Fabrication

Fuel element fabrication will consist of the following steps:

1. The fuel will be formed into two types of microspheres.
2. The microspheres will be bound into 0.5- by 1.5-inch pellets.
3. The pellets will be inserted into the graphite blocks.

In HTGR's, the first fuel loading will consist of U-235 and Th-232. For subsequent loadings, the U-233 produced in the reactor from the Th-232 and recovered in the reprocessing step (Section 6.3.7) will be used as the nuclear fuel. At present, no large commercial HTGR fuel fabrication plants are in existence, but an HTGR refabrication pilot plant has been proposed by the AEC (1974g). The plant would be built at Oak Ridge National Laboratory and operated for two years; its basic purpose would be the development of fuel cycle technology.

6.3.5.2.1 Technologies

In the present HTGR fuel element fabrication process, the three input streams are the U-235F_6 from the enrichment plant, the ThO_2 from the mill, and the recycled U-233 from the reprocessing plant. These three materials will be formed into two types of microspheres, one containing the U-235 and the other containing a combination of thorium and U-233. Fabrication of the two types of spheres will be similar except that the U-235 receives an extra coating of carbon as shown in Figure 6-12.

To form the microspheres, fuel particles will be dried and baked in an oven. The particles will be then inspected, sorted, and weighed to insure a uniform size for each type (AEC, 1974b: 19). After acceptance, the particles will be sent to a furnace to be coated with layers of graphite. Following the coating, the microspheres will again be checked for uniformity.

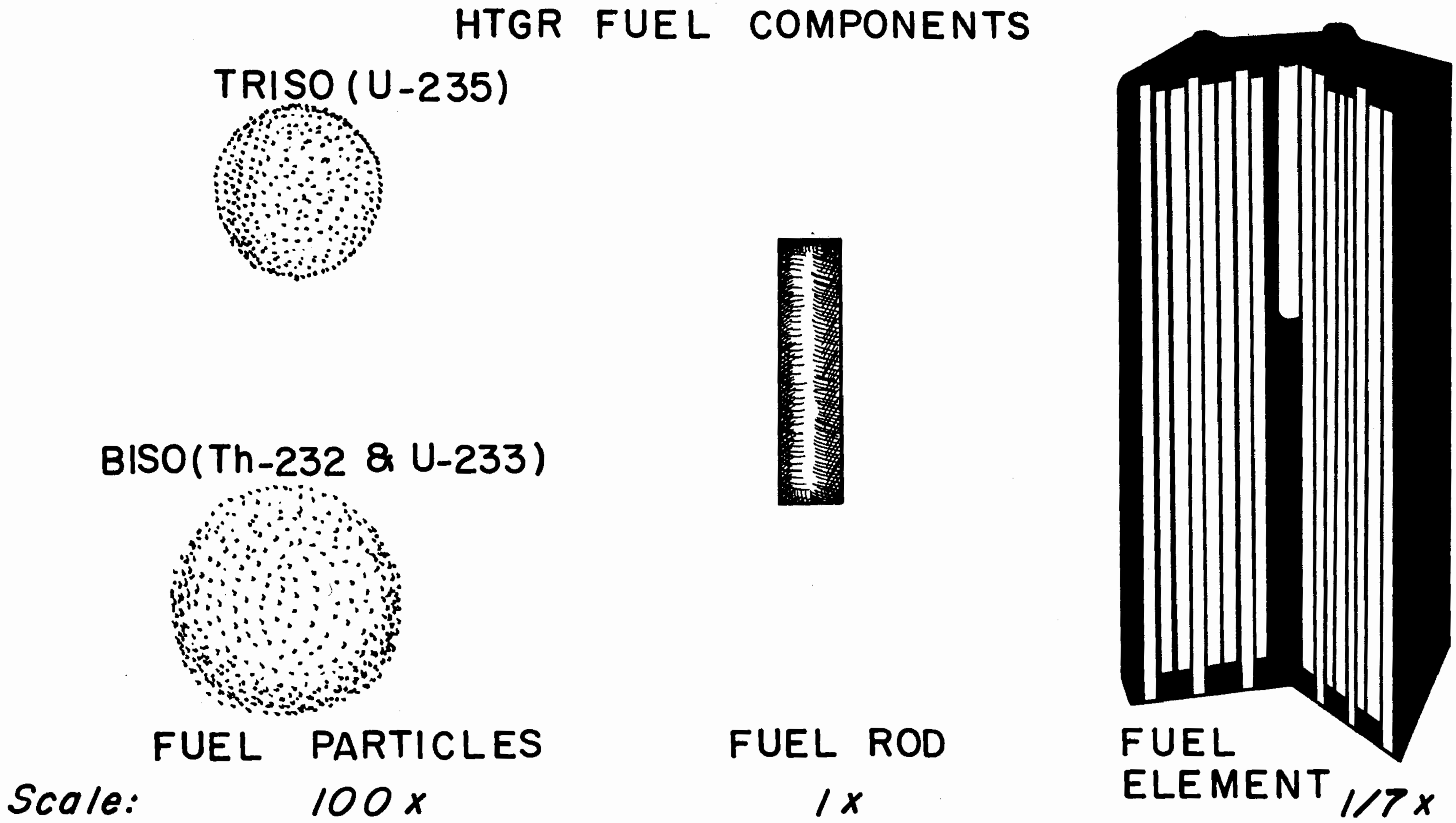


Figure 6-12. HTGR Fuel Components
Source: AEC, 1974d: A.12-12.

To form pellets, the two types of microspheres are blended together and poured into molds with a carbonaceous "binder" (a material that will hold the microspheres together in the mold). After heating to drive off any volatile materials, pellets approximately 0.5 inch in diameter and 2.5 inches in length will be created (AEC, 1974f: 20).

These pellets, labeled fuel rods in Figure 6-12, are positioned in the holes of the machined graphite blocks. Approximately 2,000 fuel rods are needed to fill a single fuel element.

6.3.5.2.2 Energy Efficiencies

Since no commercial plants are presently operating, the ancillary and primary energy efficiencies cannot be calculated. However, the primary energy efficiency should be quite high; that is, approximately 99 percent.

6.3.5.2.3 Environmental Considerations

6.3.5.2.3.1 Chronic

The stack chemical effluents listed in Table 6-22 are calculations for the HTGR refabrication pilot plant for a daily operation of 25 kilograms of uranium and thorium per day. The major chemical stack effluent will be 53.0 metric tons per year of CO_2.

The main solid chemical residual will be sodium nitrate ($NaNO_3$), and the largest release of a solid radioactive residual will be 13.0 curies per year of U-233. The gaseous radioactive effluents, U-233 and U-232, will be released in small amounts (AEC, 1974g: 23).

6.3.5.2.3.2 Major Accidents

An analysis of the pilot plant indicates that an inadvertent criticality, a fire, or an explosion could result in the release of radioactive material. However, shielding, containment, and ventilating systems are designed to contain the radioactive material in the plant in case of accident (AEC, 1974g: 26).

6.3.5.2.4 Economic Considerations

Table 6-20 lists a combined cost of $7.5 million (1980 dollars) per year or 1.26 mills per kwh for milling and fabrication to support a 1,000-Mwe HTGR plant.

6.3.6 High Temperature Gas Reactor

6.3.6.1 Technologies

A schematic of the high temperature gas reactor is shown in Figure 6-13. The heat created by the fissioning of U-235 and/or U-233 is transferred to the helium, which is circulated through the core, to a steam generator, and back to the core. The production of electricity from the steam is via a turbine-generator as described in Chapter 12.

The other major pieces of equipment shown in Figure 6-13 are the control rods (which control the rate of fission), the prestressed concrete reactor vessel (PCRV), the steam generator, and the containment structure. The PCRV is a unique feature of the HTGR. All the major equipment, including the primary coolant system, is contained inside the PCRV. The PCRV eliminates the worry over a primary pipe rupture that occurs outside the reactor vessel, as associated with an LWR. If a break occurs in one of the helium pipes, the PCRV is designed to contain the leaking gas.

The HTGR can achieve overall thermal efficiencies of about 40 percent due to the high temperature and pressure capabilities of helium. In the Fort St. Vrain plant, the helium will be heated to 1,430°F at 700 pounds per square inch atmosphere (psia) (Gulf General Atomic, 1973: 6). These helium conditions create steam at 1,005°F at 2,512 psia.

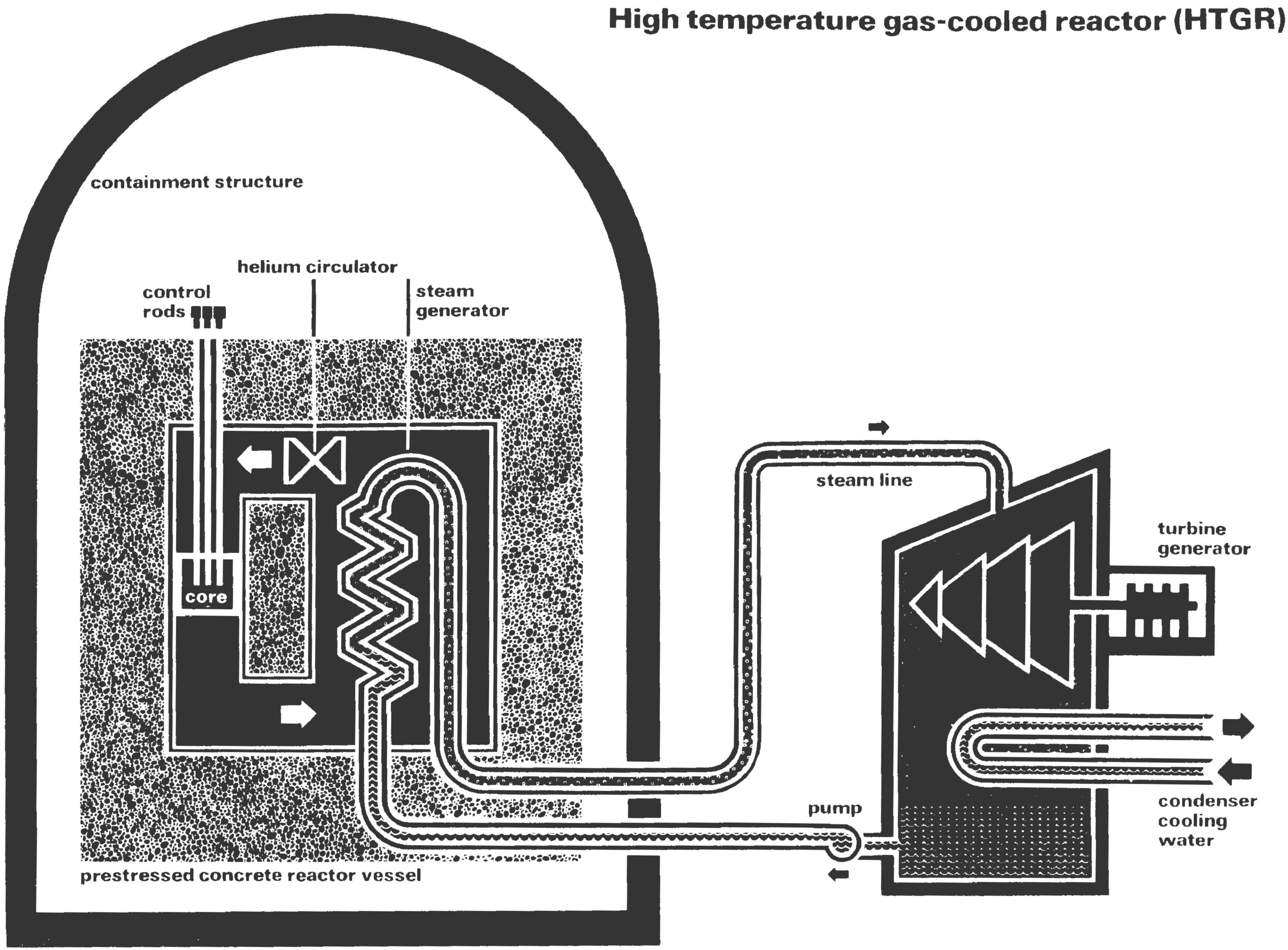


Figure 6-13. High Temperature Gas-Cooled Reactor

Source: Atomic Industrial Forum, Incorporated.

TABLE 6-22

CHEMICAL STACK EFFLUENTS FROM HTGR FUEL REFABRICATION PILOT PLANT (BASED ON 25 KILOGRAMS OF HEAVY METAL, U + Th, PER DAY)

Chemical	Annual Release Rate (metric tons per year)	Concentration ($\mu g/m^3$)	
		At Stack Exit[a]	At Site Boundary[b]
Hydrogen	1.8	$2.6x10^3$	0.015
Inert (Ar, He)	25.0	$3.6x10^4$	0.20
Carbon dioxide	53.0	$7.2x10^4$	0.40
Carbon monoxide	2.7	$3.6x10^3$	0.020
Nitrogen oxide	0.124	174	0.00001
Surfactant	0.0033	4.8	0.000029
2-ethyl-l-hexanol	0.0033	5.2	0.000029

Source: AEC, 1974g: Appendix A.

[a]Just prior to leaving top of the stack on the basis of a stack flow rate of 60,000 standard cubic foot per minute.

[b]Based on dispersion factor (χ/ Q) of $2x10^{-7}$ seconds per meter cubed.

The HTGR has a number of safety advantages when compared to an LWR or an LMFBR (AEC, 1974d: A.1.2-20). First, the loss of the helium coolant is not a severe problem as compared to the loss of water coolant in a LWR. The graphite core can absorb large amounts of heat, and the temperature change of the core will be slow. Second, the PCRV adds to overall reactor safety, as mentioned earlier. Third, the use of small, coated fuel particles reduces the amount of radioactive fission products released into the coolant. If a fuel rod ruptures in an LWR or LMFBR, large quantities of radioactive material can be released into the coolant; however, the rupture of one coated particle in an HTGR would result in a far smaller release of radioactivity.

The HTGR has one undesirable feature. The use of graphite introduces the problem of a possible steam-carbon reaction. If large amounts of steam enter the core, the reaction could result in structural damage and the release of some fission products.

6.3.6.2 Energy Efficiencies

The net plant efficiency of an HTGR is about 40 percent.

6.3.6.3.1 Chronic

The primary chronic residuals, as shown in Table 6-20, will be radioactive emissions to the air and water, thermal discharges, and low-level solid radioactive wastes. The radioactive releases of tritium and Kr-85 will be four and nine curies respectively as compared to LWR releases of 10 to 50 curies of tritium. The total radioactive release to the water will be four curies. The thermal discharge will be $1.1x10^{10}$ kwh (thermal). Approximately 2,200 cf of low-level solid radioactive waste will require burial each year. The total radiation dose to the general public is expected to be indistinguishable from the natural background radiation dose of 125 mrem per year.

6.3.6.3.2 Major Accidents

As described in the LWR section, the loss of core coolant is a major accident. Since the HTGR graphite core can absorb much larger amounts of heat without melting than can LWR cores, coolant loss accidents should be much less severe in HTGR's than in LWR's.

6.3.6.4 Economic Considerations

The capital costs of a 1,300-Mwe HTGR introduced in 1985 are projected to be $419 per kwe (kilowatts-electric). The annual operating and maintenance costs are estimated to be $12.7 million for the 1,300-Mwe plant (AEC, 1974d: Appendix 11).

Table 6-20 lists the economics for 1,000-Mwe plant in 1980 dollars. Of the total reactor plant annual costs of about $68 million, five percent is for fuel, 84 percent is for plant capital, seven percent is for operating and maintenance, and four percent is for the cooling towers. The total power generation costs are expected to be 12.3 mills per kwh.

The figures from Table 6-20 and the values in the above paragraph are from different sources.

6.3.6.3.5 Other Considerations

Future research efforts on HTGR's will examine the possibility of using a direct cycle, where the helium expands through the turbine. Coupled with a bottoming cycle (explained in Chapter 12), the primary efficiency of these HTGR's could be increased to 50 percent (AEC, 1974d: A.1.2-23). The HTGR could also be used as a source of process heat for coal gasification, steelmaking, hydrogen production, etc. (AEC, 1974d: A.1.2-24).

6.3.7 Reprocessing

The purpose of reprocessing HTGR fuel is to recover the unused U-235, Th-232, and the created U-233 for reuse as nuclear fuel.

The status of the HTGR reprocessing industry is characterized by uncertainties. Presently, there are no operating plants, but an HTGR fuels reprocessing facility has been proposed for construction at the National Reactor Testing Station, Idaho (AEC, 1974g). The most probable situation is that reprocessing of HTGR fuel will not be needed until 1990 (Battelle, 1973: 507).

The actual reprocessing method is not completely known. The chemical processing of the used fuel has been established on a small scale, but the physical procedures for preparing the fuel elements for the chemical processes have not been established. The problems involved in scaling up both the chemical and physical processing will be examined at the proposed facility in Idaho (AEC, 1974d: A.1.2-23).

6.3.7.1 Technologies

The first step in reprocessing the HTGR fuel is to reduce the fuel to a form ready for chemical processing. One proposed method is to ship the large block graphite fuel elements to the reprocessing plants where the graphite is burned (AEC, 1974d: A.1.2-22) and the microspheres of fuel are separated from the graphite. The two types of microspheres can then be separated by further burning because the coating on the U-235 pellets will not disintegrate while the coating on the Th-232 and U-233 pellets will.

The second step is the chemical processing of the two types of microspheres. The U-235 is reprocessed by the method described in the LWR section. For the microspheres containing thorium, the "Thorex" process has been and will be used (AEC, 1969: 121). In the "Thorex" process, solvent extraction is used to separate both the uranium and thorium from the majority of the fission products. The thorium can then be separated from the uranium by dissolving both in a weak nitric acid solution; the thorium reacts while the uranium does not. Each is then recovered from its respective solution. The uranium will be shipped to the fuel fabrication plant, but the thorium will probably be stored (AEC, 1974d: A.1.2-19) for about 12 years to allow the level of radioactivity to decrease. If low-cost thorium is not available, the storage period could be shorter.

6.3.7.2 Energy Efficiencies

The primary energy efficiency will probably be large; that is, greater than 90 percent. The ancillary energy requirement has not been calculated.

6.3.7.3 Environmental Considerations

Table 6-20 contains the residuals for reprocessing and transportation. In reprocessing, the main radioactive releases to the atmosphere will be 16,000 curies of tritium and 570,000 curies of Kr-85. The main radioactive release to the water will be 350 curies of tritium. The exposure to the general public is expected to be indistinguishable from background.

Major accident considerations will be similar to those in the LWR reprocessing section.

6.3.7.4 Economic Considerations

The preliminary estimate to build the reprocessing facility in Idaho is $30 million, although inflation will probably increase this figure (AEC, 1974g: 68). The operating costs of this plant are expected to be $3 million per year for a processing capability of 24 fuel elements per day.

Table 6-20 lists a reprocessing cost of $1.5 million or 0.25 mill per kwh for a 1,000-Mwe plant for a year.

6.3.8 Radioactive Waste Management

The radioactive waste management program of the HTGR fuel cycle is expected to be similar to the program for the LWR. No major shipments of HTGR wastes have taken place or will take place in the near future. Since commercial reprocessing capability will not be needed until around 1990 and since the high-level waste can be stored at the reprocessing plant for up to 10 years, the first large shipments of high-level waste may not occur until 2000.

The only significant difference between the HTGR and LWR program is the amount of burial ground needed for the radioactive wastes. Since the HTGR does not use cladding and has a higher efficiency, the volume of radioactive wastes will be about 70 percent of those generated by a comparable size LWR (AEC, 1974d: A.1.2-28).

6.3.9 Transportation

The solid lines in Figure 6-11 represent transportation of radioactive material. In addition to the necessary uranium transportation steps described in the LWR section, a certain number of movements of radioactive thorium materials are necessary. At present, however, no major movements of thorium are being performed or anticipated because the resource needs of the HTGR industry are small. Therefore, the economics and details of transportation in the HTGR fuel cycle are not well known.

6.3.9.1 Technologies

The necessary transportation steps are:

1. The steps described in the LWR transportation section for uranium through the enrichment process.
2. Thorium concentrate from the mine to processing.
3. ThO_2 from processing to the fuel fabrication plant.
4. Fuel elements from fabrication plant to the reactor.
5. Used elements from the reactor to the reprocessing plant.
6. Recovered U-233 from the reprocessing plant to the fuel fabrication plant.
7. High-level radioactive waste from the reprocessing plant to the burial site.

8. Low-level radioactive waste from all the steps to the burial site.

The transportation methods and containers will be similar to those used in the uranium fuel cycle. If the fuel fabrication and fuel reprocessing plants are located at the same site, one transportation step is eliminated.

A shipping cask has been approved for the shipment of HTGR fuel elements that contain U-233, U-235, and Th-232. The highly enriched uranium (95-percent U-235) requires more stringent measures than transporting low enrichment uranium.

6.3.9.2 Energy Efficiencies

The total ancillary energy requirement for HTGR fuel transportation has not been calculated; once the commercial facilities have been established, the ancillary energy needs will represent the fuel requirements for the various modes of transportation.

6.3.9.3 Environmental Considerations

Table 6-20 lists residuals for transportation and reprocessing combined. The transportation residuals should be comparable to those described in the LWR section.

For major accidents, the analysis given in the LWR transportation section should be applicable.

6.3.9.4 Economic Considerations

Table 6-20 gives a reprocessing and transportation cost figure of $1.5 million per year or 0.25 mill per kwh for a 1,000-Mwe HTGR. The transportation portion of this value is probably for the transportation of the high-level waste from the reprocessing plant to the disposal site.

No separate economic data are available for the other transportation steps.

6.4 LIQUID METAL FAST BREEDER REACTOR (LMFBR) SYSTEM

6.4.1 Introduction

The term "fast breeder reactor" refers to nuclear reactors that, in addition to providing useful electric power output, convert abundant U-238 into fissile Pu-239 and thereby produce more fissile nuclear fuel than they consume. The AEC has been conducting basic studies on the breeder reactor concept for more than 20 years and, about eight years ago, launched an intensive effort (in cooperation with industry) to develop a liquid metal fast breeder reactor (AEC, 1974e: 26).

To indicate the level of this development effort, the breeder reactor program represented more than 42 percent of all federal energy R&D expenditures in the fiscal 1973 budget. The primary goal of this program is to build and operate a 400-Mwe power plant on the Clinch River in Tennessee by the early 1980's. Another principal element of the breeder program is the commitment to build and operate the Fast Flux Text Facility for the purpose of testing instrumented fuels and materials.

The major difference between LMFBR's and other reactors is that the central reactor core is surrounded by an outer core or "blanket." The fuel rods in the central core contain a mixture of plutonium dioxide (PuO_2) and UO_2 (primarily U-238), while the blanket is loaded only with UO_2. As the plutonium in the central core fissions, neutrons interact with the U-238 in both the core and blanket, transforming the U-238 into Pu-239. For every four pounds of Pu-239 consumed by an LMFBR, approximately five pounds will be created, thus the term "breeder reactor."

Compared to LWR's and HTGR's, the LMFBR has two other distinctive features. First, the LMFBR core employs "fast" neutrons

(neutrons whose speed has not been slowed by a moderating substance, such as hydrogen) to achieve fission. For this reason, LMFBR's are known as "fast" reactors while reactors using moderated neutrons (such as the LWR's and HTGR's) are known as "thermal" reactors. Second, the LMFBR used liquid sodium to transfer heat from the reactor core to the water/steam that drives the turbine-generators. Combined with the plutonium breeding capabilities, these features give the reactor its name, "liquid metal fast breeder reactor."

The LMFBR has two basic advantages. One, of course, is that it creates fissile fuel (Pu-239) out of U-238, thereby greatly increasing the usable nuclear energy resources. The second advantage is that the liquid metal coolant permits higher operating temperatures, thus giving projected plant efficiencies of 41 percent as compared to 32-percent efficiency for LWR plants.

However, the LMFBR also has two major disadvantages. First, plutonium is one of the most toxic substances known to man, and a major LMFBR industry would require handling large amounts of plutonium safely. Second, sodium is extremely reactive chemically and its use as a reactor coolant also creates significant safety problems.

Figure 6-14 is a simplified flow diagram for the LMFBR system. In the fuel fabrication step, both U-238 and Pu-239 are involved. The three U-238 supply options are: uranium that is mined and processed as in the LWR system except that the enrichment step is not necessary; U-238 from the depleted stream in the uranium enrichment step for the LWR system; and U-238 that is recovered from the used LWR fuel. In the near future, all U-238 for the LMFBR will come from depleted enrichment tailings. Plutonium comes from two sources: Pu-239 recovered from the used LWR fuel and (eventually) Pu-239 that is bred in an LMFBR. For a full description of the LWR fuel fabrication process, see Section 6.2.

Figure 6-14 shows that the fabricated fuel feeds into the LMFBR which generates electricity. Used fuel is reprocessed, the Pu-239 going to the fuel fabrication plant and the radioactive wastes (fission products) going to the radioactive waste management step. All solid arrows in the figure indicate transportation steps described in Section 6.4.7.

The following descriptions are brief because of a lack of LMFBR system information on efficiencies, environmental residuals, and economic costs. Further, much of the available data is speculative due to a lack of operating experience with the LMFBR system technologies.

6.4.2 Resource

The LMFBR system resources are more complex to treat than those for other energy sources. As mentioned above, heat used for generating electric power comes from the fissioning U-238 and Pu-239, and the Pu-239 is created from U-238 either in an LWR or in an LMFBR.* Therefore, the total LMFBR energy resource depends on the total uranium resource base, which was discussed in Part I. The difference is that the LWR system uses the U-235 isotope (which constitutes only 0.71 percent of naturally occurring uranium) while the LMFBR utilizes the U-238 isotope (which constitutes the remaining 99.29 percent of the naturally occurring uranium). Thus, the total energy resource base for the LMFBR is many times larger than the LWR energy resource base.

However, the LMFBR system will also require initial plutonium inventories to operate until the generated plutonium

---

*Although Pu-239 does exist naturally, it is in such small concentrations that it would be costly to recover, and its quantity could not provide a major energy base.

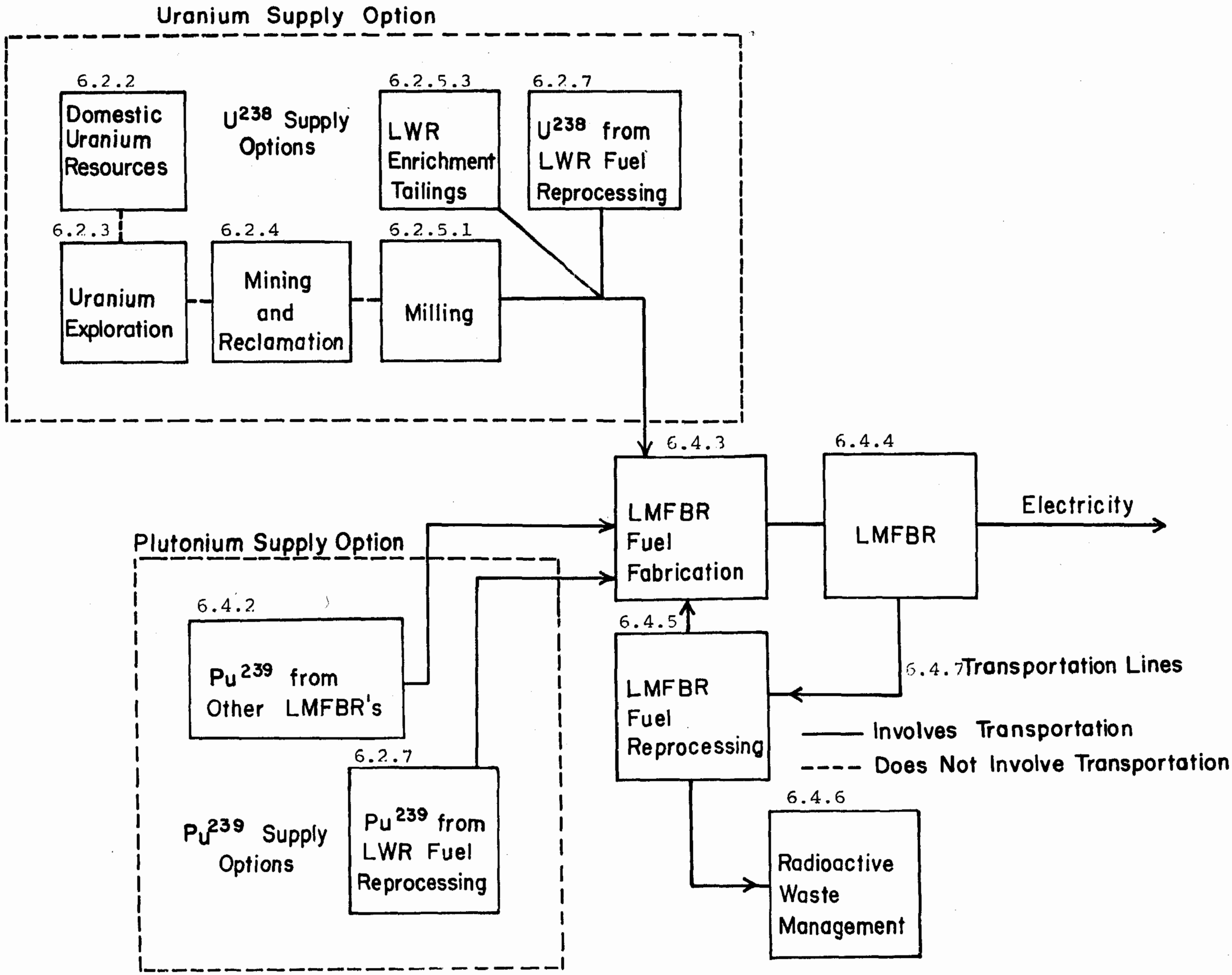


Figure 6-14. Liquid Metal Fast Breeder Reactor Fuel Cycle

supplies are sufficient to supply the needed fuel. This initial plutonium must come from the LWR system. Thus, plutonium sufficiency will be determined by the excess quantities produced in the LWR economy, by the growth rate and timing of the LMFBR economy, and by the doubling time of the plutonium inventory due to the breeding gain in the LMFBR's (AEC, 1974d: 4.1-20). Figure 6-15 is a projection of plutonium availabilities and requirements. LMFBR inventory requirements do not exceed the plutonium available from LWR's until the year 2000, at which time excess plutonium from LMFBR's will provide inventories for new plants.

Since the primary source of U-238 will be the depleted uranium streams from the enrichment plants, the current projections of depleted uranium are crucial to LMFBR development. Table 6-23 gives projected quantities of depleted uranium from the enrichment of LWR and HTGR fuels. Since a 1,000-Mwe LMFBR uses less than one ton of uranium per year (Creagan, 1973: 14), the potential supply of UF_6 appears to be adequate for LMFBR needs for hundreds of years without additional mining operations.

6.4.3 Fuel Fabrication

6.4.3.1 Technologies

As noted, the initial fuel loadings for LMFBR plants will consist of Pu-239 recovered from LWR fuels and U-238 from the enrichment plant tailings. The plutonium will be converted to PuO_2 for shipment from stockpiles to the fabricating plant. The uranium is shipped to the fuel fabrication plant as UF_6.

The fabrication plant produces two types of pellets: mixed oxide pellets containing UO_2 and PuO_2 to be used in the reactor core, and UO_2 pellets to be used in the blanket. At present, there are no commercial fuel fabrication plants devoted solely to LMFBR fuels. Nine existing small-scale plants are capable of performing all or part of the necessary steps, and a plant capable of producing 220 tons per year of mixed oxide fuel is scheduled to begin operation in 1977 (AEC, 1974d: 4.3-2).

The fuel elements for both the core and the blanket consist of long thin tubes (cladding) that are filled with either UO_2 pellets or mixed oxide (both UO_2 and PuO_2) pellets. These pellets are similar in size, being approximately 0.25 inch in diameter and 1.5 inches in length.

The fuel fabrication plant will consist of two physically separated sections, one to produce the UO_2 fuel elements and one to produce the mixed oxide fuel elements. The division is necessary because the plutonium containment regulations are much more stringent than those for the depleted uranium. Figure 6-16 shows the flow diagram for a plant capable of producing 5.5 tons of LMFBR fuel per day (AEC, 1974d: 4.3-10), which would be sufficient to supply 80 1,000-Mwe plants.

The mixed oxide section mechanically mixes the PuO_2 and UO_2 powders. Pellets are produced from the mixed powder and sintered in a high-temperature oven. The pellets are then ground to size and loaded into the stainless steel cladding tubes.

The UO_2 section of the plant involves both chemical and mechanical processing and is similar to the fuel fabrication plant described in Part I. The depleted UF_6 is converted to UO_2 by successive reactions using water and ammonia. The product of these reactions is heated to a high temperature to produce the UO_2 powder. Processing the UO_2 powder into fuel pellets follows the same process as that for the mixed oxide powder.

6.4.3.2 Energy Efficiencies

At present, there is insufficient information to calculate the energy efficiency of the fuel fabrication step. The

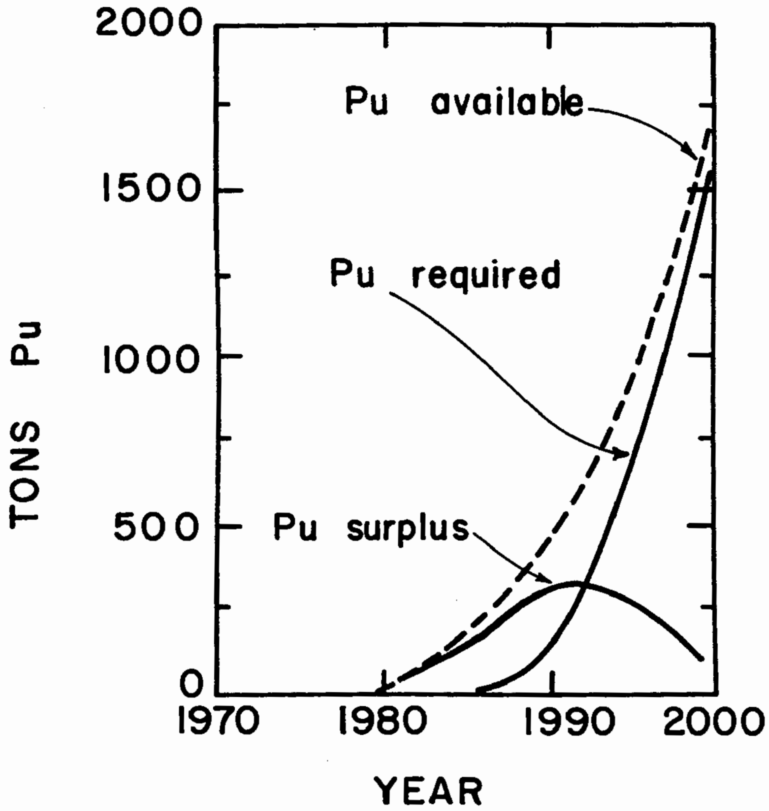


Figure 6-15. Plutonium Availabilities and Requirements
Source: Creagan, 1973: 16.

TABLE 6-23

PRODUCTION OF DEPLETED UF_6 FORECAST FOR THE YEARS 1972-2000

Year	Fabrication Load, Metric Tons of U				UF_6 Metric Tons of U	
	LWR UO_2	HTGR Fissile	LMFBR Mixed Oxide	LMFBR Blanket	Conversion	Depleted[a]
1972	750	1	0	0	3,700	2,949
1975	1,970	0	0	0	12,400	10,430
1980	4,600	7	5	1	25,500	20,893
1985	8,400	23	56	23	48,100	39,677
1990	14,000	44	850	310	81,900	67,856
1995	17,700	60	3,300	1,150	102,600	84,840
2000	19,700	70	6,900	2,500	110,200	90,430

Source: AEC, 1974d: 4.1-42.

[a]Depleted UF_6 = (conversion UF_6) - (LWR UO_2) - (HTGR fissile).

primary loss of uranium and plutonium would be negligible. The ancillary energy would be the energy required to operate the fuel fabrication plant.

6.4.3.3 Environmental Considerations

6.4.3.3.1 Chronic

The information on environmental residuals in Table 6-24 is based on a model plant and the residuals have been normalized to reflect the requirements for a 1,000-Mwe LMFBR power plant.

In Table 6-24, the two principal liquid chemical effluents of the UO_2 section are ammonium hydroxide, NH_4OH, and calcium hydroxide, Ca $(OH)_2$. After passing through a waste treatment plant, the residue is pumped to a lined lagoon for fluoride precipitation. The remaining wastes are pumped to another lined storage lagoon where they are retained. The accumulation of these wastes requires the periodic construction of new lagoons. (AEC, 1974d: 4.3-33).

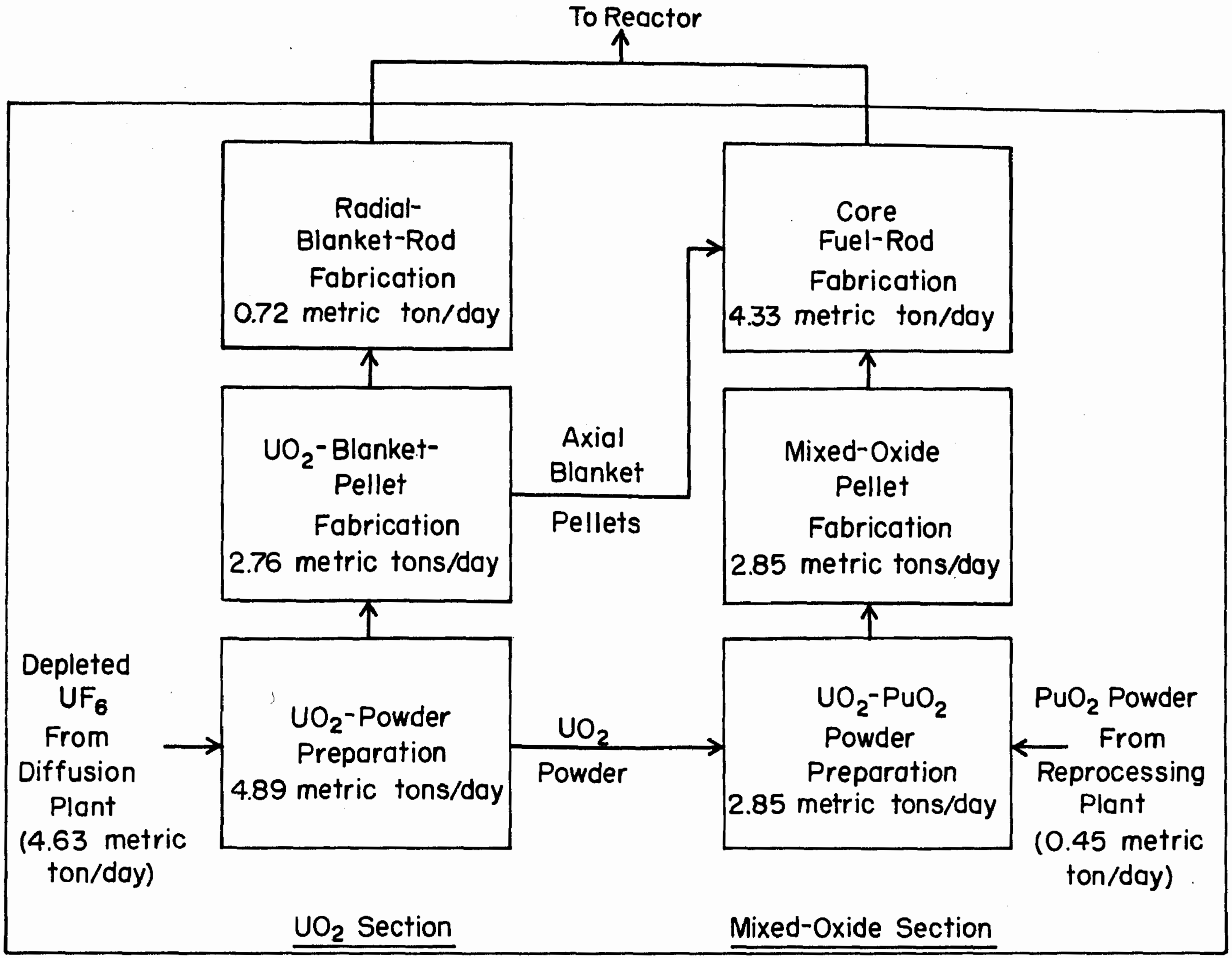
The gaseous chemical effluents would be small amounts of NO_x and about 2,000 grams of hydrogen fluoride (HF) and 6,000 grams of ammonia (NH_3) per day (AEC, 1974d).

Tables 6-25 and 6-26 give the radioactive emissions in the gaseous and liquid effluents respectively (AEC, 1974d: 4.3-52). The maximum individual radiation dose from both gaseous and liquid emissions during normal operations is estimated to be 0.059 mrem per year (AEC, 1974d: 4.3-92). This is approximately 2,000 times less than natural background radiation and represents the "fence-post" dosage (the radiation expsoure of a person living at the power plant boundary 24 hours per day, 365 days per year).

6.4.3.3.2 Major Accidents

The potential for major accidents differs in the two sections of the fabrication plant. In the UO_2 section, the rupture of a UF_6 cylinder would result in the release of uranium and HF. The gaseous effluent would result in a localized radiation level 285 times greater than normal operations. The HF may present a greater potential hazard than the uranium. Under extreme conditions, human health could be affected by HF in the air (AEC, 1974d: 4.3-144).

In the mixed oxide section of the plant, the worst postulated accident would be a general fire that resulted in the release of



Note: Numbers represent the weight of material being processed, including reject material and loss, due to simplification, weights will not balance.

Figure 6-16. LMFBR Fuel-Fabrication Plant
(5-Metric Tons of Heavy Metal Per Day)

Source: AEC, 1974d: 4.3-10.

TABLE 6-24

CHEMICAL RESIDUALS IN LIQUID EFFLUENTS FROM 1,000-Mwe LMFBR

Chemical	Release Rate (metric tons per year)		
	Mixed-Oxide Section	Uranium Dioxide Section	Combined Plant
H_2SO_4	0.0537		0.0537
HNO_3	0.0248		0.0248
HCL	0.0164		0.0164
$NaNO_3$	3.52		3.52
NaOH	0.507		0.507
NH_4OH		2,850.	2,850.
$Ca(OH)_2$		166.	166.
CaF_2		0.0737	0.0737
PO_4^{3-}	0.745	1.490	2.23
PO_4^{3-} (after degrading)	0.0745	0.149	0.223
Solids	2.814	5.62	8.44
PO_4^{3-} (in cooling tower)	0.040	0.0840	0.124

Source: AEC, 1974d: 4.3-41.

TABLE 6-25

POTENTIAL RADIONULCIDES IN THE GASEOUS EFFLUENTS FROM AN LMFBR FUEL FABRICATION PLANT

Radionuclide	Annual Release (10^{-6} Curies per year)		
	Mixed-Oxide Section	Uranium Dioxide Section	Combined Plant
Pu-236	2.58 E-3		2.58 E-3
Pu-238	2.88 E1		2.88 E1
Pu-239	5.91		5.91
Pu-240	8.07		8.07
Pu-241	8.34 E2		8.34 E2
Pu-242	2.20 E-2		2.20 E-2
U-232	9.12 E-5		9.12 E-5
U-234	2.17 E-4	1.01 E2	1.01 E2
U-235		1.25 E1	1.25 E1
U-236		1.58 E1	1.58 E1
U-238	2.35 E-4	9.19 E2	9.19 E2

TABLE 6-25. (Continued)

Radionuclide	Annual Release (10^{-6} Curies per year) Mixed-Oxide Section	Uranium Dioxide Section	Combined Plant
Th-228	2.40 E-5		2.40 E-5
Th-231		1.25 E1	1.25 E1
Th-234		9.19 E2	9.19 E2
Am-241	1.37		1.37
Np-237	2.30 E-7		2.30 E-7
Pa-234		9.19 E2	9.19 E2

Source: AEC, 1974d: 4.3-49.

[a]The radionuclides listed for the mixed-oxide section and the UO_2 section would be released from individual rooftop stacks (60 feet aboveground level) about 1,000 m from the site boundary.

TABLE 6-26

RADIONUCLIDES IN THE LIQUID EFFLUENTS FROM AN LMFBR FUEL FABRICATION PLANT

Radionuclide	Annual Release (10^{-6} Curies per year) Mixed-Oxide Section	Uranium Dioxide Section	Combined Plant[a]
Pu-236	2.8 E-1		2.8 E-1
Pu-238	2.4 E3		2.4 E3
Pu-239	5.0 E2		5.0 E2
Pu-240	6.7 E2		6.7 E2
Pu-241	7.3 E4		7.3 E4
Pu-242	1.8		1.8
U-232	7.6 E-3		7.6 E-3
U-234	1.8 E-2	2.6 E4	2.6 E4
U-235		3.2 E3	3.2 E3
U-236		4.1 E3	4.1 E3
U-238	2.0 E-2	2.4 E5	2.4 E5
Th-228	2.0 E-3		2.0 E-3
Th-231		3.2 E3	3.2 E3
Th-234		2.4 E5	2.4 E5
Am-241	1.2 E2		1.2 E2
Np-237	1.9 E-5		1.9 E-5
Pa-234		2.4 E5	2.4 E5

Source: AEC, 1974d: 4.3-52.

[a]Contained in liquid effluent from combined plant and discharged at a rate of 237,000 gallons per day.

a significant amount of plutonium. The resulting gaseous radioactive effluent would be 90 to 100 times greater than those associated with normal operations. The expected dosage to the general public is expected to be well below current AEC guidelines (AEC, 1974d: 4.3-146).

The accidents involved in the above discussion assume multiple failures of all preventative equipment.

6.4.3.4 Economic Considerations

The economics of LMFBR fuel fabrication are uncertain because of the lack of operating experience. The fuel now being produced for the Fast Flux Text Facility will cost about $3,000 per kilogram of UO_2 and PuO_2 contained in the fuel elements (AEC, 1973a: Element 8, 22). The cost in large-scale production is expected to range between $100 and $200 per kilogram (AEC, 1973a: Element 8, 23).

6.4.4 Reactor and Power Generation System

6.4.4.1 Technologies

The concept of the LMFBR was described in Section 6.4.1. Figure 6-17 is a schematic diagram of an LMFBR power generation system. Although not shown separately in Figure 6-17, the central core contains mixed oxide fuel rods, while the blanket fuel rods are loaded with UO_2 pellets only. During operation, the U-238 in both the core and the blanket is converted to plutonium. For every four pounds of plutonium consumed, approximately five pounds will be created (AEC, 1973b: 6).

The heat created by the fissioning fuel is transferred to liquid sodium that flows through the core. However, since sodium becomes radioactive in passing through the reactor core, an intermediate heat exchanger is necessary to transfer the heat to a second loop of nonradioactive sodium, which flows through the steam generator. In the steam generator, the heat is transferred to water, thereby creating steam which then drives the turbine. The sodium used in the primary and secondary loops is an alkali metal that melts at about 210°F, vaporizes at 1,640°F, and has excellent heat transfer properties. Sodium can be heated to high temperatures at relatively low pressures, thus permitting the use of low-pressure cooling circuits which are less susceptible to failure.

Since the operation of a breeding reactor depends on the availability of high-energy neutrons, no moderating material exists in an LMFBR core. The control rods are used to change the power level and to shut down the reactor. To provide the necessary core stability and accident response, the LMFBR is designed so that the reaction rate tends to slow down as the core temperature increases.

Among the many design problems of the LMFBR is the tendency of the fast neutrons in the core to damage the stainless steel used as structural material in the reactor and as cladding for the fuel rods. Radiation damage creates small voids in the steel which cause the material to swell and become brittle.

Another potential problem is created by the use of the sodium coolant. Sodium is extremely chemically active. When exposed to air in the liquid state, sodium burns; when exposed to water, it reacts violently (explodes). Sodium also forms radioactive isotopes under irradiation, making the containment of the sodium coolant a critical aspect of LMFBR design.

6.4.4.2 Energy Efficiencies

As noted previously, the LMFBR can operate at higher temperatures than an LWR and therefore can achieve higher efficiencies. The net plant efficiency for an LMFBR plant is expected to be around 40 to 41 percent, while LWR plants can only achieve efficiencies near 32 percent.

6.4.4.3 Environmental Considerations

The land requirements for a 1,000-Mwe LMFBR will range from 100 to 400 acres, depending on the type of cooling system used.

6.4.4.3.1 Chronic

The total waste heat for a 40-percent efficient 1,000-Mwe plant with at least 75-percent load factor would be 33.6×10^{12} Btu's annually. This would compare with 47.6×10^{12} Btu's waste heat annually for a 32-percent efficient plant.

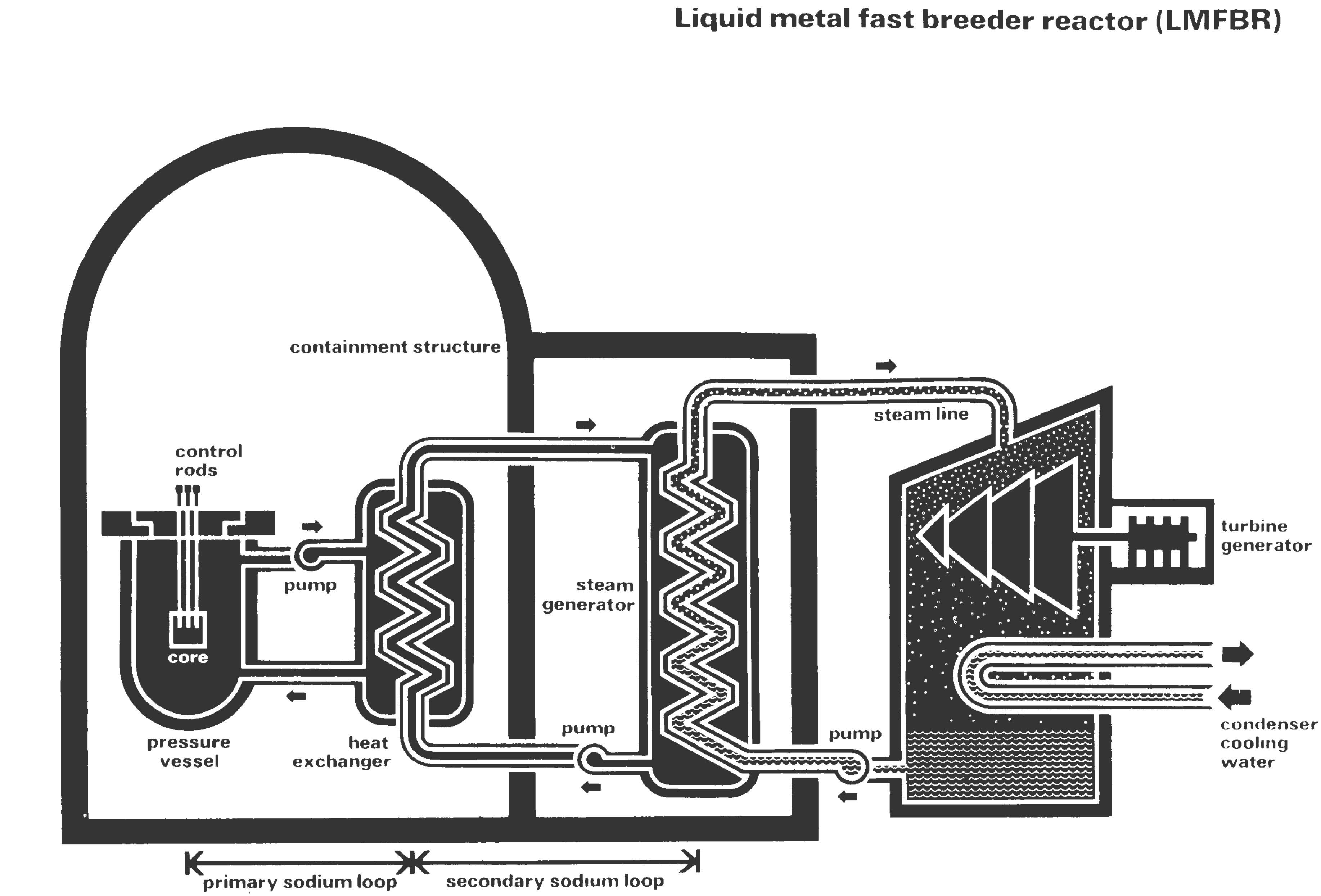


Figure 6-17. Liquid Metal Fast Breeder Reactor

Source: Atomic Industrial Forum, Incorporated.

TABLE 6-27

POSTULATED LMFBR RADIONUCLIDE RELEASES
(1,000-Mwe POWER PLANT AT 100-PERCENT CAPACITY FACTOR)

Nuclide	Atmospheric Release (Ci per year)	Liquid Release (Ci per year)
H-3 (Tritium)	60.	60.
Ar-39	80.	
Kr-85m	0.3	
Kr-85	0.4	
Kr-87	0.4	
Kr-88	0.5	
Xe-133	0.03	

Source: AEC, 1974d: 4.2-54.

In addition to thermal pollution, LMFBR power plants create liquid, gaseous, and solid wastes. Liquid wastes associated with the reactor operation will be negligible, but chemical agents will be required for water treatment in the steam system and for suppressing biological growths in the cooling water. The nature and volume of these chemical wastes are expected to be similar to those of conventional power plants of the same capacity.

Table 6-27 lists the annual postulated radioactive effluents from a 1,000-Mwe plant with a 100-percent load factor. As noted in Table 6-12, an LWR will emit 10 to 50 curies of tritium and 7,000 to 50,000 curies of krypton and Xenon; this compares to LMFBR gaseous releases of 60 curies of tritium and neglible amounts of krypton and Xenon. All radioactive effluents represent a maximum dosage that is small compared to natural background (AEC, 1974d: 4.2-118).

6.4.4.3.2 Major Accidents

The AEC has analyzed potential LMFBR accidents and divides these accidents into three categories: (AEC, 1974d: Section 4.2.7)

1. Reasonably anticipated occurrences leading to no significant release of radioactivity.
2. Unlikely events with a potential for small-scale radioactive release.
3. Extremely unlikely events with a potential for large-scale radioactive release.

The first category includes such events as plumbing leaks of nonradioactive materials. The second category includes accidents involving the release of stored radioactive gas. The third category includes massive sodium leaks, refueling accidents, or accident sequences that could involve substantial damage to the core.

The AEC has not been able to assess probabilities and environmental impacts for the various accident sequences, citing the lack of experimental data and analytic models. Thus, further analysis is needed; one operating LMFBR (Fermi, located near Detroit) was shut down because a portion of the core did melt after a coolant passage was blocked.

6.4.4.4 Economic Considerations

At present, LMFBR costs are speculative at best. The high start-up costs normally associated with a new and complex technology

TABLE 6-28

ESTIMATED LMFBR POWER PLANT CAPITAL COSTS (1974 DOLLARS)

	Capital Costs (dollars per kilowatt-hour)		
	1974	1980	1990
LWR (1,300 Mwe)	420	420	420
HTGR (1,300 Mwe)	419	419	419
LMFBR 1,300 Mwe)	NA	NA	487

Source: AEC, 1974d: Appendix III-B, p. 4-5.

are likely to be exaggerated by the need for complex provisions against catastrophic failure and the atmosphere of public concern in which the LMFBR is being developed.

Table 6-28 compares the AEC estimates for LMFBR power plant capital costs in 1974 dollars with those for LWR's and HTGR's. These cost estimates should be viewed with caution, as the cost of the Clinch River project, originally estimated at $700 million by the AEC, has been recently re-estimated at $1,800 million. At a total cost of $1,800 million, the Clinch River project would cost approximately $4,000 per kwe.

6.4.5 Fuel Reprocessing

6.4.5.1 Technologies

Reprocessing is an important part of the LMFBR fuel cycle because the recovery of Pu-239 from the core fuel and the blanket is necessary to provide new fuel supplies. At present, no commercial plants exist for reprocessing LMFBR fuel. Although the chemical processes are similar to those for LWR fuels, the preparation of the LMFBR fuel for chemical conversion will be significantly different because of the increased amount of heat in the fuel, the rugged construction of the fuel assemblies, and the criticality control problem caused by the high plutonium content (AEC, 1974d: Section 4.4).

A plant producing 5.5 tons of uranium and plutonium per day (approximately 1,650 tons per year) would be adequate for 80,000 Mwe of installed LMFBR capacity. The weight of the plutonium processed each year would be 150 tons (AEC, 1974d: Section 4.4).

The following steps are involved in reprocessing LMFBR fuel (AEC, 1974d: 4.4-12, 4.4-14):

1. The incoming fuel assemblies are stripped of sodium.
2. The fuel cladding is broken up and shredded by mechanical and torch cutting.
3. The nuclear fuel is reacted with nitric acid.
4. The heavy metal is separated from the fission products.
5. Uranium is separated from the plutonium.
6. Uranium is converted to UO_3.
7. Plutonium is converted to PuO_2.
8. Radioactive wastes are diverted to the appropriate liquid, gas, or solid waste streams.

In general, the fuel will be allowed to "cool" one year before reprocessing. If a shorter time delay is involved, the shielding must be increased.

6.4.5.2 Energy Efficiencies

The ancillary energy is the energy required to operate the fuel reprocessing plant, but no information on this requirement is currently available. The primary efficiency is related to the percent of plutonium and uranium recovered, which presumably is near 100 percent.

6.4.5.3 Environmental Considerations

A reprocessing plant capable of producing 5.5 tons per day of uranium and plutonium will occupy approximately 1,000 acres of land (AEC, 1974d: 6).

6.4.5.3.1 Chronic

Only a very small amount of waste heat will be discharged. Small amounts of gaseous chemical effluents (primarily NO_x)

directly associated with the processing will be emitted. There are liquid chemical wastes, but these are discharged to a retention pond (AEC, 1974d: 4.4-57).

The radioactive wastes (including krypton, tritium, iodine-129, iodine-131, plutonium, and various isotopes of uranium) have been estimated by AEC (1974d: 4.4-57). The maximum individual dose at the site boundary, including ingestion through the food chain, is estimated by the AEC at 1.0 mrem per year, compared to a natural background of 125 mrem per year.

6.4.5.3.2 Major Accidents

In postulating accidents, the AEC has assumed that the plant would be protected from floods by siting considerations and that the vital structures would be resistant to tornadoes and earthquakes (AEC, 1974d: 4.4-84). Man-originated accidents that could result in the release of radioactivity are:

1. Fuel element rupture.
2. Leakage of radioactive liquid.
3. Solvent fire.
4. Nuclear criticality.
5. Explosive rupture of a process vessel.
6. Catastrophic failure of a Kr-85 storage vessel.

For all the above accidents, the maximum dose absorbed by an individual at the plant boundary was calculated by the AEC to be less than 1.0 mrem, as compared to an average natural background of 125 mrem per year.

6.4.5.4 Economic Considerations

The reprocessing cost estimates are shown in Table 6-29 for LMFBR fuels and LWR fuels.

6.4.6 Radioactive Waste Management

The radioactive waste management technologies are similar for the LWR, HTGR, and LMFBR. However, the amounts and types of wastes can vary.

TABLE 6-29

LMFBR REPROCESSING COST ESTIMATES
(1974 DOLLARS)

Fuel Type	Dollars per Kilogram	
	Initial	2020
LMFBR	92	75
LWR	94	41

Source: AEC, 1974d: Appendix III-B, p. 4-18.

Table 6-30 compares the radioactive solid wastes from an LWR with plutonium recycle and an LMFBR, each with an output of 1,000 Mwe. The quantities of high-level waste for the two programs are approximately the same at 55 and 60 cf per year respectively.

The LMFBR will generate 170 cf of cladding hulls per year compared to 60 cf for the LWR. The LMFBR produces fewer cf of solids at the reactor than the LWR.

6.4.7 Transportation

Many of the transportation steps involved in LMFBR operation are similar or identical to those described for the LWR. Thus, only those procedures or equipment unique to the LMFBR cycle will be described in this section (AEC, 1974d: Section 4.5).

6.4.7.1 Technologies

In addition to the transportation steps described for the LWR, the following four steps are required for LMFBR operation.

1. PuO_2 from the LWR reprocessing plant to the LMFBR fuel fabrication plant.
2. Nonirradiated fuel containing PuO_2 from the fuel fabrication plant to the reactor.
3. Irradiated fuel from the reactor to the reprocessing plant.
4. Recovered PuO_2 from the reprocessing plant to the fuel fabrication plant.

TABLE 6-30

ESTIMATED ANNUAL QUANTITIES OF RADIOACTIVE SOLID WASTES FROM AN LWR AND LMFBR

Production Location	1,000-Mwe LWR With Pu Recycle	1,000-Mwe LMFBR
Produced at Reactor Site		
Other-than-High-Level		
Cubic feet per year used, square feet per year	2,000-4,000	1,000-2,000
Burial ground area used	400 - 800	200 - 400
Noble Gases		
Cylinders per year		<1
Produced at Reprocessing Plant Site		
High-Level Solid		
Cubic feet per year	55	60
RSSF repository[a] space required, square feet per year	11	12
Cladding Hulls		
Cubic feet per year	60	170
Repository[a] or burial space required, square feet per year	12	35
Other Solid Wastes		
Cubic feet per year	600-4,000	5,000-10,000
Burial ground, square feet per year	100 - 800	1,000 - 2,000
Noble Gases		
Cylinders per year		1
Produced at Fabrication Plant Site Other-than-High-Level Including Plutonium Contaminated Wastes		
Cubic feet per year	10,000-30,000	10,000-30,000
Repository[a] space, square feet per year	2,000 - 6,000	2,000 - 6,000

Source: AEC, 1974d: 4.6-12.

[a]If required by future regulations.

Approximately 1,700 kilograms of PuO_2 must be shipped over an average distance of 750 miles each year for a typical 1,000-Mwe LMFBR (AEC, 1974d: 4.5-15). Approximately 16 metric tons of nonirradiated uranium and plutonium must also be shipped over the same distance each year.

At present, no casks have been designed for shipping LMFBR-irradiated fuel. Such casks are expected to be similar to those used for LWR fuel, which weigh 50 to 100 tons and are shipped by rail or barge.

6.4.7.2 Energy Efficiencies

The primary efficiency should be 100 percent. The ancillary energy is the fuel required to power the vehicles, which should be small compared to total power output of the fuel.

6.4.7.3 Environmental Considerations

In routine shipping operations, the thermal load and radiation exposure are expected to be small. The former will be negligible by comparison to the heat generated by an ordinary automobile engine. The radiation exposure to the general public will be small compared to natural background radiation.

The AEC has analyzed a number of potential transportation accidents. Their analysis of extreme accidents for a container of PuO_2, or for shipments of nonirradiated fuel containing PuO_2, indicates that radioactive releases would be negligible.

A series of postulated events for an irradiated fuel cask leading to an extreme accident could result in high radiation doses near the cask. The dose rate at the cask surface has been estimated to be 10 to 500 mrem per hour. This is within the current AEC limits but could be greater than the natural background radiation of 125 mrem per year.

6.4.7.4 Economic Considerations

No specific data is available on the costs of the various transportation steps. However, the costs of shipping used fuel is expected to be approximately \$36.40 per kilogram of heavy metal (AEC, 1971: 113).

REFERENCES

Atomic Energy Commission, Division of Reactor Development (1969) The Use of Thorium in Nuclear Power Reactors. Washington: Government Printing Office.

Atomic Energy Commission, Division of Reactor Development and Technology (1971) Reactor Fuel Cycle Costs for Nuclear Power Evaluation. Washington: Government Printing Office.

Atomic Energy Commission, Directorate of Regulatory Standards (1972) Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants. Washington: Government Printing Office.

Atomic Energy Commission (1973) The Safety of Nuclear Power Reactors (Light Water-Cooled) and Related Facilities. Washington: Government Printing Office.

Atomic Energy Commission, Division of Reactor Research and Development (1973a) Liquid Metal Fast Breeder Reactor Program Plan, compiled by LMFBR Program Office, Argonne National Laboratory. Springfield, Va.: National Technical Information Service, 10 elements.

Atomic Energy Commission (1973b) "The Breeder Reactor." Washington: AEC.

Atomic Energy Commission (1974a) "AEC Estimates U.S. Uranium Reserves at 277,000 Tons U_3O_8." Grand Junction Office, News Release, No. 654, March 27, 1974.

Atomic Energy Commission (1974b) Statistical Data of the Uranium Industry, Grand Junction Office, GJO-100.

Atomic Energy Commission (1974c) Environmental Survey of the Uranium Fuel Cycle. Washington: Government Printing Office.

Atomic Energy Commission (1974d) Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington: Government Printing Office, 4 vols.

Atomic Energy Commission (1974e) The Nuclear Industry 1973. Washington: Government Printing Office.

Atomic Energy Commission (1974f) Environmental Statement: HTGR Fuel Fabrication Pilot Plant, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Washington Government Printing Office.

Atomic Energy Commission (1974g) Environmental Statement: HTGR Fuels Reprocessing Facilities, National Reactor Testing Station, Idaho. Washington: Government Printing Office.

Atomic Energy Commission (1974h) Reactor Safety Study. Washington: Government Printing Office.

Atomic Energy Commission (n.d.) "AEC Release a Preliminary Resource Estimate of the San Juan Basin," AEC News Release, No. 665.

Atomic Industrial Forum (1974) "Comparison of Fuels Used in Power Plants." Background INFO, published under the Public Affairs and Information Program. New York: AIF.

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle.

Brobst and Pratt, eds. (1973) United States Mineral Resources, USGS Professional Paper 820. Washington: Government Printing Office.

Cochran, J.A., D.G. Smith, P.J. Magno, and B. Shlein (1970) An Investigation of Airborne Radioactive Effluent from an Operating Nuclear Fuel Reprocessing Plant. Northeastern Radiological Health Laboratory, BRH/NERHL 70-3.

Creagan, R.J. (1973) "Boon to Society: The LMFBR." Mechanical Engineering (February 1973).

Elliot, David, and Lynn Weaver, eds. (1972) Education and Research in the Nuclear Fuel Cycle, based on a symposium held at the University of Oklahoma, October 5-7, 1970. Norman, Oklahoma: University of Oklahoma Press.

Gulf General Atomic (1973) "Fort St. Vrain HTGR." San Diego: Gulf General Atomic.

House Committee on Interior and Insular Affairs, Subcommittee on the Environment (1973) America's Energy Potential: A Summary and Explanation, by Morris Udall. Washington: Government Printing Office.

INFO (1973) News Release, "The Nuclear Industry in 1973: No Longer the Understudy in Energy Drama," December 31, 1973. New York: Atomic Industrial Forum, Inc.

INFO (1974) Public Affairs and Information Program, No. 70, May 1974. New York: Atomic Industrial Forum, Inc.

Kubo, Arthur S., and David J. Rose (1973) "Disposal of Nuclear Wastes." Science 182 (December 21, 1973): 1205-1211.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee, Nuclear Task Group (1973) U.S. Energy Outlook: Nuclear Energy Availability. Washington: NPC.

Nuclear News (1974) "UEA Options Alabama Site for Diffusion Plant." Nuclear News 17 (August 1974): 65.

Nuclear News Buyers Guide (Mid-February 1974).

Nuclear Task Force (1974) Project Independence Blueprint, Draft Summary Report Washington: Federal Energy Office.

Shleien, B. (1970) An Estimate of Radiation Doses Received by Individuals Living in the Vicinity of a Nuclear Fuel Reprocessing Plant in 1968. Northeastern Radiological Health Laboratory. BRH/NERHL 70-1.

Singleton, Arthur L. (1968) Sources of Nuclear Fuel, AEC Understanding the Atom Series. Washington: Government Printing Office.

Senate Committee on Interior and Insular Affairs (1973) Energy Research and Development: Problems and Prospects. Washington: Government Printing Office.

Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case, for Office of Research and Monitoring, Environmental Protection Agency. Berkeley, California: Teknekron, Inc.

Weekly Energy Report (1973) "Administration Weights Laser Enrichment Data." Weekly Energy Report 1 (November 12, 1973).

Westinghouse Electric Corporation, Nuclear Fuel Division (1968) Nuclear Fuel. Pittsburgh: Westinghouse.

Yemel'vanov, V.S., and A.E. Yevstyukhin (1969) Metallurgy of Nuclear Fuel. Braunschweig, Germany: Pergamon Press.

Youngberg, Elton A. (1972) "Uranium Exploration, Mining," in David Elliot and Lynn Weaver (eds.) Education and Research in the Nuclear Fuel Cycle. Norman, Oklahoma: University of Oklahoma Press.

CHAPTER 7

THE NUCLEAR ENERGY-FUSION RESOURCE SYSTEM

7.1 INTRODUCTION

The most optimistic proponents of nuclear fusion as a source of commercial energy do not expect it to be available until after the year 2000. Therefore, fusion is a long-term energy alternative and does not meet the criteria specified for inclusion in this report. However, fusion has been the subject of so much continuing discussion that it needs to be set in perspective vis-a-vis the other resource systems. This very brief discussion, which is organized differently than the other chapters, has five purposes: to describe briefly the history of fusion as a potential energy source; to indicate why it is considered by many to be an attractive energy alternative; to indicate its state of scientific development; to indicate the current level of government R&D funding; and to summarize the role of fusion as an energy alternative in the context of environmental impact statements.

7.2 FUSION AS A POTENTIAL ENERGY SOURCE

The first demonstration of fusion as a source of energy was the explosion of a hydrogen bomb in 1952. Following that thermonuclear explosion, the Atomic Energy Commission (AEC) established, in late 1952, a project to investigate the possibility of generating energy by fusing atoms in a controlled manner within a reactor (AEC, 1973: 7).

The continuing interest in fusion has resulted from what appear to be attractive fuel and environmental characteristics. Among the most important of these is the expectation that the fuel sources for a fusion reactor would be plentiful. Specifically, the first fusion reactors are expected to use heavy isotopes of hydrogen: deuterium and tritium. Deuterium exists naturally in sea water (Glasstone, 1974: A.1.6-12). Tritium does not occur naturally but is expected to be produced from lithium in normal operation of a fusion reactor (Hansborough and Draper, 1973: 43). Lithium is a relatively plentiful natural element. Environmentally, fusion reactors are expected to be more attractive than fission because of less serious fuel handling problems, lower radioactive inventories, and because fewer radioactive wastes will be generated.*

Present strategies for developing fusion reactors involve two concepts: magnetic confinement and laser implosion. In the first, the hydrogen isotopes exist in a gas (plasma) that is being contained within a magnetic field. The magnetic field accelerates the isotopes to high velocities; when the isotopes collide, fusion will occur. The second concept uses concentrated light from lasers to compress and heat a pellet of deuterium and tritium causing fusion (Metz, 1972: 1180).

The first strategy for developing fusion and the one that has received the most attention to date, is being pursued by

*There is disagreement on this point. See, for example, Post and Ribe (1974) and Starr and Hafele's response (1975).

the Controlled Thermonuclear Reaction Division of the Atomic Energy Commission.* The program is being planned to proceed through five major steps in magnetic containment technology ending with construction and operation of a demonstration reactor. These are: hydrogen plasma experiments at near the conditions necessary in a reactor between now and 1980; fusion test reactors at the level of 1 to 10 megawatts-thermal between 1980 and 1985; an experimental power reactor producing 20 to 50 megawatts-electric (Mwe) between 1985 and 1989; a second experimental power reactor producing more than 100 Mwe between 1989 and 1997; and finally a demonstration reactor producing more than 500 Mwe in 1997 (AEC, 1974: I-4). No similar timetable has been offered for the laser technology option, but at the present time, laser fusion does not appear to be as far advanced as the magnetic containment technologies.

Although work on fusion is only in the scientific feasibility phase, the AEC is providing increased support. AEC's support pattern for five years is reported in Table 7-1. The nearly 70-percent increase in total estimated support for 1975 reflects an effort to accelerate fusion development.

Even with accelerated support, however, commercial use of fusion energy is at least 25 years away. Further, both its purported energy and environmental benefits are extrapolations from theory and laboratory work. Until additional experience and data are available, no firm conclusions concerning benefits or costs are warranted (Metz, 1972: 1180). What can be concluded is that fusion is not an available energy alternative in the context of contemporary environmental impact statements.

*This program is now in ERDA.

TABLE 7-1

FEDERAL R&D FUNDING FOR FUSION
(MILLIONS OF DOLLARS)

Type	1971	1972	1973	1974	1975
Magnetic	33.3	39.6	39.7	57.0	102.3
Laser	19.5	25.9	35.1	44.1	66.3
TOTAL	52.8	65.5	74.8	101.1	168.6

Source: Gillette (1974: 637).

REFERENCES

Atomic Energy Commission, Division of Controlled Thermonuclear Power (1973) Fusion Power. Washington: Government Printing Office.

Atomic Energy Commission, Division of Controlled Thermonuclear Research (1974) Fusion Power by Magnetic Confinement. Washington: Government Printing Office.

Gillette, Robert (1974) Energy Science, 183 (February 15, 1974).

Glasstone, Samuel (1974) Controlled Nuclear Fusion, AEC Understanding the Atom Series. Washington: Government Printing Office.

Hansborough, Lash, and E. Linn Draper, Jr. (1973) Overall Tritium Considerations for Controlled Thermonuclear Reactors. Austin, Texas: University of Texas.

Metz, William D. (1972) "Laser Fusion: A New Approach to Thermonuclear Power." Science 177 (September 29, 1972).

Post, R.F., and F.L. Ribe (1974) "Fusion Reactors as Future Energy Sources." Science 186 (November 1, 1974): 397-407.

Starr, Chauncey, and Wolf Hafele (1975) Letter to the Editor. Science 187 (January 24, 1975): 213-214.

CHAPTER 8

THE GEOTHERMAL ENERGY RESOURCE SYSTEM

8.1 INTRODUCTION

Generation of electricity from geothermal steam resources occurred for the first time in 1904 at Larderello, Italy. Continuous generation began in 1913 with a 12.5-megawatt-electric (Mwe) plant, and current output at Larderello is 360 Mwe. The only commercial geothermal production in the U.S. is in the Geysers area of California and it dates from about 1960. In 1974, output was 412 Mwe (0.1 percent of U.S. electric power generation capacity). Annual increases of 110 Mwe until 1980 are planned. With these additions, geothermal power should provide about one percent (under very favorable conditions, several percent) of electric power in the U.S. from 1980 through the year 2000. Although its national role is small, geothermal power can be a significant supplement to other forms of electric power in local areas (e.g., California).

Besides power generation, geothermal steam is produced for space heating at Klamath Falls, Oregon and Boise, Idaho.

Geothermal electric production is distinctive in that all steps in the fuel cycle are localized at the site of the power production facility; thus, there are no transportation alternatives. Aside from steam transport from the wellhead to the power plant, the only transportable item is electricity.

As shown in Figure 8-1, there are four principal activities in using geothermal energy: exploration, extraction, pipeline transportation, and electric power generation. (Extraction includes both drilling and production phases.) Following a description of U.S. geothermal resources, these activities and the technologies for achieving them will be described. A summary section then discusses total trajectory efficiencies, environmental residuals, and costs.

8.2 RESOURCE CHARACTERISTICS

8.2.1 Quantity

Estimates of geothermal reserves vary considerably. Table 8-1 gives resource estimates using the U.S. Geological Survey (USGS) categories with some explanation of which reservoirs each author includes in a category. Reserve estimates vary from 1,000 Mwe (10^{16} Btu's at the wellhead) to 60,000 Mwe. Total resource estimates vary from 400,000 to 148,000,000 Mwe for 50 years. Several factors explain the variance in reserve and resource estimates. The limited exploration for geothermal resources to date has resulted in a lack of agreement on unexplored reservoir characteristics, on the time required for the needed new technologies to become commercially available, and on future changes in cost factors within the energy sector of the economy, some of which would stimulate geothermal production.

To provide perspective and a basis for comparing potential geothermal-electric reserves, Table 8-2 contains 1985 installed capacity estimates under various growth scenarios. The estimates range from 3,500 to 132,000 Mwe in 1985. In Table 8-3, the economic dimension is added to the

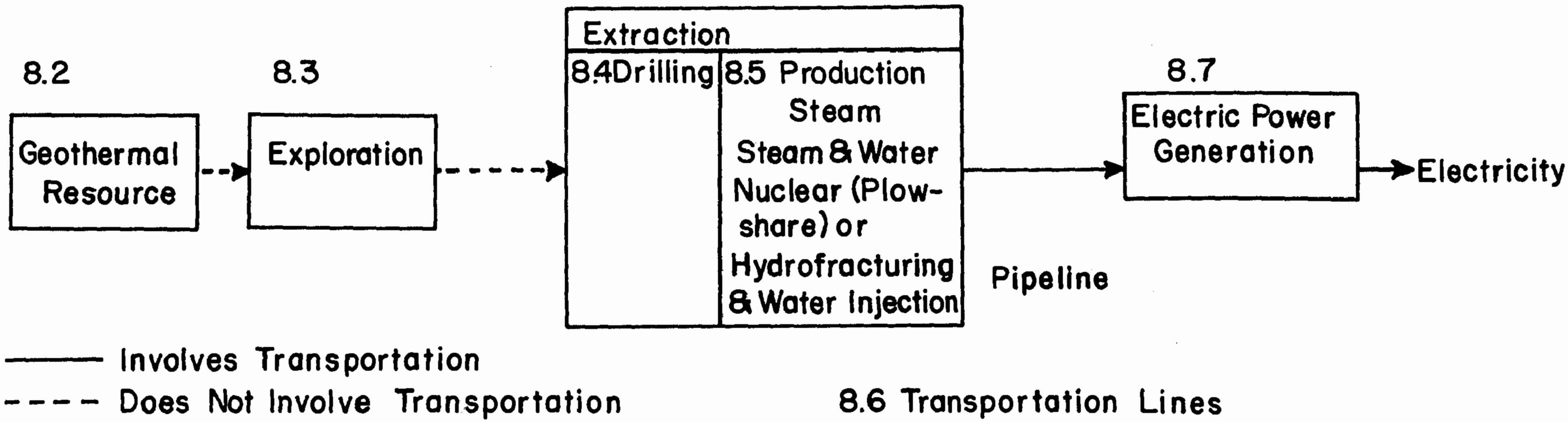


Figure 8-1. Geothermal Resource Development

TABLE 8-1

GEOTHERMAL RESOURCE ESTIMATES

Source	Btu's *In Situ* (10^{16})	Btu's[a] at the Wellhead (10^{16})	Megawatts[a] of Electricity for 50 Years
Muffler and White, Identified recoverable or reserves (the Geysers and several others)	6	1	1,000
Undiscovered recoverable	40-80	6-12	3,000-6,000
Paramarginal (high temperature hot-water systems nearly economical)	400	60	40,000
Submarginal to a depth of 10 kilometers (neither economical nor technically feasible)	4,000	600	400,000
White, Proved (recoverable at present cost and technology)	7	1	1,200
Paramarginal (present technology, one-third increase in price)	24	3.6	4,000-8,000
Rex and Howell, Known reserves (Geysers and Imperial Valley)	360	54	60,000
Probable reserves (Western U.S. hydrothermal systems)	12,000	1,800	2,000,000
Undiscovered reserves (dry hot resources to a depth of 35,000 feet)	880,000	133,200	148,000,000

Sources: Muffler and White, 1972: 50; White, 1973: 91; Rex and Howell, 1973: 63.

[a]Conversion from Btu in the ground assumes current efficiencies (15 percent of the *in situ* energy is deliverable to the wellhead and electrical generating efficiency is 14 percent.

TABLE 8-2

POTENTIAL INSTALLED GEOTHERMAL CAPACITY BY 1985

Organization Cited (with scenarios used from each)	Projected Capacity in Mwe 1985
National Petroleum Council[a]	
Most optimistic scenario (maximum technological progress with no impediments)	19,000
Large areas of land available with no environmental delays	9,000
Realistic estimate based on current costs and technologies	7,000
Least optimistic	3,500
Hickel Panel[b]	
Moderate R&D Program	19,000
Accelerated R&D Program	132,000
Bureau of Mines[c]	
Based on projects currently under consideration	4,000
Atomic Energy Commission[d]	
Active R&D program to stimulate production	20,000
Bureau of Land Management[e]	
All western sources (assumes technology for hot water systems available)	7,000 to 20,000
Rex and Howell[f]	
Assumes hot dry rock systems are now technically exploitable Estimate is for development in western U.S. only	400,000[g]

Sources: [a]Kilkenny, 1972: 27-35.
[b]Hickel, 1972: 15.
[c]Interior, 1973: Vol. I, p. II-19.
[d]AEC, 1973: 119.
[e]BLM, 1973: 347.
[f]Rex and Howell, 1973: 63.

[g]By 1993.

TABLE 8-3

EFFECT OF PRICE ON POTENTIAL INSTALLED GEOTHERMAL CAPACITY BY 1985

National Petroleum Council[a]		Rex and Howell[b]			
Power Cost (mills per kwh)	Installed Capacity 1985 (Mwe)	Fuel Price[c] (mills per kwh)	Known Reserves	Probable Reserves	Undiscovered
			Units Mwe for 50 Years		
5.25	7,000	2.9-3.0	2,000	10,000	20,000
5.75	14,000	3.0-4.0	60,000	800,000	4,000,000
6.25	19,000	4.0-5.0	0	1,200,000	24,000,000

Sources: [a]Kilkenny, 1972: 27-35, 1972 dollars.
[b]Rex and Howell, 1973: 63, 1972 dollars.

[c]A price of 2.9 mills per kwh (cost of the produced steam) is roughly equivalent to a power cost of 5.25 mills per kwh.

resource estimate, indicating price rises required to stimulate additional production.

Most estimates indicate that geothermal energy may make substantial contributions in the western U.S. by the end of the century. By 1985, contributions are postulated to be on the order of one percent of U.S. electric capacity.

8.2.2 Geology

Normally, the heat of the earth is diffuse. When local geologic conditions concentrate heat energy into hot spots or thermal reservoirs, it becomes a potential energy resource. Three categories of thermal reservoirs are defined geologically: hydrothermal, geopressured, and dry hot rock reservoirs.

8.2.2.1 Hydrothermal Reservoirs

Hydrothermal reservoirs are the most desirable type for producing geothermal energy. These reservoirs consist of a heat source (magma) overlain by a permeable formation (aquifer) in which the groundwater circulates through pore spaces. The aquifer is capped by an impermeable formation which prevents water loss. Water and steam transport the heat energy from the rock to the well and finally to the surface. Two categories of hydrothermal reservoirs are defined, based on whether hot water or vapor dominates the reservoir. Vapor dominated systems, such as the Geysers in California, are the most commercially attractive but are relatively rare. Hot water dominated reservoirs, sometimes termed wet steam, are 20 times more common.

8.2.2.2 Geopressured Reservoirs

No production from geopressured reservoirs has occurred to date, although these reservoirs differ from hydrothermal reservoirs only in the source of heat. Rather than a magma, the clays in a rapidly subsiding basin area, such as the Texas and Louisiana Gulf Coast, trap heat in underlying water-bearing formations. California's Imperial Valley geothermal reservoir may be a combination of a hot water hydrothermal and a geopressured reservoir.

8.2.2.3 Dry Hot Rock Reservoirs

In dry hot rock systems, no permeable aquifer (and thus no water or steam) overlies the heat source. Consequently, production requires fracturing the rock and injecting water. No production from this type of reservoir has occurred.

8.2.3 Physical and Chemical Characteristics

Only vapor and hot water dominated hydrothermal reservoirs can presently be defined as reserves. For both technological and economic reasons, commercial production now requires the following characteristics (White, 1973: 69):

1. Reservoir depth not exceeding 1.86 miles.
2. Naturally occurring reservoir water for transferring the heat.
3. Reservoir volume greater than 1.2 cubic miles.
4. Sufficient reservoir permeability.

In the U.S., empirical data exist for only two reservoirs, the Geysers and Niland (Salton Sea). The characteristics for these two reservoirs, given in Table 8-4, represent the range of known U.S. reservoir characteristics to date, although this range is expected to widen as exploration expands. In general, vapor dominated reservoirs have a higher heat content, lower salinity, lower temperature, and deeper drilling requirements than hot water dominated reservoirs. The high mass flow for the hot water system represents both water and steam.

8.2.4 Location

Figure 8-2 is a map of U.S. geothermal regions, including the geopressured zone of the Gulf Coast. In the U.S., all locations likely to be developed until 1985 (and probably until 2000) are in the western one-third of the country. There are currently 43 known geothermal resource areas in the U.S. (Godwin and others, 1971: 2), 14 of which are in California, 13 in Nevada, 7 in Oregon, and the remainder in Alaska, Idaho, Montana, New Mexico, Utah, and Washington. A known geothermal resource area (KGRA) occurs where "the prospect of extraction of geothermal steam or associated geothermal resource from an area is good enough to warrant expenditure of money for that purpose" (Godwin and others, 1971: 2). Currently 1.8 million acres are classed as KGRA. An additional 96 million acres are termed as having prospective value. All are hydrothermal reservoirs.

Areas where geothermal development is expected in the near future are the Imperial Valley (hot water-brine), Clear Lake-Geysers (vapor), Mono-Long Valley, California (hot water), and several hot water dominated reservoirs in Nevada.

8.2.5 Ownership

Of the 1.8 million acres classed as KGRA's, 56 percent occur on federal land. Sixty percent of the 96 million acres termed prospective are on federal land.

8.3 EXPLORATION

8.3.1 Technologies

The great majority of presently explored hydrothermal systems display surface discharges of hot water or steam, accompanied by strong surface temperature anomalies. Since such systems are readily detectable (and many are currently known), U.S. geothermal exploration in the near future will probably be confined to these reservoirs (Banwell, 1973: 42).

Although both passive and active exploratory techniques are available, these tools and methods were developed principally for defining the extent of the reservoir and determining its characteristics, not for locating reservoirs lacking surface discharges. However, even these techniques are unsophisticated, and little direct knowledge of thermal reservoir characteristics is obtainable without drilling.

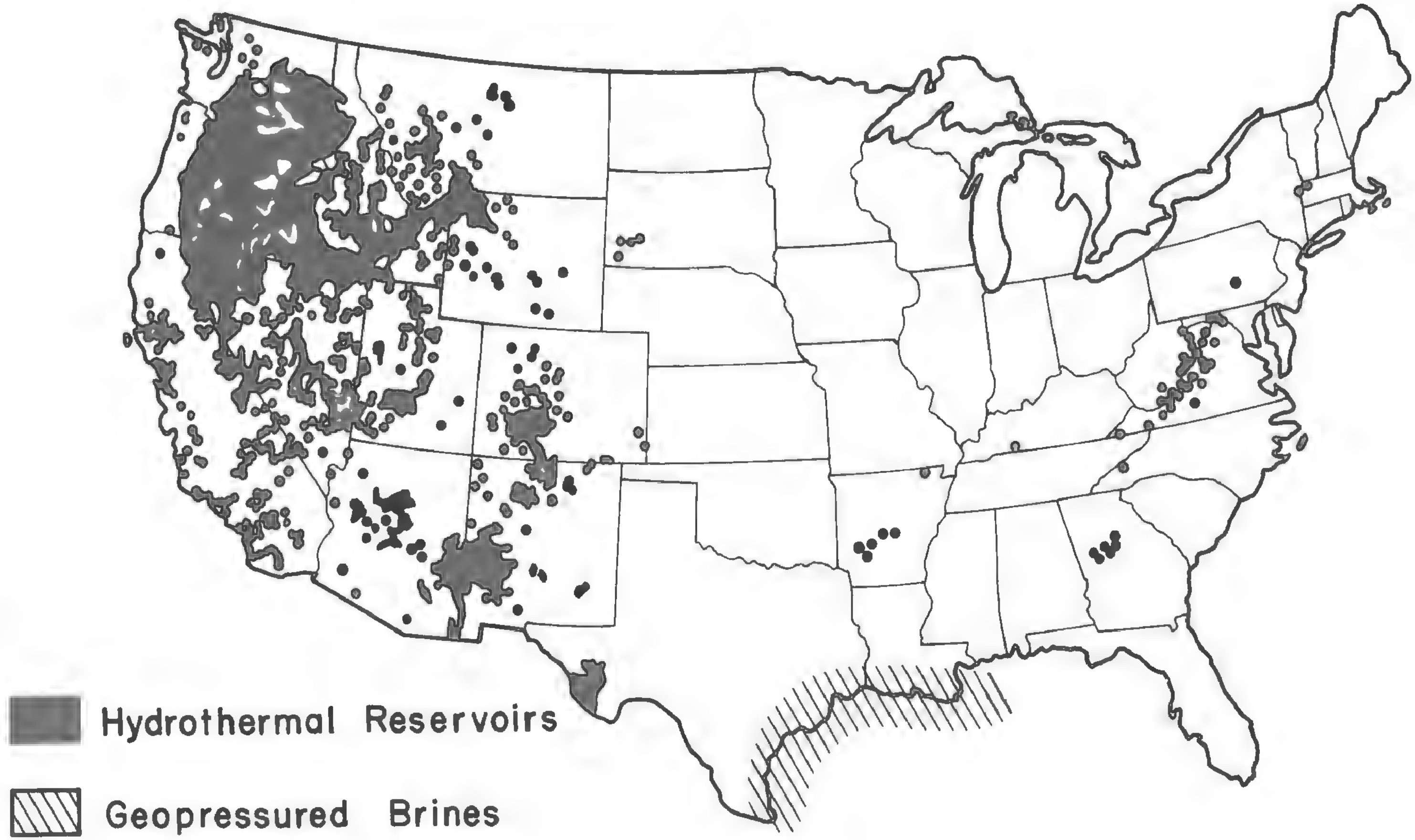


Figure 8-2. Distribution of U.S. Geothermal Resources

Source: Interior, 1973: Vol. 1, p. II-17.

TABLE 8-4

CHARACTERISTICS OF U.S. GEOTHERMAL FIELDS

	Geysers[a] Vapor Dominated	Niland[b] Hot Water Dominated Brine
Reservoir temperature (degrees Centigrade)	245	300+
Reservoir pressure (pounds per square inch)	500	2,000
Wellhead pressure (pounds per square inch)	150	400
Heat content (Btu's per pound)	1,200	560
Average well depth (feet)	8,200	4,250
Fluid salinity (parts per million)	1,000	250,000
Average mass flow per well (pounds per hour)	150,000	440,000
Non-condensable gases (weight percent)	1	1

Sources: [a]Koenig, 1973: 24.
[b]Austin and others, 1973: 4, 5, 16.

8.3.1.1 Passive Exploration Techniques

Passive exploration techniques are usually surface-oriented, although airborne geologic reconnaissance flights may be used in data gathering. The first step is normally compilation of a catalog of existing geological, geochemical, and geophysical data. If necessary, several quick and easy field measurements may then be made to supplement the existing data. Geologic techniques include stratigraphic and structural mapping and locating surface thermal manifestations (hot springs). Also, temperature and discharge measurements are made on hot and cold springs.

Passive geophysical techniques also include gravity and magnetic surveys for delineating major structural features and the measurement of ground noise and microearthquakes. Many geothermal reservoirs are characterized by abundant microearthquakes and high noise levels. Individual geothermal systems may even have characteristic seismic signatures as measured with ultrasensitive, high frequency geophones.

Geochemical techniques involve analyzing thermal surface waters to determine whether the reservoir is hot water or vapor dominated as well as to estimate the reservoir minimum temperature, chemical character, and source of recharge water. For example, a chloride content in a hot spring of greater than 50 parts per million (ppm) usually indicates a hot water reservoir, while less than 20 ppm indicates a vapor dominated reservoir (Combs and Muffler, 1973: 100).

8.3.1.2 Active Exploration Techniques

Active exploration techniques include seismic measurements, electrical conductivity tests (earth resistivity surveys), and thermal gradient surveys. In the seismic tests (described in Section 3.3), reflected sound waves are translated into subsurface maps which indicate the structural nature of the rocks at depth.

In the electrical conductivity and thermal gradient tests, small diameter holes are drilled (from 50 to 330 feet for earth resistivity measurements and to a minimum of 330 feet for heat flow measurements), and measurements are made by instruments lowered down the boreholes. Because the temperature, material porosity, and fluid salinity of geothermal reservoirs tend to be high, these reservoirs are good conductors of electricity and thus low in resistivity. The same characteristics also result in higher than normal heat flow rates and temperature gradients in the immediate vicinity of the reservoirs.

If the results of the above tests are sufficiently promising, a hole is drilled into the producing zone to evaluate reservoir production potential. Drilling technology is discussed in Section 8.4.

8.3.2 Energy Efficiencies

Since no energy conversions are involved in exploration, primary energy efficiencies are not applicable. The manpower, technology, and power for shallow drilling reflect the ancillary energy used in geothermal exploration. Numerical estimates of this energy have not been made.

8.3.3 Environmental Considerations

Prelease exploration (all techniques except drilling for thermal measurements) involve minor impacts. Some alteration in land use from construction of access roads, cross country roads, and clearings occurs.

8.3.4 Economic Considerations

Geothermal exploration costs account for only a small percentage of development costs unless exploratory drilling costs are included. Thus, the costs of reconnaissance surveys and measurements on the surface do not inhibit development. However, when several exploratory test wells are drilled, costs escalate. Armstead (1973: 163) has estimated that three million dollars is required for exploration of one developed zone or geothermal field.

8.4 EXTRACTION--DRILLING

The extraction system for geothermal energy is similar to oil and gas in that a well is drilled to sufficient depth, cased, and completed to provide a stable conduit for fluids. Facilities required to control and transport the fluid to its point of utilization are added at the wellhead. Only those characteristics and problems unique to the extraction of geothermal energy are discussed here. The details of drilling rigs are discussed in Chapter 3.

8.4.1 Technologies

Experience indicates that the differences between oil drilling and geothermal drilling are:

1. Slower penetration rates are common due to harder rock.
2. Equipment, casing, and cement are subjected to higher temperatures in geothermal wells; thus, some variation in cement types and equipment occurs.
3. A more elaborate system for cooling mud is required. (A cooling tower may be used.)
4. Completion is usually some combination of cased wellbores and an open hole at the bottom. (Slotted or pre-perforated casing becomes clogged with chemical deposits.)

5. The casing itself is used as the production string due to the high volume and velocity of discharge.
6. Air drilling is common below segments where water-bearing formations have been cased off.
7. Due to caking and subsequent steam blockage, drilling mud cannot be used within the steam-bearing formation.

Completed wells at the Geysers range from 600 to 9,000 feet; a typical depth and diameter configuration is shown in Figure 8-3 (Budd, 1973: 133).

8.4.2 Energy Efficiencies

Steam losses occur during the drilling phase because of testing and well bleeding.* Data on the ancillary energy (power required at the drilling rig) are unavailable. Ancillary energy is apparently small, relative to the energy extracted.

8.4.3 Environmental Considerations

The minor impacts of air pollutants from motor vehicles coming to and from the site, the acre of land cleared for the drill site, and water contaminants from condensed steam will not be discussed here. The significance of venting formation dust into the air during air drilling is not known. The following three categories represent areas of concern; two are chronic and one represents a major accident.

8.4.3.1 Chronic

8.4.3.1.1 Noise

Table 8-5 gives some noise levels for two operations. Due to the frequency distribution, noise from muffled testing wells does not attenuate as rapidly with distance as air drilling noise. Air drilling noise comes from the air compressors and discharge vents. At the Geysers, well testing may last only a few weeks; however, a time lag of several years between testing and utilization of the steam often occurs. The wells are bled continuously during this interium (Interior, 1973: Vol. II, p. V-55), and noise levels are the same as for a muffled testing well.

*"Well bleeding" refers to the venting of the steam to the atmosphere before well equipment is attached at the wellhead.

TABLE 8-5

NOISE FROM GEOTHERMAL OPERATIONS

Operations	Distance Measured (feet)	Noise Level[a] (decibels)
During air drilling of a well	25	125
	1,500	55
Muffled testing well	25	100
	1,500	65

Source: Interior, 1973; Vol. II, p. V-56.
[a]For comparison, jet aircraft takeoff noise is approximately 125 decibels (dB) at 200 feet.

8.4.3.1.2 Air Pollutants

During testing and bleeding of the wells, all the noncondensable gases contained in the steam are vented to the atmosphere. Table 8-6 gives the gas concentrations in Geysers steam and total quantities as calculated by Teknekron (Finney and others, 1972). The total quantities assume that venting of each well occurs for two months prior to production and that reservoir and power plant life are 25 years.

Hydrogen sulfide (H_2S), occurring as 500 ppm in the steam, is the principal air pollutant of concern because of toxicity and nuisance odor. Standards for operating personnel set by the Occupational Safety and Health Administration (OSHA) state that 20 ppm H_2S in the air may not be exceeded during a normal eight-hour day. Although undiluted steam concentrations are higher than this, concentrations in the

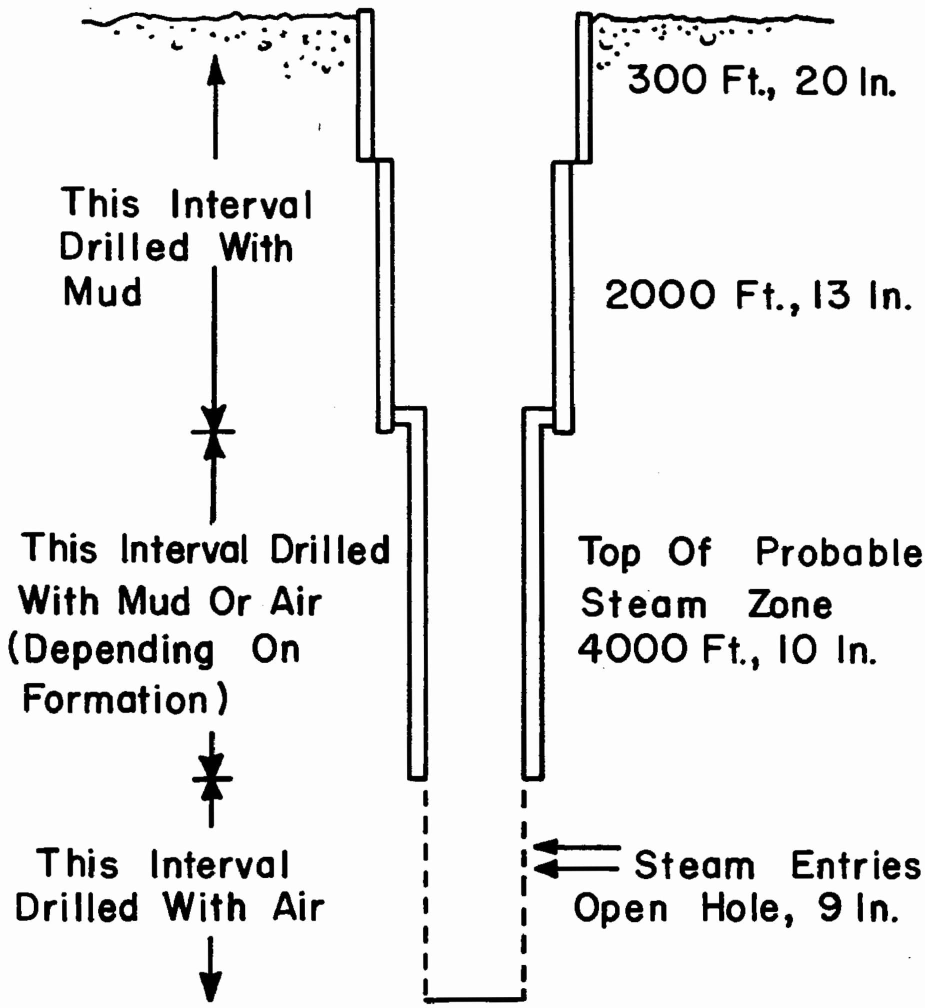


Figure 8-3. Typical Well Configuration at the Geysers

Source: Adapted from Budd, 1973: 135.

TABLE 8-6

GASES RELEASED TO THE AIR DURING DRILLING AT THE GEYSERS

Parameter	Concentration[a] (weight percent)	Quantity Released By 1,000-Mwe Plant[b] (tons per year)	Quantity[b] (tons per 10^{12} Btu's input)
Steam	99.0	533,169	2,791.5
Carbon dioxide	0.79	4,211.5	22.1
Hydrogen sulfide	0.05	266.4	1.4
Methane	0.05	266.4	1.4
Ammonia	0.07	373.1	1.9
Nitrogen, Argon	0.03	160.1	0.8
Hydrogen	0.01	53.4	0.3

Sources: [a]Finney and others, 1972.
[b]Calculated from Teknekron, 1973: 144, assuming a 25 year power plant life.

air at the Geysers range from 5 to 10 ppm (Interior, 1973: Vol. II, p. V-78). However, the unpleasant odor threshold for H_2S has been defined by the California Air Resources Board as 0.03 ppm. This is not a regulation but represents the nuisance odor threshold.

Mercury and radon gas occur in geothermal steam in trace amounts. Since methyl mercury accumulates in the food chains, monitoring of the mercury pathway after emission is needed. Radon is a natural radioactive material and could build up in the environment of geothermal facilities. The environmental impact of the mercury and radon emissions is not known.

8.4.3.2 Major Accident--Blowout

Like oil and gas wells, geothermal wells may experience blowouts. Two types of blowouts may occur in these wells: hot fluid may move up the well during drilling, or the hot fluid may leave the well through a permeable channel, traveling to the surface and emerging with eruptive force. To prevent the first type of occurrence, blowout preventers (similar to those on oil wells and described in Chapter 3) are routinely used at the wellhead. The second type of blowout prevention (again taken from oil well technology) is installation of a suitable casing and complete cement fill around the casing. Additionally, during the drilling of geothermal wells, the drilling mud must be cool to prevent excessive pressure development.

Several impacts may result from a blowout:

1. Bodily injury to workers may occur at two times: at the time of the blowout, which is sudden and violent, and during subsequent control attempts.
2. Noise nuisance.
3. Air contamination from gaseous emissions.
4. Possible pollution of surface and groundwater resources.

The probability of a blowout has been greatly reduced through improved drilling techniques and blowout preventers. However, the potential for one is highest during the exploratory drilling stage when subsurface conditions are unknown. No serious blowouts have occurred since 1961 at the Geysers or Imperial Valley locations.

8.4.4 Economic Considerations

Average drilling costs are $150,000 per well in a hot water field (such as Niland in the Imperial Valley) and $250,000 per well in the deeper steam fields (such as the Geysers). Rex and Howell's (1973: 65) drilling cost estimates for future, deeper wells range from $300,000 for a 6,000-foot well through $635,000 for a 10,000-foot well to $2,750,000 for a 20,000-foot well.

8.5 EXTRACTION--PRODUCTION

Production begins when the steam lines are connected to the wellhead. The wellhead production objective is to collect and deliver the steam free of water droplets and particulate matter with little reduction in energy.

8.5.1 Technologies

8.5.1.1 Hydrothermal Reservoirs

In hydrothermal reservoirs, pressure differentials force the steam or water to the surface. In vapor dominated reservoirs, only steam is produced. In hot water reservoirs, the surface output is a mixture of steam and water because 13 to 25 percent of the hot water flashes to steam (due to pressure reductions) as it rises in the well.

The production system at the wellhead includes:

1. Safety features (valves which open automatically with any pressure increase) to relieve line pressure in the event of a plant shutdown.
2. A meter at each wellhead to measure the production rate.
3. Separating devices and vessels for removal of liquids and solids.

In terms of production requirements, the principal difference between vapor and hot water reservoirs is the amount of water and particulate separation required before the steam can be used. In the vapor dominated type, a centrifugal separator* (which is normally installed in the well discharge line) removes formation dust and corrosion particles (grit). In the hot water types, both water and grit must be removed. The water, which is often a brine, is not utilized for power production and thus must be discarded after separation from the steam. This wastewater is normally collected from all the wellheads and conveyed to reinjection wells located throughout the field.

In hot water reservoirs, minerals are released in the wellbore when the water flashes to steam. These minerals (mainly silicon [Si] and calcium carbonate [$CaCO_3$]) collect in the well shaft, often to the point where the well requires redrilling to maintain adequate production. Unlike drilling the original borehole, however, redrilling can normally be accomplished quickly and with only a light drilling rig.

Production rates at the Geysers, a vapor dominated field, range from 40,000 pounds of steam per hour per well from shallow wells to 320,000 pounds per hour from deeper wells (Interior, 1973: Vol. I, p. II-20). The average is 150,000 pounds per hour. In the Imperial Valley, a hot water dominated field, the average is 440,000 pounds of steam and water per hour. Since individual wells decline in production with time, additional wells must be continually drilled to maintain the steam supply.

8.5.1.2 Dry Hot Rock Reservoirs

Dry hot rock reservoirs are being examined for their potential, but no production from these fields has occurred anywhere in the world. In addition to the

---

*As it rotates, a centrifugal separator throws particles and water (which are heavier than steam) to the outside and the steam leaves the middle of the separator through the top or bottom.

production system discussed earlier, dry hot rock reservoirs require that the rock be fractured and water injected to produce the necessary steam. As shown in Figures 8-4 and 8-5, a pair of wells is needed. Cool water is pumped into the deeper well and circulated through the hot, cracked zone into the higher well where it returns to the surface. If the water returns to the surface as steam, the steam can be used to drive the turbine. If it returns as hot water, the heat energy can be extracted through a heat exchanger (see Section 8.7.1.2). In either case, the re-cooled water is pumped down the deeper well again to be reheated, thus effecting a closed circulation system.

Two stimulation methods, differing only in the manner in which the rock is fractured, are being studied. Both approaches are unproven and speculative.

8.5.1.2.1 Hydraulic Fracturing

Hydraulic fracturing involves pumping water under high pressure (7,000 pounds per square inch [psi]) (Smith and others, 1973: 258) into a well, causing the rock to crack around the borehole. The Los Alamos Scientific Laboratory has conducted an initial test of the method at the edge of a volcanic crater in the Jemez Mountains of New Mexico. The test was considered successful in that the granite fractured as expected and the water was maintained in the rocks (Hammond, 1973: 43-44).

8.5.1.2.2 Nuclear Fracturing--The Plowshare Geothermal System

In the Plowshare system, the fracturing agent is an array of multiple nuclear explosives. Although the feasibility of this method was examined by the American Oil Shale Corporation and the Atomic Energy Commission (AEC) in 1971, no experiments have been conducted. Similar techniques have been tried with very little success to stimulate natural gas wells. Explosions would be in the multi-megaton range, array configurations ranging from 238 devices at 200 kilotons each to 10 devices at 1,000 kilotons each. Some of the energy from the explosion is trapped as heat; thus, unlike hydraulic fracturing, heat recovery for power generation involves the heat from both the original rock and the nuclear explosion.

8.5.2 Energy Efficiencies

The recovery efficiency for hydrothermal reservoirs (percent of stored Btu's delivered to the wellhead) is currently about 15 percent (Muffler and White, 1972: 50).

8.5.3 Environmental Considerations

Essentially all the environmental concerns resulting from production in hydrothermal systems are also present in hot dry rock systems. Hydraulic fracturing results in no new problems, but nuclear fracturing presents a number of concerns. This section first discusses the general area of environmental concerns in production followed by those specific to nuclear fracturing.

8.5.3.1 Noise

When a wellhead power plant is shut down, geothermal steam must be vented to the atmosphere. Noise from steam line vents averages 100 decibels (dB) at 50 feet and 90 dB at 250 feet (Interior, 1973: Vol. I, p. III-6). At the Geysers, the common procedure is to use a muffler attached to the relief valves in the steam line. Where water is abundant, discharging the flow through a submerged outlet into a large volume of water eliminates noise.

8.5.3.2 Water and/or Brine Disposal from the Separator

A typical brine in the Imperial Valley consists of 250,000 ppm dissolved solids--primarily Si, $CaCO_3$, sodium chloride (NaCl), boron (B), ammonia, and argon (Ar). Because these concentrations and types of materials preclude release in fresh surface or

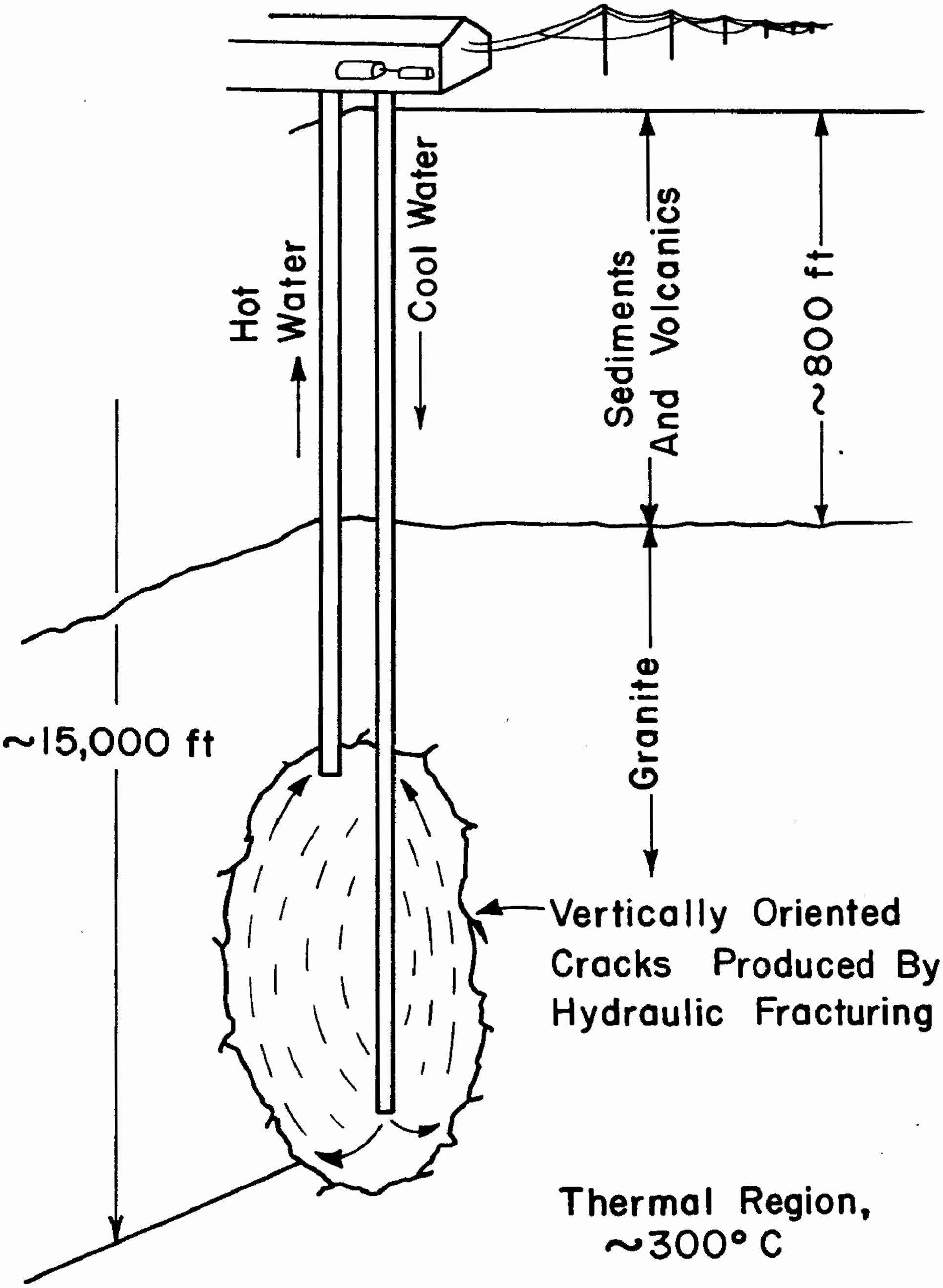


Figure 8-4. Dry Rock Geothermal Energy System by Hydraulic Fracturing

Source: AEC, 1973: A.4-20.

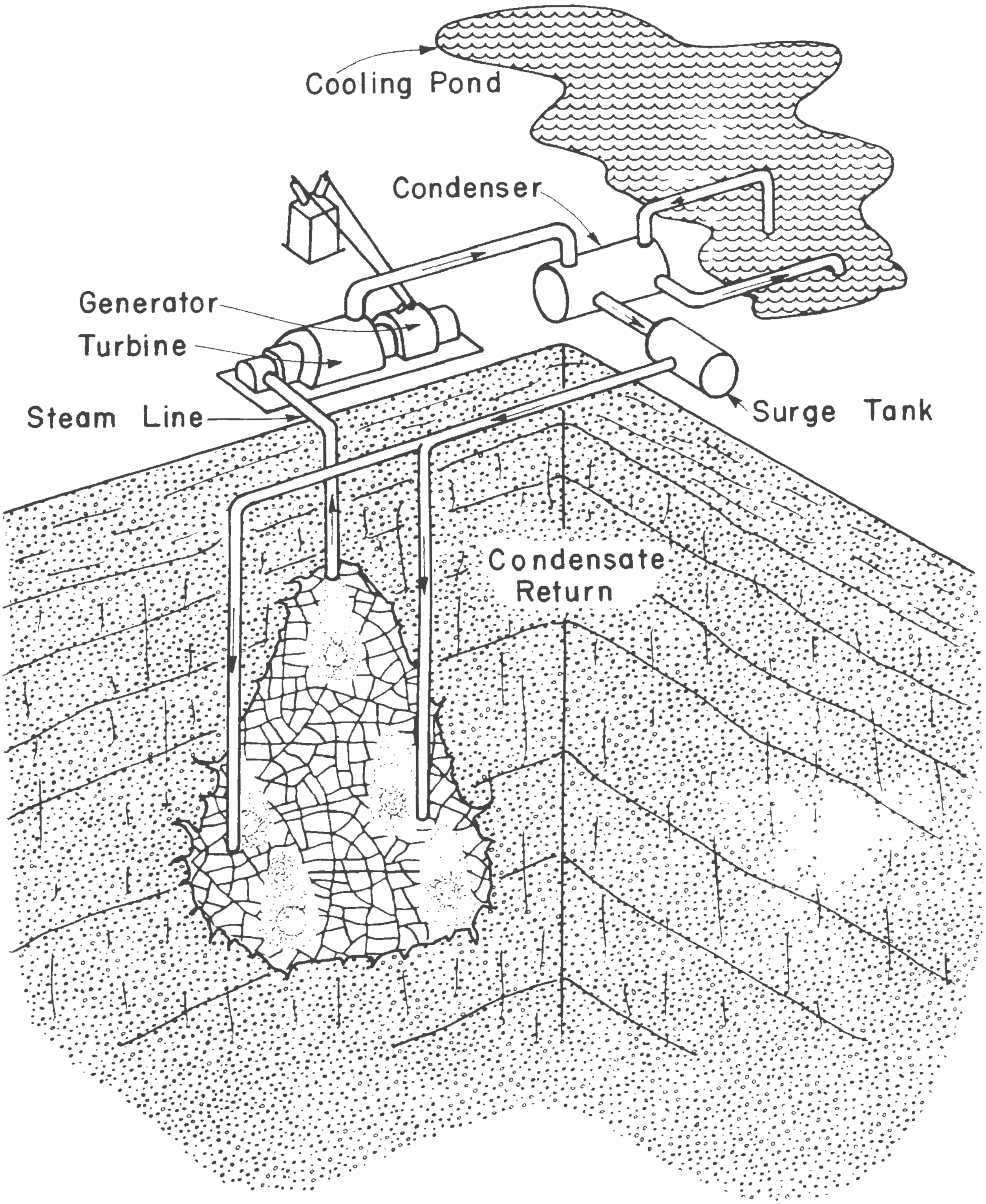


Figure 8-5. Plowshare Concept of Geothermal Heat Extraction

Source: American Oil Shale Corp. and AEC, 1971: 2-3.

groundwater, the separated brine must be reinjected into the formation from which it was extracted or eliminated in some other manner. As an indication of the problem's magnitude, disposal of an estimated 50 billion gallons of brine per year containing 50 million tons of solids would be required for a 1,000-Mwe plant in the Imperial Valley (Battelle, 1973: 550). Reinjection of the wastewater, in addition to economic and environmental advantages over other disposal methods, may have the added effects of preventing land subsidence and facilitating greater steam production as noted below.

8.5.3.3 Land Subsidence

Whenever fluids are extracted from a groundwater reservoir (withdrawals exceed recharge, thus decreasing the reservoir pressure), land subsidence may occur. Further geothermal reservoirs may be especially susceptible to this phenomenon because of the high mass removals required for production. Subsidence has occurred at Wairakei, New Zealand and Cerro Prieto, Mexico after the extraction of geothermal water. The Imperial Valley appears to be a likely candidate for subsidence, although the data required to predict the rate is unavailable.

Minimizing subsidence requires maintaining adequate fluid in the strata by natural or artificial recharge (reinjection).

8.5.3.4 Earthquakes

Changes in reservoir pore pressure (due to either injection or withdrawal of large volumes of fluid) may result in instability leading to earthquakes along faulted or fractured zones. Instability due to oil withdrawal occurred in the Wilmington Oil Field, California (Poland and Davis). Instability due to injection has been documented at the Baldwin Hills Oil Field, California (Hamilton and Muchan, 1971: 333-344), the Rangely Oil Field, Colorado (Healy and others, 1970: 205-214), and at the Rocky Mountain Arsenal, Colorado (Healy and others, 1968: 1301-1310).

Both withdrawal and injection occur in geothermal fields. Intuitively, one would be expected to cancel the other. However, evaluation of earthquake possibilities in U.S. geothermal fields must await a test case. Large withdrawals and injections are planned in the Imperial Valley; thus, this area may provide the needed experience. Continuous monitoring for earthquake activity will be necessary.

8.5.3.5 Groundwater Contamination

If a fresh water aquifer occurs above a geothermal reservoir, tapping the geothermal strata could contaminate the freshwater strata through the well. Proper and complete cementing of well casings in both production and reinjection wells is required to eliminate this possibility.

8.5.3.6 Land Use

For a 110-Mwe geothermal unit, the drill site pads and work area require 28 to 35 acres, which is 3.5 percent of the total acreage needed for all facilities. Of the total, however, only about 10 percent is used directly (Interior, 1973: Vol. I, p. III-6).

8.5.3.7 Air Pollutants

Venting steam to the atmosphere occurs in the production phase only during blowdowns.* The types of air pollutants released during blowdowns are the same as those released in the drilling phase. Total quantities of air pollutants released during production are not known. As mentioned previously, the problem pollutant is H_2S, which primarily creates a nuisance odor.

*Blowdowns are the release or cleaning out of water with high solids content, the solids accumulating each time water evaporates.

8.5.3.8 Additional Concerns Caused by Dry Rock Fracturing with Nuclear Devices

8.5.3.8.1 Groundmotion

At the time of detonation of a nuclear fracturing device, damage to natural and man-made structures may occur as the shock wave moves to the surface. Thus, although the Plowshare concept of geothermal development has been proposed for Appalachia and the Ozarks, as well as for the western U.S. (Horvath and Chaffin, 1971: 17-33), the use of multimegaton nuclear devices in most of the continental U.S. may be impractical.

8.5.3.8.2 Radiation Releases

With any nuclear explosion, whether from fission devices or fusion devices with fission triggers, radiation is released. At the depths contemplated for Plowshare activities, however, the possibility of radiation leakage to the atmosphere should be minimal. Also, with proper cementing of the drill hole, radiation leakage to the groundwater aquifers is unlikely. Although the steam brought to the surface for power production would contain small quantities of radioactive isotopes, almost all the radiation would be returned to the fractured region with the recirculation steam.

8.5.3.8.3 Aftershocks

Local seismic activity may be affected by an underground nuclear explosion. Readjustment of the surrounding ground to the transient shock waves could theoretically produce an earthquake. The Plowshare geothermal study (American Oil Shale Corporation and AEC, 1971: 4.3.2) indicates that the probability is "negligible in stable areas and low, but nonnegligible in tectonically active areas."

8.5.3.8.4 Volcanic Stimulation

A remote possibility exists that molten rock from an underground explosion might be extruded onto the surface through an older established vent. The probability would depend on local geologic conditions as well as the size and depth of the explosion.

8.5.3.8.5 Hydrothermal Explosion

If there were hot springs in the vicinity of an explosion site, and if the water was near its flash temperature, the nuclear explosion could cause the whole section of fluid to flash to steam, producing a hydro-thermal explosion. This possibility is considered remote because Plowshare geothermal applications are intended for areas where there is no natural water circulation system.

8.5.4 Economic Considerations

Armstead (1973: 163) estimates that wellhead equipment costs--including separator, silencer, valves, pipework, and gauges--average $35,000 per well. The actual cost of the production step (capital and operating) is not available. Cost factors differ with the type of reservoir:

1. Vapor dominated. These reservoirs are currently the most economical geothermal power sources because all the steam produced is utilized.
2. Hot water dominated. Additional costs associated with these reservoirs result from:
    a. The need to reinject large quantities of water or brine into the formation.
    b. The possible need to redrill existing wells because of mineral depositions downhole.
3. Dry hot rock. Additional costs associated with these reservoirs result from:

a. The need to drill two wells (an injection well and a recovery well) for each production unit.

b. The expense of the initial fracturing, whether water-induced or by nuclear explosion.

8.6 TRANSPORTATION--STEAM TRANSMISSION SYSTEM

8.6.1 Technologies

Four parameters characterize the geothermal steam transmission system. First, because of thermal expansion and contraction and because regular maintenance is required, the insulated pipes must be above ground with U-shaped expansion loops at frequent intervals. Second, pipe sizes must be relatively large to minimize frictional losses. The present system at the Geysers utilizes 10-inch diameter pipes at the wellhead expanding to 36-inch diameter pipes at the turbine inlets.

Third, steam transmission distances from the wellhead to the power plant are generally short due to pressure and temperature loss factors. The greatest distance of any connected well at the Geysers is 1,200 feet. Fourth, air-actuated relief valves are used in the steam line to vent the steam to the atmosphere in the event of a power plant shutdown. At the Geysers, these valves activate automatically when the pressure increases from the normal 100-120 psi to 150 psi. The control valve exhausts are equipped with mufflers for noise attenuation.

8.6.2 Energy Efficiencies

Since $10^{\circ}F$ or one percent of the heat content is lost between the wellhead and power plant at the Geysers, pipeline transportation there is 99-percent efficient.

Reservoirs developed in the future will have different transport efficiencies because wellhead pressures and temperatures will vary.

8.6.3 Environmental Considerations

Air pollutants released during steam venting were discussed in Section 8.5. Concentrations are the same here; total quantities are not known.

The land requirement for steam lines is the only other impact category. The terrain is laced with exposed steam pipes radiating from the power plant to the wellheads. Steam lines and access roads constitute 3.5 percent of the 800 to 1,000 acres needed for each 110-Mwe system at the Geysers. Accompanying the land requirement is the reduction in plant and animal habitat caused by it.

8.6.4 Economic Considerations

Cost data for the kind of pipelines used to transmit geothermal steam are not available.

8.7 POWER GENERATION

8.7.1 Technologies

8.7.1.1 Geothermal Steam Generator

The power generation step in the geothermal resource system parallels that described in Chapter 12, Electric Power Generation. Commercially available geothermal systems are distinctive primarily in that they use low pressure steam turbines to drive generators. Once the steam has passed through the turbine, condensers convert it to hot water by mixing it with cool water. The hot water then goes to an evaporative cooling tower where 75 percent evaporates into the air. The remaining, cooled water is recirculated through the condenser, reinjected in the reservoir, or both. This power generation sequence applies to both vapor dominated (Figure 8-6a) and water dominated systems (Figure 8-6b) where only the steam produced is used.

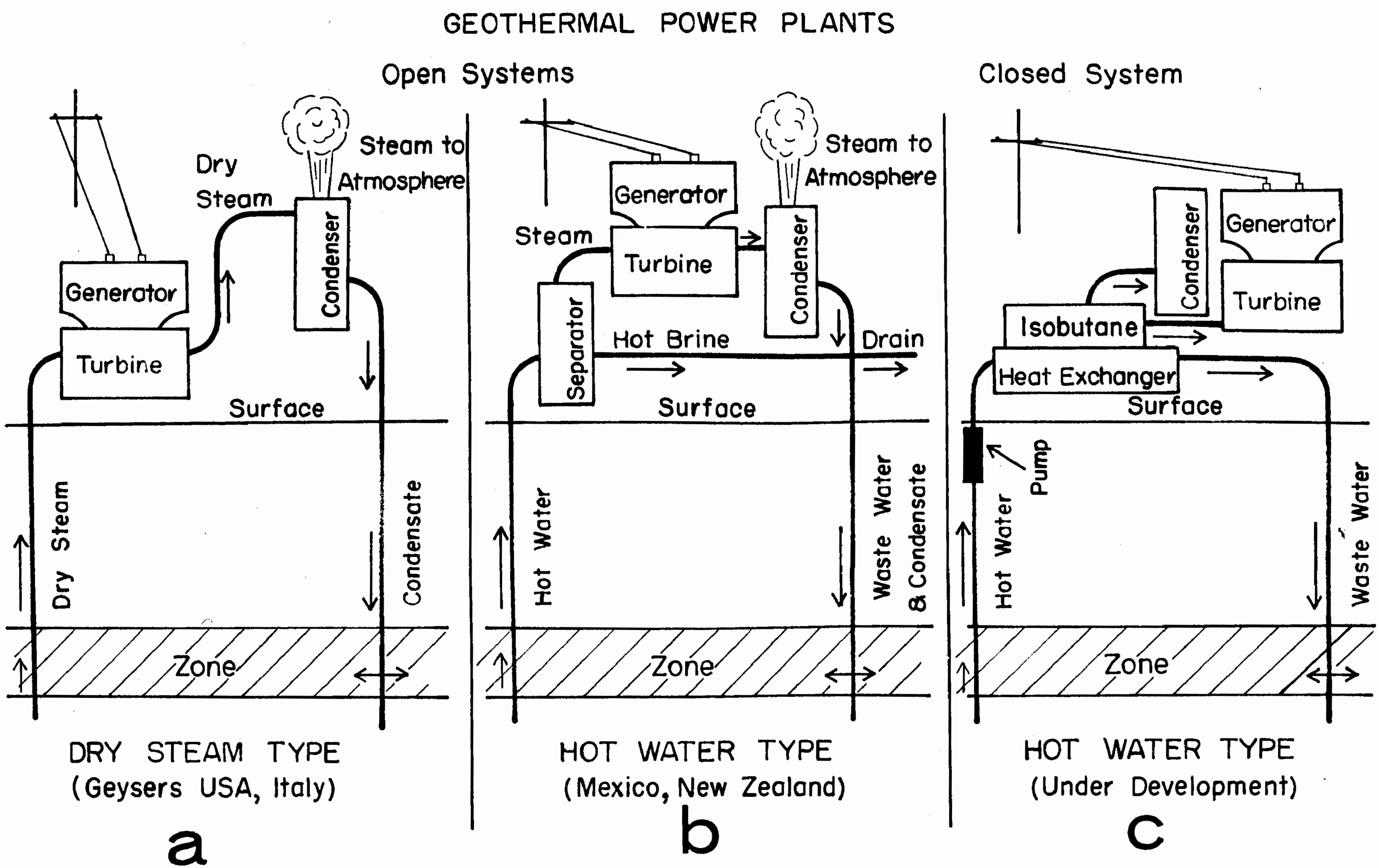


Figure 8-6. Geothermal Power Plant Types

Source: Interior, 1973: Vol. 2, p. V-156.

The distinctive characteristics of geothermal power generation are:

1. No combustion of any fuel occurs in a geothermal plant.
2. Low efficiencies result from the low temperature and pressure of the steam. The temperature of steam entering the turbines at the Geysers is 350°F at 100 psi (75 psi in a hot water field), while inlet temperatures for a modern fossil-fueled plant are 1,000°F at 3,500 psi. The turbine at the Geysers is about 22 percent efficient.
3. The overall plant efficiency for geothermal power production is approximately 15 percent, compared to 35 to 38 percent for a fossil-fueled plant. This means that a geothermal plant requires 22,000 Btu's to generate one kilowatt-hour (kwh) while a modern fossil-fueled plant requires 9,000 to 10,000 Btu's.
4. Due to long, complicated start-up procedures, geothermal units should operate as base-load units rather than peak-load units.
5. Since steam cannot be transported over long distances, geothermal generating plants are relatively small. At the Geysers, each plant has a 110-Mwe capacity and consists of two 55-Mwe generators.
6. A 110-Mwe station requires two million pounds of steam per hour or the output of 14 wells at 150,000 pounds per hour each.
7. Direct contact condensers are used in which the steam and cooling water mix directly.
8. No external makeup water for cooling is required. The steam flow to the turbines exceeds the cooling tower evaporation rate; thus, condensed exhaust is used as cooling tower makeup water.
9. In the power generation step, noncondensable gases are released into the air from the condenser and from the cooling tower.
10. At the Geysers, 75 to 80 percent of the condensed steam evaporates in the cooling tower; 20 to 25 percent is reinjected into the geothermal steam-bearing formation.
11. In hot water systems, (Figure 8-66), the water or brine is passed through a separator, which draws off steam to drive the turbine, then routed to reinjection wells. Additional water from the cooling tower may also need reinjection.
12. The minerals in the steam cause corrosion and erosion in the turbine, requiring continuous and extensive maintenance.

8.7.1.2 Alternative Power Generation Systems

In response to the desire to improve geothermal power generation efficiency, several modifications are being investigated. One approach, now at the pilot plant stage, uses a heat exchanger to transfer the heat energy from the hot, geothermal water to a second (working) fluid which is then fed into the turbine, (Figure 8-6c). After being exhausted from the turbine, the working fluid is cooled in a condenser and pumped back into the circulatory system. Magma Power Company of Los Angeles is developing one of these binary fluid systems in which isobutane is the working fluid. Construction of a 10-Mwe pilot plant using that system is underway in Brady, Nevada. Also, a 0.5-Mwe pilot plant is operational at Kamchatka, USSR, in which Freon is the working fluid.

A second approach to hot water systems would connect high- and low-pressure turbines in tandem (Figure 8-7). Steam from the wellhead separator would drive the high-pressure turbine as in existing plants. The low-pressure turbine would be driven by both the high-pressure turbine exhaust and steam created by flashing part of the otherwise rejected hot brine in a flash boiler.

A third approach focuses on development of impulse turbines (basically modern water wheels) in which a high velocity jet of water impinges on vanes or buckets at the wheel periphery. (See Chapter 9 for a more complete description of impulse turbines.) To obtain the jet of water, the geothermal water-steam mixture is expanded through a converging-diverging nozzle to a low pressure and high velocity. This system, termed total fluid flow (Smith

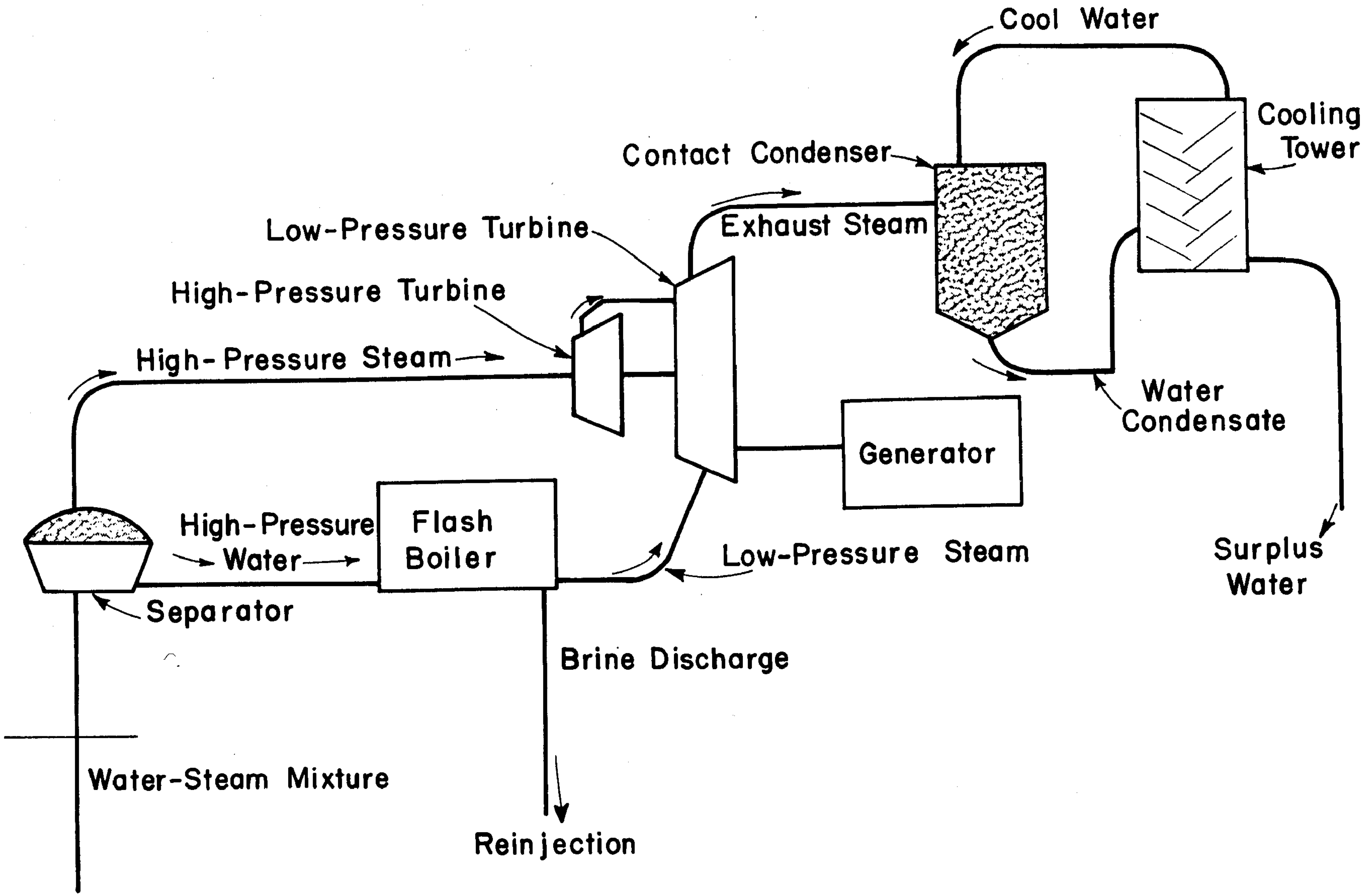


Figure 8-7. Geothermal Power Plant

Source: Interior, 1973: Vol. 1, p. II-30.

and others, 1973: 252), is being developed by the Lawrence Livermore Laboratory principally for the hot brine geothermal reservoirs typical of the Imperial Valley.

A variation of the impulse turbine is the helical screw expander being developed by the Hydrothermal Power Company of California.

8.7.2 Energy Efficiencies

The power generation step (turbine and generator) is more efficient in vapor dominated systems than in hot water dominated systems because the steam enters at a higher temperature and pressure. (Turbine efficiency is about 22 percent at the Geysers, as stated earlier.) Similarly, the power generation step where the total fluid is utilized in a heat exchanger or impulse turbine is less efficient because of lower temperatures and pressures. However, total efficiencies in hot water dominated systems (from the wellhead through power generation) may be equal to or greater than vapor dominated types because the heat content of the water is used. Total system efficiencies are discussed in the summary section of this chapter.

At the Geysers, an ancillary electrical energy requirement of 3.6 percent generated power is needed for coolant pumps, cooling tower blowers, and other plant equipment (Teknekron, 1973: 144).

8.7.3 Environmental Considerations

Teknekron calculations for power plant air pollutant emissions and cooling tower effluent at the Geysers are given in Tables 8-7 and 8-8, respectively. Land utilization for each power house and cooling unit is six acres or 0.75 percent of the gross area required to serve a 110-Mwe plant.

Noncondensable gas fractions are usually higher from a hot water dominated reservoir than from the vapor dominated reservoir shown in Table 8-7. Noxious gas control is expected to become a part of the

TABLE 8-7

AIR EMISSIONS AT THE GEYSERS PLANT[a]

Parameter	Quantity for a 1,000-Mwe Plant (per year)	Quantity per 10^{12} Btu's Input to Power Plant
Water (10^6 gallons)	15,800	83
Waste heat (10^9 kwh)	44.9[b]	0.23
Carbon dioxide (tons)	631,732	3,307
Ammonia (tons)	54,000	283
Methane (tons)	40,020	209
Hydrogen sulfide (tons)	39,249	205
Nitrogen, argon (tons)	24,034	126
Hydrogen (tons)	7,993	42

Source: Teknekron, 1973: Figure 9.1.

[a]From the cooling tower and steam gas ejectors.

[b]3,630 Mwe of heat are rejected by a 1,000-Mwe vapor dominated geothermal plant (a nuclear plant rejects 2,000 Mwe).

power plant technologies for hot water type reservoirs (Battelle, 1973: 550).

Heat rejection from the power plant in a hot water type reservoir is expected to be 2.5 times that from a vapor type--10,000 Mwe rejected for a 1,000-Mwe plant (Battelle, 1973: 550). In both cases, rejection is into the atmosphere via a cooling tower.

Where binary fluid systems are used, the water is reinjected directly with fewer gas releases to the air. However, these systems will be even less efficient than vapor or standard hot water systems, have greater thermal effluents, and may require an external source of water to condense the working fluid.

TABLE 8-8

COOLING TOWER DISCHARGE PLANT REINJECTED AT THE GEYSERS

Parameter	Concentration (milligrams per liter)	Quantity for a 1,000-Mwe Plant (tons per year)	Quantity (tons per 10^{12} Btu's input to power plant)
Carbonates (alkalinity)	42.9	5,590	29.3
Ammonia	148.3	1,929	10.1
Sulfur dioxide	2.0	26	0.14
Sulfate	131.2	1,708	8.9
Sulfur	8.3	109	0.6
Nitrate	0.1	1.3	0.007
Chloride	3.5	45.5	0.24
Calcium	5.3	69.0	0.36
Magnesium	1.0	13.0	0.07
Silicon	3.7	48.7	0.25
Boron	17.1	223.0	1.17
Total solids from evaporation	185.2	2,414	12.6
Organics and volatile solids	206.3	2,690	14.1
Water[a] (gallons per year)	NA	31.2×10^8	U

NA = not applicable, U = unknown

Source: Teknekron, 1973: 144.

[a]One large injection well can accommodate the one million gallons per day output of a 100-Mwe unit which is fed by about 14 wells.

8.7.4 Economic Considerations

Based on existing geothermal installations, Armstead (1973: 170) has estimated power plant capital costs, including buildings and cooling water facilities (Table 8-9). Note that these costs are less sensitive to scale than conventional thermal plants; this is due to the small size units required, even for large total installed capacity.

8.8 SUMMARY

Since all technologies associated with the utilization of geothermal energy are located at one site and ambient conditions are the same throughout the trajectory, total system environmental residuals may be summed. In this summary, data for the total system are presented.

TABLE 8-9

CAPITAL COSTS OF
GEOTHERMAL POWER PLANTS, 1973

Size (Mwe)	Cost (per kw)
20	$160
50	140
100	125
200	110

Source: Armstead, 1973: 170.

TABLE 8-10

SYSTEM EFFICIENCY: WELLHEAD THROUGH ELECTRIC POWER GENERATION[a]

Type	Efficiency Percent
Vapor dominated reservoir (Geysers)[b]	14.7
Hot water dominated reservoir (flushed steam)[c]	11
Binary fluid type[c]	11
Total flow impulse turbine[c]	18

[a]Reservoir recovery efficiency included.

[b]Teknekron, 1973: 144.

[c]Austin and others, 1973: 20.

8.8.1 Energy Efficiencies

Table 8-10 gives primary efficiencies for four geothermal energy systems. Note that the total fluid flow impulse turbine system appears to give the best efficiency. This system, however, is still unproven commercially. Using steam from vapor dominated reservoirs is currently the most efficient system.

8.8.2 Environmental Considerations

Major impact categories which were more fully discussed under each technology are listed here, as well as quantitative estimates of the residuals for a 1,000-Mwe installation using several reservoir types. In addition, Table 8-11 gives water and air residuals on a per 10^{12} Btu's input basis for the Geysers. The air pollutants include those from testing and bleeding wells during the drilling phase and those emitted at the power plant. Excluded are emissions that occur intermittently during the production phase when the power plant is shut down and pipelines are bled to the atmosphere. Although concentrations in the steam are the same, total quantities emitted during production are not known. Since the contribution during the drilling phase is only about one percent of that from the power plant, and air emissions during production are less than during drilling, the values on Table 8-11 appear to be good estimates of total air emissions.

8.8.2.1 Land

Between 3,000 and 5,000 acres (Battelle, 1973: 550) are required for a 1,000-Mwe plant, with 7 to 10 percent of this directly used for facilities. Subsidence may occur due to removal of fluids, and seismic activity may be generated from fluid withdrawal and/or reinjection.

8.8.2.2 Water

No makeup water is required for vapor dominated systems. The cooling water requirement could be significant in closed cycle designs unless air-cooled condensers are used.

In all cases, wastewater cannot be discharged into surface water without treatment. In the U.S., wastewater is reinjected through a well into the geothermal reservoir. A 1,000-Mwe vapor dominated plant requires disposal of $3x10^9$ gallons per year containing 10^5 tons of solids (Battelle, 1973: 550).

TABLE 8-11

ENVIRONMENTAL RESIDUALS FOR GEOTHERMAL DEVELOPMENT AT THE GEYSERS[a]

Pollutants	Quantity (tons per 10^{12} Btu's)
Water[b]	
Bicarbonate	29.3
Nitrogen oxides	10.1
Sulfur oxides	9.7
Total dissolved solids	63.7
Organics	14.1
Air	
Carbon dioxide	3,329
Ammonia	57
Methane	210
Hydrogen sulfide	206

Source: Calculated from Battelle, 1973: 550 and Teknekron, 1973: 144.

[a]Through electric power generation.

[b]Condensate return water; it is reinjected, thus does not reach surface waters.

Brine hot water dominated power plants require disposal of $5x10^{10}$ gallons per year containing $5x10^{5}$ tons (Cerro Prieto) to $5x10^{7}$ tons (Salton Sea) of solids (Battelle, 1973: 550).

8.8.2.3 Air

Hydrogen sulfide is the most troublesome air pollutant, amounting to 500 ppm in the steam. Total release from a Geyser type system for a 1,000-Mwe plant would range from $3.6x10^{7}$ pounds of H_2S per year (100,000 pounds per day) to $7.8x10^{7}$ pounds per year (215,000 pounds per day) (Battelle, 1973: 550).

For hot water systems, H_2S releases are higher. At Cerro Prieto, H_2S would be 1,250,000 pounds per day or $4.56x10^{8}$ pounds per year for a 1,000-Mwe plant (Battelle, 1973: 550). This exceeds the amounts released from burning high sulfur fuel in fossil-fueled plants.

Other chemicals (such as mercury, radon, ammonia, boron, and flourides) drift from the cooling towers and rain out. The severity of these pollutants is site dependent and, in the case of mercury and radon, the impact is unknown.

Heat rejection to the atmosphere (thermal pollution) via cooling towers is 3,630 Mwe by a 1,000-Mwe plant for the Geysers. Up to 50,000 acre-feet of water per year (Battelle, 1973: 550) is evaporated in cooling towers. This amount of heat is not large, but if a concentration of 1,000-Mwe plants occurred, their combined heat output would affect local climate. Hot water systems reject 2.5 times the heat output of the Geysers plant.

8.8.2.4 Occupational Health

Noise pollution can be a problem, with levels well above 100 dB for venting and similar activities.

8.8.3 Economic Considerations

Table 8-12 summarizes the component costs of obtaining geothermal power. Exploration costs appear high because exploratory drilling throughout the life of the reservoir is included in that category. Economies of scale are due principally to decreases in exploration costs as they are averaged over total kilowatts generated. These estimates were made in 1972 and range from $232 per kwh for a 200-Mwe installation to $465 per kwh for a 20-Mwe installation.

Table 8-13 presents estimates on the cost of power generation from various types of geothermal reservoirs. Estimates are based on 1970 or 1972 dollars and range from five to eight mills per kwh in this country.

TABLE 8-12

1972 COSTS FOR GEOTHERMAL POWER

Component	Cost (dollars per kilowatt)			
	20-Mwe	50-Mwe	100-Mwe	200-Mwe
Exploration	150	60	30	15
Drilling	18	16.2	16.2	15.7
Wellhead gear and collection pipeline	59.8	53.8	53.8	52.4
Power Plant	160	140	125	110
Subtotal	387.8	270.0	225.0	193.1
20-percent interest during construction and contingencies	77.6	54	45	39.5
TOTAL	465.4	324.0	270.0	232.6

Source: Armstead, 1973: 170.

TABLE 8-13

COSTS OF GEOTHERMAL POWER GENERATION SYSTEMS

Type	Cost (mills per kwh)
Vapor dominated	
Geysers[a]	5.0
Larderello, Italy[a]	4.8 to 6.0
Matsukawa, Japan[a]	4.6
Hot water dominated	
Wairakei, New Zealand[b]	5.14
Namafjall, Iceland[a]	2.5 to 3.5
Cerro Prieto, Mexico[a]	4.1 to 4.9
Pauzhetsk, USSR[a]	7.2
Total flow impulse turbine[c]	8.0
Dry hot rock systems	
Hydraulic fracturing[d]	
15,000-foot wells	4.7
18,000-foot wells	8.0
Plowshare--nuclear fracturing[e]	6.0 to 7.5

Sources: [a]Koenig, 1973: 19. 1972 dollars.

[b]Armstead, 1973: 167, 172. 1972 dollars.

[c]Austin and others, 1973: 34. 1972 dollars.

[d]Smith and others, 1973: 263. 1972 dollars.

[e]American Oil Shale Corp. and AEC, 1971: 7.47-7.51. 1970 dollars.

REFERENCES

American Oil Shale Corporation and Atomic Energy Commission (1971) A Feasibility Study of a Plowshare Geothermal Power Plant. Oak Ridge, Tenn.: AEC.

Armstead, H. Christopher H. (1973) "Geothermal Economics," pp. 161-174 in H. Christopher H. Armstead (ed.) Geothermal Energy. Paris: UNESCO.

Atomic Energy Commission (1973) The Nation's Energy Future; A Report to Richard M. Nixon, President of the United States, submitted by Dixie Lee Ray, Chairman. Washington: Government Printing Office.

Atomic Energy Commission (1974) Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington: Government Printing Office, 4 vols.

Austin, A.L., G.H. Higgens, and J.H. Howard (1973) The Total Flow Concept for Recovery of Energy from Geothermal Hot Brine Deposits. Lawrence, California: Lawrence Livermore Laboratory.

Banwell, C.J. (1973) "Geophysical Methods in Geothermal Exploration," pp. 41-48 in H. Christopher H. Armstead (ed.) Geothermal Energy. Paris: UNESCO.

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

Budd, Chester F. Jr. (1973) "Steam Production at the Geysers Geothermal Field," pp. 129-144 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

Bureau of Land Management (1973) Energy Alternatives and Their Related Environmental Impacts. Washington: Government Printing Office.

Combs, Jim and L.J.P. Muffler (1973) "Exploration for Geothermal Resources," pp. 95-128 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

Department of the Interior (1973) Final Environmental Statement for the Geothermal Leasing Program. Washington: Government Printing Office. 4 vols.

Finney, J.P., F.J. Miller, and D.B. Mills (1972) "Geothermal Power Project of Pacific Gas and Electric Company of the Geysers, California" presented at the IEEE Power Engineering Society Summer Meeting, 1972 as cited on p. 147 in Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I; Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif.: Teknekron.

Godwin, L.H., and L.B. Haegler, K.L. Kioux, D.E. White, L.D.P. Muffler, and R.G. Wayland (1971) Classification of Public Lands Valuable for Geothermal Steam and Associated Geothermal Resources, USGS Circular 647. Washington: Government Printing Office.

Hamilton, D.H. and R.L. Muchan (1971) "Ground Rupture in the Baldwin Hills." Science 172 (April 23, 1971): 333-344.

Hammond, A.L. (1973) "Dry Geothermal Wells: Promising Experimental Results." Science 182 (October 5, 1973): 43-44.

Healy, J.H., W.W. Rubey, D.T. Griggs, and C.B. Raleigh (1968) "The Denver Earthquakes." Science 161 (September 27, 1968): 1301-1310.

Healy, J.H., R.M. Hamilton and C.B. Raleigh (1970) "Earthquakes Induced by Fluid Injection and Explosion." Tektono Physics 9 (March 1970): 205-214.

Hickel, Walter J. (1972) "Geothermal Energy: A Special Report." University of Alaska, Fairbanks.

Horvath, J.C. and R.L. Chaffin (1971) "Geothermal Energy, Its Future and Economics in Atlanta." Economic Review 21 (December 1971): 17-33.

Kilkenny, John E. (1972) "Geothermal Energy--Part II" in National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee, U.S. Energy Outlook: An Interim Report; An Initial Appraisal by the New Energy Forms Task Group. Washington: NPC.

Koenig, James B. (1973) "Worldwide Status of Geothermal Resources Development," pp. 15-58 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

Muffler, L.D.P. and D.E. White (1972) Geothermal Energy Resources of the U.S.,USGS Circular 650. Washington: Government Printing Office.

Poland, J.F. and G.H. Davis. "1969 Land Subsidence Due to Withdrawal of Fluid." Geological Society of America Reviews in Engineering, Geology II, pp. 187-269.

Rex, Robert W. and David J. Howell (1973) "Assessment of U.S. Geothermal Resources," pp. 59-68 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

Smith, Morton, R. Potter, D. Brown, and R.L. Aamodt (1973) "Induction and Growth of Fractures in Hot Rock," pp. 251-268 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I; Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif.: Teknekron.

White, Donald E. (1973) "Characteristics of Geothermal Resources," pp. 69-94 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

CHAPTER 9

THE HYDROELECTRIC RESOURCE SYSTEM

9.1 INTRODUCTION

Water power for central station electricity generation was first used in Wisconsin in the 1880's. By about 1940, hydroelectric power represented 30 percent of the installed electric generating capacity in the U.S. (Doland, 1954: 5). Although the nation's hydroelectric generating capacity has continued to expand since 1940, its relative role had declined to 15 percent of installed generating capacity in 1971. Several factors apparently account for this relative decline and reliance on other energy resources, including limited availability of dam sites and high capital costs. Although hydroelectric facilities have always been attractive as renewable power sources (and frequently have multiple uses including recreation, irrigation, and flood management), most dam construction projects have sparked controversy, especially over changed land use and impact to wildlife.

The output of hydroelectric power plants is easily adjusted by manipulating water flow to follow demand loads for meeting peak electricity needs. Storage of water for use during peak demand periods has become increasingly significant. One technique is pumped storage, where electricity from another power source (such as a nuclear plant) is used to pump water from a low basin into an upper storage reservoir for subsequent hydroelectric generation during peak demand periods. The first pumped storage plant was installed in 1930; by 1970, nine pumped storage plants were operating (AEC, 1974: Vol. IV, p. A.3-4). A new development of apparently limited potential significance is tidal power, where daily changes in sea level are used to drive reversing turbine-generators. Tidal power is essentially derived from the earth's rotation and gravitational forces exerted by the moon and sun. The limited potential of this energy source is discussed briefly in Section 9.8.

Components of conventional hydroelectric resource systems consist of an initial water source, storage reservoir, pipe transport system, and a turbine-generator complex that feeds electricity into a transportation network as diagrammed in Figure 9-1. As shown, the pumped storage subsystem usually employs reversible pump-generators that elevate water back through the pipes into the reservoir for use during the peak demand periods.

9.2 CHARACTERISTICS OF THE RESOURCE

Water is considered a hydroelectric resource when adequate quantity or flow rate occurs together with a suitable elevation difference between the surface of the water storage and the outlet of the turbine discharge. This minimum elevation or "head" is about 20 feet (FPC, 1970: IV-1-72).

Since hydroelectric resources are renewable, they are usually calculated as annual rates or installed capacity for producing power, rather than as fixed quantities of depletable fossil fuels.

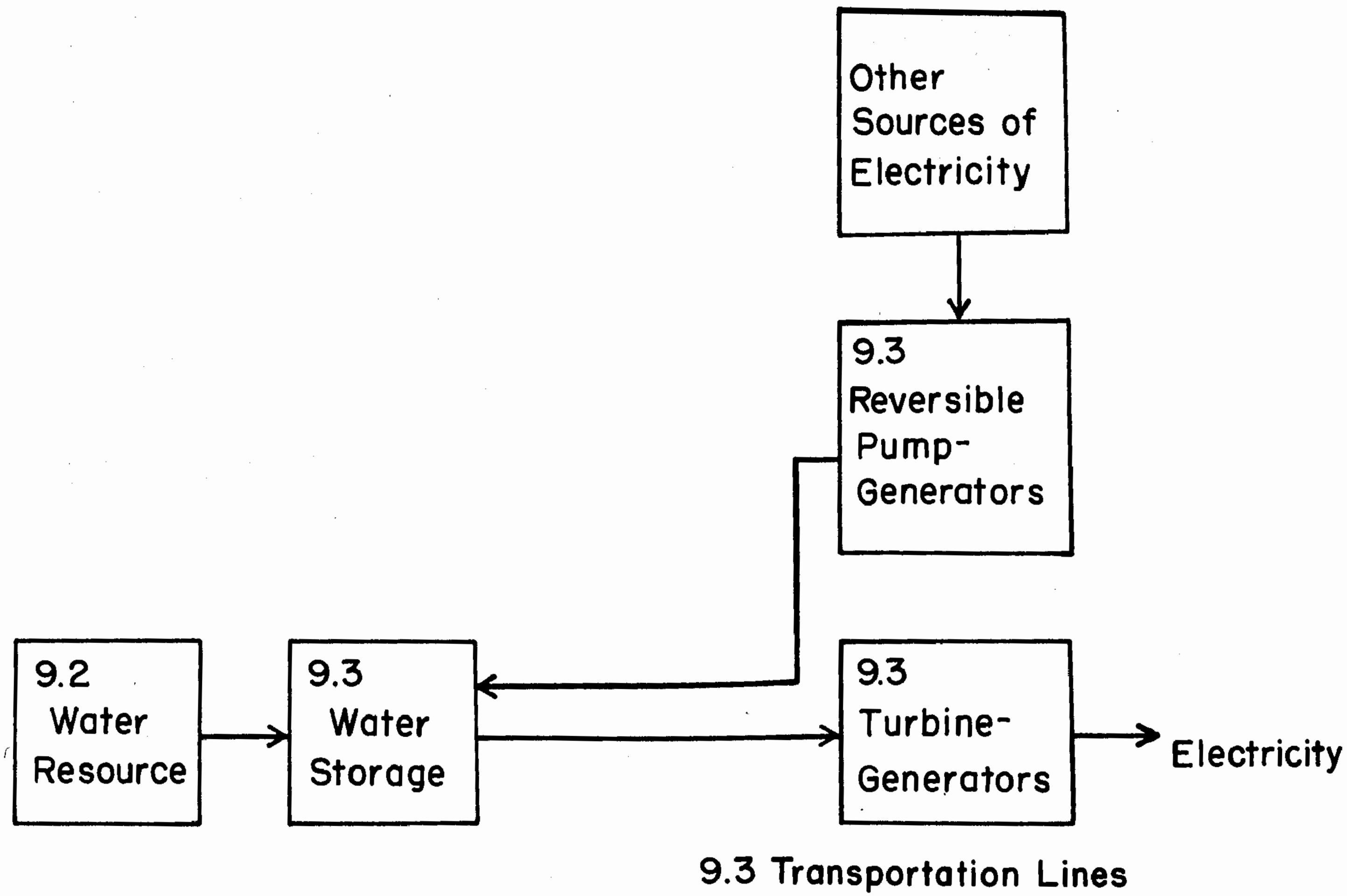


Figure 9-1. Hydroelectric Resource Development

Hydroelectric power is also affected by weather, and seasonal or annual changes in precipitation can have a major impact on available power. The variability in weather patterns might be minimized by weather modification, or weather modification might augment the total quantity of water available. For example, one study found that snow augmentation in the Rocky Mountains would produce substantial increases in hydroelectric resources (Weisbecker, 1974: 295, 553). However, attempting to modify characteristic weather patterns on a national scale could produce changes in the availability of water resources, and the impacts of this are little known.

9.2.1 Quantity of the Resources

Assuming average rainfall, the hydroelectric potential of the U.S. can be calculated on the basis of the average flow of all streams and their change in elevation. This theoretical resource has been estimated at 390,000 megawatts-electric (Mwe) capacity* (Landsberg and others, 1963: 416). Engineering constraints alone (such as difficulties in designing turbines that can take advantage of heads less than 20 feet) reduce this estimate to 179,000 Mwe (AEC, 1974: Vol. IV, p. A.3-4), and economic, environmental, and political constraints make actual development less than one-third of the technically available figure. As of January 1971, the total installed capacity was 51,900 Mwe.

Present installations represent a large portion of the most attractive hydroelectric dam sites in the U.S. Thus, even without such restrictive legislation as the Wild and Scenic Rivers Act of 1968,* near-future development will probably result in only small generating capacity increases. In recent years, capacity has increased at a rate of about five percent per year and apparently most of this increase is from new dams (NPC, 1972: 228).

9.2.2 Location of the Resources

The distribution of hydroelectric resources is highly regional, with about 46 percent of the operating capacity in Washington, Oregon, and California as shown in Figure 9-2 (AEC, 1974: Vol. IV, p. A.3-3). About half of the undeveloped U.S. capacity is located in the conterminous Pacific and Rocky Mountain states, with another undeveloped 25 percent located in Alaska (AEC, 1974: Vol. IV, p. A.3-5). Although the data on potential power reserves in Table 9-1 indicate that substantial power increases in hydroelectric capacity are possible in several regions, these appear to present a highly optimistic picture.

9.2.3 Ownership of the Resources

The federal government owns about 44 percent of the installed capacity, privately owned utilities account for 33 percent, and non-federal public utilities own 23 percent (FPC, 1971: I-7-9). In addition, a major portion of the potential resources, especially in the western states and Alaska, are under federal control.

9.2.4 Summary

Although the hydroelectric resource represents a significant potential source of power (179,000 Mwe), a number of constraints limit its likely development.

---

*This total resource estimate excludes Alaska and Hawaii. With a 100-percent load factor (390,000 Mwe of continuous operation) this resource represents 3.42×10^{12} kilowatt-hours (kwh) per year, and this would require 1.7×10^{9} tons of subbituminous coal annually or 3.0×10^{16} Btu's in a 39-percent efficient power plant. Total U.S. energy input in 1970 was 6.9×10^{16} Btu's.

*The Wild and Scenic Rivers Act of 1968 (Public Law 90-542, October 2, 1968) excludes portions of 37 rivers from hydroelectric development. However, this exclusion represents only about 9,000 Mwe of potential power (FPC, 1970: I-7-21).

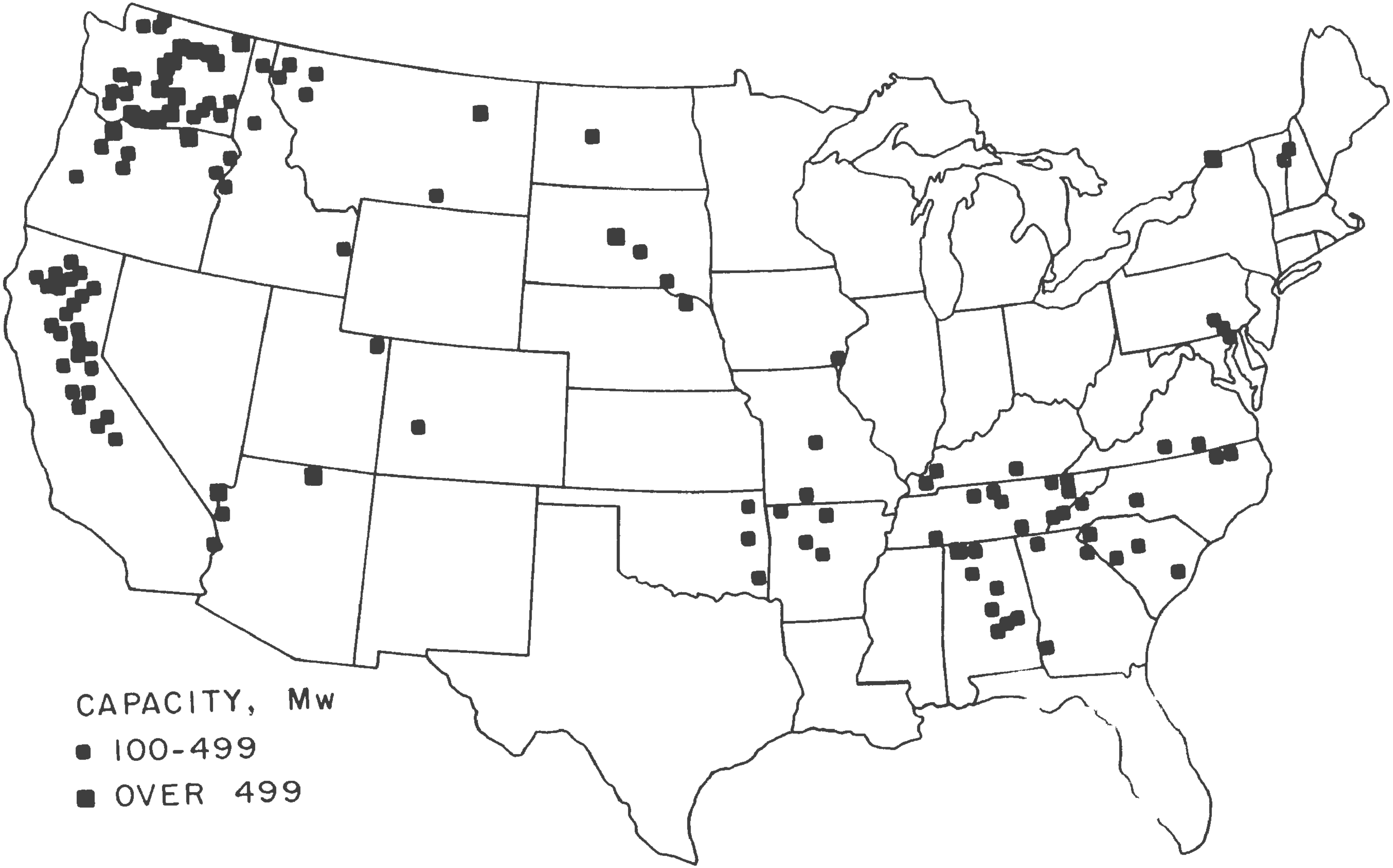


Figure 9-2. Distribution of Developed U.S. Hydroelectric Resources

Source: FPC, 1971: I-7-12.

TABLE 9-1

U.S. HYDROELECTRIC POWER RESOURCES BY REGION

Region	Potential Power (10^3 Mwe)	Developed Capacity (10^3 Mwe)	Percent Developed
New England	4.8	1.5	31.3
Middle Atlantic	8.7	4.2	48.3
East North Central	2.5	0.9	36.0
West North Central	7.1	2.7	38.0
South Atlantic	14.8	5.3	35.8
East South Central	9.0	5.2	57.8
West South Central	5.2	1.9	36.5
Rocky Mountain	32.9	6.2	18.8
Pacific	62.2	23.9	38.4
Subtotal (lower 48 states)	147.2	51.8	35.2
Alaska	32.6	0.1	0.3
Hawaii	0.1	0.0	0.0
TOTAL	179.9	51.9	29.0

Source: Interior, 1973: Vol. I, p. IV-170.

Even if hydroelectric power continues to expand at recent rates, there seems little chance that its share of total U.S. energy supply will increase.

9.3 TECHNOLOGIES

Water pressure for generating hydroelectric power may exist as a naturally flowing stream, but a head is most often obtained by building a dam from which the water is then released via a pipe termed a penstock. As shown in Figure 9-3, this high-pressure water drives a turbine which, in turn, drives one or more generators to produce electricity.

9.3.1 Dams

Impoundments for storing water are engineered following detailed studies of the hydrology and geology of the area. Dams are normally built to achieve multiple objectives, such as maintaining an adequate head for hydroelectric generation, providing significant water storage, and serving flood control, recreational, and water supply objectives. Dams are classified as low or high, run-of-river or storage, and are of earth or concrete construction.

Low dams range up to about 100 feet in elevation and are normally located on rivers of relatively continuous flow. Unless the impounded water occupies a vast area for storage (e.g., 10 to 20 square miles), low dams most frequently function as run-of-river facilities with the water running continuously through the turbines to provide electricity for baseloads rather than for peak demands. The primary

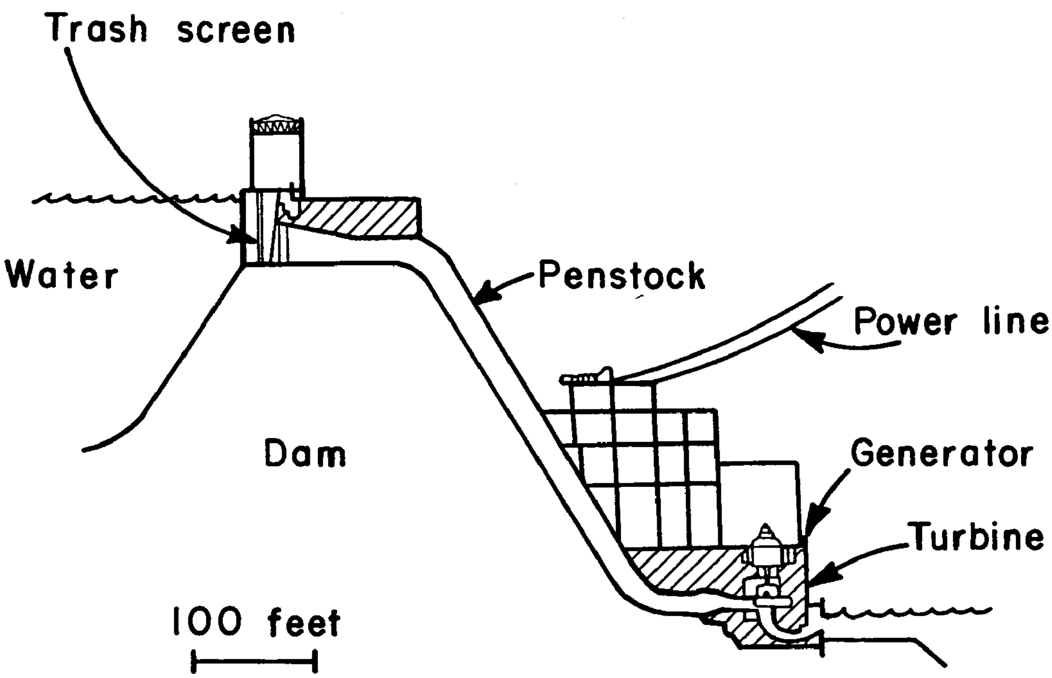


Figure 9-3. Components of a Hydropower System

Source: Creager and Justin, 1950: 193.

purpose of this type of dam is to obtain a nominal water elevation that can provide pressure to run the turbines.

High dams range from about 100 to about 1,000 feet in height and are capable of storing great quantities of water. These dams are frequently located in mountains where rivers have seasonal flows (e.g., are dependent on snow runoff). Stored water can be controlled to provide power during periods of peak electricity demand.

Construction of either an earth-fill or concrete dam of sufficient size for power generation is a locally massive activity. For example, a 400-foot high earth-fill dam several miles wide takes about five years of round-the-clock construction time and requires the movement of as much as 80 million cubic yards of materials. While concrete dams have much narrower base and crest, they require large quantities of expensive steel and cement, as well as specially prepared sand and aggregate. Also, vast quantities of supplies, equipment, and personnel are required for both types of construction. Construction activities usually include clearing the reservoir area and modifying and excavating the location of the dam site before actual building begins.

The longevity of storage capacity in a reservoir is a function of the sediment content of inflowing waters. The rate of sediment addition or "siltation" varies with location and is a particularly significant problem in the southwest, where rainstorms are severe and soil-stabilizing vegetation is scarce (Creager and Justin, 1950: 167). Short of utilizing streams with a low silt load, few methods are both economical and effective in reducing siltation. According to general guidelines developed by the Corps of Engineers, most reservoirs have a life expectancy of several hundred years (Garvey, 1972: 158).

Evaporation from reservoirs can result in substantial losses of water depending primarily on temperature, humidity, and wind conditions. Several evaporation prevention techniques have received attention, including structural coverings and the use of floating oils or plastics. However, none of these techniques has been used commercially.

9.3.2 Transport and Turbines

Penstocks, illustrated in Figure 9-3, convey water from screened intakes (trash racks) located near the inside base of the dam to the turbines. The turbines are usually located in a power house just below the dam but may be several miles from the reservoir if a large drop in elevation from the impoundment to the turbine is available (permitting additional head pressure even with a low dam height). Penstocks are usually made of steel, can be installed either above- or belowground, and, in some instances, may be tunneled through mountains.

Both impulse and reaction turbines are used to drive the electric generators. In impulse turbines, a nozzle transforms the static head into a high-velocity jet that exerts a high pressure on cup-shaped blades at the perimeter of the turbine as shown in Figure 9-4. This type of unit is called a "Pelton wheel." Impulse turbines are normally used with heads of greater than 1,000 feet to achieve the high velocity jet (FPC, 1971: IX-1-72).

In reaction turbines, the water from the penstocks flows directly through the turbine, exerting pressure on the angled blades or "vanes" as shown in Figure 9-5. Unlike the impulse turbine, the reaction turbine uses total blade area pressure to turn the shaft rather than applying pressure at one side or edge. Thus, reaction turbines do not require a high velocity jet and can operate efficiently with heads as low as 20 feet. Some reaction turbines

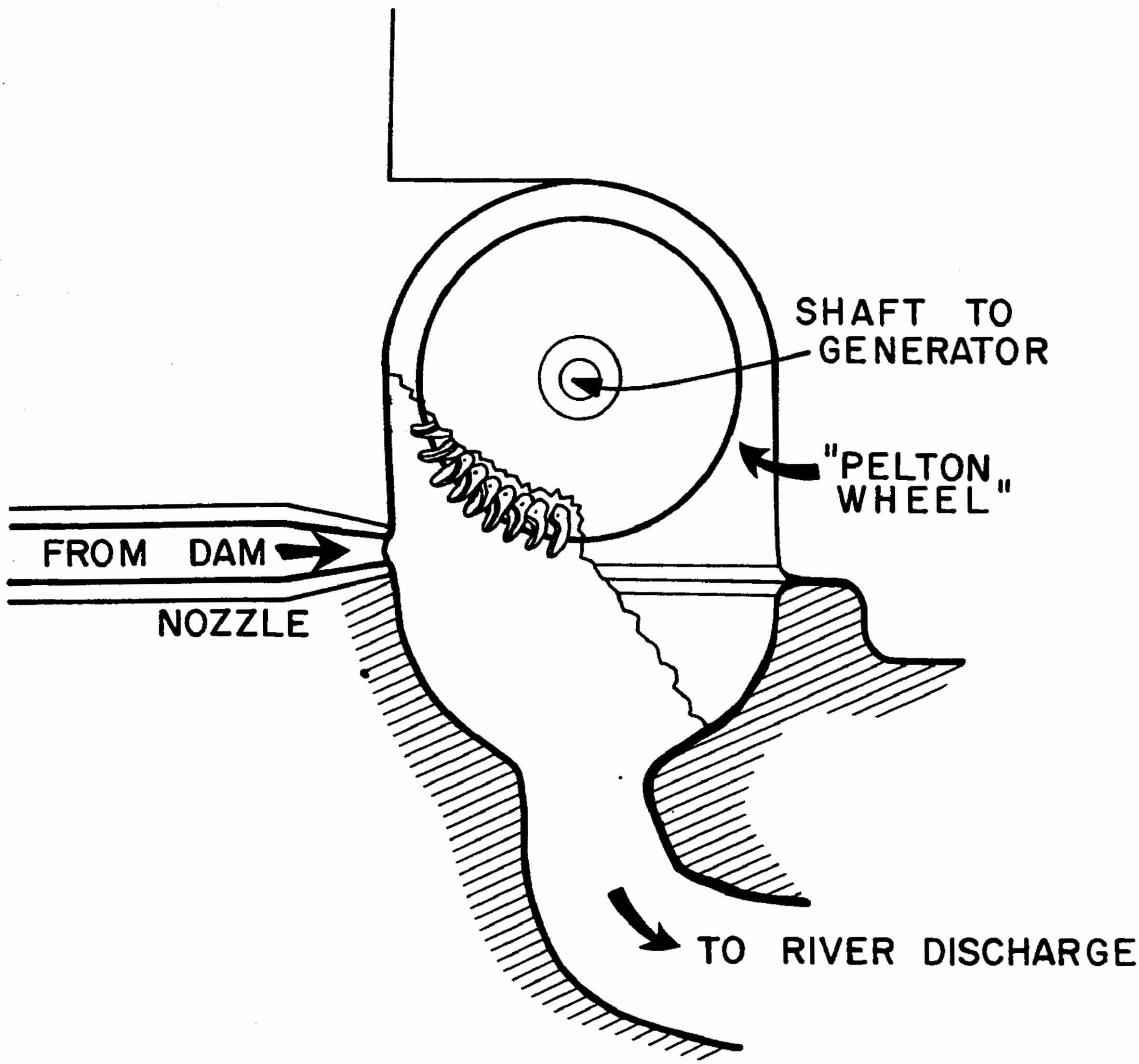


Figure 9-4. Impulse Turbine

Source: Adapted from Brown, 1958: Vol. II, pp. 25-90.

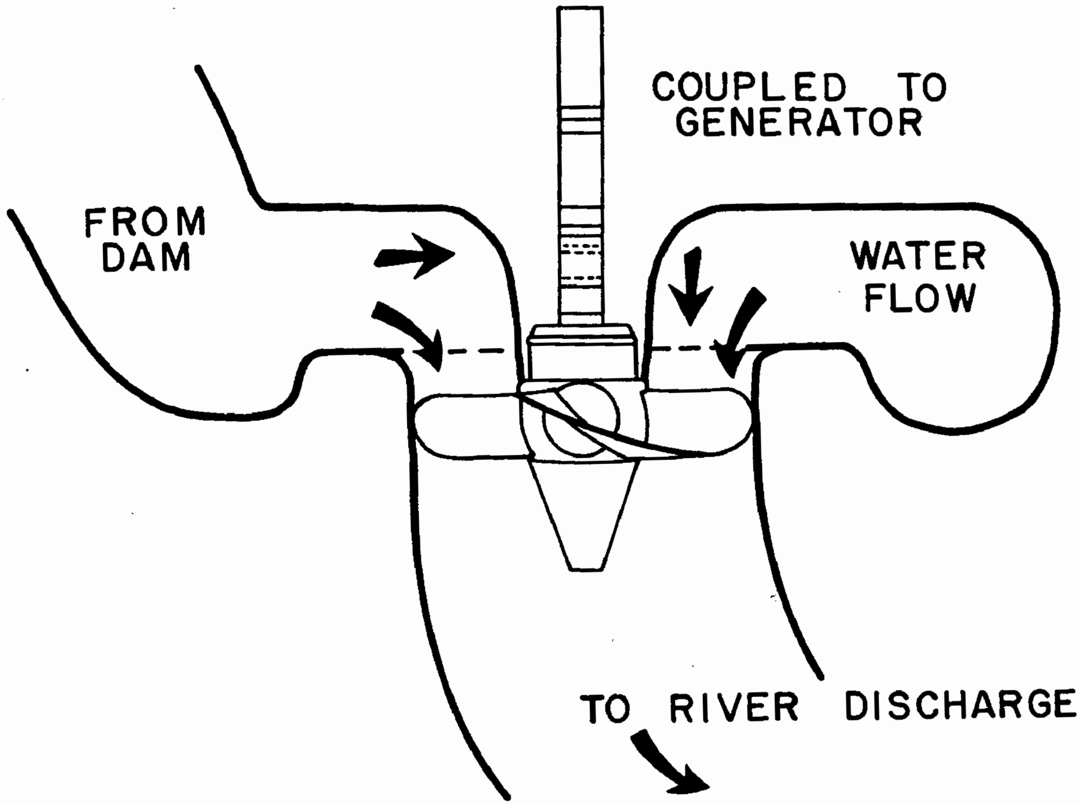


Figure 9-5. Reaction Turbine

Source: Adapted from Brown, 1958: Vol. II, pp. 91-132.

have adjustable blade pitch, and these can efficiently utilize variable flow rates to follow demand loads. Also, newer turbine designs have permitted efficient and economical use of low-head dams and may provide a method of utilizing rivers in relatively flat terrain.

The generator is usually located above the turbine and is connected to the turbine by a steel shaft. Normally, one generator is installed for each turbine as indicated in Figure 9-6.

Turbine-generator units come in many sizes but frequently have 100 to 400 Mwe of capacity. Also, several units are usually installed, depending on the amount of water available. Recently, units as large as 600 Mwe have been installed at the Bonneville dam. Although the amount of electricity produced from a given flow rate and head varies from one installation to another, typically a gallon of water per second falling a distance of about 100 feet will produce one kilowatt (kw). The head, water flow, and power output of several installations are given in Table 9-2.

9.3.3 Reversible Pump-Generators

As shown in Figure 9-7, a pumped storage facility is a closed-cycle (except for evaporation and seepage losses) system. During light load periods, water is pumped from a lower reservoir to an upper (storage) reservoir for use during peak demand. With the exception of the storage basin below the dam, the external features of this system closely resemble those of conventional hydroelectric power systems. The major equipment difference is that the generators are reversible; that is, they act as motors when supplied with electricity. During low demand periods, electricity is supplied from an outside source and the generator-motors rotate the turbines (in reverse of normal operations) to pump the water to the upper storage area.

Pumped-storage is especially attractive in conjunction with nuclear power because it allows a nuclear plant to run at normal operating loads consistently, using the off-peak excess electricity to pump water which can then supply overload requirements during peak demands. The effectiveness of pumped storage depends in part on the extent of evaporative losses and the efficiency of pumping and conversion. These are discussed in the following section.

TABLE 9-2

RELATIONSHIP OF OPERATING HEAD AND WATER FLOW TO POWER OUTPUT

Input Characteristics		Output
Head (feet)	Flow (gallons per second)	Power (megawatts)
100	120,000	120
680	110,000	680
1,000	23,000	210

Source: California Resources Agency, 1974: 13.

9.4 ENERGY EFFICIENCIES

Hydroelectric facilities are among the most efficient energy-producing systems, primarily because there are no chemical or thermal energy transformations. Optimum designs for turbine generators are about 94-percent efficient in transforming the potential energy in water to electricity (Doland, 1954: 27). However, most installations have actual efficiencies of about 75 to 80 percent (Doland, 1954: 13).

Aside from the major energy requirements during construction, there are virtually no ancillary energy requirements; within-plant energy consumption is associated with lights, control equipment, and maintenance and other service needs. Although significant water losses can occur

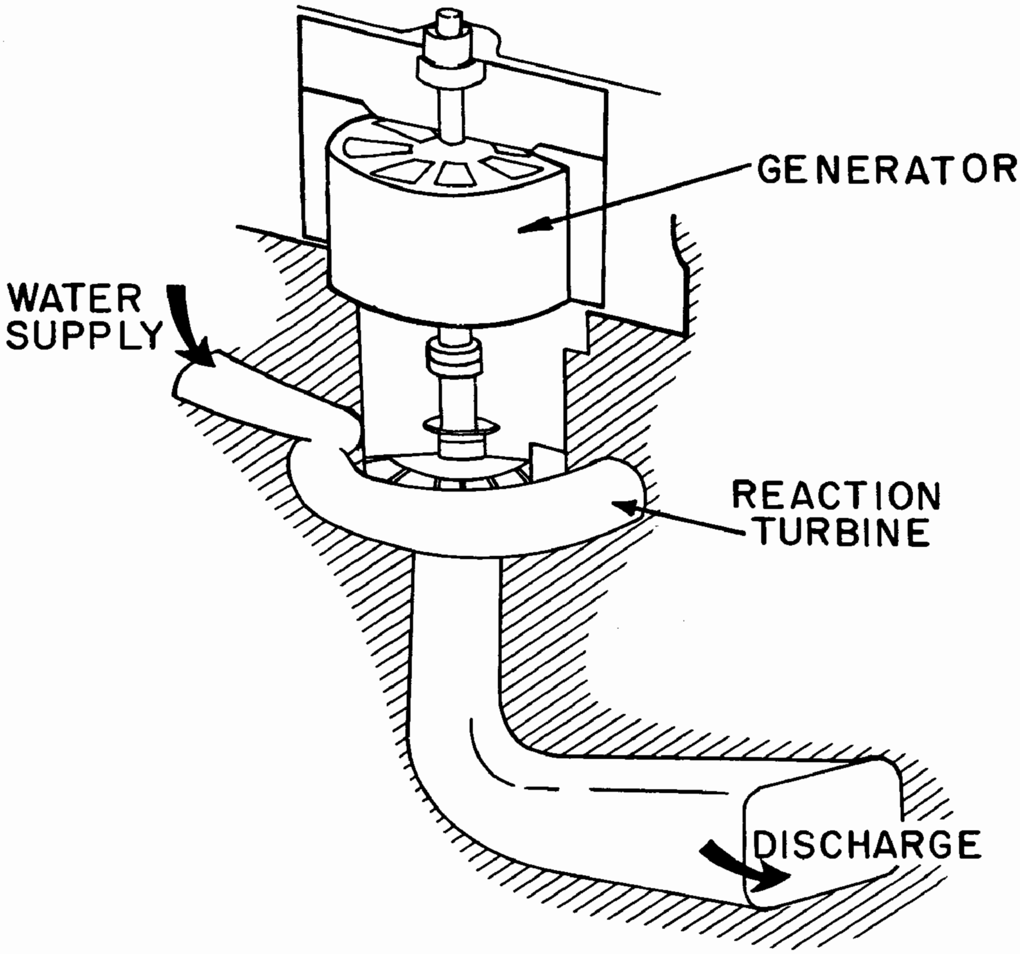


Figure 9-6. Turbine-Generator Unit

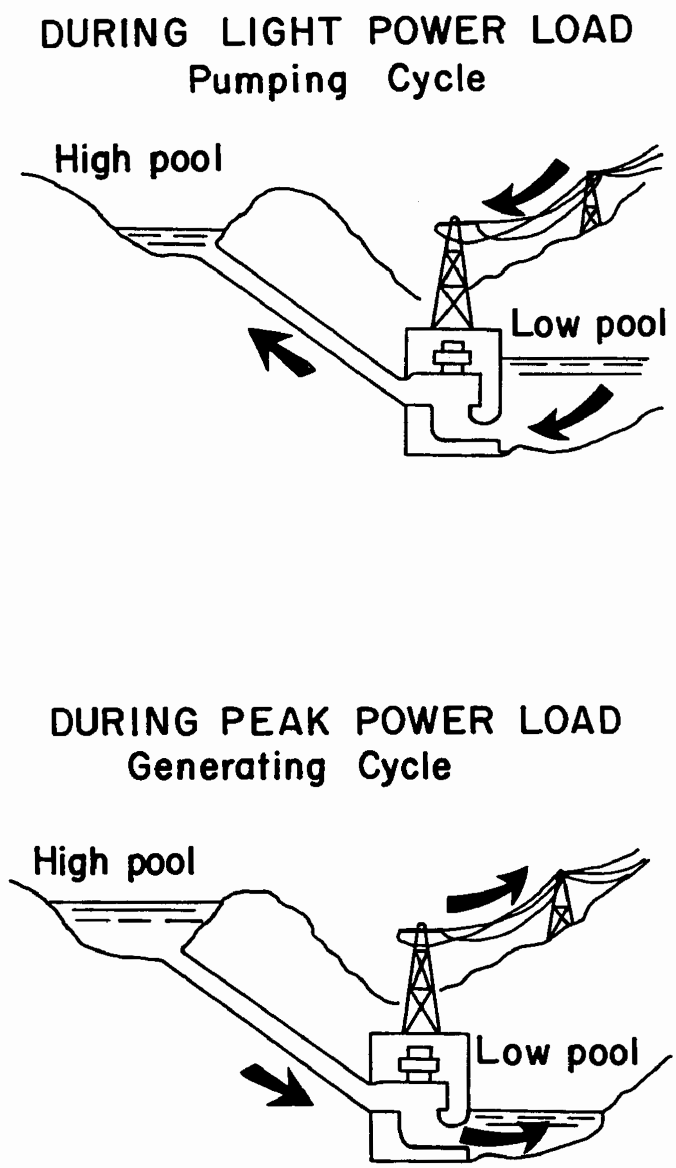


Figure 9-7. Pumped-Storage Operation

Source: California Resources Agency, 1973: 13.

in the reservoir, quantities are location specific. Water loss data are not available for existing or potential pumped-storage systems.

Pumped-storage facilities operate with substantially lower efficiencies than conventional hydroelectric plants. The need for both pumping and generation cycles results in a compromised generator efficiency so that optimum units are about 90- to 92-percent efficient in transforming potential energy to electricity (FPC, 1971: IV-1-81). In addition, the best pump designs operate with only about 90-percent efficiency.

Thus, the highest overall efficiency for future pumped-storage facilities is expected to be about 80 percent, not including reservoir evaporative losses or electrical transmission losses. The efficiencies of most proposed plants range from 66 to 72 percent; thus, about three kw of energy from a fossil-fuel or nuclear power plant will be required to generate two kw after transmission from a pumped-storage facility. Some existing pumped-storage installations have efficiencies as low as 50 percent (FPC, 1971: IV-1-81).

9.5 ENVIRONMENTAL CONSIDERATIONS

The degree to which hydroelectric facilities affect air, land, and water quality depends on location, design, use, and other factors. In a number of instances, impacts have been interpreted as beneficial changes, depending on the values against which those changes were compared. The residuals and impacts from hydroelectric facilities differ during the construction and operating phases.

9.5.1 Air

Large quantities of dust and vehicle emissions are produced during the multi-year construction periods, but the only such emissions during operational periods come from recreational vehicles (including powerboats). However, emissions from such vehicles are not comparable to emissions from equal-capacity fossil-fuel plants. Since large impoundments are sources of water vapor, some local increases in humidity may occur. However, such increases typically represent only a small portion of the water vapor in the atmosphere in a given location.

9.5.2 Water

During the long construction period, erosion, dust, and other discharges may contribute to downstream siltation and pollution. Following construction, the physical and chemical characteristics of the impounded water will differ from those of streams or rivers previously occupying the location. As a result, impoundments have plant and animal life entirely different than the streams and land they replace.

Dams act as barriers to movements of chemicals and organisms. For example, the reproductive activities of migrating fish may be curtailed unless means are provided for crossing the dam. Even then, some losses will occur because many native species (such as salmon) require flowing streams for egg-laying habitats. To alleviate fish losses, many dams incorporate ladders* to allow fish to circumvent the dam, and state or federally operated fish hatcheries with artificial breeding ponds help replenish losses due to reduced breeding habitats.

Dams also change the water conditions downstream. If little water is released from the reservoir (during off-peak demand periods), downstream water temperatures may increase, making these areas unsuitable for many fish and other biota that are successful in colder waters. Although minimum water flow requirements are typically established by government agencies, downstream conditions still may be modified

*Fish "ladders" are stepped spillways.

because the water discharged through the turbines is normally taken from the deeper, oxygen-depleted zones of the lake. The result can be oxygen-poor downstream conditions during certain periods.*

Although penstocks and turbines are usually screened to prevent the entrance of fish, small organisms** pass through. A significant proportion of these organisms can be killed by impact against the cups if Pelton wheel turbines are being used. Apparently, reaction turbines cause less damage to aquatic life. Other adverse impacts to water quality from hydroelectric facilities that reduce stream flow include possible saline water intrusion into waterways and decreased ability to tolerate chemical, municipal waste, and thermal discharges (Nisbet, 1974: 5).

9.5.3 Land

Typically, most impoundments inundate extensive areas (often between 1,000 and 20,000 acres) and, after many years, fill through the process of siltation. As a result, the previous topography is irretrievably lost. Depending on the land use, areas adjacent to reservoirs are frequently affected. Recreational and other uses may damage vegetation and cause increased erosion. In the California State Water Project, for example, the use of about 10 major reservoirs accounted for about two million recreation man-days per year.

A variety of other uses of reservoirs is apparent, including flood control. Although this allows for occupation of previously uninhabited downstream flood plains, periodic siltation and nutrient addition to flood plains and river deltas is also curtailed (Nisbet, 1974: 5). Support facilities for power generation (such as roads and transmission line rights-of-way) may also affect surface use.

9.6 ECONOMIC CONSIDERATIONS

Most hydroelectric facilities require large expenditures of capital over a multiyear period. In the past, the low costs of fuels and fossil fuel electric plants have made hydroelectric generation less attractive, but this may not continue to be the case.

Specific construction costs are variable and depend on the size, type, and location of the dam. Land and relocation of people, buildings, and facilities can be the greatest costs, depending on existing land-use patterns. For example, one small hydroelectric facility in Pennsylvania cost only $15 million for the dam in 1971, but relocation and property adjustment added $100 million to the total facility cost.

An important consideration in calculating the cost per unit of power is the annual capacity factor or percent of time the facility is being used to generate electricity. In recent years, this factor has been decreasing as hydroelectric facilities are used more to satisfy peak demands. In 1970, the annual operating factor averaged 55 percent for U.S. hydroelectric facilities (NPC, 1973: 26). One proposed facility in Oregon is scheduled to have a capacity of 1,640 Mwe and cost $275 million. It will have an annual capacity factor of 20 percent, which is typical of new sites. The cost of its peaking power will be about 10 mills per kwh. A 1972 survey of costs of hydroelectric power in various regions of the country is given in Table 9-3.

Capital costs of the powerhouse and equipment decrease with an increase in the operating head, as shown in Table 9-4. Average costs for hydroelectric facilities have varied between $200 and $400 per kw.

*In some instances, excess gas such as nitrogen can be a problem. Well-aerated spillway discharges may result in high nitrogen content which kills fish.

**Such as zooplankton and juvenile fish.

TABLE 9-3

1972 U.S. HYDROELECTRIC POWER COSTS BY REGION

Region	Cost (mills per kilowatt hour)
Northwest	2.4
Southwest	8.4
Midwest and East	4.3 to 5.6

Source: NPC, 1973: 27.

TABLE 9-4

RELATIONSHIP OF 1967 CAPITAL COST TO OPERATING HEAD

Head (feet)	Cost per Kilowatt (dollars)
100	130
400	90

Source: FPC, 1970: IV-1-73.

New economies are apparently being realized through development in design and construction of dams and new tunneling and underground excavation equipment.

The cost of electricity from pumped-storage includes both the cost of building and operating the facilities and the price of the input electricity. These costs are substantial because about three kw of electricity must be purchased for each two kw produced when pumping, generation, transmission, and evaporative losses are taken into consideration. However, the cost of facilities alone, in terms of installed generating capacity, is relatively low; a 1967 estimate ranged from $150 to $220 per kw (NPC, 1973: 29). One study found that pumped-storage facilities were used about 17 percent of the time and resulted in an average 1967 cost of 3.4 mills per kwh in addition to the purchase price of the electricity (NPC, 1973: 28).

9.7 TRANSPORTATION

Transportation of electric power is described in Chapter 12.

9.8 TIDAL POWER

The tidal bulge in the ocean is caused by the gravitational pull of the sun and the moon. The bulge of water "moves" as the earth rotates and creates a changing water elevation which might be used to drive a turbine. One estimate suggests that the tidal energy in the ocean, if accessible, would provide about half the energy needs of the entire world (AEC, 1974: A.6-8). On the open ocean, the average surface height change is only about two feet, but when the tidal bulge impinges against shorelines, this height change may be accentuated. In locations where a bay may partially enclose the tidal wave, significant amplification of the wave height may occur; in several bays in the world, these resonance amplifications increase the height to 50 or more feet.

At present only two tidal sites have been developed: one in the Soviet Union with 400-kw capacity and one in France with 240,000-kw capacity (Quigg, 1974: 32). Two locations near or in the U.S. have been considered as potential resources: the Bay of Fundy area and Turnagain Bay in Cook Inlet, Alaska (AEC, 1974: A.6-8). The Bay of Fundy has nine sites primarily in Canadian waters that have a potential power capacity of 29,000 Mwe, and the Alaskan site has the potential for about 9,500 Mwe.

Utilizing these resources would require construction of dams across bays and installation of turbines. In the past, economic analysis has usually found that the estimated cost was too high for the production of intermittent power. The potential environmental and social impacts have not been assessed. Because of limited resource availability, and relatively high cost in recent comparisons with more conventional energy resources, tidal power will not be an important contribution to energy production in the future.

REFERENCES

Atomic Energy Commission (1974) Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington: Government Printing Office, 4 vols.

Brown, J. Guthrie, ed. (1958) Hydroelectric Engineering Practice, Vol. II. London: Blackie and Son, Ltd.

California Resources Agency, Department of Water Resources (1974) California State Water Project, Annual Report 1973. Sacramento: California Resources Agency.

Creager, William P. and Joel D. Justin (1950) Hydroelectric Handbook. New York: John Wiley.

Department of the Interior (1973) Final Environmental Statement for the Geothermal Leasing Program. Washington: Government Printing Office, 4 vols.

Doland, James J. (1954) Hydro Power Engineering. New York: The Ronald Press.

Federal Power Commission (1971) 1970 National Power Survey. Washington: Government Printing Office, 4 vols.

Garvey, Gerald (1972) Energy, Ecology, Economy: A Framework for Environmental Policy. New York: W.W. Morton and Company.

Landsberg, Hans H., Leonard L. Fischman, and Joseph L. Fisher (1963) Resources in America's Future: Patterns of Requirements and Availabilities. Baltimore: Johns Hopkins.

National Petroleum Council, Committee on U.S. Energy Outlook (1972) U.S. Energy Outlook. Washington: NPC.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee, New Energy Forms Task Group (1973) U.S. Energy Outlook: New Energy Forms. Washington: NPC.

Nisbet, Ian C.T. (1974) "Hydroelectric Power: A Non-Renewable Resource?" Technology Review 76 (June 1974: 5, 64).

Quigg, Philip W. (1974) "World Environment Newsletter: Alternative Energy Sources." Saturday Review/World 1 (February 9, 1974: 29-32).

Weisbecker, L.W. (1974) The Impacts of Snow Enhancement. Norman, Okla.: University of Oklahoma Press.

CHAPTER 10

THE ORGANIC WASTE RESOURCE SYSTEM

10.1 INTRODUCTION

Until the recent energy shortages, organic and inorganic wastes had been considered primarily as disposal (and thus energy consuming) problems in the U.S. Although electricity has been generated for years in Europe by burning municipal wastes, U.S. efforts have been directed primarily at environmental considerations, such as reducing landfill and pollution problems by recycling of inorganic wastes. Further, these recycling efforts have generally been minimal because they were not economically feasible as long as raw materials were plentiful and energy for their conversion into finished goods was cheap.

Now, the cost of energy has increased dramatically, some raw material shortages have occurred, and the Environmental Protection Agency (EPA) and other government agencies have given increased attention and funding support to the development of technologies for recycling and energy conversion. As a result, a number of technologies for converting organic wastes into usable energy are now in the pilot plant or early commercial operation stages. Figure 10-1 is a diagram of the basic technological processes involved in the conversion of organic wastes to liquid or gaseous fuels. As indicated, the wastes must be collected and prepared (shredded and sorted) before the materials can be fed to the conversion process that is to be used. Generally, the sorting process consists of removing the inorganic matter, which is then disposed of or transported for recycling.

In the following discussion, recycling is covered only where a specific technology is designed for total resource recovery; that is, where recycling and fuel conversion cannot be separated in the description. Further, although recycling paper (as well as metal and glass) may ultimately be more economical than converting it to fuel, the technologies here assume that paper will be incorporated into the organic waste and converted to fuel. No paper recovery technologies are discussed. If paper were recovered from the wastes, the heat content of the remaining waste would be low, precluding conversion to a fuel form.

Although the total amount of energy potentially available from organic wastes is small (two percent of U.S. energy input in 1971), utilization of these wastes results in several positive environmental effects: all processed products are low in sulfur, and all processes reduce the landfill requirement.

10.2 RESOURCE

10.2.1 Characterization

Of the solid waste generated in the U.S., only the dry organic solids portion can be converted into energy; thus, the dry organic solids are the resource. These solids include portions of municipal refuse, manure, agricultural crop waste, logging and wood manufacturing residues, sewage sludge, and some categories of industrial waste. These wastes are, in effect,

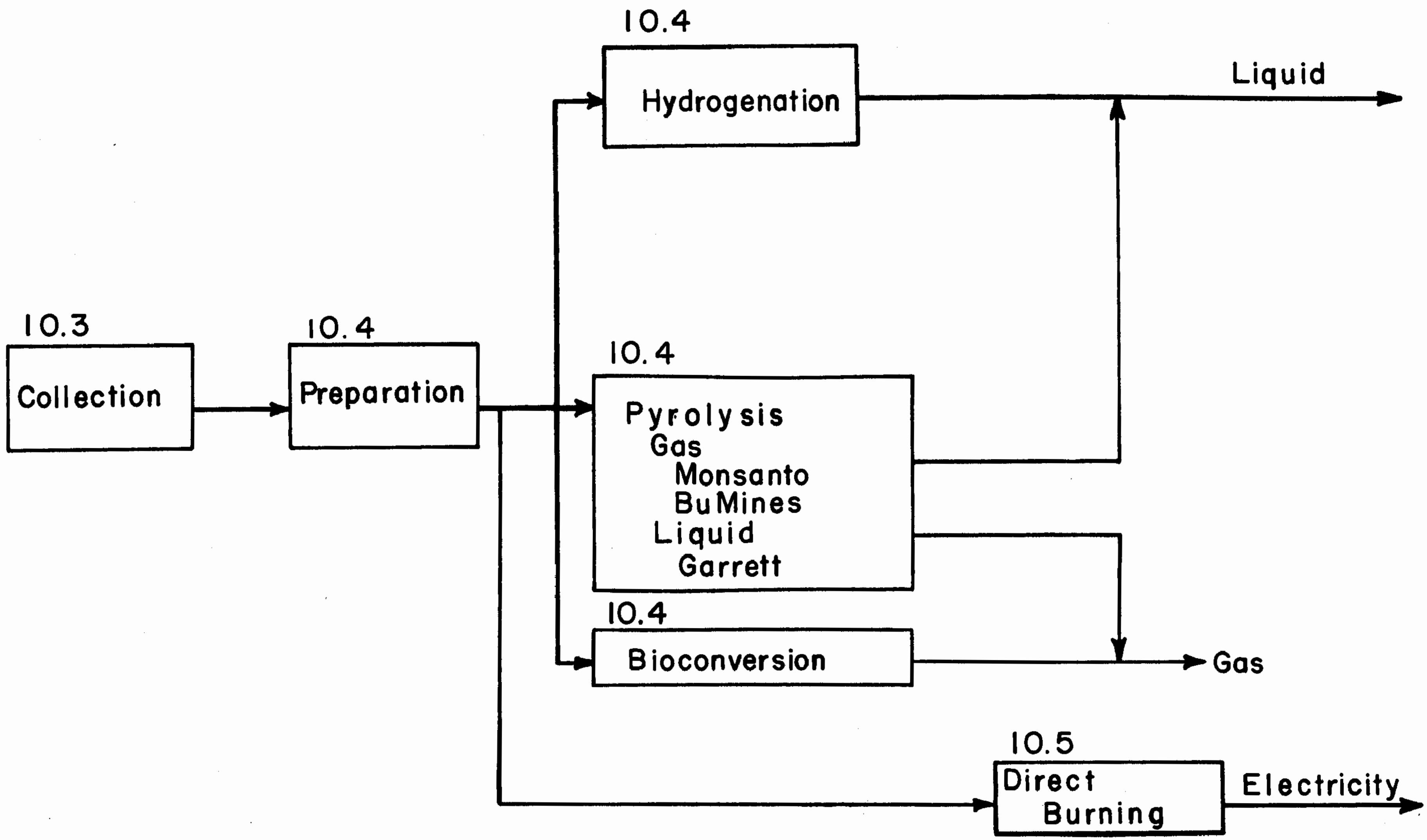


Figure 10-1. Organic Waste Resource Development

TABLE 10-1

COMPOSITION OF MUNICIPAL REFUSE
MATERIALS AND CHEMICALS

	Weight Percent of Total Refuse
Materials	
Paper	53.0
Food	8.0
Glass	8.0
Ferrous and nonferrous metals	7.0
Miscellaneous--grass clippings, rags, leather, etc.	24.0
Chemicals	
Volatile matter	52.7
Fixed carbon	7.3
Ash and metals	20.0
Moisture	20.0

Source: Anderson, 1972: 3.

residuals from other processes. Assuming that the overall patterns of society do not change, the organic waste system represents a renewable resource which is expressed as a rate rather than a fixed amount.

Table 10-1 gives the composition of municipal refuse by product and by chemical constituent. The 60 percent of the refuse that is combustible (volatile matter plus fixed carbon) has a heat content of 8,700 Btu's per pound, while the heat content of raw refuse is 5,200 Btu's per pound. For comparison, low rank lignite has a heat content of 6,000 Btu's per pound. Although only 53 percent (by weight) of the refuse, paper products provide 71 percent of the potential heat (Kasper, 1973: 3-4). Thus, paper recycling precludes use of the waste for fuel.

10.2.2 Quantity

Since organic waste is a renewable resource, the terms "reserve" and "resource" are expressed here as a rate (per year). In compliance with the general definition of a reserve (the portion that is economically recoverable under present market conditions), the organic waste reserve is that portion of the dry solids available at a point relatively near a market (urban area). The organic waste resource is the total amount of dry organic solids generated per year. These are diffuse and cannot now be collected economically.

Table 10-2 gives organic waste reserve resource estimates in tons. To put these numbers in perspective, Table 10-3 indicates the percent of total U.S. energy input (1971) that the various fuel forms of these wastes represent. If all were collected, reserves could represent two percent of total U.S. energy input in one of the following forms: if converted into crude oil, reserves would represent three to four percent of crude oil demand; if converted to natural gas, they would represent six percent of natural gas demand; and if burned directly, they would represent 6.8 percent of electricity generation in 1971 where they would be substituting for eight to nine percent of coal demand. If all organic waste resources could be collected and converted, they could provide 13 percent of U.S. energy input.

10.2.3 Location and Ownership

As noted above, the key to economic recovery of organic wastes is concentration and near-market location. For manure, this means the quantity generated by animals in confinement (feedlots). Agricultural crop wastes are usable only at specific processing plants such as canneries and mills. Urban refuse and sewage sludge are concentrated in large cities, and wood manufacturing wastes include those from sawmills (bark and sawdust).

TABLE 10-2

QUANTITIES OF ORGANIC WASTE BY SOURCE
(DRY WEIGHT IN TONS PER YEAR)

Source	Reserve 1971 (Readily collectable)	Resource 1971 (Total amount generated)	Resource 1980 (Total amount expected)
Urban refuse[a]	71.0[b]	129	222
Manure	26.0	200	266
Logging and wood manufacturing	5.0	55	59
Agricultural crops and food wastes	22.6	390	390
Industrial wastes	5.2	44	50
Municipal sewage solids	1.5	12	14
Miscellaneous	5.0	50	60
TOTAL	136.3	880	1,061

Source: Anderson, 1972: 8, 13.

[a]Domestic, municipal, and commercial components of this waste amount to 3.5, 1.2, and 2.3 pounds per capita per day respectively.

[b]Based on the 100 largest population centers in the U.S.

The process system that generates the waste is usually responsible for its disposal; that is, cities "own" municipal refuse and feedlot operators "own" the manure. Presently, these owners must pay for disposal (landfills) and, therefore, are willing to donate the wastes to any conversion operation, such as those described here. Thus, the owner pays for collection but saves the cost of disposal. As processing technologies develop, the waste eventually may be sold to the processor.

10.3 COLLECTION

Collection of refuse is not unique to energy recovery programs. Wastes require collection and disposal whether or not any resource utilization is or will be involved.

10.3.1 Technologies

Except in the case of sewage, collection is by trucks ranging up to the 30-cubic-yard packer types. Frequency of collection in municipalities is usually once or twice a week. Feedlot waste is often piled near the lot but may be trucked away for fertilizer.

10.3.2 Energy Efficiencies

Although no quantitative estimates are available, truck fuel is a major ancillary energy requirement in solid waste collection and the reason that diffuse sources are not collected. However, if processing facilities are located within an urban area, as opposed to landfills which require long hauls, this ancillary fuel requirement could be reduced.

TABLE 10-3

PERCENT OF VARIOUS FUELS POTENTIALLY REPRESENTED BY ORGANIC WASTES

	Quantity Dry Organic Waste[a] (10^6 tons per year)	Percent of Total Energy Input[b] in 1971	Percent of Crude Oil Demand[c]	Percent of Natural Gas Demand[d]	Percent of 1971 Coal Demand[e]	Percent of 1971 Electricity Consumption[f]
Reserve (Readily collected now)	136.3	2	3-4	6	8-9	7
Resource 1971	880.0	13	19	39	50	44
Resource 1980	1,061.0	NA	NA	NA	NA	NA

NA = not applicable

[a]Anderson, 1972: 8, 13.

[b]Based on an average heat content for refuse of 5,260 Btu's per pound (Kasper, 1973: 7) and a 1971 U.S. energy input of 69.0×10^{15} Btu's (Senate Interior Committee, 1971: 85).

[c]Hydrogenation process at 1.25 net barrels per ton of dry wastes (Anderson, 1972: 3) and a 1971 crude oil demand of 5.7 billion barrels.

[d]Conversion to methane at 5 cubic feet per pound dry waste (Anderson, 1972: 3) and a 1971 natural gas demand of 23 trillion cubic feet.

[e]Coal demand of 600 million tons per year.

[f]Based on 2,000 billion kilowatt-hours consumed.

10.3.3 Environmental Considerations

No residuals are generated except those that already result from current collection and transportation practices. These include nuisance collection noise and air pollutants from the vehicles.

10.3.4 Economic Considerations

Of the total cost of solid waste management in municipalities now, collection accounts for about 80 percent and disposal about 20 percent (EPA, 1974: 7). In large cities where land is expensive or incinerators are used, disposal cost may be a slightly higher percentage. Collection cost, however, is the major economic factor governing the utilization of diffuse waste sources. Nationally, collection costs averaged $18 per ton in 1971 (EPA, 1974: 7). Total collection cost in municipalities in the U.S. was $2.16 billion in 1971 (120 million tons collected) and is expected to be $2.7 billion by 1980.

10.4 PROCESSING

Processing includes the technologies necessary to convert the organic waste into a usable fuel form (Figure 10-1). This trajectory includes some waste preparation or beneficiation and one or two technologies for converting the waste to oil, gas, or electricity.

10.4.1 Preparation

10.4.1.1 Technologies

The technologies employed in organic waste preparation are designed to ready the waste for further processing and to recover salable products. Some combination of three units--hammermill shredders, magnets, and air classifiers--is normally used. Shredding reduces waste volume and produces a uniform particle size, thus always precedes further processing. Sorting, by either magnets or air classifiers or both, usually precedes conversion to a fuel (the Monsanto pyrolysis unit is an exception).

Several sizes of hammermills may be required to achieve the desired particle size. Depending on the conversion process to be used, input particle size may range from about eight inches (primary shredder in the Wilmington, Delaware direct burning system) to less than 0.015 inch (secondary shredder in the Garrett pyrolysis process).

Sorting techniques are primarily designed to recover metals and glass. Ferrous metals are recovered by passing large magnets over the waste stream, usually after primary shredding.

Shredded waste is further sorted into two fractions--a light combustible waste fraction (organics) and a heavy waste fraction (inorganics)--by air classification. In this method, air is forced up through a cylindrical container at the velocity required to force light materials out the top while allowing heavy materials to fall to the bottom. Glass falls to the bottom and is recovered as part of the inorganic heavy fraction.

In addition to these three fundamental units, other units may be employed for a higher degree of process feed preparation. Dryers precede secondary shredding in the Garrett Research and Development Company, Inc., pyrolysis system to remove moisture and thus enhance particle separation. A proprietary froth-flotation glass reclamation unit developed by Garrett recovers over 70 percent of all glass with a product purity of 99.7 percent (Mallan and Finney, 1973: 58). Separation and recovery of nonferrous metals with high energy electromagnetic separators have been examined under an EPA grant at Vanderbilt University (Appell and others, 1971). Garrett is also examining new techniques for recovering aluminum, copper, and brass (Mallan and Finney, 1973: 58).

10.4.1.2 Energy Efficiencies

According to Garrett (Mallan and Finney, 1973: 58), each hammermill unit requires about 50 horsepower-hours per ton of waste processed. This is an ancillary energy requirement of about 130,000 Btu's per ton per shredder; that is, 1.3 percent of the energy in the incoming waste is required for each shredder.

10.4.1.3 Environmental Considerations

Residuals include: the metals and glass products, which are salable; the light fraction coming out of the air classifier, which is the feed for the energy conversion process; and other products, ranging from 6 to 15 percent of the incoming stream, which require landfilling.

Although decibel measures are not available, hammermill shredders are notoriously noisy. Mufflers mitigate the problem somewhat.

10.4.1.4 Economic Considerations

Economic estimates are given on a total plant basis in the conversion process section. Hammermill shredders contribute significantly to the operating costs of a system. Garrett expects the costs for daily maintenance of the primary and secondary shredders to be $1.60 per ton (1971 dollars) in a commercial scale plant (Mallan and Finney, 1973: 59).

10.4.2 Hydrogenation to Oil

10.4.2.1 Technologies

Hydrogenation is basically the addition of hydrogen to an organic molecule to achieve a higher hydrogen-to-carbon ratio. The process for hydrogenating organic waste is an outgrowth of research on the hydrogenation of coal, which is discussed in the liquefaction technologies section of Chapter 1.

In the Bureau of Mines (BuMines) process, carbon monoxide and water (steam) are introduced at high temperatures (570 to 750°F) and pressures (3,000 to 4,000 pounds per square inch [psi]) in the presence of a catalyst to react with the organic waste (Appell and others, 1971: 17-18). Residence time in the reactor is about two hours. Although the chemical aspects of the process are not yet completely understood, basically a water-gas shift reaction occurs where the carbon monoxide and water react to form hydrogen and carbon dioxide. Some of this hydrogen is then added to the organic compounds during their conversion to oil.

The BuMines pilot plant (Appell and others, 1971), which is a 480-pounds-per-day continuous reactor, has obtained two barrels of oil per ton of dry organic material with 0.75 barrel per ton required for the process, resulting in a net yield of 1.25 barrels per ton. The oil has a heating value of 15,000 Btu's per pound (Friedman and others, 1972: 15). For comparison, number six fuel oil has a heating value of 18,200 Btu's per pound. A full scale commercial plant is expected by 1980 (Hammond and others, 1973: 75).

10.4.2.2 Energy Efficiencies

The hydrogenation process has a primary energy efficiency of 39 percent* based on the net amount of oil output, and a heating value for the dried organic waste of 8,000 Btu's per pound.

10.4.2.3 Environmental Considerations

Residuals include a carbon residue, water and its pollutants, and carbon dioxide. Total quantities are not known. The process water requires treatment. The oil has a low sulfur content (0.1 percent), a desirable feature for fuel oils.

10.4.2.4 Economic Considerations

The largest cost items for the hydrogenation process are the capital investment in high-pressure equipment and the cost of carbon monoxide, which is now about one cent per pound (Friedman and others, 1972: 16). Income from the oil, assuming $4 per barrel (1972 market price) and 1.25 barrels per ton, would be $5 for each ton of dry refuse processed.

BuMines cost data indicate a break-even size of 900 tons of prepared organic waste per day. This is roughly equivalent to the amount of daily waste generated by 300,000 people. However, these data are not directly comparable to other processes given here because the estimate includes an income of $5 per ton refuse disposal charge to the community. Rather than paying $5 per ton for landfilling, the municipality pays the processor $5 per ton for disposal. In addition, the municipality is assumed to pay for collection. Although hydrogenation appears to be the most expensive conversion technique (Hammond and

---

*1.25 barrels of oil per ton of dry waste at 5×10^6 Btu's per barrel (Hammond and others, 1973: 75) is equivalent to an output of 6.25×10^6 Btu's per ton of dry waste. At 8,000 Btu's per pound, the dry waste has a heating value of 16×10^6 Btu's per ton. Dividing the output by the input (6.25×10^6 Btu's per ton divided by 16×10^6 Btu's per ton) yields 0.39.

others, 1973: 76), it does produce a high-grade product in terms of heat content.

In 1972, Congress appropriated $200,000 to increase the BuMines plant capacity to one ton of animal waste per day and $300,000 for design studies of a $1.75 million plant to convert wood processing and logging wastes to oil.

10.4.3 Bioconversion

10.4.3.1 Technologies

Bioconversion is the conversion of organic wastes into methane (natural gas) through the action of microorganisms. Chemically, this is the reduction of complex organic compounds to simpler, more stable forms, including methane. (The reaction occurs spontaneously in the absence of oxygen.) Technologically, the process is simple, occurring at atmospheric pressure and temperatures in the range of 70 to 120°F. Bioconversion is part of the present sewage treatment process where it is termed anaerobic digestion. There, the methane is flared off or trapped and burned to heat the sewage. Sewage digestion, however, is designed to maximize the rate of breakdown rather than methane production.

Conditions that maximize methane production should yield about 70 percent methane and 30 percent carbon dioxide, plus small amounts of ammonia, hydrogen, mercaptans, and amines. Gas production is estimated to be 10,000 cubic feet (cf) of methane per ton of organic material with a heat content of 1,000 Btu's per cf (Hammond and others, 1973: 77).

The National Science Foundation (NSF) has begun funding research in anaerobic digestion with a $600,000 three-year feasibility study at the University of Pennsylvania. If feasibility is proven, an NSF-funded pilot plant could be in operation in five years and a demonstration plant in 8 to 10 years.

10.4.3.2 Energy Efficiencies

Primary efficiency is about 60 percent.* Unlike other calculations in this description, this efficiency estimate does not account for process heat required. The process heat requirements are unknown but would reduce the efficiency estimate.

10.4.3.3 Environmental Considerations

Residuals include sludge and water, both of which require treatment and disposal, and cleaning these by-products is a major block to immediate use of bioconversion. Organic sludge may amount to 40 percent of the starting material and would require landfilling. The water requires treatment by conventional sewage treatment processes. The methane must be scrubbed for removal of carbon dioxide, water, hydrogen sulfide, and ammonia.

10.4.3.4 Economic Considerations

No economic estimates have been made for bioconversion. The economics of sludge disposal may play a major role in determining the viability of the process (Hammond and others, 1973: 78).

10.4.4 Pyrolysis

Pyrolysis is the chemical decomposition of waste without oxidation. It involves heating material at atmospheric pressure in the absence of air. The advantages of pyrolysis are that it occurs at atmospheric pressure (eliminating the expense of high pressure equipment) and requires neither hydrogen nor catalysts. The disadvantage is that several fuel forms are produced; low-Btu gas and char are always produced, and a heavy, tar-like oil may be produced. Product distribution among the three fuel forms is primarily

---

*Output energy is 10,000 cf per ton at 1,000 Btu's per cf or 10 million Btu's per ton. Input energy is 8,000 Btu's per pound or 16 million Btu's per ton. Ten million divided by 16 million equals 0.625.

determined by the moisture in the incoming waste stream.

Although a number of research groups are investigating pyrolysis, the three processes discussed here are the most fully developed. The first process, developed by Monsanto Enviro-Chem Systems, Inc., is currently at a commercial scale level (1,000 tons per day) and produces gas and char. The second process, developed by Garrett, is at a demonstration scale level (200 tons per day) and produces oil, gas, and char with the objective of maximizing oil production. The third process is the BuMines pilot plant operation which produces oil, gas, and char in various quantities depending on the feed type, preparation, and pyrolysis temperature.

10.4.4.1 Technologies

10.4.4.1.1 Monsanto LANDGARD System

The Monsanto LANDGARD System is designed for total resource recovery; thus, fuel (gas) is only one of the products. Figure 10-2 illustrates the discrete steps in the Monsanto system. Basically, the shredded waste is pyrolyzed at temperatures reaching 1,800°F. The product is a low-Btu gas (100 Btu's per cf) which is burned in an afterburner (gas purifier of Figure 10-2), thus generating steam. Magnetic metals, a glassy aggregate, carbon, char, and ash are separated after the pyrolysis process.

A 35-ton-per-day prototype plant in St. Louis County has demonstrated the feasibility of the system. A LANDGARD plant being constructed in Baltimore will handle 1,000 tons per day of solid waste, and start-up was planned for late 1974.

Products in the Baltimore facility are: 80 tons per day of carbon, char, and ash; 70 tons per day of ferrous metals; 170 tons per day of glassy aggregate; and 4.8 million pounds per day of steam (District Heating, 1974: 2). The char and ash will probably be landfilled (six percent of original volume) but may be mixed with sewage sludge for fertilizer use. The ferrous metal and glassy aggregate (used for street paving) are salable. The steam is sold to Baltimore Gas and Electric Company for use in its steam distribution system. The City of Baltimore has constructed a one-mile, 12-inch steam main at a cost of $1,101,000 to connect the LANDGARD plant to the Baltimore Gas and Electric facility.

Although Baltimore's system appears quite feasible, the general LANDGARD system has several limitations. The impurities in the gas preclude its use as a gas turbine fuel. And, since this gas is low in heat content, it must be used at a point close to the source of production. Producing steam directly in an afterburner has this same transportation limitation. There is the possibility of upgrading the gas to high-Btu fuel (see Chapter 1 for high-Btu gasification), but this has not been investigated.

10.4.4.1.2 Garrett Pyrolysis

As in the Monsanto process, the pyrolysis system developed by Garrett is designed for total resource recovery. In the Garrett process, however, the principal fuel recovered is oil, which is given the trade name Garboil. A schematic of the resource recovery plant is shown in Figure 10-3. Initially, the raw refuse is shredded (reduced to one- to two-inch particles), dried, and air-classified to remove most of the metals, glass, and other inorganics.

However, the key to the Garrett process is the secondary shredding and drying. To maximize oil yields, a finely divided and dry organic feed to the pyrolysis reactor is essential. The secondary shredder (hammermill) reduces the feed particles to one-eighth inch by one-eighth inch maximum size before a pyrolysis

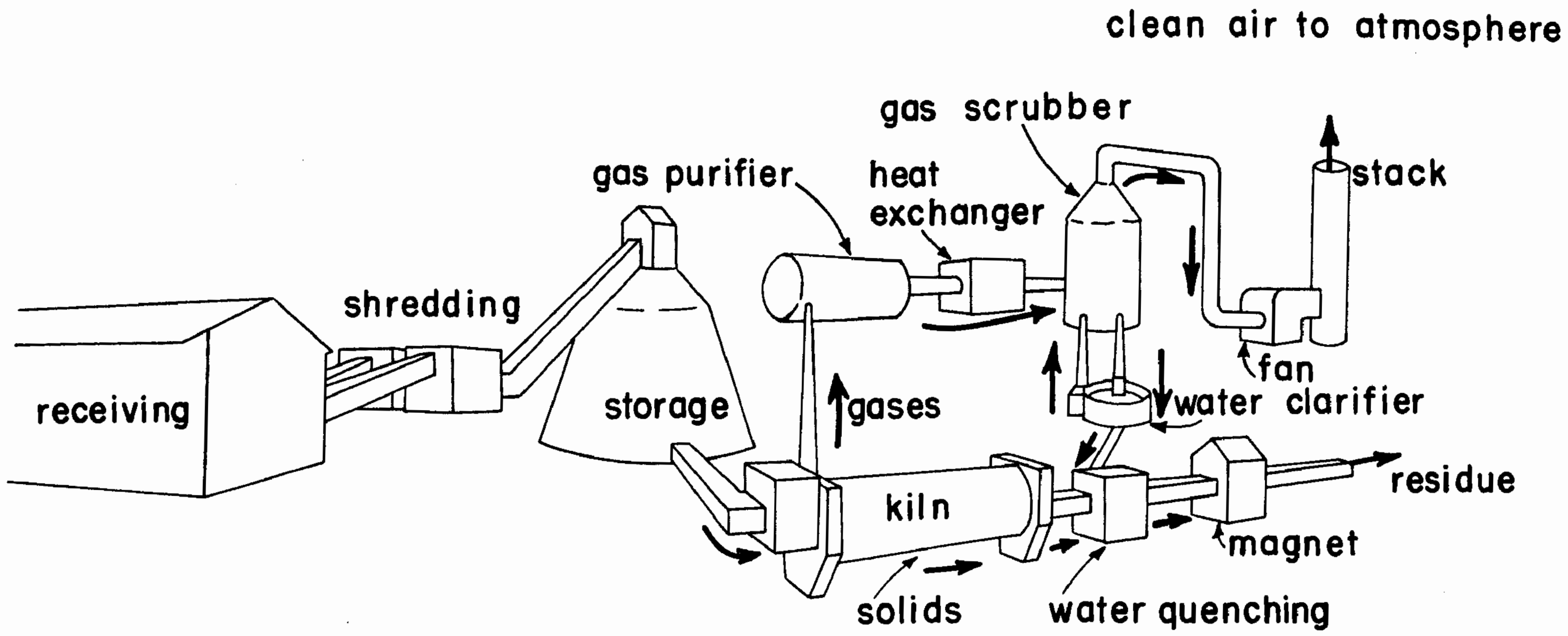


Figure 10-2. LANDGARD Solid Waste Disposal System

Source: District Heating, 1974.

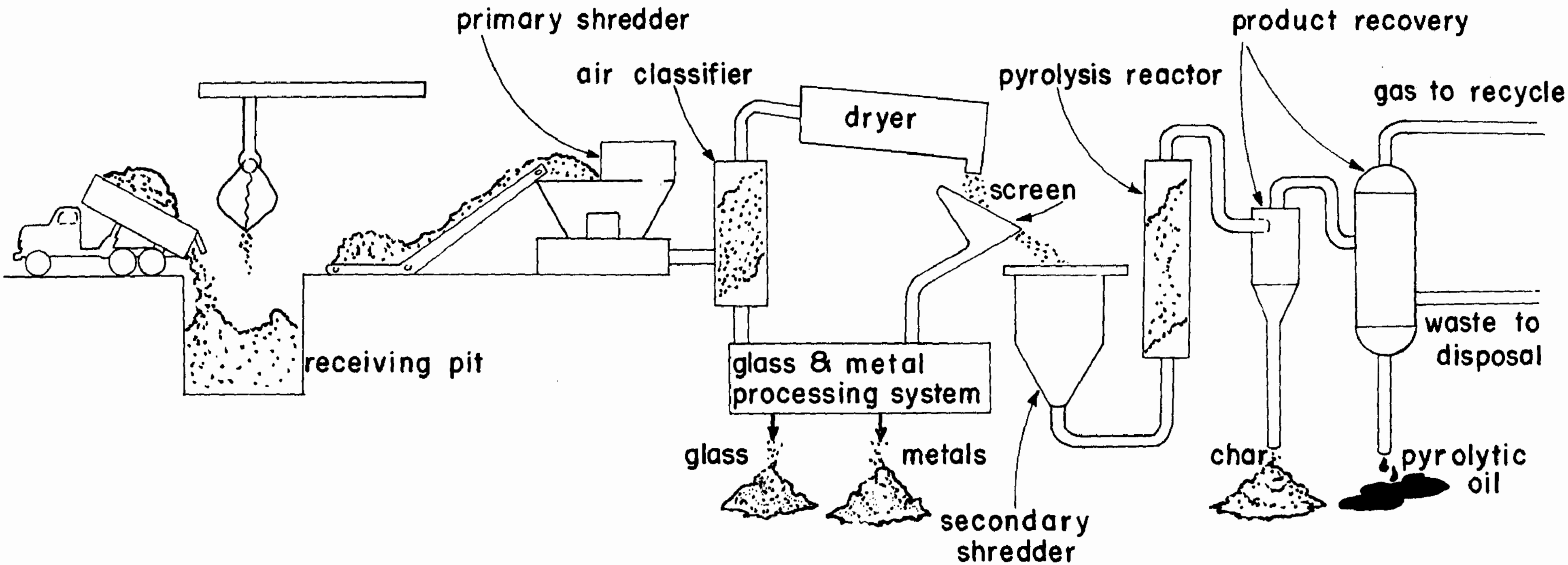


Figure 10-3. Garrett Pyrolysis System

Source: Garrett Research and Development Company, Inc.

TABLE 10-4

PRODUCTS FROM GARRETT PYROLYSIS

	Amount of Product (percent by weight)	Amount Produced (per ton raw refuse)	Heating Value
Oil	40	1 barrel	4.78×10^6 Btu's per barrel
Gas	27	unknown	500 Btu's per cubic foot
Char	20	160 pounds	9,000 Btu's per pound
Water	13	NA	NA
Magnetic metals	NA[a]	140 pounds	NA
Glass	NA[a]	120 pounds	NA

NA = not applicable

Sources: Mallan and Finney, 1973: 59-61; Hammond and others, 1973: 75.

[a]Removed from waste prior to pyrolysis.

reactor rapidly heats the particles to 500 to 900 degrees Centigrade (°C) (930 to 1,650°F). Oil, gas, and char (as well as water) are collected and separated from the pyrolysis reactor. All the gas and one-third of the char are used to supply heat for the dryer and pyrolytic reactor. Pertinent characteristics of the products are given in Table 10-4. The oil has the desirable characteristic of being only 0.1- to 0.3-percent sulfur by weight.

A four-ton-per-day pilot plant at LaVerne, California has proven the feasibility of the Garrett pyrolysis system. Presently, a 200-ton-per-day recovery plant is being built to handle the waste from Escondido and San Marcos, California. Oil is to be sold to the San Diego Gas and Electric Company.

Although Garboil can be used as a fuel supplement in electric power generation, it has different chemical properties than crude oil and could not be refined in a typical oil refinery to produce gasoline, lubricating oils, etc. In addition Garboil is quite viscous, requiring heating to temperatures around 160°F before it can be pumped (Mallan and Finney, 1973: 60). The char produced has a 40-percent ash content, which limits its usefulness as a fuel supplement.

10.4.4.1.3 Bureau of Mines Pyrolysis

Unlike Garrett and Monsanto, BuMines has not been designing total resource recovery systems but has been examining, at a pilot plant, the pyrolysis reaction of various waste materials, including municipal wastes, tires, and cow manure. Shredding and separation precedes the process, which essentially consists of an electric furnace, cylindrical steel retort, condensing and scrubbing train to recover products, and gas metering and sampling

TABLE 10-5

PRODUCTS FROM BuMINES PYROLYSIS
(PER TON OF REFUSE)

	Municipal Waste at 1,650°F		Passenger Tires at 1,650°F	Cow Manure at 930 to 1,650°F
	Wet Feed (43.3 percent moisture)	Dry Feed (7.3 percent moisture)		
Gas (cubic feet)	17,741	18,470	11,460	10,983
Oil (gallons)	0.5	16.2	51.5	17.4
Char (pounds)	200	200	1,046	702
Heating values, Gas (Btu's per cubic foot)	447	545	700	500
Char (Btu's per pound)	5,000	5,000	13,500	7,380

Source: Schlesinger and others, 1972: 425-427.

devices. Products include three fuels (gas, oil, and char) as well as an ammonium sulfate solid and an aqueous solution containing organic compounds.

Products from pyrolysis of several waste streams are given in Table 10-5. Lower temperatures yield less gas and more oil; similarly, dry feed yields the most oil. The heating value of the gas averages 500 Btu's per cf; thus, enough gas is produced in all cases to supply the required process heat of two million Btu's per ton of refuse. Although excess gas could be burned industrially, it has no value for home heating because it does not burn properly when mixed with natural gas and the carbon monoxide content exceeds allowable limits.

10.4.4.2 Energy Efficiencies

The efficiency of the Monsanto LANDGARD pyrolysis process is 71 percent,* of the Garrett process is 45.7 percent,** and of the BuMines process is 68.5

---

*Energy In: Raw Refuse: 10.5×10^6 Btu's per ton times 312,500 tons per year equals 3.28×10^{12} Btu's per year.

Fuel Oil: 2.2×10^6 gallons per year times 0.14×10^6 Btu's per gallon equals 0.31×10^{12} Btu's per year.

Energy Out: 2.54×10^{12} Btu's per year (<u>District Heating</u>, 1974: 2).

Efficiency: 2.54×10^{12} divided by (3.28×10^{12} plus 0.31×10^{12}) equals 0.707.

**Energy In: 10.5×10^6 Btu's per ton.

Energy Out: 1 barrel per ton at 4.8×10^6 Btu's per barrel.

Efficiency: 4.8×10^6 divided by 10.5×10^6 equals 0.457.

percent* using a wet feed and 59.1 percent using a dry feed.** The calculations include process heat requirements, which are 7.1 gallons of number two fuel oil per ton (one million Btu's per ton) of solid waste for the Monsanto process, the entire amount of gas produced in the Garrett process, and two million Btu's per ton for the BuMines process.

Other ancillary energy requirements include the electricity needed for the shredders, fans, and separating units. Shredders require 127,350 Btu's per ton of refuse shredded. The total electric requirement for the Garrett process is 960,000 Btu's (as oil) per ton of refuse or 9.1×10^{10} Btu's per 10^{12} Btu's of refuse input to the process (Mallan and Finney, 1973: 58).

Electricity requirements for the Monsanto and BuMines systems are not known.

10.4.4.3 Environmental Considerations

Nonsalable residuals resulting from pyrolysis include stack gas, water from the pyrolysis reactor, and char. The char, amounting to 0.06 to 0.07 ton per ton of raw refuse, is landfilled. The pyrolytic water, which contains organic compounds and a very high biochemical oxygen demand, requires secondary sewage treatment. In the Monsanto process, the water is continuously clarified in a closed recirculatory system. No effluent is discharged. The Garrett process, as applied in San Diego, will discharge water into the municipality's sewerage system.

The stack gases require cleaning for removal of particulates and certain compounds, such as the methyl chloride that results from the pyrolysis of chlorinated plastics. Scrubbing transfers the undesired compounds to water. Combustible gases are burned (by the Monsanto process in the afterburner and by the Garrett process in the process heater) to oxidize odor-causing compounds and incinerate particulates. In the Garrett process, stack gases are cooled and vented through a bag filter. Particulate emissions are 0.08 grain per cf or 6,400 grains per ton of raw refuse. In the Monsanto process, gases are cleaned by passing them through a water spray scrubbing tower. In addition, the gases are passed through a dehumidifier to suppress formation of a steam plume.

In general, a pyrolysis plant is a low-profile, light-industry installation suitable for an urban area.

10.4.4.4 Economic Considerations

The Monsanto LANDGARD system in Baltimore (1,000 tons per day) is being built at a total 1974 cost of $16,177,000 (EPA, 1974: 96). Financing for this installation is a combination of a $6 million grant from EPA, $4 million from the Maryland Environmental Service, and $6,177,000 from the city treasury.

The Garrett pyrolysis system being built in San Diego County (200 tons per day) will have a 1974 cost of $4,012,710 with EPA providing $2,962,710, San Diego County providing $600,000, Garrett Research and Development providing $300,000, and San Diego Gas and Electric providing $150,000 (EPA, 1974: 96).

---

*Energy In: 9.65×10^6 Btu's per ton in feed plus 2×10^6 Btu's per ton in process heat.

Energy Out: 7.93×10^6 Btu's per ton in gas plus 0.1×10^6 Btu's per gallon times 0.5 gallon in oil.

Efficiency: 7.98 divided by 11.65 equals 0.685.

**Energy In: 17.78×10^6 Btu's per ton in feed plus 2×10^6 Btu's per ton in process heat.

Energy Out: 10.07×10^6 Btu's per ton in gas plus 0.1×10^6 Btu's per gallon times 16.2 gallons in oil.

Efficiency: 11.69 divided by 19.78 equals 0.591.

TABLE 10-6

PYROLYSIS COSTS AND REVENUE
(DOLLARS PER TON)

Source of Estimate	Cost	Revenue	Net Cost
Monsanto Process			
Monsanto[a]	9.60	4.70	4.90
Kasper[b]	11.00	4.67[c]	6.33
EPA[d]	10.50	4.35	6.15
Garrett Process			
Garrett[e]	5.40[f]	5.70	-0.30
Kasper[b]	7.35[f]	6.10	1.25
EPA[d]	9.79[f]	3.87[g]	5.92

[a] <u>District Heating</u>, 1974: 2, 1973 cost data.

[b] Kasper, 1973: 19, using 1973 cost data.

[c] The steam from one ton of solid wastes sells for \$3.89, the iron for \$0.44, and the glassy aggregate for \$0.34.

[d] EPA, 1974: 95-96, using 1974 cost data.

[e] Mallan and Finney, 1973: 62, using 1971 cost data.

[f] The large difference in these estimates is partially attributable to the size of facility assumed (see text).

[g] The oil from one ton of solid wastes was estimated in 1972 to be worth \$2.27, the iron worth \$1.28, and the glass worth \$0.32.

Table 10-6 gives cost and revenue estimates per ton of incoming raw refuse from three data sources for the Monsanto pyrolysis process and the Garrett process. Approximately half of each cost estimate is operating cost and half is plant cost amortization. The apparent discrepancy between the Garrett and EPA cost estimates for the Garrett process is attributable to economies of scale; Garrett's estimates are figured for a 2,000-ton-per-day plant while EPA's are based on the 200-ton-per-day plant being built in San Diego County. In addition, Kasper uses an amortization of capital costs over a 10-year period with a five-percent interest rate while Garrett uses 25 years at six percent.

BuMines preliminary cost data for their pyrolytic process are in the same range as the Monsanto and Garrett processes (Schlesinger and others, 1972: 425-427).

Depending on the size of the installation and assumptions made, the net cost of pyrolysis may be anywhere from zero to \$6.33 per ton (Table 10-6). In no case does this net cost reflect the savings in reduced landfill requirements, which now average \$4 to \$5 per ton nationally and are higher in urban areas where land costs are high.

10.5 DIRECT BURNING FOR ELECTRICAL GENERATION

10.5.1 Technologies

Prepared (shredded and sorted) solid waste is burned as a supplementary fuel in existing coal- and gas-fired boilers in St. Louis (Union Electric). The boilers there are 20 years old and were designed to burn pulverized coal and gas. The only boiler modification required was addition of a solid waste-firing port in each corner (Lowe, 1973: 7). Each boiler now has four coal-firing ports, one solid waste-firing port, and five gas-firing ports in each corner. Burning organic waste saves Union Electric 300 tons of coal per day by supplying 10 percent of the heat requirement for two 125-Mwe boilers.*

In Wilmington, Delaware, a processing facility to be operating by 1977 will process 500 tons of municipal waste, 15 tons of industrial waste, and 230 tons of sewage sludge (eight percent solids) per day. Most of the organic waste will be used as a fuel supplement for electric power generation in an existing oil-fired boiler. The dewatered sewage sludge and some organic waste will be converted to compost,

*650 tons per day of raw waste are prepared, producing 520 tons of supplemental fuel per day with a heating value after preparation of about 5,800 Btu's per pound (EPA, 1974: 91).

and the industrial waste will be pyrolyzed. Pyrolysis gases will be burned for heat to dewater the sludge (EPA, 1974: 92).
Boilers that burn oil can be adapted to burn solid waste only if they were originally designed to burn coal and have bottom ash and fly ash (particulate) handling equipment. This is the case in Wilmington.

10.5.2 Energy Efficiencies

Although data are not available, electric power generation with organic waste making up some part of the fuel is presumably about as efficient as fossil fuel-fired plants (35 to 38 percent).

10.5.3 Environmental Considerations

Principal residuals from electric power generation are particulates, nitrous oxides, and sulfur dioxide as air pollutants and ash as solids (see Chapter 12 for a detailed discussion). When supplementing a coal-fired facility with organic wastes, particulate and nitrous oxide emissions are about the same as with coal alone (EPA, 1974: 92). (When supplementing an oil-fired plant with solid waste, particulate emissions may be greater than for oil alone.) However, sulfur emissions are lower. The sulfur content of organic waste averages 0.12 percent by weight* which is, on an equivalent heat basis, the same as burning bituminous coal with a 0.3 percent sulfur content (EPA, 1974: 96).

In the St. Louis system, boiler bottom ash is sluiced to a settling pond. Of the raw incoming waste, 13 percent (by weight) requires landfilling. This reduces the land requirement for solid waste disposal by as much as 95 percent (Lowe, 1973: 7).

*0.12 percent sulfur equals 0.23 pound of sulfur per million Btu's (EPA, 1974: 96). Federal emission standards for a coal-fired plant are 0.4 pound of sulfur per million Btu's and for an oil-fired plant are 0.4 pound of sulfur per million Btu's.

10.5.4 Economic Considerations

Total 1974 cost for designing constructing, operating, and evaluating the St. Louis system (including shredding and sorting) through August 1974 was $3,888,544. EPA has paid $2,580,026 or 66.3 percent of the total. Of the non-federal share, Union Electric provided $950,000, and the City of St. Louis provided $358,518 (EPA, 1974: 91).

In Wilmington, the total cost for design, construction, operation, and evaluation to May 1978 is expected to be $13,760,000 with EPA paying $9,000,000 or 65.4 percent (1974 dollars). The State of Delaware is providing the remaining $4.76 million (EPA, 1974: 93).

Projected 1974 system costs in St. Louis and Wilmington are given in Table 10-7. In St. Louis, the system costs the city $4.00 per ton but saves the electric company $3.15 per ton for an overall net cost of $0.85 per ton.

Although the Wilmington system appears very expensive ($15.24 per ton), it provides (through other processes) disposal of industrial wastes and sewage sludge as well as municipal wastes.

10.6 TRANSPORTATION OF PROCESSED PRODUCTS

Methods of transporting pipeline gas produced by bioconversion or oil produced from hydrogenation are the same as those discussed in the crude oil and natural gas resource descriptions. Due to its low heat content, pyrolysis gas requires utilization close to production.

10.7 SUMMARY

Organic waste reserves (that portion which is readily collectable) constitute about two percent of total U.S. energy input. Converted to oil, this amount would represent three to four percent of the total 1971 U.S. demand; converted to natural gas, it would represent six percent of the gas demand; used as a coal replacement,

TABLE 10-7

1972 COSTS FOR DIRECT BURNING OF ORGANIC WASTE

	St. Louis System		Wilmington System
	Preparation Costs Charged to the Municipality	Burning Costs Charged to Union Electric	
Capital investment	$2,394,000	$600,000	$11,200,000
Annual costs			
Amortization and interest	227,000	120,000	1,400,000
Operation and maintenance	618,000	20,000	1,520,000
Total	$ 845,000	$140,000	$ 2,920,000
Costs per ton of input waste			
Before revenue	$5.00	$1.05	$22.40
Revenue			
Metal	1.00	NA	1.25
Fuel	NA	4.20	0.57
Other	NA	NA	5.34[a]
Revenues subtotal	$1.00	$4.20	$ 7.16
Net cost per ton	$4.00	$-3.15	$15.24
	Net = $0.85		

NA = not applicable

Source: EPA, 1974: 92-93.

[a]Includes humus at $2.35 per ton, nonferrous metal at $2.40 per ton, glass at $0.49 per ton, and paper at $0.10 per ton.

it would represent eight to nine percent of the coal demand, thus being capable of generating 6.8 percent of electricity consumption on a yearly basis. Although power from organic wastes could never become the primary fuel source, it could be a significant supplement in selected areas.

10.7.1 Energy Efficiencies

Table 10-8 summarizes efficiencies for processing organic wastes. Process heat requirements are included in the primary efficiency. Ancillary energy requirements, in particular electricity needed for each process, are unknown. Those trajectories that reduce the number of steps are the most efficient; for example, direct burning for electrical generation rather than conversion to oil and gas followed by burning for electrical generation.

10.7.2 Environmental Considerations

Residuals from hydrogenation, bioconversion, and pyrolysis of organic wastes are similar. Water, containing a high biochemical oxygen demand, requires treatment. This may be done on site, or the water may be routed to the municipalities' sewage treatment plants. Stack gases require scrubbing for particulate removal in all cases. Solids requiring landfilling are char from hydrogenation and pyrolysis, and sludge from bioconversion. Char quantities range from 0.07 to 0.1 ton per ton of raw

TABLE 10-8

ENERGY EFFICIENCIES FOR UTILIZATION OF ORGANIC WASTES

Process	Product	Efficiency[a] (percent)	Trajectory Efficiency[b] (processing and electric generation) (percent)
Hydrogenation	oil	39	15
Bioconversion	natural gas	unknown[c]	unknown
Pyrolysis, Monsanto	low-Btu gas (space heating)	71	NA
Pyrolysis, Garrett	oil	45.6	17.3
Pyrolysis, BuMines	gas, oil	59 to 68	22 to 26
Direct burning	electricity	NA	34

NA = not applicable

[a]Includes process heat.

[b]Process efficiency times 38 percent electric power generation efficiency.

[c]Process heat requirement is unknown; efficiency without process heat is 62.4 percent.

refuse or 6,000 to 9,000 tons of char per 10^{12} Btu's input to the process.

Three positive impacts result from any of the processes:

1. All process products are low in sulfur. Raw refuse is 0.12 percent (by weight) sulfur or 0.23 pound of sulfur per million Btu's which is, on a heat content basis, equivalent to coal with a 0.3 percent (by weight) sulfur content.
2. All processes reduce the landfill requirements, some by as much as 95 percent.
3. There is an unmeasured social benefit of resource recycling for future societies.

10.7.3 Economic Considerations

Costs for hydrogenation and bioconversion are unknown due to their very preliminary stage of development. After accounting for revenues received from salable products, the net cost of pyrolysis averages \$6.00 per ton and \$0.85 per ton for direct burning in St. Louis (1972 dollars). Both estimates include separation costs. For comparison, the cost of incineration is about \$8 per ton (1972 costs) (Schlesinger and others, 1972: 425-427), and the cost of landfill disposal is \$4 to \$5 per ton (1973 costs). Direct burning in an existing coal-fired plant appears to be the most economical because it takes advantage of an established system for providing, distributing, and marketing the products.

REFERENCES

Anderson, Larry L. (1972) Energy Potential from Organic Wastes: A Review of the Quantities and Sources, Bureau of Mines Information Circular 8549. Washington: Government Printing Office.

Appell, H.R., Y.C. Fu, Sam Friedman, P.M. Yavorsky, and Irving Wender (1971) Converting Organic Wastes to Oil: A Replenishable Energy Source, Bureau of Mines Report of Investigations 7560. Pittsburgh, Pa.: Pittsburgh Energy Research Center.

District Heating (1974) "Baltimore's Resource Recovery Centre: The World's First Pyrolysis Solid Waste System." District Heating (January-February 1974).

Environmental Protection Agency (1974) Second Report to Congress: Resource Recovery and Source Reduction. Washington: Government Printing Office.

Friedman, Sam, Henry H. Ginsberg, Irving Wender, and Paul M. Yavorsky (1972) "Continuous Processing of Urban Refuse to Oil Using Carbon Monoxide." Paper presented at The 3rd Mineral Waste Utilization Symposium, IIT Research Institute, Chicago, March 14-16, 1972.

Garrett Research and Development Company, Inc., "Solid Waste Disposal and Resource Recovery," process description. La Verne, Calif.: Garrett Research and Development Company, Inc.

Hammond, Allen L., William D. Metz, Thomas H. Maugh II (1973) Energy and the Future. Washington: American Association for the Advancement of Science.

Kasper, William C. (1973) Solid Waste and Its Potential as a Utility Fuel, Office of Economic Research Report No. 18. Albany, N.Y.: New York State Public Service Commission.

Lowe, Robert A. (1973) Energy Recovery from Waste: Solid Waste as Supplementary Fuel in Power Plant Boilers, Environmental Protection Agency Solid Waste Management Series. Washington: Government Printing Office.

Mallan, G.M., and C.S. Finney (1973) "New Techniques in the Pyrolysis of Solid Wastes," pp. 56-62 in AIChE Symposium Series, Vol. 69, No. 133.

Monsanto Enviro-Chem (1973) "'LANDGARD' System for Resource Recovery and Solid Waste Disposal: Process Description for Baltimore, Maryland." St. Louis: Monsanto Enviro-Chem Systems, Inc.

Schlesinger, M.D., W.S. Sanner, and D.E. Wolfson (1972) "Pyrolysis of Waste Materials from Urban and Rural Sources," pp. 423-428 in Proceedings of the Third Mineral Waste Utilization Symposium. IIT Research Institute, Chicago, March 14-16, 1972.

Senate Committee on Interior and Insular Affairs (1972) The President's Energy Message. Hearing, 92nd Cong., 1st sess., June 15, 1971, pp. 85-104, as cited in Anderson, Larry L. (1972) Energy Potential from Organic Wastes: A Review of the Quantities and Sources, Bureau of Mines Information Circular 8549. Washington: Government Printing Office.

CHAPTER 11

THE SOLAR RESOURCE SYSTEM

11.1 INTRODUCTION

The inflow of solar energy warms the earth's surface and atmosphere, drives the winds and ocean currents, and produces (through photosynthesis) all the food, fuel, and free oxygen on which life depends.*

In the past, solar radiation provided a major share of the total energy used in preindustrial and early industrial societies. As wind, it served to grind the grain, pump the water, and drive the ships. Converted to firewood, it heated homes and public buildings and provided steam for industrial heat engines. As the forests disappeared, both the industrial and private sectors turned to coal and other fossil fuels to meet the increasing demand for cheap energy.

A return to some limited reliance on direct solar energy would represent a turn toward familiar and essentially benign technologies and an expansion of existing energy sources. As recently as 1969, woodburning in the U.S. provided as much total energy as all the operating nuclear power plants (Commerce, 1973: 518, 630).

Figure 11-1 is a flow diagram of four potential sources of solar energy: direct radiation, the wind, organic fuels, and ocean thermal gradients. Each has its own unique characteristics and its own potential time scale. None is likely to have any major impact in the next 10 years, although the expected R&D activity in this field will insure that a number of pilot programs will be in operation before 1985.

In the following section, each of the four major solar energy sources is discussed in detail, along with the anticipated energy efficiencies, environmental impacts, economics, and other factors associated with specific applications.

11.2 DIRECT SOLAR ENERGY

11.2.1 Resource Base

The sun radiates energy in a relatively narrow band of wavelengths between 0.22 and 3.3 microns. This results from the transformation of a portion of the sun's mass from hydrogen to helium through the fusion of hydrogen nuclei (see Chapter 7). It has been estimated that the transformation of only one percent of the sun's mass from hydrogen to helium would supply enough energy to keep it shining for one billion years.

At the outer limits of the earth's atmosphere, the solar radiation falling on a surface perpendicular to the sun's rays has an intensity of 442.2 Btu's per hour per square foot. This quantity, known as the solar constant, is reduced by an average of 54 percent in the earth's atmosphere, where 35 percent is reflected back into space and 19 percent is absorbed and then reradiated to space. The total amount of solar radiation intercepted by the earth is $5.9\text{x}10^{17}$ Btu's per hour. But at the surface of the earth, this is reduced to

*Gravitational pull from the sun also accounts for a small percentage of tidal movements (see Chapter 9).

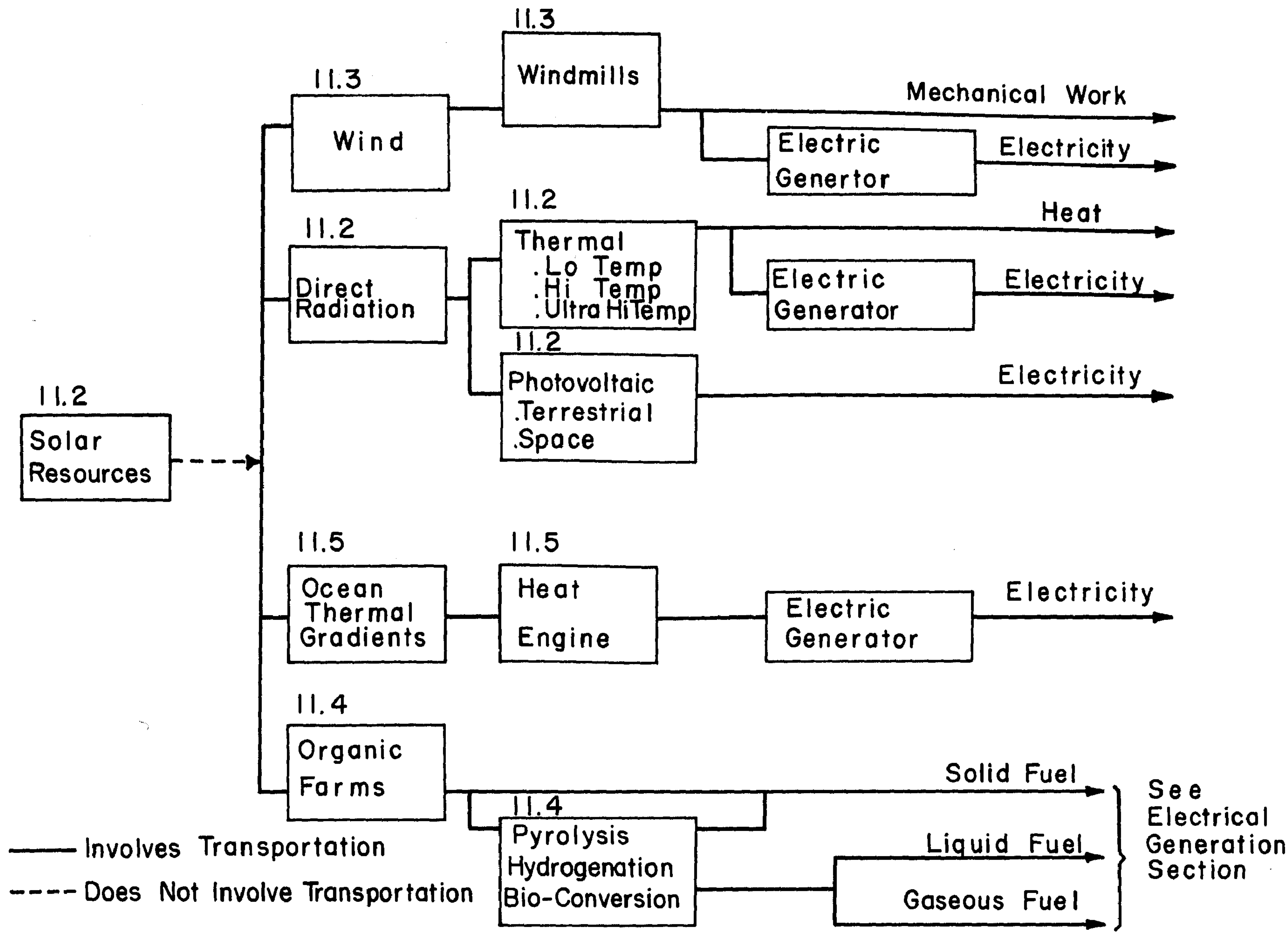


Figure 11-1. Solar Energy Resource Development

2.4×10^{21} Btu's per year or roughly 18,000 times as much energy as is consumed in all man-made devices currently in use throughout the world (Encyclopaedia Britannica, 1973: Vols. 20 and 21).

At any given point on the earth, the amount and intensity of solar radiation varies with season, latitude, and atmospheric transparency. Figure 11-2 shows the distribution of solar energy in the U.S. As might be expected, the maximum intensities occur in the southwestern portions of the U.S. Table 11-1 shows the seasonal variation in local solar energy for a variety of U.S. cities. The annual average for all locations listed is 1,450 Btu's per square foot per day. As a measure of the potential for solar energy, all the electricity used in the U.S. in 1972 could have been generated from a land area of about 3,000 square miles in Arizona, assuming a generating efficiency of 12 percent. For a typical city of one million in the northern part of the U.S., the electrical needs could be satisfied by a tract of land less than five miles on a side.

However, such simplified examples ignore the very real problems associated with the use of solar energy. Because of the variability of solar radiation, either energy storage or backup power is needed to provide failure-free capacity at night or when the sun is obscured. A second major problem is the low density of solar radiation, which requires large land areas devoted to energy collection. Finally, solar energy sources tend to operate at relatively low efficiencies. Thus, even though the fuel itself is free, the capital investment for collecting, storing, and transforming the energy is high.

Solar radiation in the U.S. has been studied and mapped in great detail over the years. It appears that the information now available is adequate to characterize the potential of solar radiation for any specific location in the U.S.

11.2.2 Technologies

Solar radiation may be used either to heat an object directly, as with a home water heater, or to heat a working fluid that may be used to develop power in a heat engine or to transfer heat to the ultimate receiver.

Solar energy through thermal conversion may be divided into three categories: low-temperature direct radiation, high-temperature concentrators, and ultrahigh-temperature concentrators. A fourth category includes the various applications of photovoltaic cells in the conversion of energy directly to electrical power.

11.2.2.1 Low-Temperature Collectors

About 6 to 10 times the amount of energy required to heat the average building in the U.S. radiates down on the building from the sun each year (Professional Engineer, 1973: 15). If this radiation is allowed to enter the building through windows in winter and is shaded from the interior in summer, fossil fuels are conserved. If the solar radiation is used to heat a working fluid, a major share of the energy requirements of the house can be satisfied by various conversion processes, including the generation of electricity. Space heating by solar energy has been used in a variety of structures over the years, but the long-term and continuous experience with solar power generation is limited.

When solar radiation falls on a darkened surface, the shortwave radiation is absorbed and converted into heat. The temperature of the surface will rise until it can dissipate energy at the same rate at which energy is being absorbed. If the surface is painted black and is covered by a sheet of clear glass, spaced about

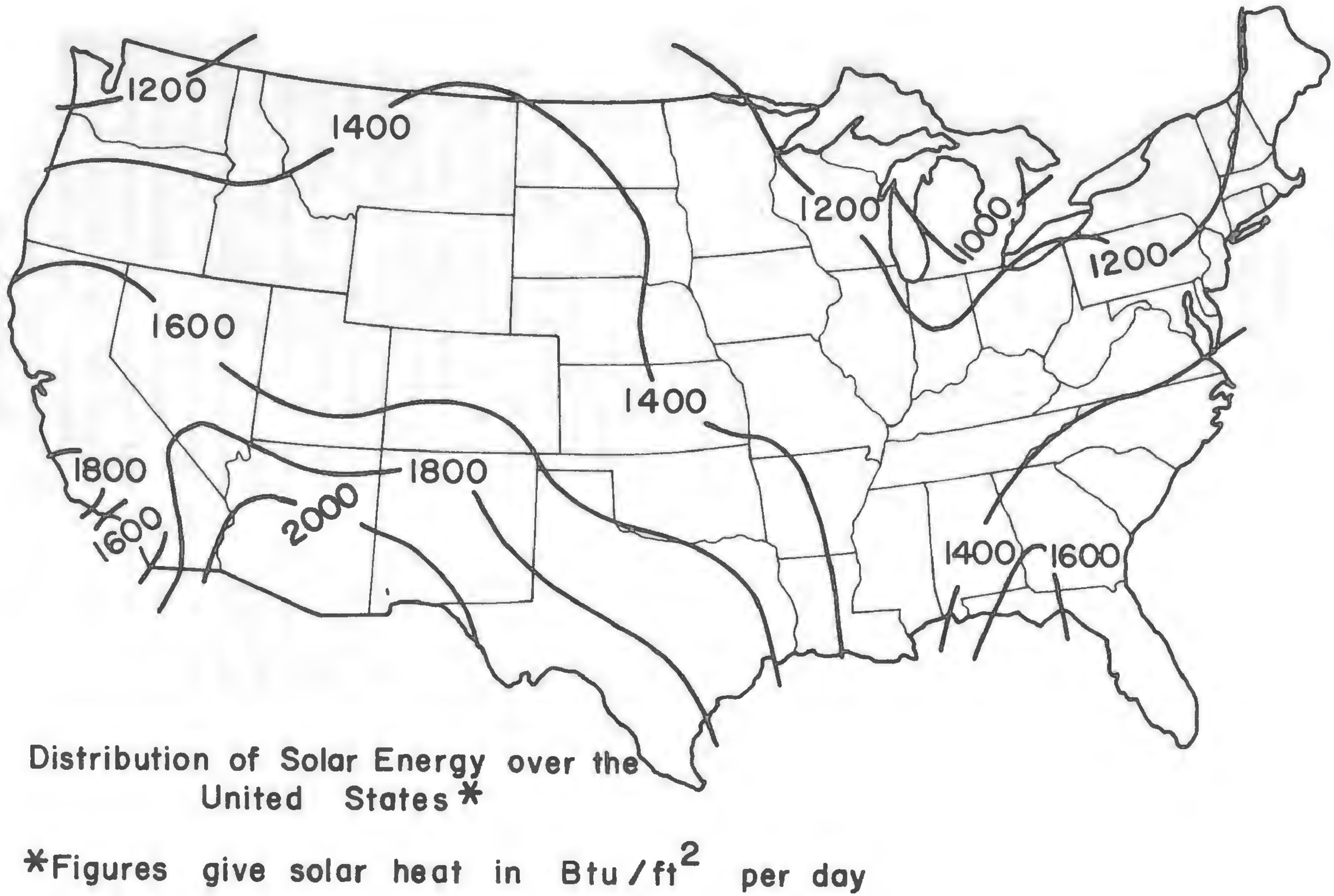


Figure 11-2. Distribution of U.S. Solar Energy

Source: AEC, 1974: A.5-7.

TABLE 11-1

SOLAR RADIATION AT SELECTED LOCATIONS IN THE UNITED STATES DURING 1970

Location	Average Total Daily Insolation (Btu's per square foot per day)												
	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Annual Average
Seattle-Tacoma, Washington	278	688	1,069	1,354	1,950	2,065	2,105	1,750	1,217	747	370	229	1,152
Fresno, California	710	1,117	1,709	2,205	2,609	2,579	2,576	2,412	2,050	1,425	910	614	1,743
Tucson, Arizona	1,110	1,391	1,750	2,202	2,435	2,449	2,190	1,983	1,735	1,587	1,221	870	1,745
Omaha, Nebraska	777	1,110	1,284	1,576	1,939	2,165	2,002	1,865	1,280	944	581	596	1,351
San Antonio, Texas	862	1,103	1,432	1,506	1,906	2,083	2,176	2,057	1,587	1,388	1,310	784	1,516
Lakeland, Florida	1,029	1,436	1,480	1,983	2,079	2,042	1,883	1,680	1,639	1,436	1,302	1,169	1,597
Atlanta, Georgia	873	1,203	1,288	1,635	1,991	1,854	1,917	1,628	1,591	1,021	955	714	1,389
Burlington, Vermont	581	781	1,088	1,384	1,447	1,758	1,587	1,835	1,195	759	444	448	1,109

Source: Commerce, 1970: Vol. 21, Nos. 1-12.

one-half inch above the surface, it will reach an equilibrium temperature of 225 to 250°F under favorable conditions. This temperature can be maintained for about five hours during the middle of the day, dropping off rapidly to ambient temperature at sunset and not increasing again until well after sunrise (Yellot, 1973: 5).

The glass cover is important because solar radiation can pass quite readily through the glass but the longwave radiation from the sun-heated surface cannot pass outward through the same glass. The cover also reduces convection and conduction losses to the atmosphere.

One of the earliest uses of low-temperature solar radiation was to distill salt from brackish water in arid regions. Modern developments throughout the world have made well-designed installations competitive with other means of producing drinking water in sunny climates. They are not presently adaptable for producing water on the scale needed for irrigation or large industrial demands.

Other applications for low-temperature solar collectors are based on the use of a working fluid (normally water) to furnish space and water heating directly, as shown in Figure 11-3. Hot water can also provide energy for thermally-driven refrigeration units and, when kept in insulated tanks, can store heat during the night and when the sun is obscured. Low-boiling-point fluids, such as Freon, have also been used to generate vapor to operate a heat engine. The engine in turn may be used to drive a pump or electrical generator unit.

11.2.2.2 High-Temperature Concentrators

To attain temperatures higher than 200 to 250°F, the sun's rays must be concentrated by the use of reflecting surfaces. Parabolic troughs--two-dimensional parabolic mirrors--with water pipes running along their focal lines are relatively simple and have been most commonly used for this purpose. Steam temperatures on the order of 600°F are possible from these units. For maximum efficiency, the units must be capable of following the sun, since only direct solar rays will be reflected to the foci.

The resulting high-temperature steam is both more efficient and more versatile than the output of flat plate collectors. It can be used for space heating, for absorption refrigeration, for industrial process steam, and for the development of mechanical or electrical power in Rankine or Brayton cycle engines, as shown in Figure 11-4. The technologies required for both the collection and use of high-temperature solar energy are well developed. Their technical feasibility has been established by a variety of experimental and operational units during the past 100 years. Until recently however, the economic aspects of solar concentrators have suffered by comparison with those of fossil-fueled power sources. Although the gap is narrowing, a considerable disparity still exists.

The use of solar-generated steam has been proposed for large-scale electrical generation by combining the output of a large number of collectors to drive conventional turbine generators. If the plant is to be able to operate continuously, some type of energy storage will be required. Molten salts, in which the energy is stored as heat of fusion, have been suggested for this purpose. The principle is shown in Figure 11-4. If storage is not used, it will be difficult to integrate the discontinuous and variable output into the existing demand system, although the statistical predictability of solar radiation on a nationwide scale should permit some limited reliance on central solar power plants.

11.2.2.3 Ultrahigh-Temperature Concentrators

Extremely high temperatures (approaching 5,000°F) may be obtained through the

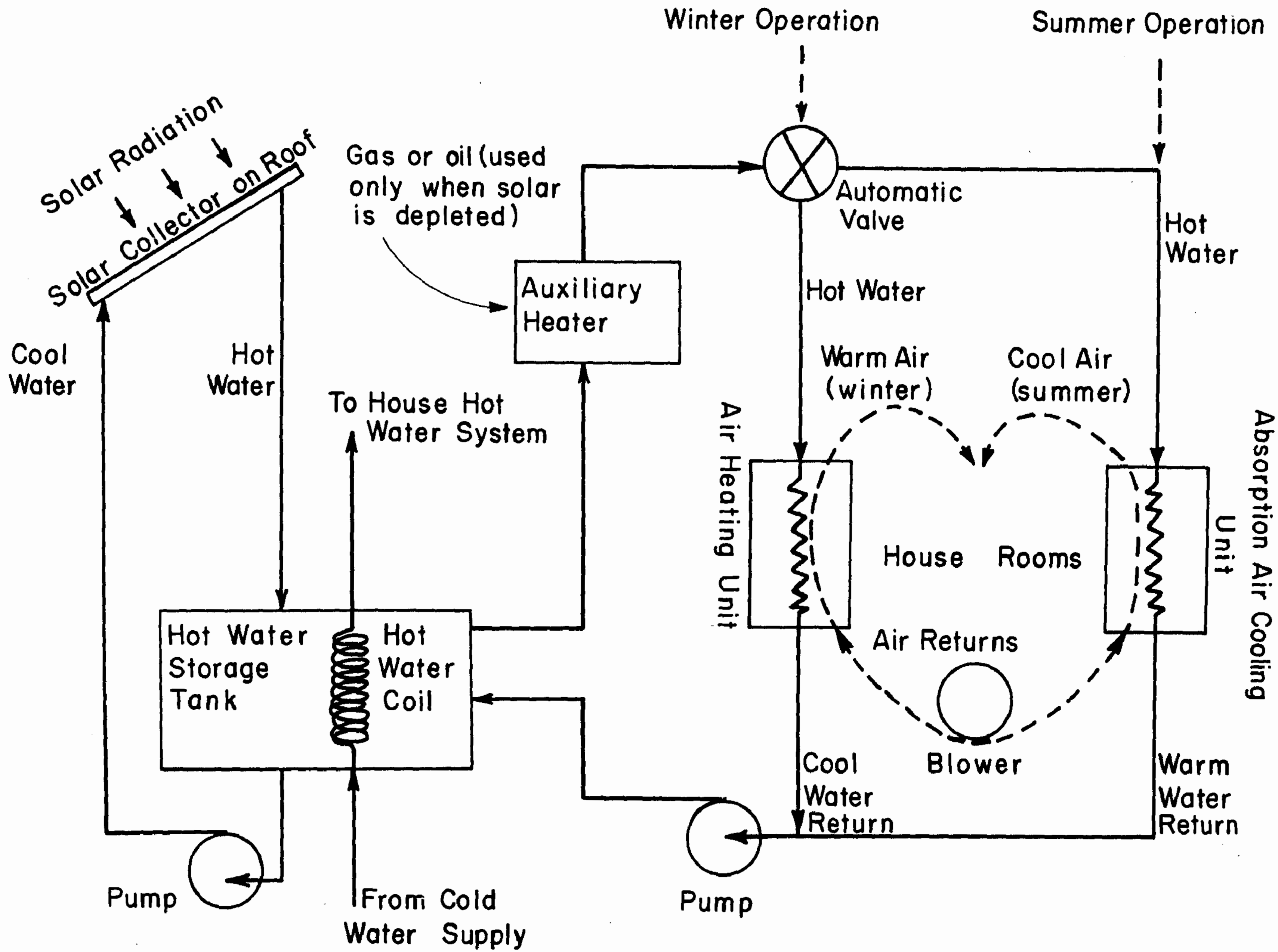


Figure 11-3. Residential Heating and Cooling with Solar Energy

Source: AEC, 1974: A.5-17.

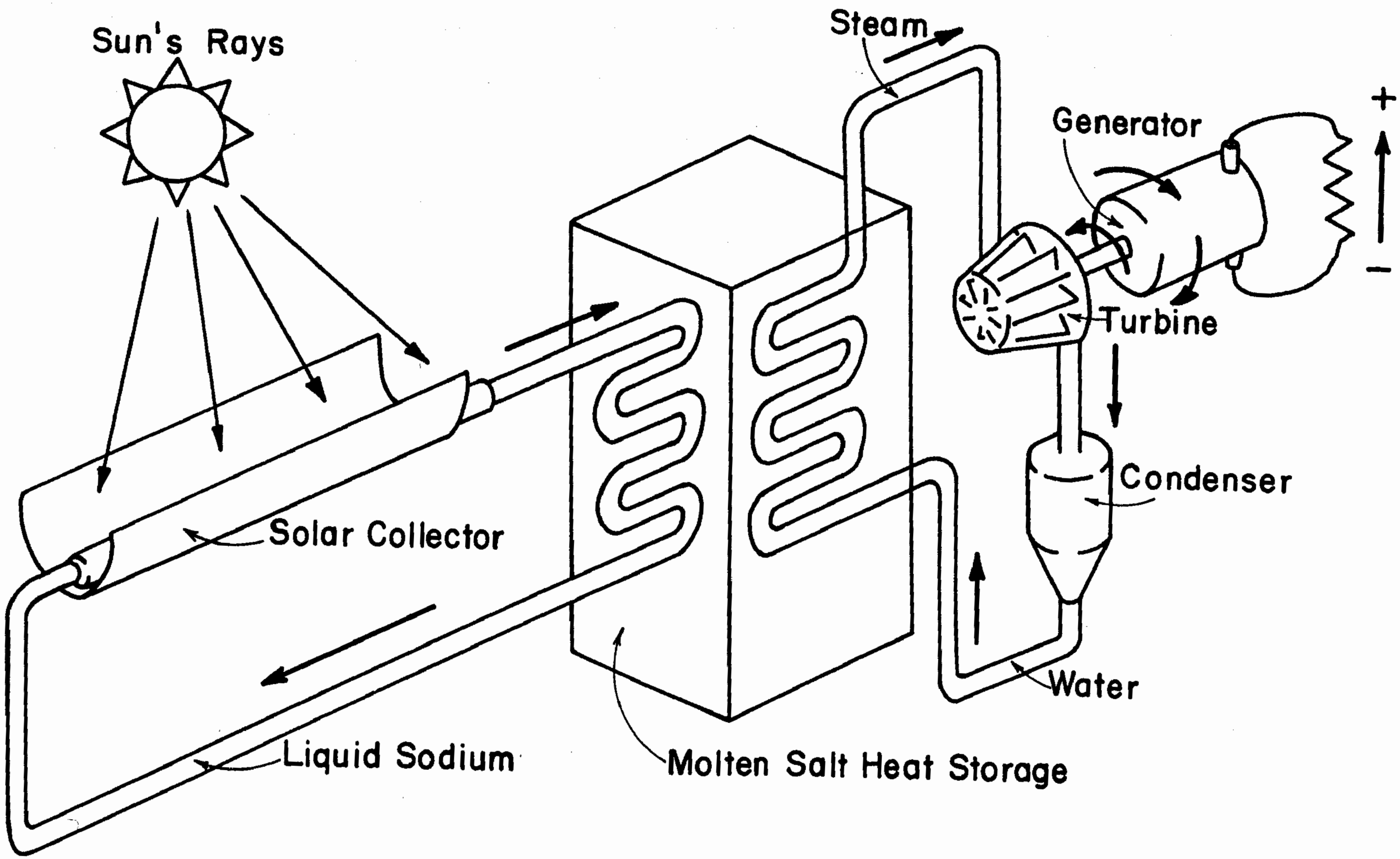


Figure 11-4. Solar Thermal-Conversion Power System

Source: AEC, 1974: A.5-9.

use of precisely contoured parabolic reflectors. These reflectors differ from trough-type concentrators by being true paraboloids which reflect all incoming solar energy to a single point. Although solar furnaces are being used for research in many parts of the world, none are currently being used for power generation. The largest such furnace in the world today is a French installation in the Pyrenees which, on a clear day, can attain a thermal rating of 3.4×10^6 Btu's per hour and temperatures of 3,000°F. It is used primarily for research on high-temperature refractory materials.

The major advantage of extremely high-temperature solar concentrators is their potential for high conversion efficiencies in steam engines or steam turbines. Carefully designed heat absorbers located at the focal point are capable of heating flow-through working fluids to temperatures of 1,500°F or more.

11.2.2.4 Photovoltaic Cells

The photovoltaic convertor, a silicon solar cell, was developed in 1954 by Bell Laboratories as an outgrowth of previous work on the transistor. It converts solar radiation directly into electrical current. Used first on an American satellite in 1958, solar cells have now become the major source of power for space vehicles which are required to operate reliably for long periods of time. Their high cost has limited their use for terrestrial power generation and results from the fact that individual silicon cells must be made from single crystals. It has been estimated that solar cell costs must be reduced by a factor of 1,000 before they become economically feasible for large-scale power generation.

Figure 11-5 shows cost projections for solar cells as a function of total production (Glaser, 1973: 9). Recent successes in the growth of continuous crystals and the abundance of the silicon base material give some hope for achieving appreciably lower costs in the short-term future.

To avoid the losses due to atmospheric attenuation and the nighttime outage, proposals have been made to place large arrays of solar cells in a near-equatorial synchronous orbit, where the sun would shine on them nearly 100 percent of the time (Brown, 1973: 39). The direct current (DC) power obtained from the photovoltaic arrays would then be converted into microwave power, beamed to large receivers on the surface of the earth, and there converted back to DC power. The concept envisions 32 square kilometers of solar cells in each satellite station and an area of 55 square kilometers for each ground receiver. It has been estimated that a satellite system of this size would provide 10,000 megawatts-electric (Mwe). The principle is illustrated in Figure 11-6.

The technical developments required to make satellite power stations feasible are so formidable that such stations are not likely to play any part in supplying energy for the foreseeable future.

11.2.3 Energy Efficiencies

In discussing efficiency for solar-related energy sources, it is important to recognize that the input energy is free and essentially inexhaustible. Thus, the conversion efficiency has less effect on direct operating costs than it does for conventional fossil-fuel plants. Conversion efficiency does, however, influence the size of the facility required to produce a given amount of energy. As a consequence, it has a great deal to do with capital investment and overhead costs.

When solar energy is used for direct heating, either with flat plate collectors or with parabolic concentrators, the conversion efficiencies can be relatively high, with a maximum between 60 and 70 percent. The actual value depends strongly

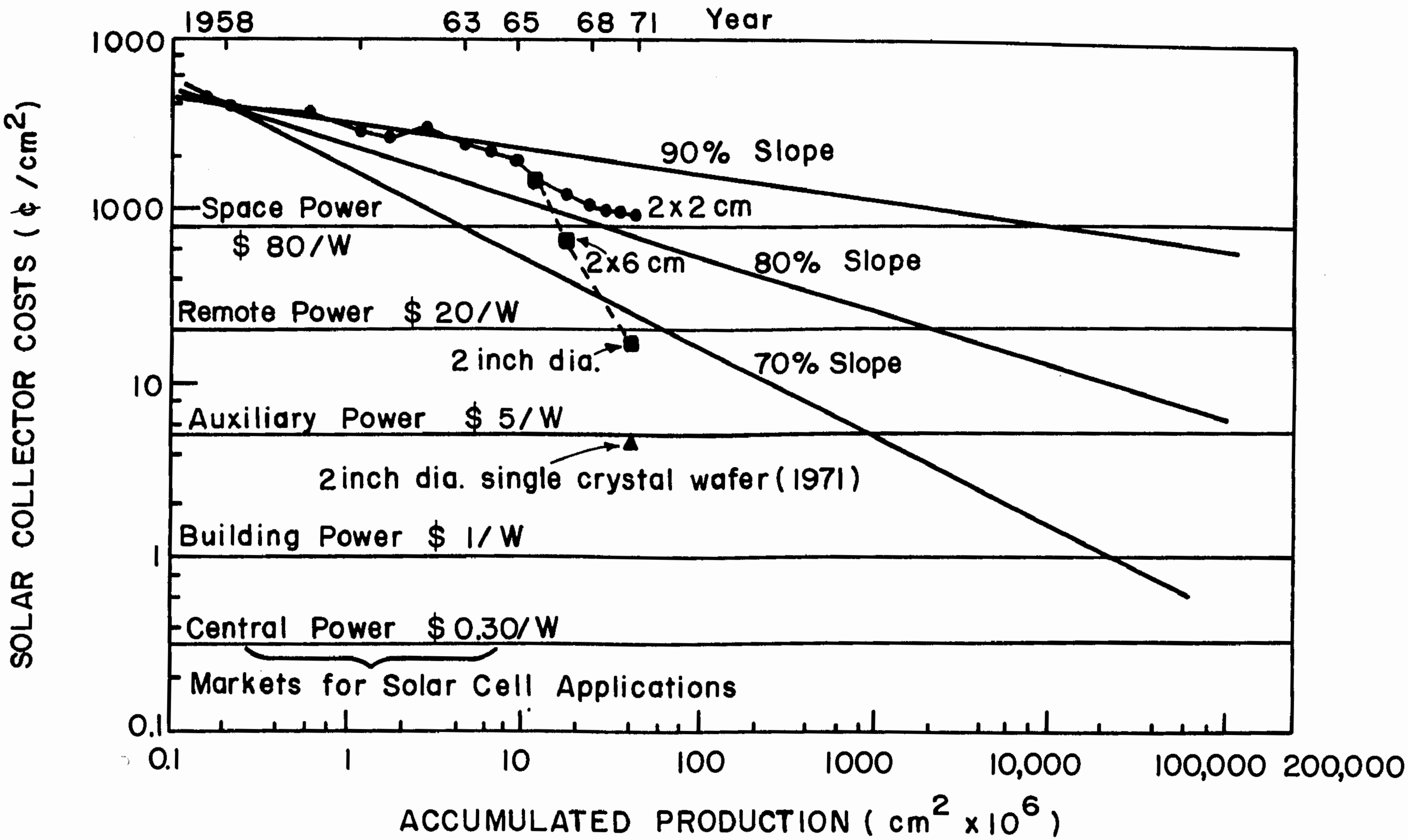


Figure 11-5. Silicon Solar Cell Cost Projections

Source: Glaser, 1973: 9.

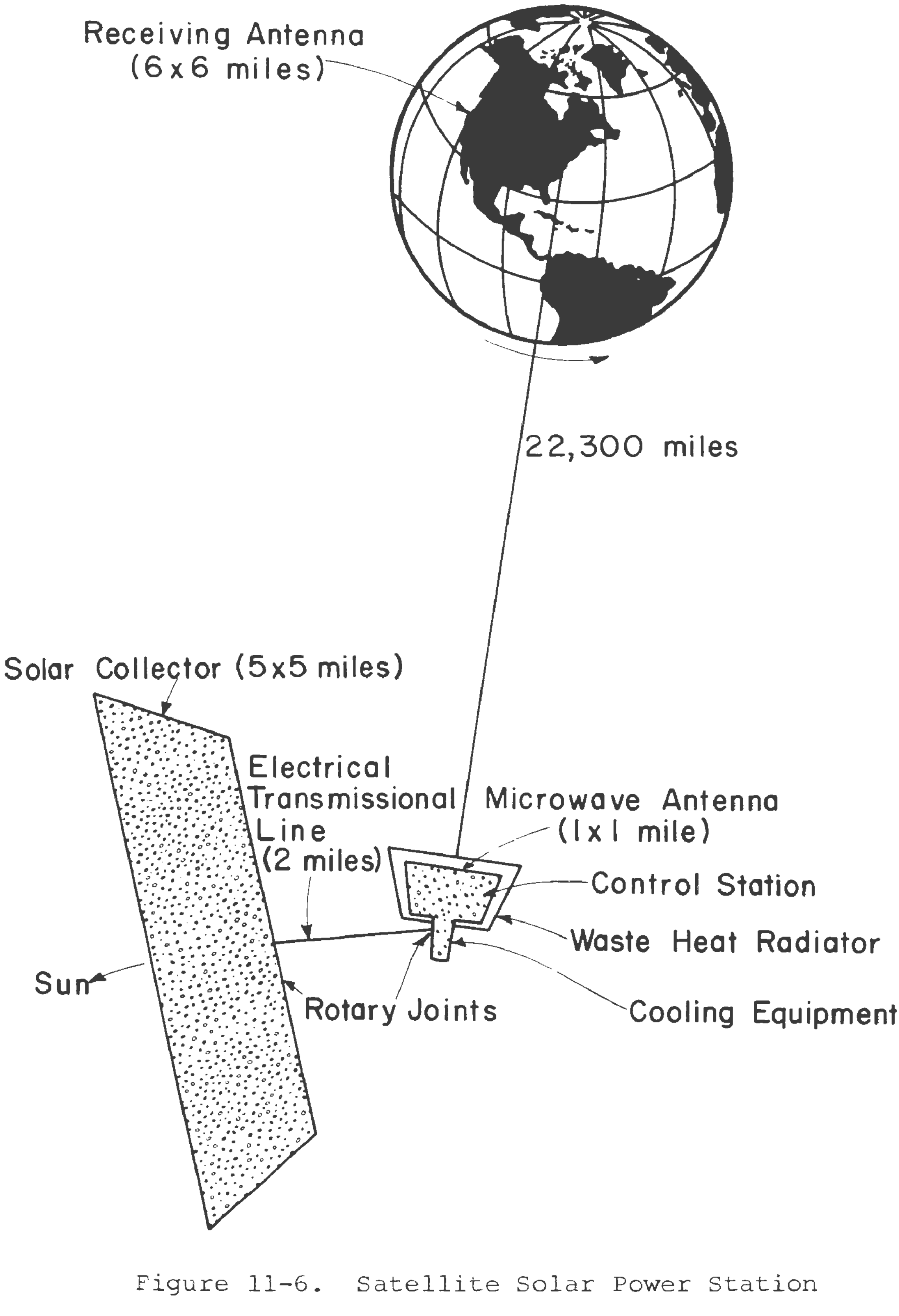


Figure 11-6. Satellite Solar Power Station

Source: AEC, 1974: A.5-13.

on the particular application and on the design of the system. When solar radiation is used to generate electricity, the combined efficiency of collectors, storage, heat engines, and the associated electrical equipment is not likely to be more than 20 percent and may be much less. The overall efficiency of photovoltaic generators, whether located on the earth or in space, is not likely to exceed 10 percent.

11.2.4 Environmental Considerations

The residuals associated with solar space heating are negligible, aside from the land area requirements discussed in the following section. The net heat residuals for solar electrical power generation are also negligible, but solar heat will be removed from the collection area and transferred to the generating plant in the form of heated wastewater and electrical output. As a result, there may be some cases of localized thermal pollution associated with electrical generation from solar radiation.

The most promising geographic areas for solar power generation are located in the southwestern part of the U.S. Much of the land is sparsely settled and of low productivity. The development of such land into solar farms will involve some damage to the local ecosystems as a result of road-building, grading, and the installation of the solar collectors and generating equipment. On the other hand, the Meinels, the principle proponents of such solar farms in the West, believe the areas shaded by an array of solar collectors could become more productive as rangeland (Meinel and Meinel, 1972).

Since the solar farms are likely to be located some distance from population centers, there would be a need for power lines to transmit the electricity over long distances.

Finally, the development of power plants in desert areas would require the construction of new towns in relatively inhospitable circumstances. The resulting demands on limited local resources will vary with the size of the facility and the maintenance and operational requirements. Solar farms could also disrupt ecological processes involving local plant and animal systems.

11.2.5 Economic Considerations

The two factors that have a major effect on the economics of direct solar conversion are its relatively low density at the earth's surface and its intermittency. The former imposes a need for large surface areas devoted to the collection of solar energy and a correspondingly high capital investment in solar energy devices. The latter requires either large-scale storage or sufficient backup capacity to meet the energy demand when solar energy output is low or nonexistent.

The land use problem is mitigated by the permanence of the power generation capability of a given land area, in contrast, for example, to the incremental needs in strip mining to supply adequate fuel to coal-fired boilers. Although research and analysis are required on this aspect of solar power, some evidence suggests that the self-sufficiency and permanence of solar energy sites will compare favorably on a land-use basis with fossil or nuclear fission energy sources (AEC, 1974: Vol. IV, A.5-22). Figure 11-7 shows a comparison of total land disturbed by surface-mined coal and solar electric plants for equivalent 1,000-Mwe power plants. It is also important to note that federal lands include many areas with high solar energy potential.

For a given output, the capital investment required for a conventional fossil-fueled plant is determined largely by system efficiency and load factor. Load factor is the ratio between the actual output and the total plant capacity. For fossil

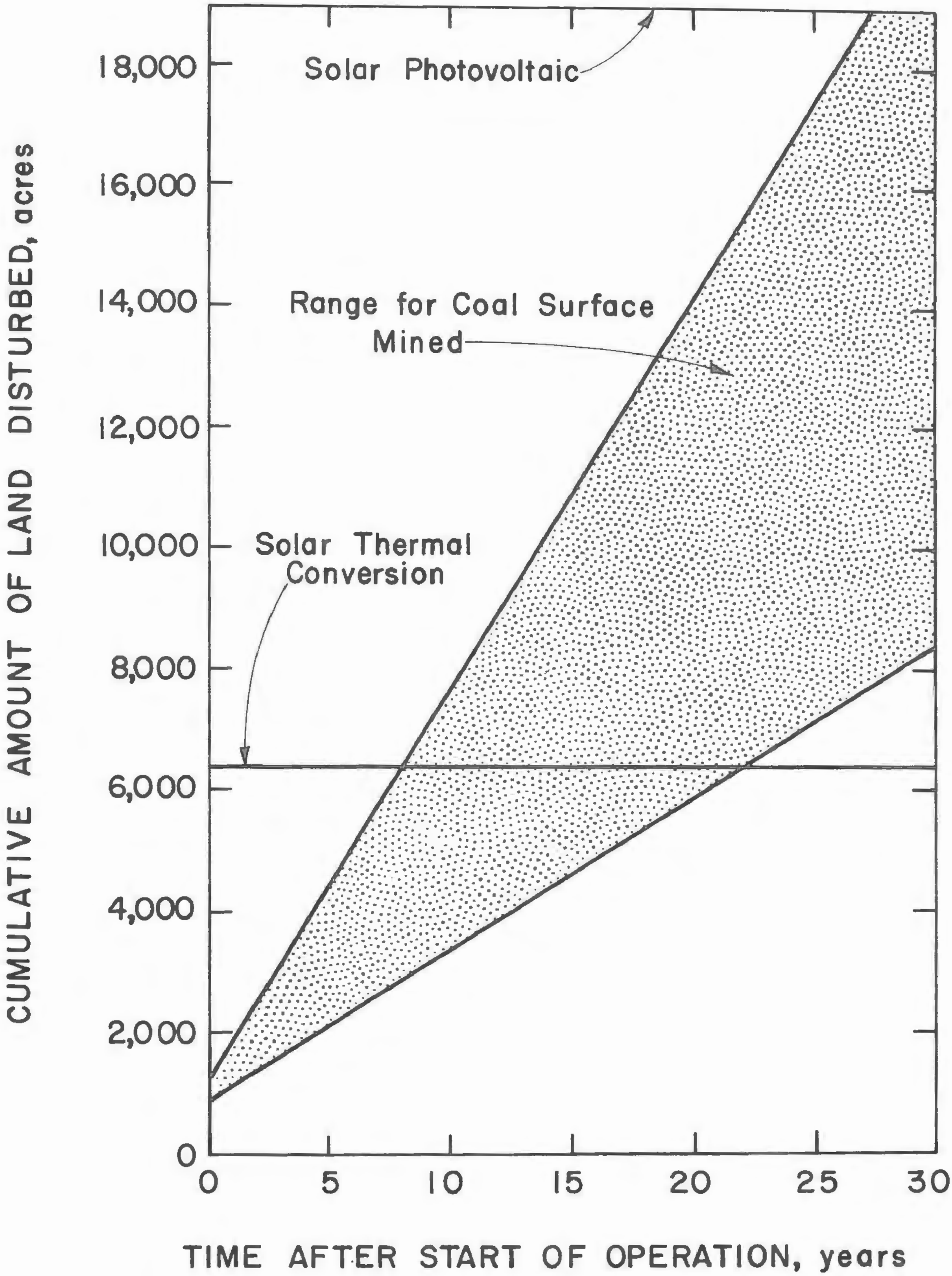


Figure 11-7. Comparison of Land Disturbed from Surface-Mined Coal and Solar Electric 1000-Mwe Power Plant

Source: AEC, 1974: A.5-23.

and nuclear plants, load factors of 50 to 85 percent are common. Solar plants, restricted to daylight use, operate at load factors on the order of 20 to 25 percent. As a result, the capital investment in a solar plant is likely to be relatively high, assuming similar costs per installed kilowatt (kw).

The intermittency problem is less tractable than the land-use issue. If backup capacity based on fossil or nuclear plants is used, the one-for-one duplication required to assure a continuous supply at maximum demand levels will result in excessive capital costs and reduced efficiency. In any transition from fossil- to solar-based power sources, such backup is a natural and reasonable approach. However, reliance on backup fossil power is not likely to be cost effective in the long term and would not conserve depletable resources to the maximum possible extent.

Energy storage provides both backup capacity and the potential for large-scale conservation of fossil fuel resources. Energy storage can take a number of forms, from pumping water to high dams for later use, to the generation and storage of hydrogen. All are relatively expensive in terms of capital costs, and only pumped water storage has a history of successful long-term experience as a basis for accurate cost estimates. (Hydroelectric power is discussed in Chapter 9.) For any situation in which direct solar radiation provides the baseload capacity, the cost of storage must be added to the basic cost of the solar conversion units.

As a consequence of intermittency, the installed capacity of a solar power plant must be somewhere between three and six times the capacity of an equivalent fossil-fueled power plant for a given annual output.

Since no large-scale solar units have been built recently (a large array was erected at Meadi in Egypt in 1913), any estimates of unit cost per installed kw must be considered speculative at the present time. Further, since large solar arrays are made up of a large number of small concentrators, the effect of economies of scale, in both fabrication and installation, is not entirely clear. At present, the most generally accepted cost estimates place the cost per installed kw well above that of fossil-fueled plants. For a continuous energy plant (including collectors, storage, turbines, and peripheral generating equipment), the costs in 1973 dollars may range from $750 (NSF/NASA Solar Energy Panel, 1972: 50) to $1,100 (Alexander and others, 1973) per kw. This represents a capital cost of three to five times that of an equivalent fossil-fueled plant. The lower of the two estimates is based on mass-produced components and an assumed solution to several unresolved technical problems.

Although operating costs of solar power plants are expected to be low, the amortization of capital investment will represent a major share of generating costs and will cause solar-generated energy to be several times as expensive as fossil or conventional nuclear power so long as fuel costs remain at or near present levels. Installed costs are expected to compare favorably with breeder nuclear power plants.

Electrical transmission costs are expected to be similar to those of conventional power plants, as described in Chapter 12.

11.3 WIND ENERGY

11.3.1 Resource Base

In any discussion of the windpower potential for the continental U.S., it is important to recognize that, at present, there is no completely adequate basis for making an accurate assessment. Although there is a satisfactory knowledge of the total atmospheric energy flux, there are a number of practical limitations. How closely can windmills be spaced without unacceptable losses in efficiency? Is it economical to build tall support towers to tap the winds at high altitudes? The answers to these and other related questions have a strong bearing on the total available wind energy.

Despite these problems, approximations are not only possible but are adequate for development in many areas. For example, a precise measure of the total wind resource is not necessary before undertaking the development of windpower. Our use of oil and gas is in no way inhibited by an inability on the part of geologists to define an accurate resource base for geological fuels.

At the most general level, about two percent of all solar radiation to the earth is converted to wind energy in the atmosphere (Brunt, 1941: 287). A simple calculation shows that the rate at which wind energy is being generated over the 48 contiguous states is about 14 times the 1973 energy demand.

Although the conversion of solar energy to wind energy takes place at all levels, 30 percent of the wind energy is generated in the lowest 3,280 feet of the atmosphere (Kung, 1966: 635). Only a small part of the energy flux in this lower level is available for conversion to a form of power directly useful to man. The amount is, however, more than might be supposed from an analysis of the energy contained in, for example, the lower 500 feet of the atmosphere. As energy is removed from the winds close to the ground, kinetic energy is transferred downward from higher altitudes through the energy transfer mechanism of the earth's boundary layer. Thus, the lower atmosphere from which energy is removed is continually replenished by natural meteorological processes.

In a recent study sponsored jointly by the National Science Foundation (NSF) and the National Aeronautics and Space Administration (NASA), a research team at the University of Maryland estimated that an annual output of 5.1×10^{15} Btu's of wind energy would be possible by the year 2000 (NSF/NASA Solar Energy Panel, 1972: 50). That amount is close to the total electrical demand in the U.S. for the year 1972.

The most promising geographical locations for windpower generation in the U.S. occur along the coastal margins and throughout the Great Plains Region from Texas through the Dakotas. Proposals have also been put forward to harness the steady offshore winds through the use of ocean-based windrotor complexes.

11.3.2 Technologies

As with most technologies, windpower has its characteristic measures of performance. In the case of conventional windmills, the output from the rotor is a direct function of the square of the diameter of the blades and the cube of the wind velocity. The potential range of performance for a windpower system is thus relatively large for only modest changes in size or operating conditions. It is this exponential relationship between wind velocity and output that places such a high premium on identifying sites with continuous high winds.

Conventional rotor-style windmills retain the basic configuration that has been used for thousands of years to pump water and grind grain. This configuration consists of a horizontal shaft to which is attached a number of blades, from two to several dozen, depending on the operating conditions and the desired characteristics. A schematic diagram of a typical modern windrotor system is shown in Figure 11-8.

Even though a windrotor's output is proportional to the wind velocity cubed, it is often not economical to design the electrical generating equipment to absorb all the rotor power at maximum possible

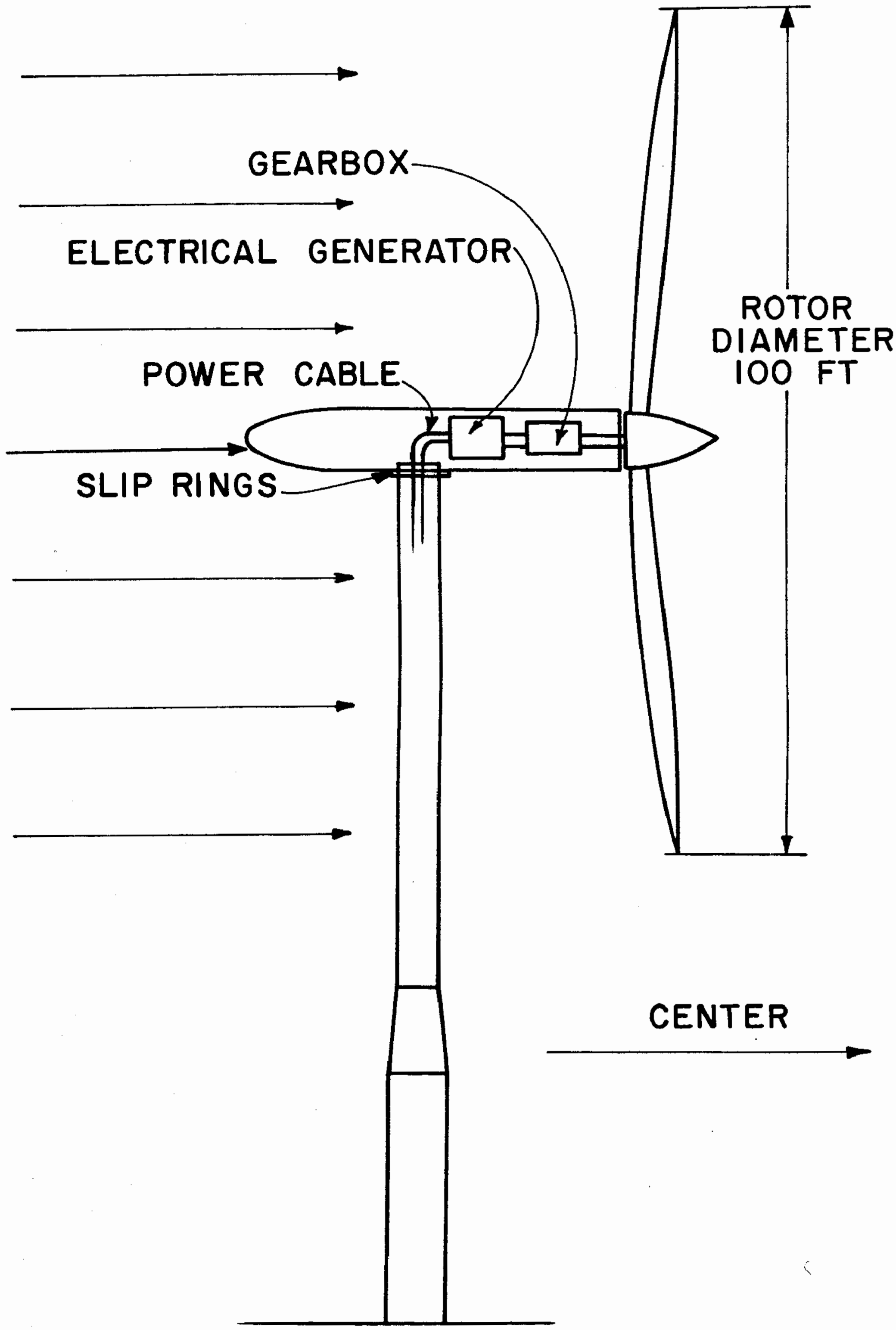


Figure 11-8. Typical Wind Rotor System

TABLE 11-2

ANNUAL ENERGY OUTPUT FOR VARIOUS WINDMILL DIAMETERS IN CENTRAL UNITED STATES

Windmill Diameter (meters)	Installed Capacity (kw)	Energy Output (kwh/yr)
10	31	49,000
20	126	196,000
30	282	442,000
40	502	785,000
50	785	1,227,000

Source: Bergey, 1971: 6.

wind speeds. Since high winds occur only infrequently, it is more cost effective to use a smaller generator which maintains a constant output at all speeds above its design wind velocity. This is known as flat-rating and, in most cases, does not seriously degrade the overall performance of the system.

At the low speed end of the scale, windmills are designed to start rotating at some minimum wind velocity. The selection of this start-up speed serves to define the period during which no power is being generated. Typically, in the Great Plains Region of the U.S., the windmill-height winds are blowing at eight knots or more about 70 percent of the time (Crawford and Hudson, 1970: 10). Table 11-2 shows the annual output for various sizes of windpower generators in this region.

Windpower generators operate at their installed capacity only when the wind is blowing at or above their flat-rate wind speed. At all other times, the generator is developing less than full output. As a consequence, a typical windpower generator operates at an overall load factor between 15 and 25 percent, only one-fourth that of a typical fossil-fueled plant. Thus, for a given annual power output, the windpower generator will need approximately four times the installed capacity of a conventional steam plant.

Wind variability also has an effect on rotor revolutions per minute, which in turn influences the output frequency of the generator. Since existing power nets--and many machines and appliances--depend on constant-frequency (60-Hertz) alternating current (AC) for their operation, some means for regularizing the output frequency is required. Either constant-speed drives or inverters will satisfy the requirement, but both are relatively expensive. Although it is reasonable to expect their costs to go down with large-scale production, other solutions may be more desirable.

The production of hydrogen by electrolysis, for example, is the subject of considerable interest at the present time. The hydrogen would be used in an engine or turbine to generate constant-frequency AC. Alternatively, it has been proposed that the hydrogen be piped to the customer in place of electrical current.

Another possibility is the conversion of at least a part of our electric demand to DC, which can be generated from a variable speed source without complex conversion. Many present applications for electric power will operate as well on DC as on AC. It is worth noting that DC is also generated by other promising energy conversion units, such as fuel cells and magnetohydrodynamic generators, which are described in Chapter 12.

In general, the components of a windpower generating system have relatively modest technical requirements by today's standards. Many are available as off-the-shelf items. This is particularly true for electrical generators, control system components, and transmission equipment. The integration of these parts into an efficient system will require engineering and development, but the design problem is largely one of demonstration rather than research.

Some windpower proposals, such as those for gigantic multirotor wind frames, will require further research and economic studies. By and large, however, a major part of the potential for windpower in the U.S. can be realized with current technology and with straightforward development.

As noted before, part applications of windpower have involved mechanical work--for propelling boats, grinding corn, and pumping water, for example. In contrast, the future of large-scale windpower is tied almost completely to electrical generation. Central generating systems can feed directly into existing power nets from large-scale wind farms. Smaller wind units can supply power for a variety of applications, from remote stations to individual homes.

For large-scale, central-power applications, there is much to recommend straightforward energy farms, each covered with a grid of identical wind generating units. Aside from the relative simplicity of the concept, it takes advantage of mass production economics and simplifies the development and demonstration of basic windpower units.

Power densities of 40 Mwe per square mile are possible in the Midwest with this approach. Wherever soil and water conditions permit, conventional agriculture can be carried on in conjunction with wind farms, since a grid of windpower generators is entirely compatible with high-yield farming and cattle grazing.

The intermittence of wind energy is likely to be less critical than that of solar energy. If windpower is introduced into multiregional power grids as baseload capacity, the emergency fill-in and peaking can be accomplished by existing fossil-fueled units. The key to this approach is to cover a sufficiently broad area so that the wind is sure to be blowing in some parts of the subgrids at all times. Modern interconnecting and power-sharing technology is already adequate for this purpose.

Small-scale applications are also promising. A ten-foot rotor will recharge a small urban car overnight. A 25-foot rotor will provide enough energy for an all-electric single family home in many parts of the U.S. In all such individual applications, the problem of windpower outages cannot be avoided. To insure adequate service, either storage or an alternate energy source must be provided. The former appears to be prohibitively expensive for average homes at the present time. Alternate energy sources are more attractive. As noted in the section on solar radiation, a promising option is to tie into--or remain tied into--the existing utility line, switching to central-station power when the windpower source is inadequate.

11.3.3 Energy Efficiencies

The rotary motion of a conventional windmill represents mechanical energy which may be used to drive electrical generating equipment directly. The maximum theoretical energy recovery for any wind-driven device is about 60 percent of the energy contained in the airstream intercepted by the windmill blades. This is true for conventional horizontal-axis rotors and for the variety of alternate configurations which have been suggested from time to time. Blade inefficiencies and mechanical losses reduce the theoretical recovery to a maximum of about 40 percent. The overall wind efficiency of an individual rotor generating system is not likely to be more than 35 percent, and may be less. The solar efficiency of windmill farms, defined as the energy output as a percentage of total solar insolation for a given land area, is a measure of land-use efficiency. It is likely to range between five and seven percent in the Midwest. As noted before, efficiency has very little effect on direct operating costs, but it does influence capital investment and overhead costs.

11.3.4 Environmental Considerations

Windpower has no significant environmental residuals. It produces no waste heat and, for the most part, is compatible with multiple land uses, including farming. It has been suggested that large windpower units be sited along railways and highways, taking advantage of existing rights-of-way and thereby tending to reduce land-use conflicts.

Some restraints may be imposed on the use of airspace over large wind farms, but there seems to be no reason to believe that tower-rotor systems with total heights of 200 to 300 feet will interfere with normal air traffic, except in the immediate vicinity of airports.

Finally, on the matter of aesthetics, some people may find the prospect of giant towers marching across the landscape to be distasteful, no matter how great their dedication to nonpolluting energy sources. In general, however, it appears possible to develop wind energy in areas with low population densities and to transmit the resulting electrical power to major population centers with conventional electrical power nets, thus reducing the aesthetic impact.

11.3.5 Economic Considerations

As with any new technology, the initial unit costs for windpower generators will be high. Until the inevitable bugs are worked out of prototype systems, the operating costs will also be high. Assuming that these early hurdles can be passed successfully, it has been estimated that windpower generating systems can be built for about \$150 to \$200 (equivalent 1974 dollars) per installed kw (Hughes and others, 1974: 23). This compares with today's costs of \$200 to \$350 for conventional fuel plants and \$500 for conventional nuclear plants. For the same annual output, the windpower systems will require about three times the capacity of the other two systems. Initial capital investment will be roughly in proportion.

Assuming a 25-year payback of capital along with a 25-percent load factor, 10-percent interest on debt, no provisions for energy storage, and a conservative allowance for operating costs, a typical installation will produce electricity at an average of 2.0 to 2.5 cents (1974) per kwh.

11.4 ORGANIC FARMS

11.4.1 Resource Base

A pound of dry plant tissue will yield about 7,500 Btu's of heat when burned directly. A ton of dry biomass, when heated in the absence of air, will produce 1.25 barrels of oil, 1,200 cubic feet (cf) of medium-Btu gas, and 750 pounds of solid residue with a heat content roughly equal to that of coal. By adjusting the process temperatures and pressures, the relative amount of solid, liquid, and gas generated can be varied to meet end-use specifications.

Although attractive from many standpoints, the growing of plants for energy generation is relatively inefficient. The solar conversion efficiency of the photosynthetic process is seldom over three percent during the growing season. A year-round average of just over one percent is typical for most high-yield crops. As a result, the land required for a given energy output is very high relative to other solar power sources. Based on yields of 10 to 30 tons of biomass per acre per year, the land required for a 100-Mwe organic-fired power plant would be somewhere between 25 and 50 square miles.

The development of algae as an energy biomass has also received some attention, largely because the oceans comprise about 70 percent of the earth's surface area. High productivity has been demonstrated under controlled conditions, but harvesting and dewatering represent major obstacles (Inman, 1973: 20).

The total land area in the U.S. is just over 3.5 million square miles. Nearly one-third (1.1 million square miles) is owned by the federal government. The Bureau of Land Management controls about two-thirds of the federal lands and the Forest Service just under one-fourth. The remainder is divided among nine major agencies and a variety of smaller agencies (World Almanac, 1973: 739-740). In the lower 48 states, 34 percent of the land is classified as forest area and 29 percent as rangeland (Agriculture, 1973: 22). The productivity of forest/rangeland varies widely throughout the country, a major limitation being imposed by the availability of water. In the southwestern part of the U.S., much of the rangeland is characterized by sparse vegetation, although a rapid growth of annual grasses is common in the rainy seasons. In the Northwest, South, and East, the natural forests and croplands are more productive. Under intensive cultivation, both forest and field crops can yield 20 tons of biomass per acre per year.

Irrigation is an important factor in the productivity of crops without deep root systems capable of tapping underground water resources or in areas where the normal rainfall is insufficient for high-yield agriculture. Less than five percent of the cropland was irrigated in the 1930's, rising to 10 percent in 1959 (Rottan, 1965: 10).

In most eastern regions, the expansion of irrigated acreage is limited more by the cost recovery from high-value crops than by the physical limitation of soil and water availability. In the western regions, the water resources vary widely as do the potential increases in productivity due to irrigation. In general, the gains from a given level of irrigation in arid regions are likely to be high.

11.4.2 Technologies

Agriculture and silviculture (development and care of forests) are based on processes that have, in principle, remained unchanged for millennia. The basic functions of soil preparation, planting, fertilizing, irrigation, crop maintenance, and harvesting are all familiar and recognizable elements in modern farming and forestry. This seeming familiarity, however, tends to mask the radical changes which have taken place in food and fiber production methods during the past 40 years.

Farm productivity per acre has tripled since 1934, and the output per man-hour has increased by a factor of seven. Machines have replaced farm animals, hybridized and genetically manipulated seed have replaced the best of "natural" grains, and modern forestry practices have increased productivity dramatically. Figure 11-9 shows some important measures of change from 1910 to 1960 (Starr, 1971: 41). It is this change which has made it possible to consider the development of energy plantations as a partial substitute for the use of fossil fuels. The equipment required for organic energy production is well developed and in a continual state of improvement.

A number of improvements in plants and in the photosynthetic process appear to be possible and would significantly enhance the economics of organic energy production. These improvements include plants with increased biomass production and plants which conserve water and nutrients.

To date, no major efforts have been made to maximize biomass production per unit of land area. Most crops, whether field or forest, have a specific high-value component which has been emphasized genetically, often at the expense of other growth factors. Certain plants do, however, have fortuitously high biomass yields. Among them are the genus Eucalyptus, which consists of over 500 species of broad-leaved evergreen trees native to Australia (Inman, 1973: 8). Eucalyptus trees grow in most of the temperate regions of the world, some in hot, dry weather where annual rainfall averages 10 inches or less. Biomass yields

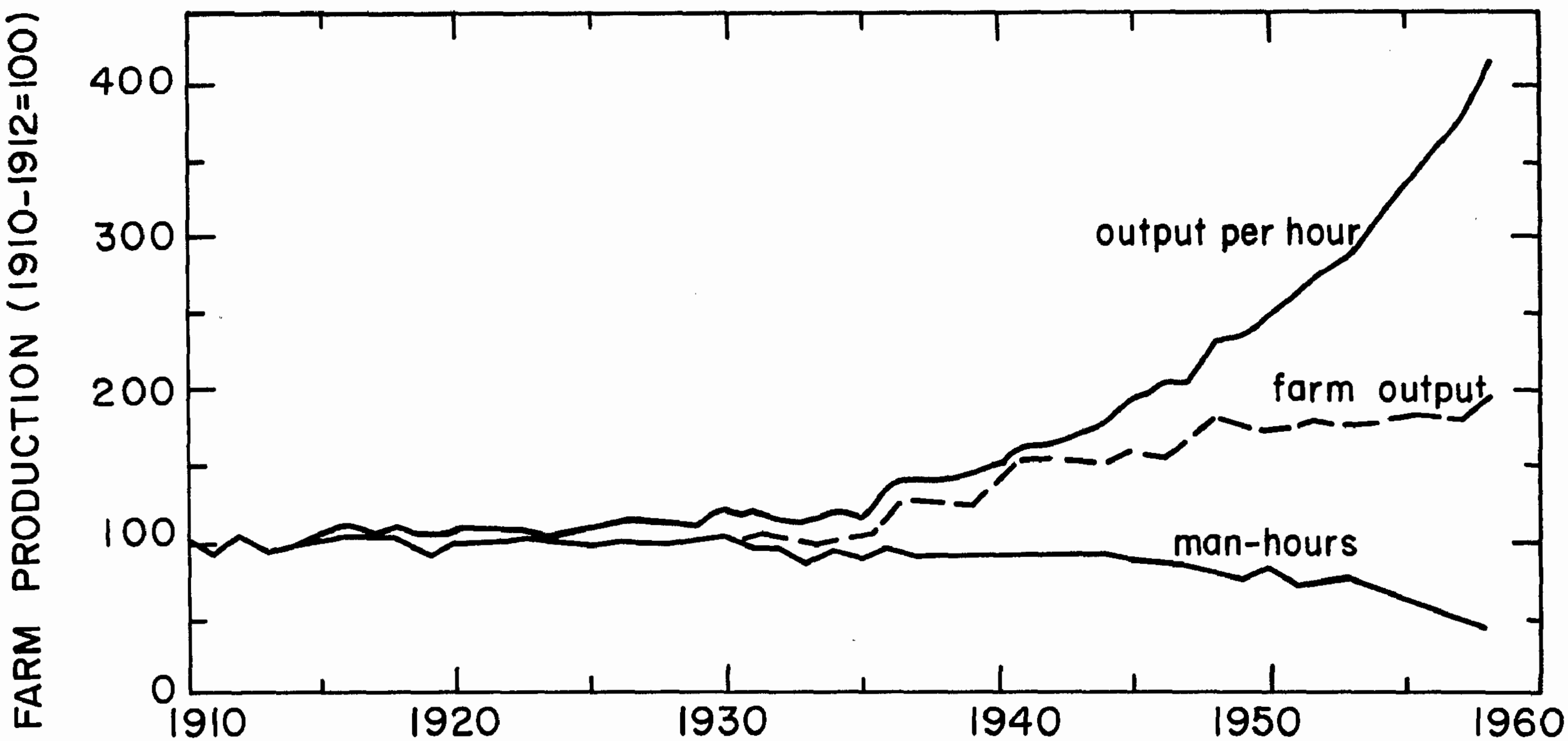


Figure 11-9. Farm Output Per Man Hour

From "Energy and Power," Chauncey Starr.

on the order of 8 to 25 tons per acre per year have been recorded, the highest being in California.

Other high-yield crops are sugar cane (12 to 50 tons), sorghum (8 to 30 tons), kenaf (8 to 20 tons), algae (15 to 30 tons), and sunflower (10 to 20 tons).

The potential for increasing biomass yields (while at the same time decreasing the need for water and fertilizer) exists because of natural variations in the photosynthetic pathways, some of which reduce photorespiration and provide greater heat and drought resistance.

Other plants, such as soybeans, peas, and alfalfa, can extract nitrogen from the air and convert it into protein. This ability to "fix" atmospheric nitrogen avoids the need for nitrogen-rich fertilizers and tends to protect the fertility of the soil. There is some hope that research now going on with the alternate photosynthetic pathways and with nitrogen-fixing will permit, through hybridization or other processes, the extension of these desirable traits to other species (Bjorkman and Berry, 1973: 93).

Finally, the possibility of large-scale plant growth in a controlled environment has been investigated, primarily in Arizona. Large inflated plastic structures provide protection against wind and weather. The solar rays passing through the plastic cause the plants to grow just as they would in the open, but the moisture which transpires through the leaves of the plants condenses on the underside of the plastic and is directed back to the roots of the plants. The net water consumption could be as little as 10 percent of that which would normally be required. As a further advantage, it is possible to increase the carbon dioxide concentration in the controlled environment and thus accelerate the growth rate of the plants (Yellot, 1973: 8).

The first large-scale application of plastic domes for plant production is now in operation on an island off Abu Dhabi, where it supplies a major share of the fresh vegetables consumed by the local population.

High yield agriculture demands high insolation, adequate water supplies, and the availability of nutrients, either through natural soil conditions or the use of fertilizer. Based only on temperature and insolation characteristics, the southwestern quarter of the U.S. offers the best growing conditions. Annual insolation is lower in the Southeast because of increased cloud cover. Lakeland, Florida, for example, received only 67 percent of the sunlight possible in 1970 as compared to averages of 80 to 90 percent in the Phoenix-Tucson-Yuma area. Annual rainfall in 1970, on the other hand, was 46.5 inches in Lakeland and only 7.3 inches in the Phoenix-Tucson-Yuma area.

The use of nitrogen-fixing plants will tend to reduce the need for some types of fertilizer. Other strategies for reducing fertilizer requirements include crop rotation and the use of less demanding plants. Nevertheless, intensive farming requires soil supplements, and the demand for fertilizers represents one aspect of the energy plantation development which requires major attention. Some areas of the country, such as Florida, have large natural phosphate resources. Others require long supply lines for the required nutrients.

Since standing forests may be harvested at any time of the year and dry biomass may be stored for long periods of time, organic power has a greater potential for baseloading than any other solar energy source. The similarity of its technology to existing fossil fuel generating systems could be expected to reduce the problems associated with introducing a new source of power. Bagasse, the residue of sugar cane, has been used for years to develop both power and process steam for sugar-making.

The conversion of organic materials to gas, oil, char, and other products through pyrolysis, hydrogenation and biological processes is described in Chapter 10.

The potential for by-products from energy farms ranges from sunflower oil to furniture. Since by-products are likely to have a higher unit value than the material used for direct combustion, the economics of the multiple-output farm will benefit accordingly. In addition, the use of natural and nondepletable materials for consumer products will tend to reduce the pressure on metals, plastics, and other materials which are either in limited supply or require large amounts of energy to produce and fabricate.

11.4.3 Energy Efficiencies

As noted previously, photosynthetic conversion efficiencies are seldom higher than three percent during the growing season or more than 1.5 percent on an annual basis. Coupled with thermodynamic efficiencies of 30 to 40 percent for conventional steam-turbine power plants, the overall efficiency of organic energy forms is less than one percent.

11.4.4 Environmental Considerations

The oxygen now in the atmosphere is almost entirely of biological origin, produced through the decomposition of water molecules by light energy in photosynthesis. In the past 100 years, man's overwhelming reliance on fossil fuels has tended to change the natural balance between oxygen generated through photosynthesis and carbon dioxide generated through organic decomposition. Within that period of time, the carbon dioxide content of the atmosphere has risen from 280 to 325 parts per million (ppm), with nearly one-quarter of the rise occurring in just the past decade (Bolin, 1970: 128).

The continued increase in the consumption of fossil fuels implies that the amount of carbon dioxide in the atmosphere will increase to 400 ppm by the year 2000. The long-term effect of this change in the carbon balance of the earth is not known. It has also been suggested that possible increases in vegetation from organic farms might function as a sink for ammonia, hydrogen fluoride, sulfur dioxide, and ozone.

In addition to these specific environmental effects, there are the more intangible benefits of aesthetics and multiple use. A forest or a field of sugar cane would be considered by most people to be more attractive than a strip mine or an oil field. A forest is a more appropriate place for picnicking, camping, or hunting than a tank farm or the immediate vicinity of a uranium mine. Although it is not clear that high-yield silviculture and extensive recreational activities are entirely compatible, the possibility exists and some compromises on energy yield might make reasonable accommodation possible.

Environmental problems associated with energy plantations involve their need for land, water, and fertilizer. Even if new croplands were to be opened and yields improved, the potential for land-use conflicts still exists because of the growing worldwide demand for food. This competition poses one of the most predictable obstacles to the development of energy plantations. In the U.S., the problem is exacerbated by our preference for animal protein. Since seven calories of vegetable energy are required to produce an equivalent calorie of beef, the efficient use of land for the production of food, fiber, and energy may require some reordering of priorities and public policies.

The water problems associated with organic energy farming are extremely geo-specific, depending on local rainfall, soil conditions, depth of the water table, and availability of well water. Although plant selection can tend to reduce the need for water in arid regions, some irrigation will be required in most parts of the country where land availability and high insolation rates are favorable. The water problems described in the chapters on oil shale and coal should also apply generally to organic energy farming in the Southwest.

Fertilizer requirements may be one of the most serious limitations to biomass production. As with fossil fuels, natural fertilizer sources are limited and fertilizer transportation may involve long distances and large volumes. A major source of energy plantation fertilizer could be found in municipal sewage plant sludge, organic trash, and feedlot wastes. The resulting symbiotic relationship could result in reduced costs for both fertilizer to the farm and waste disposal by cities. Whatever its source, unabsorbed fertilizer will be subject to runoff and other pollution problems.

Since the organically fired power plants will almost invariably be located in or adjacent to the farm itself, transportation distances for the biomass will seldom exceed 5 to 10 miles, depending on the layout of the farmland and the power plant units. No appreciable environmental residuals are expected from the intrafarm transportation phase of the operations.

11.4.5 Economic Considerations

Farming costs for existing crops are well documented because of the economic importance of large-scale, intensive agriculture. Thus, a firm base exists for estimated organic farm costs, even though it is not known which species may eventually be selected or in what proportion they may be cultivated.

In early 1972, the nationwide average purchase price for farmland was $217 per acre. Most good cultivated land sold for considerably more than $217 in 1972, but much potentially arable land could be bought for considerably less. Assuming an average price of $500 per acre, an annual land "charge" of $42 (1973) per acre per year is reasonable (Inman, 1973: 20).

Production costs, including the labor, materials, and equipment needed to prepare the fields and plant and cultivate the crop, average about $57 (1973) per acre.

The cost of installing and operating irrigation systems of the self-propelled tower and rainbird type average about $30 (1973) per acre per year. This includes the costs of purchase, installation, operation, and depreciation of the complete system.

The cost of water is highly variable, ranging from zero to as high as $20 per acre-foot. For the crops of interest to energy plantations, an annual charge of $30 (1973) per acre would appear to be reasonable.

Harvest costs include labor, the operation and depreciation of harvesting equipment, and short-range hauling. Assuming field crops such as sugar cane, sorghum, and kenaf, a charge of $4.50 (1973) per ton is representative.

Combining the values above with an assumed profit of 20 percent, biomass will be approximately $18 (1973) per ton at the yield level of 15 tons per acre and $12 (1973) per ton at a yield level of 30 tons per acre. At 7,500 Btu's per pound of dry plant tissue, the cost per million Btu's would vary between $0.80 and $1.20. This compares with current prices per million Btu's for coal of $0.79, domestic oil of $0.87, and interstate natural gas of $0.43. The crop value per acre would be somewhere between $180 and $300, which is comparable to the current yield from wheat acreage in the Midwest.

Economies of scale can be expected to apply to energy plantations as they do to most industrial and agricultural processes. The operation would involve a low-density collection function, which is characterized by the large-scale replication of unit equipment and functions. Under such circumstances, the economic size is more likely to be determined by total nationwide capacity, which establishes the market and the production base for related equipment, than it is by individual plantation size.

11.5 OCEAN THERMAL GRADIENTS

11.5.1 Resource Base

The surface temperature of the oceans between the Tropic of Cancer and the Tropic of Capricorn stays remarkably constant at about 77°F because the heat gained from solar radiation is balanced by the heat lost from evaporation (Metz, 1973: 126). At depths as shallow as 3,280 feet in these latitudes, the water temperature is 41°F. This temperature difference may be used to generate electricity in a conventional heat engine.

The amount of continuous energy available from ocean thermal gradients is many times more than that consumed throughout the world today. How much more depends on a number of factors, including the depth from which the cold water must be obtained, the conversion efficiency of the system, and the transmission losses in getting the electrical energy to shore. As with the wind, an accurate assessment of the resource base is probably less important than the knowledge that the potential is greater than the existing demand.

11.5.2 Technologies

Although sea water has been used as a working fluid in demonstration units, the economic development of ocean thermal power plants requires the use of a secondary fluid which will boil at about 68°F. In operation, the working fluid would be heated and vaporized by the warm surface water in large heat exchangers. The vapor would then be expanded through turbines to produce electricity and finally condensed to the liquid state in heat exchangers cooled by deep ocean water.

The heat exchangers are the critical technology in such power plants, although the pumps, turbines, and water ducts also require major development. The heat exchangers, both condensor and evaporator, must transfer an enormous amount of heat through very thin walls which are operating in a corrosive seawater environment. Although some government-funded research is being done in this area, the technical problems are formidable. The practical application of ocean thermal gradient power sources lies well beyond the next 10-year time period.

11.5.3 Energy Efficiencies

The maximum theoretical efficiency of a power plant working with a temperature difference of 36°F is about 6.7 percent. The actual efficiency is not likely to exceed three percent and may be considerably less.

11.5.4 Environmental Considerations

Ocean thermal power appears to have very little direct environmental effect, although the subject has not been investigated to any great extent. Removal of thermal energy from the oceans is expected to be more than balanced by solar radiation to the cold discharge water at the surface. Environmental effects due to the construction and operation of large thermomechanical installations in the ocean are not known.

11.5.5 Economic Considerations

The technology is insufficiently developed at this time for calculating reliable economic information. Some thought has been given to using the nutrient-rich deep water for the cultivation of algae and marine animals for food.

11.6 SUMMARY

All solar energy sources are characterized by low power densities and low conversion efficiencies when used to generate electricity. As a consequence, the land area requirements for a given output are

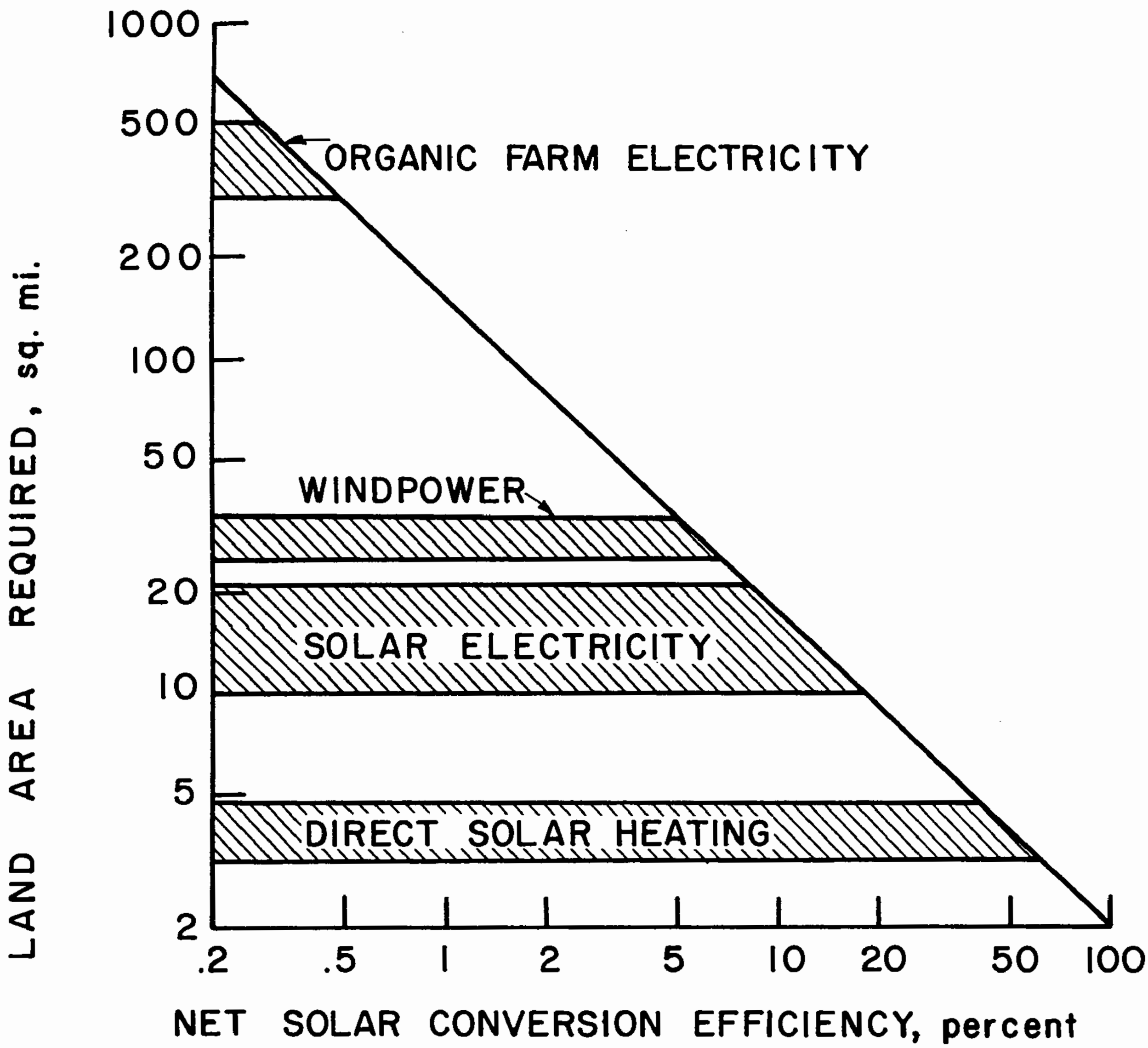


Figure 11-10. Land Area Required for 1,000 Mwe Equivalent Output as a Function of Solar Conversion Efficiency

relatively large. Although the affected land area may, in the long run, compare favorably with that of fossil-fueled power plants, the initial land commitment may seem formidable. Figure 11-10 shows the land requirements as a function of overall conversion efficiency and identifies the range for specific solar technologies. These requirements are based on an average daily solar insolation for the U.S. of about 1,450 Btu's per square foot and a load factor of 75 percent. The land area requirements shown for space heating are calculated for an output equivalent to a 1,000-Mwe power plant, although in practice individual units would be relatively small and tailored to individual building requirements.

From a land-use standpoint, direct solar heating for buildings would appear to be most attractive. If the required equipment can be made reliable and cost-competitive with current heating methods, the potential contribution to the U.S. energy demand will be large. Further, with sufficient economic incentives as a result of high fuel prices or government initiatives, solar space heating could become a significant factor in a relatively short period of time.

When solar energy is used for generating electricity or other portable power, the efficiency is greatly reduced.

Offsetting the overhead costs due to the high initial investment in solar power systems are the economic benefits associated with free energy and lower operating costs. This relative advantage of all solar-related energy sources is likely to increase in the future, since fossil and nuclear fuels require extensive (and energy-intensive) exploration, extraction, transportation, and processing before they can be converted to usable energy in a burner and heat engine. The resulting "energy debt" is a major part of fuel costs and the cost of conventional (including nuclear) power generation.

In the meantime, the relatively high capital costs of direct solar energy, combined with the present U.S. commitment to fossil and nuclear fuels, are expected to inhibit its use in the near future in the absence of specific government incentives.

REFERENCES

Alexander, L.G., and others (1973) "Solar Power Prospects." Paper presented at the Solar Thermal Conversion Workshop, University of Maryland, January 11-12, 1973.

Atomic Energy Commission (1974) Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington: Government Printing Office.

Bergey, K.H. (1971) "Feasibility of Wind Power Generation for Central Oklahoma." Aerospace and Mechanical Engineering Report, University of Oklahoma, June 1971.

Björkman, O., and J. Berry (1973) "High-Efficiency Photosynthesis." Scientific American 226 (October 1973): 80-93.

Bolin, B. (1970) "The Carbon Cycle." Scientific American 223 (September 1970): 124-132.

Brown, W.C. (1973) "Satellite Power Stations: A New Source of Energy?" IEEE Spectrum 10 (March 1973): 38-47.

Brunt, D. (1941) Physical and Dynamic Meteorology. New York: Cambridge University Press.

Crawford, K.C., and H.R. Hudson (1970) "Behavior of Winds in the Lowest 1500 Feet in Central Oklahoma: June 1966-May 1967." ESSA Technical Memorandum ERLTM-NSSL 48, August 1970.

Department of Agriculture, Forest Service (1973) The Nation's Range Resources, Forest Resource Report No. 19. Washington: Government Printing Office.

Department of Commerce (1970) Climatological Data: National Summary. Washington: Government Printing Office.

Department of Commerce (1973) Statistical Abstract of the United States, 1973. Washington: Government Printing Office.

Encyclopaedia Britannica (1973) Chicago: Encyclopaedia Britannica, 24 vols.

Glaser, P.E. (1973) "Solar Power via Satellite." Testimony before the Senate Committee on Aeronautical and Space Sciences, October 31, 1973.

Hughes, W.L., and others (1974) "Basic Information on the Economic Generation of Energy in Commercial Quantities from Wind." Report #ER 74-EE-7, Oklahoma State University, May 21, 1974.

Inman, R.E. (1973) "Effective Utilization of Solar Energy to Produce Clean Fuel." Stanford Research Institute, Third Quarter Progress Report, NSF Foundation Grant GI38723, October 30, 1973.

Kung, E.C. (1966) "Large Scale Balance of Kinetic Energy in the Atmosphere." Monthly Weather Review 94 (November 1966).

Meinel, A.B., and M.P. Meinel (1972) "Thermal Performance of a Linear Solar Collector." ASME Technical Paper No. 72-WA/Soc-7, November 1972.

Metz, W.D. (1973) "Ocean Temperature Gradients: Solar Power from the Sea." Science 180 (June 22, 1973): 1266-1267.

National Science Foundation/National Aeronautics and Space Administration Solar Energy Panel (1972) An Assessment of Solar Energy as a National Energy Resource. College Park, Md.: University of Maryland.

Professional Engineer (1973) "Solar Energy: An Idea Whose Time Has Come and Gone and Come Again." Professional Engineer (October 1973).

Rottan, V.W. (1965) The Economic Demand for Irrigated Acreage. Baltimore: Johns Hopkins Press.

Starr, C. (1971) "Energy and Power." Scientific American 224 (September 1971): 36-49.

World Almanac and Book of Facts, 1974 (1973). George E. Delury, ed. New York: Newspaper Enterprise Association, Inc.

Yellot, T.I. (1973) "Solar Energy in the Seventies." The Bent of Tau Beta Pi (Spring 1973).

CHAPTER 12

ELECTRIC POWER GENERATION

12.1 INTRODUCTION

Electric power consumption in the U.S. has grown much more rapidly than total U.S. energy consumption during the last several years, maintaining an average annual growth rate of seven percent. At this rate, electric power consumption doubles every 10 years. In 1971, electric power generation consumed 25.3 percent (or $17,500 \times 10^{12}$ Btu's) of the nation's energy. Some projections indicate that electricity production will account for 40 percent of total U.S. energy consumption by the year 2000. The energy sources used to generate electricity in 1972 are shown in Table 12-1.

A number of technical and economic problems facing the electric utility industry have made electric power generation technologies the focus of much research and debate. First, the concern with environmental quality has had a major impact because electric power plants can be large and easily identifiable polluters. For example, as discussed in the chapter on coal, environmental concerns have been responsible for the rapid shift from coal to cleaner burning fuels in electric power plants. Second, electric power generation is a relatively inefficient process (the U.S. average efficiency is around 30 percent) and thus a number of new, more efficient processes are under investigation. Third, the demand for electricity varies drastically with the time of day and season, posing a number of technical and economic problems in meeting "peak" demand. In addition, the rapid growth in demand described above has compounded these technical and economic problems.

TABLE 12-1

ENERGY SOURCES FOR 1972 U.S. ELECTRICITY GENERATION

Source	Percent of Total
Coal	44
Natural gas	21
Oil	16
Hydroelectric	16
Nuclear	3

Source: Atomic Industrial Forum, 1974.

The primary purpose of this chapter is to describe the technologies for converting solid, liquid, and gaseous fuels (chemical energy) into electrical energy. However, many of the component technologies described here also apply to other resource systems whose primary output is electrical energy. For example, the steam turbine and cooling mechanisms described in this chapter are identical to those used in nuclear power plants. Therefore, the chapter on fission refers to this chapter for descriptions of certain power plant components.

Figure 12-1 is the electric power generation flow diagram used for organizing this chapter. Five basic plant types are shown which convert the chemical energy to electrical energy: boiler-fired, gas

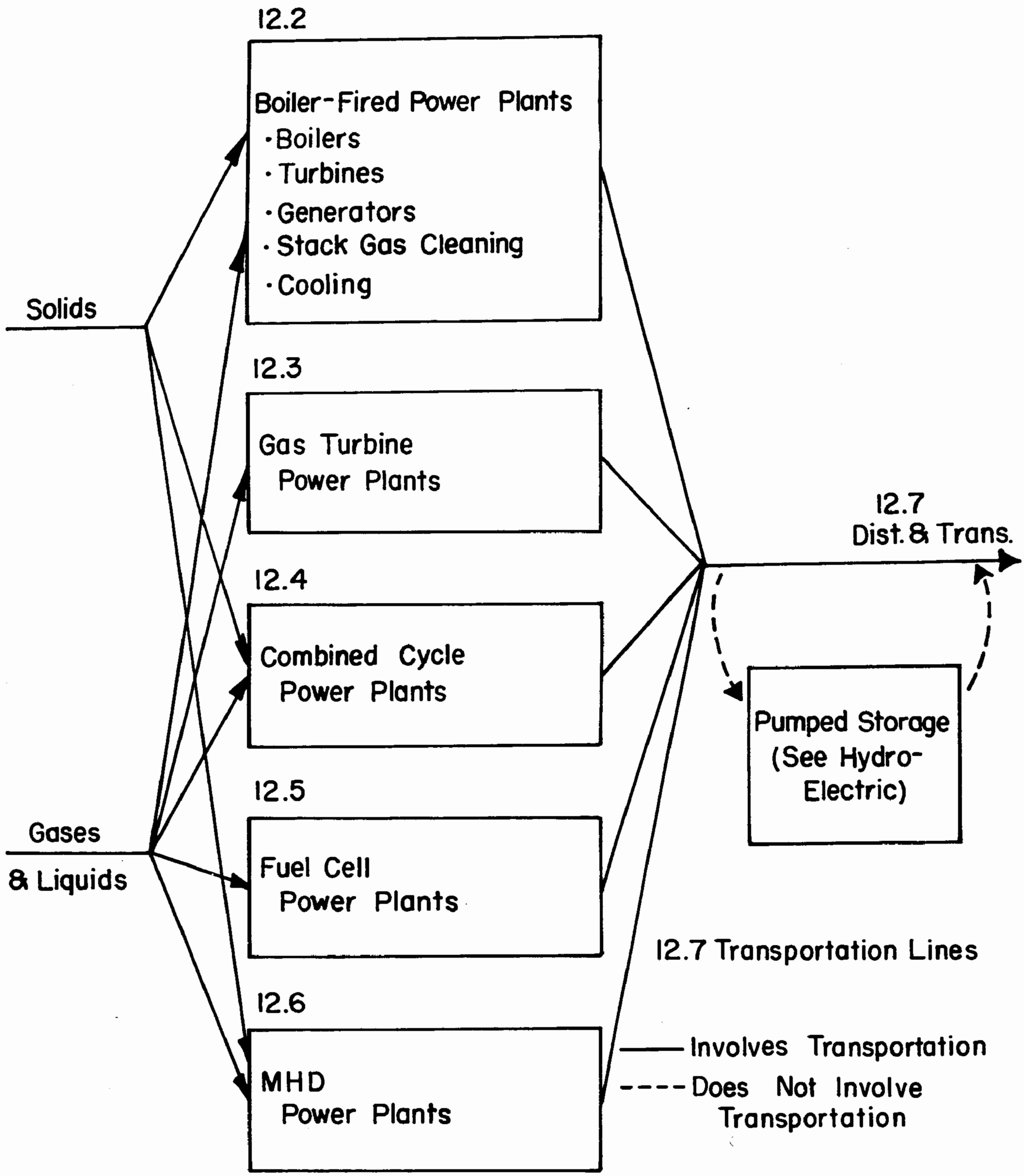


Figure 12-1. Electrical Generation System

turbine, combined cycle, fuel cell, and magnetohydrodynamic (MHD) power plants. In addition, electricity transmission and distribution is described. Pumped storage is also shown in Figure 12-1, but this component is described in Chapter 9.

As mentioned above, the demand pattern for electric power is a significant problem and, therefore, an important variable to be considered in designing a power plant. The industry identifies three types of load demands that plants must be designed to serve: base, intermediate, and peak. Base-load units are large, relatively efficient units that operate continuously at or near full capacity. Typical annual capacity factors (percent of annual output if operated continuously) are around 80 percent. Intermediate-load units are smaller, less efficient, and typically are required to shut down and start up daily as demand varies. Annual capacity factors vary from 20 to 60 percent. Peak-load units provide power for short periods of the day (when the demand for electricity is at its maximum) and generally have capacity factors of 20 percent or less.

This chapter first describes the major components identified in Figure 12-1. These descriptions include available information on efficiency, residuals, and costs. Following this description, additional sections summarize and compare environmental residuals and the economic costs of the various technological alternatives.

12.2 BOILER-FIRED POWER PLANTS

Figure 12-2 shows the various components or stages that make up a boiler-fired power plant. The unifying characteristic of boiler-fired power plants is that the electrical energy is generated by a series of three conversion stages. First, the chemical energy is converted to heat energy in the boiler and the heat is transferred to some working fluid, usually water and/or steam. Second, the heat energy of the working fluid is converted to mechanical energy by a turbine (or heat engine in thermodynamic terminology). Third, the mechanical energy is converted to electrical energy by a generator. The boiler-fired power plant may also incorporate stack gas cleaning to reduce the air pollutants created in the boiler, and it must use some cooling mechanism for disposing of waste heat. The technical description of boiler-fired power plants is organized around the five basic components shown in Figure 12-2.

A typical steam power plant consists of a "conventional" boiler, a steam turbine, a generator, and some type of cooling mechanism but normally no stack gas cleaning. These systems are currently the most important type of boiler-fired power plant, accounting for 78 percent of the nation's generating capacity. A simplified schematic of a steam power plant is given in Figure 12-3. In the boiler, heat from conventionally fueled fires (or from nuclear, solar, or geothermal sources) is transferred to water to produce high-pressure, high-temperature steam. The steam enters the turbine where it expands to a low-pressure and low-temperature and, in the process, drives the turbine which in turn drives the generator. After the thermal energy in the steam has been converted to mechanical energy, the discharged steam is reconverted to water in a condenser. The water is then pumped back into the boiler and starts the cycle over again. The heat removed in the condenser is rejected to the environment in cool bodies of water (i.e., lakes, ponds, rivers, etc.) or to the atmosphere by cooling towers.

Detailed descriptions of each of the five components are given below. Information on efficiency, environmental effects, and economic considerations for several of the alternative boiler-fired power plant configurations follows the descriptions.

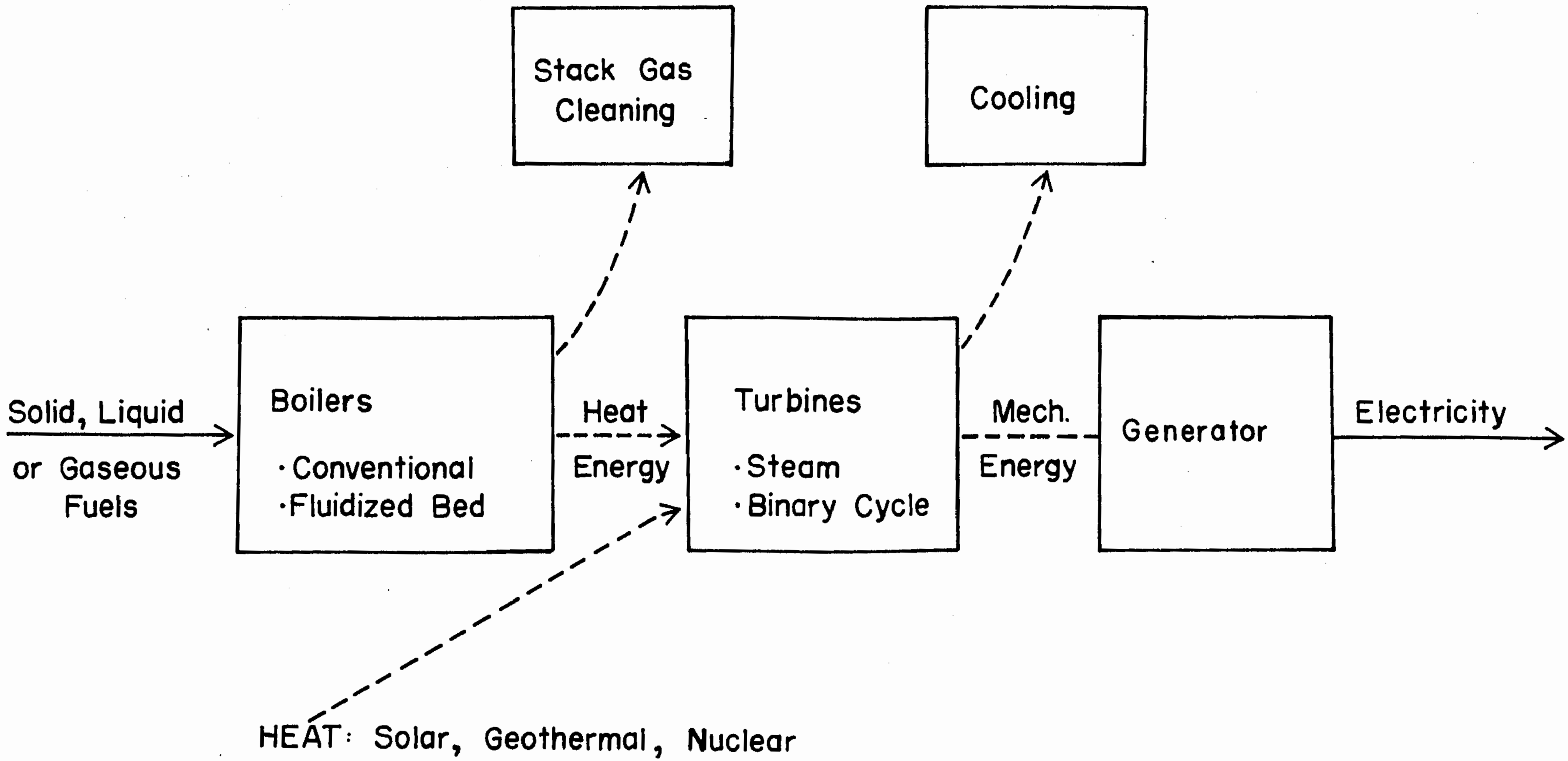


Figure 12-2. Boiler-Fired Power Plant

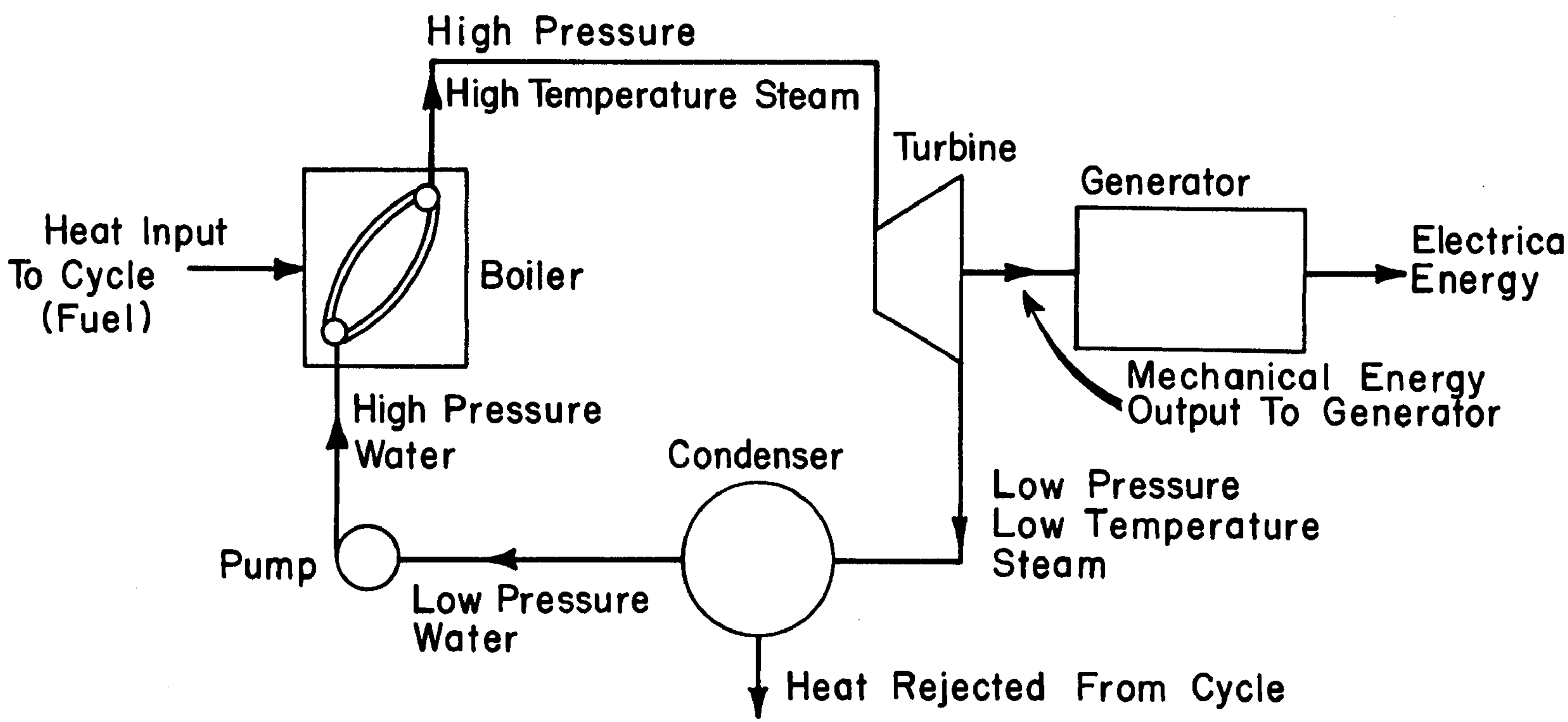


Figure 12-3. Simplified Schematic of a Steam Power Plant

Source: AEC, 1974: B.2-4.

12.2.1 Technologies

12.2.1.1 Boilers

Boilers are mechanisms that burn fuels to create heat energy which is then transferred to a fluid (normally water) to produce steam. To improve thermal efficiencies, both conventional boilers and the new fluidized bed combustors generally contain other system components such as:

1. Superheaters. A superheater is a system of tubes located at the top of the boiler in which the saturated steam is superheated by combustion gases.
2. Reheaters. A system of tubes much like the superheater, the reheater reheats partially expanded steam taken from the early stages of the turbine that is then returned to the final stages of the turbine.
3. Economizers. An economizer extracts heat from the flue gases (after the superheater) and transfers it to the boiler feedwater.
4. Air preheaters. An air preheater extracts additional heat from the flue gases (after the economizer) and transfers it to the combustion air before it is fed into the furnace.

In addition to these components, a boiler normally consists of steam separators, fans, pumps, fuel handling equipment, and combustion by-product handling equipment.

Because the boiler encompasses the fuel combustion operation, it produces most of the potentially adverse environmental residuals associated with electric power generation.

This section deals with both conventional type boilers and fluidized bed combustors.

12.2.1.1.1 Conventional Boilers

Conventional boilers are extremely large and complex pieces of equipment; some steam power plant boilers are 10 or more stories tall. Figure 12-4 is a somewhat simplified boiler design showing the air and flue gas circulation patterns.

A number of variables affect conventional boiler design, a primary one being the type of fuel to be burned. Oil and gas are both blown with the combustion air into the combustion chamber through orifices. Coal is generally pulverized to a very fine powder (approximately 200 mesh) and then blown into the furnace in much the same manner as oil and gas. However, additional problems that must be dealt with when coal is burned include fly ash and slagging.

The firing mechanism and techniques are other important conventional boiler design variables that affect the combustion pattern and temperature control. In some cases the burners are directed vertically downward, an option used primarily with solid fuels. In others, the burners are fired horizontally, in opposition, or tangentially along the walls of the furnace. In a frequently used technique, staged firing, 90 to 95 percent of the air enters the boiler as primary and secondary air with the fuel before combustion, and the remainder enters as tertiary air through auxiliary ports in the furnace. Because of imperfect mixing, approximately 20 percent more air (termed 120-percent excess air) must be injected into the combustion chamber than is theoretically required for complete combustion.

A significant advance in coal firing technology, known as the cyclone furnace, has developed over the past 35 years. In cyclone furnace operation, crushed coal (approximately 4 mesh) enters a horizontal cylinder at one end while air is injected (at high velocities) tangentially along the cylinder periphery, resulting in a cyclonic burning pattern. The advantages of this type of furnace are (Babcock and Wilcox, 1972: 10-1):

1. Reduction of fly ash content in flue gas.
2. Savings in fuel preparation, since only crushing is required instead of pulverizing.
3. Reduction in furnace size.

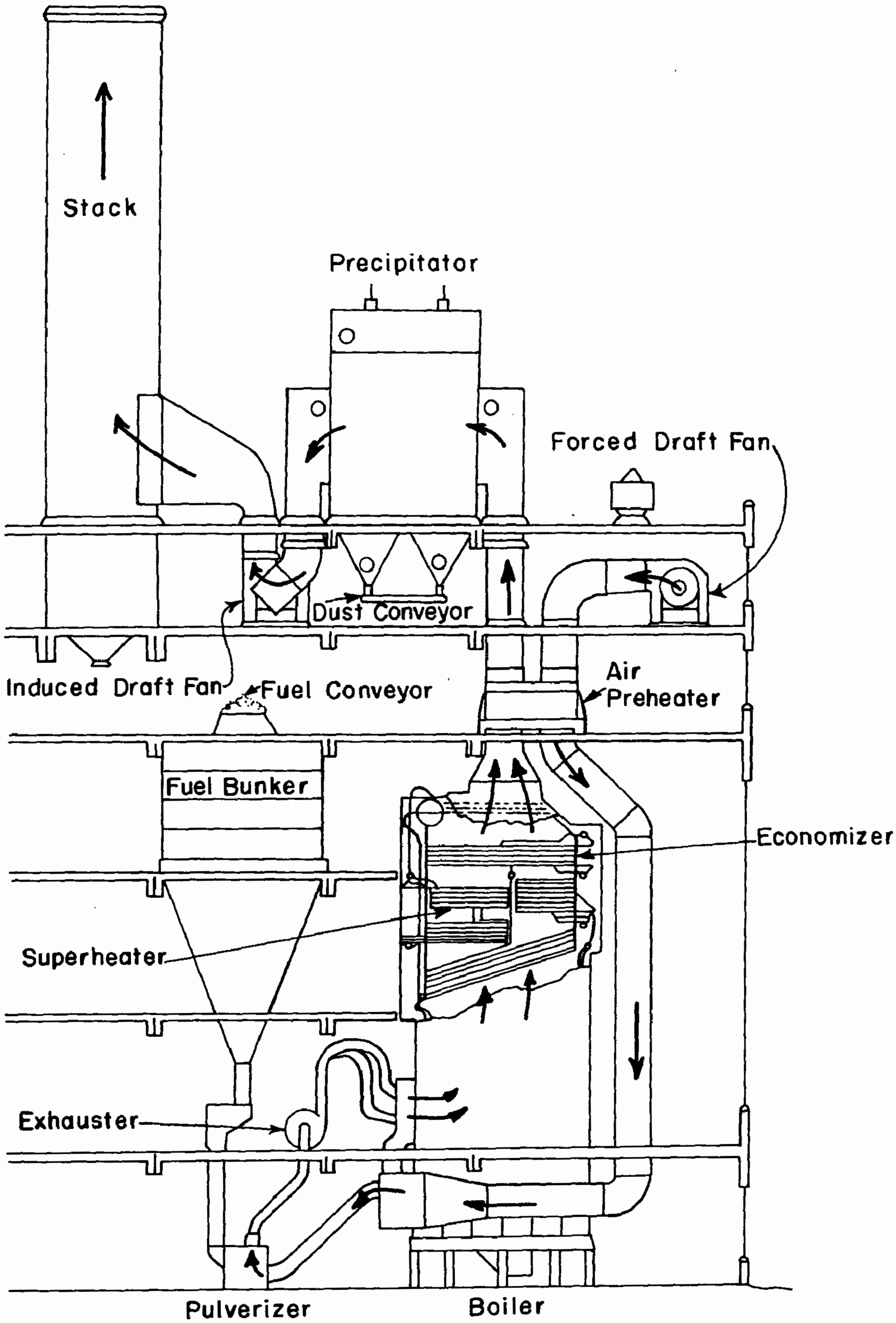


Figure 12-4. Boiler Air and Flue Gas Circulation Patterns

Source: Shields, 1961: 209.

Three major factors determine the amount and character of the air pollutants generated by a boiler: fuel burned, boiler design, and boiler operating conditions. Sulfur oxides (SO_x) emissions are directly relatable to the sulfur content of the fuel, and there is little in the way of conventional boiler design or operation that can affect this residual. Sulfur oxides must be dealt with either before or after burning. The stack gas cleaning approach will be discussed later.

Nitrogen oxides (NO_x) emissions can be significantly affected by boiler design and operating conditions, but the process of NO_x creation during combustion is not completely understood. The major factor affecting the creation of NO_x is temperature. One study indicates that the most important variables for fossil-fueled boilers in controlling NO_x emissions are staged firing, low excess air (less than 110 percent of the actual requirement for complete combustion), and flue gas recirculation (Bartok and others, 1972: 66). This study indicated the potential for similar methods to be applied for coal, but the emission of NO_x from coal-fired boilers is the least explored and the most difficult problem area of all the NO_x emission sources (Bartok and others, 1972: 72).

Particulate emissions are a major problem with coal-fired boilers and somewhat of a problem with certain fuel oils. Improved boiler design can reduce the particulate emissions. The primary advance in this area is the cyclone furnace described earlier, which can reduce fly ash by 50 percent over pulverized units.

12.2.1.1.2 Fluidized Bed Boilers

The desire to reduce pollutants as well as to improve boiler efficiency has led to increased work on fluidized bed boilers. Such boilers are not commercially available at present, but their proponents believe they hold great promise as substitutes for conventional steam boilers.

A fluidized bed boiler involves passing air upward through a grid plate supporting a thick (several feet) bed of granular, noncombustible material such as coal ash or lime. The air fluidizes the granular particulates and, with the relatively small amount of air used to inject the fuel (usually coal but possibly residual oil), serves as the combustion air (AEC, 1974: Vol. IV, p. A.2-17). The heat transfer surfaces or boiler tubes can be embedded in the fluidized bed directly because combustion takes place at temperatures (approximately 1,500°F) that will not damage the tubes.

The fluidized bed boiler has two basic advantages: the ability to burn high-sulfur coal with low sulfur dioxide (SO_2), particulate, and, to some extent, NO_x emissions; and high heat release and heat transfer coefficients that can drastically reduce boiler size, weight, and cost. This means that fluidized bed boilers can be built as factory-assembled, packaged units, shipped to sites, and arrayed as required. These factors will considerably reduce construction times for new power plants (Hittman, 1975: Vol. II, p. VI-1).

There are several fluidized bed concepts at various stages of development. In this section we will describe one of the processes treated in the Hittman study: the Pope, Evans, and Robbins Atmospheric Pressure Fluidized Bed Boiler. Another fluidized bed system treated in the Hittman study that combines gas and steam turbines will be treated in Section 12.4.

The Pope, Evans, and Robbins Atmospheric Pressure Fluidized Bed Boiler, being developed for the Office of Coal Research (OCR), is designed as a replacement for conventional boilers. This system is illustrated in Figure 12-5 The system uses repeating elements or cells to

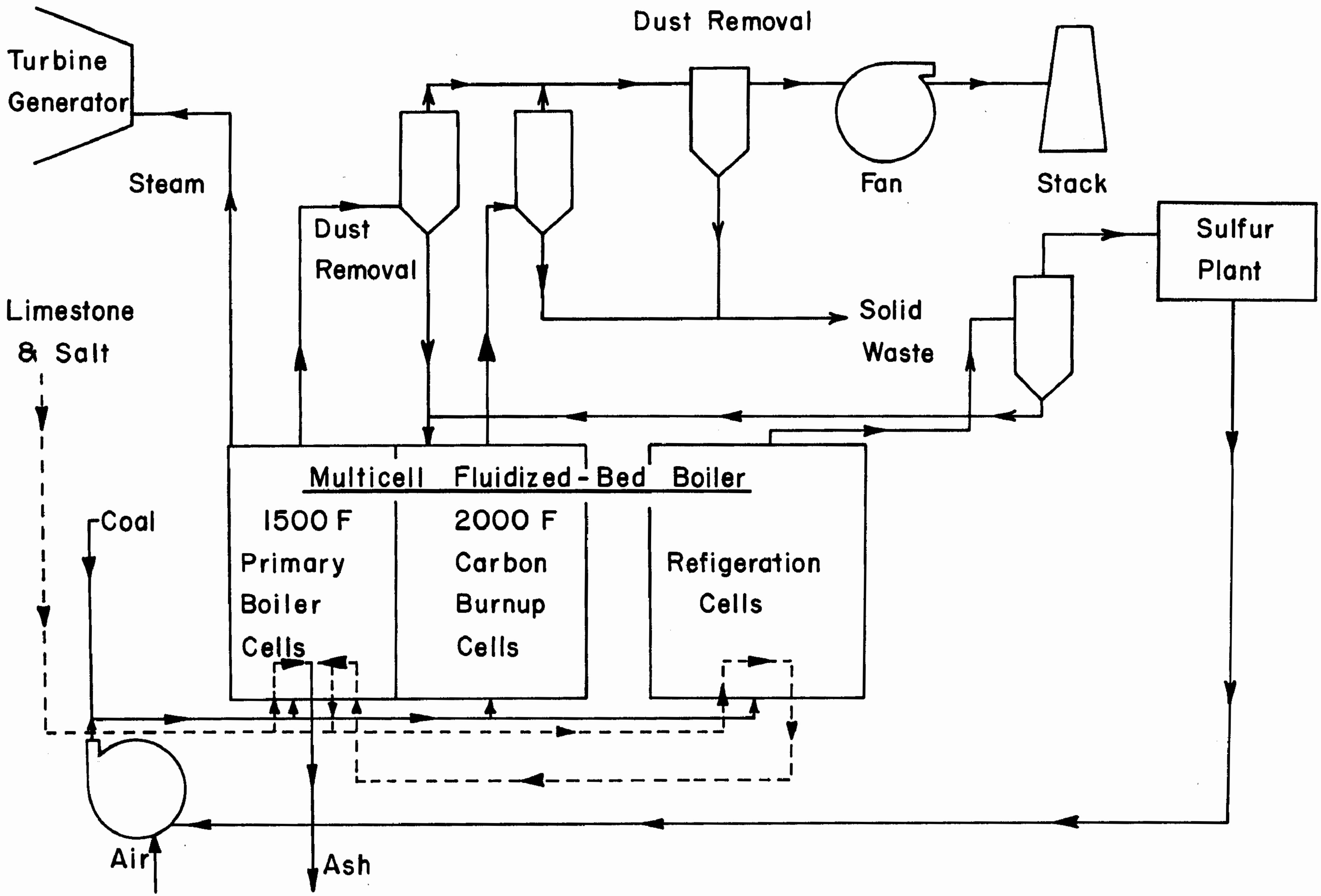


Figure 12-5. Pope, Evans, and Robbins Fluidized Bed Boiler Power Plant

Source: Hittman, 1975: Vol. II, p. VI-4.

make any size boiler desired. The cell concept reduces the scale-up problems that have been plaguing the industry. Each cell produces enough steam for a 30-megawatt-electric (Mwe) generator. A prototype cell is being installed at an existing power plant and is scheduled to go into operation by mid-1975 (Papamarcos, 1974: 39).

12.2.1.2 Turbines

The purpose of the turbines is to convert the heat energy created by the boiler into mechanical energy. Two types of turbine systems are described, the steam turbine and the binary cycle system.

12.2.1.2.1 Steam Turbines

In a steam turbine, high-temperature, high-pressure steam expands to a low-temperature and low-pressure, exerting force against the turbine blades in the process. The force on the turbine blades turns the turbine shaft which is connected directly to the generator shaft.

Steam turbine technology is well developed, and many feel that there are not likely to be any major improvements in their design. Advanced blade technology, seals, and moisture removal techniques--as well as lower-cost, high-temperature alloys--are areas receiving attention.

The steam turbine represents the most inefficient component in the electric power generation process. In thermodynamic terminology, the turbine is a heat engine (i.e., it converts thermal energy to mechanical energy) and as such is limited by the Carnot cycle efficiency. Carnot efficiency is a theoretical maximum, not achievable in practice, that is used for comparisons. It is directly a function of the temperature difference between the high- and low-temperature ends of the cycle; a typical steam turbine operating between a maximum temperature of 1,000^{o}F and a minimum temperature of 70^{o}F would have a theoretical maximum efficiency of 64 percent. In actual practice, however, steam turbines operating under these conditions only achieve efficiencies on the order of 50 percent. Attempts to obtain greater efficiencies by using higher steam temperatures and pressures are currently constrained by metallurgical limits.

12.2.1.2.2 Binary Cycle Systems

As indicated in the previous discussion, the primary disadvantage of steam turbines is their low efficiency. To improve efficiency, two or more heat engine cycles covering different parts of the temperature range can be combined. This combination is commonly referred to as a binary cycle. When the second cycle is added to the high-temperature end, it is referred to as a topping cycle; a second cycle added to the low-temperature end is termed a bottoming or tailing cycle.

In this section, two possible liquid-metal topping cycles will be described. Gas turbine/steam turbine systems--the so-called "combined cycle"--can also be classified as a topping cycle, but this will be covered in a separate section. A steam-ammonia bottoming cycle has been proposed, but many feel its advantages over the single cycle system are marginal (AEC, 1974: Vol. IV, p. B.5-1) and it will not be discussed here.

The principal advantage of using one of the "liquid metals" as the working substance in power plants is their high boiling or vaporizing temperatures at relatively low pressures. While water boils at 662^{o}F at 2,400 pounds per square inch absolute (psi-absolute), mercury boils at 907^{o}F at 100 psi-absolute and potassium boils at 1,400^{o}F at 14.7 psi-absolute (one atmosphere). The efficiency of the liquid-metal Rankine cycle by itself is not high, but with the binary cycle the condenser for the liquid metal serves as the boiler for the water, and the overall efficiency is relatively high (AEC, 1974: Vol. IV, p. B.5-2).

Between 1922 and 1950, the General Electric Company constructed a series of six fossil-fueled mercury and steam binary cycle power plants. These mercury plants demonstrated the practical feasibility of the mercury topping cycle. However, no mercury topping cycles were built after 1950 because of the improved efficiency and economies of scale of the conventional steam power plant and the price fluctuations of mercury which increased the economic risk of such plants (AEC, 1974: Vol. IV, p. B.5-4).

A potassium topping cycle has not been used in utility power plants, but possible use has been studied since the early 1960's. The potassium cycle has potential for use above about 1,400°F and thus would be considered primarily for use with fossil-fueled heat sources, although it could possibly be used in conjunction with a nuclear high temperature gas reactor (HTGR). The mercury topping cycle will require a heat source in the range of 900 to 1,300°F and thus could also be used in conjunction with the liquid metal fast breeder reactor (LMFBR), which is expected to have a sodium outlet temperature of 1,100°F. This would have the advantage of eliminating sodium-water interfaces (AEC, 1974: Vol. IV, p. B.5-6).

There do not appear to be any unsolvable technical difficulties associated with bringing binary cycle concepts to fruition, but it is unlikely they would have any significant impact on the U.S. energy picture before 1985. The primary R&D effort needed is in the area of design and testing of scaled-up key components. The Oak Ridge National Laboratory, under a grant from the National Science Foundation (NSF), has begun the construction of a small potassium boiler (AEC, 1974: Vol. IV, p. B.5-11).

12.2.1.3 Generators

The mechanical energy from the turbine is converted to electrical energy by the generator. An electrical generator relies on a basic phenomenon in electromagnetics; namely, when an electrical conductor is moved properly through a magnetic field, a voltage will develop along the conductor. The only type of alternating current (AC) generator presently used in large power plants is the synchronous type, whereby the speed of the rotor is related to the frequency of the current produced. In the large synchronous generators, the conductor is stationary while the magnetic field is rotated.

The state of the art of synchronous generators is well developed with efficiencies for the central station size ranging from 96 to 99 percent depending on the size and load.

12.2.1.4 Stack Gas Cleaning

Stack gas cleaning has been receiving considerable attention as a means of reducing air pollutants from boilers. Some stack gas cleaning processes, such as those for collecting sulfur dioxides and particulates, are commercially available at present, but this is a developing technology. The major problems with the processes are not technical but economic.

Stack gas cleaning processes vary depending on which of the three major air pollutants (oxides of nitrogen, sulfur dioxide, or particulates) they are designed to remove.

12.2.1.4.1 Oxides of Nitrogen

Oxides of nitrogen (NO_x) are now treated by modification of the combustion process as indicated in Section 12.2.1.1, Boilers. Nitrogen oxide "catalytic scrubbers" for boiler stacks have been proposed, but the scrubbers are much more expensive than combustor modification treatment.

12.2.1.4.2 Sulfur Dioxide

Sulfur dioxide (SO_2) residuals have been the major air pollution concern associated with electric power generation and the most difficult to control. Although more than 50 individual processes for removing SO_2 from stack gases have been identified (Battelle, 1973: 394), the most effective appear to be "scrubbing" processes in which the stack gas is passed over or through a material that reacts with SO_2 to form a compound. The resultant compound is then either dumped (so-called "throwaway" methods) or treated so that some useful form of the sulfur may be recovered. The throwaway methods convert an air pollution problem to a solid waste problem, while the recovery methods involve costly production of a surplus material.

The basic problem of stack gas desulfurization is that of continuously removing most of a small concentration of sulfur dioxide from very large volumes of stack gas (AEC, 1974: Vol. IV, p. A.2-24). None of the sulfur dioxide stack gas systems is yet in routine full-scale operation on large boilers burning high-sulfur coal.

Lime and limestone throwaway processes are currently favored by the electric utility industry as the best solution to SO_2 emissions (Slack and others, 1972). Their advantages are relative simplicity, relatively low investment, and freedom from the problems of marketing and making a by-product. There are three principle forms of this system, as illustrated in Figure 12-6 (Slack and others, 1972):

1. Introduction of limestone directly into the scrubber. This is the simplest route and seems to be the one favored by the power industry at present. The main drawback is that limestone is not as reactive as lime, which makes it necessary to use more limestone, install a larger scrubber, recirculate more slurry, grind the limestone finer, or otherwise offset the lower reactivity.
2. Introduction of lime into the scrubber. Scrubbing efficiency can be improved by first calcining the limestone to lime (CaO) and introducing the lime into the scrubber. However, the cost is increased greatly over that for limestone slurry scrubbing, since a lime kiln installation is expensive to build and operate. Use of lime also increases the problem of deposit formation in the scrubber (scaling).
3. Introduction of limestone into the boiler. The cost of calcination can be reduced in power plants by injecting the limestone into a boiler furnace. The gas then carries the lime into the scrubber. Problems include possibility of boiler fouling, danger of overburning and inactivating the lime, and increased scaling in the scrubber when the lime enters with the gas.

A summary of some of the main processes under consideration and their technological status as of mid-1973 are listed in Table 12-2. Some process engineers anticipate that present difficulties will be overcome by continued development and that successful regenerative units will be installed on perhaps three-fourths of the coal-fired power plants by 1980 (AEC, 1974: Vol. IV, p. A.2-27).

12.2.1.4.3 Particulates

Removing particulates from the gases can be accomplished mechanically, electrostatically, or, to a limited extent, as part of the SO_2 removal. Mechanical separation takes place in a cyclone where the flue gases are rotated at high speed to throw the higher-mass particulates against the outside walls where they are separated. The dust may be collected using water (irrigated cyclone) or simply fall into a hopper (dry cyclone). Depending on size and type, mechanical separators vary in efficiency from 65 to 94 percent (Nonhebel, 1964: 514).

Electrostatic precipitators impose a very high electric field on a series of wires and tubes (or wires and plates) so that a low-current electric discharge occurs between them. If the particulates to be removed can be ionized, they will respond to this field and be drawn to the

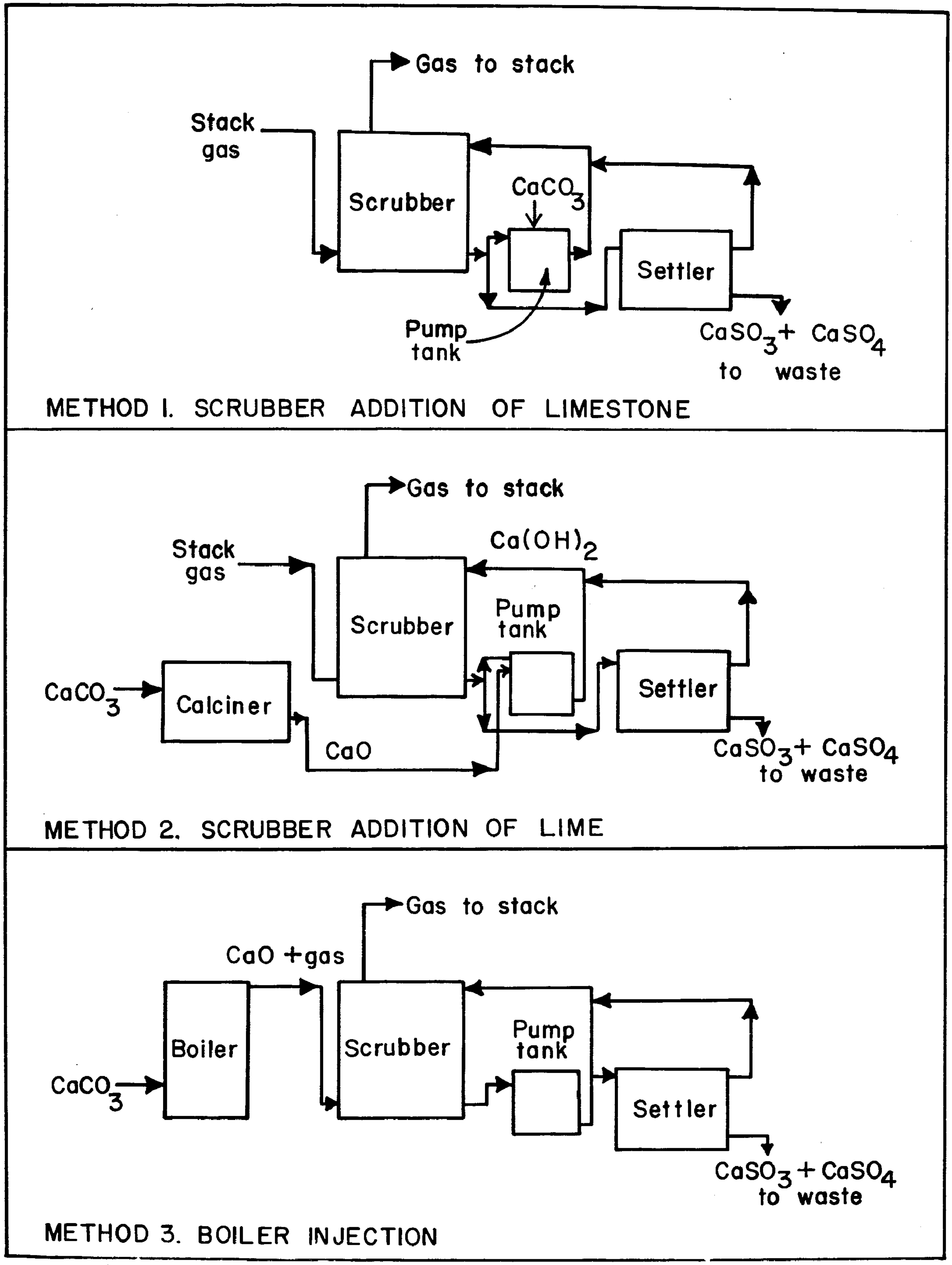


Figure 12-6. Lime and Limestone Stack Gas Scrubbing Methods

Source: Slack, Falkenberry, and Harrington 1972: 160.

Table 12-2. Technological Status of Some Stack-Gas Sulfur Dioxide-Removal Processes

Process	Major U.S. engineering participants	Status of demonstration plants: U.S. plants operating on coal of greater than two percent sulfur	Status of demonstration plants: Other plants, U.S. and foreign, operating on oil or low-sulfur coal	Status of process chemistry	Major technological problem areas
Magnesium oxide wet scrubbing	Chemico	100-Mw unit near startup	Two 150-Mw units in operation; U.S. on oil, Japan with throwaway cycle	No major uncertainties	Ash removal requirements
Sodium solution scrubbing	Wellman-Lord	125-Mw unit under construction	250-Mw unit near startup for coal of one percent sulfur. Smaller units of several types operating without difficulty	Additives required to minimize oxidation to Na_2SO_4	Sulfate formation requires waste bleed and caustic makeup
Catalytic oxidation	Monsanto	100-Mw unit completed in 1972 but not yet in operation	Small units for process development only	Apparently no problems	Ash removal requirements; high operating temperatures; catalyst attrition; low H_2SO_4 quality
Limestone into boiler with wet scrubbing	Combustion Engineering	Shut down as a result of continuing operating difficulties	No additional plants; scheduled units have been canceled	Complex $CaSO_4$ scaling difficult to control	Severe boiler operating problems; poor limestone utilization; severe scaling, demister plugging
Wet scrubbing with lime slurry feed	Combustion Engineering CHEMICO	Several near startup	Successful operation of 150-Mw unit in Japan on coal of two percent sulfur; other plants operating	Complex $CaSO_4$ scaling difficult to control	Severe scaling, demister plugging
Wet scrubbing with limestone slurry feed	Babcock and Wilcox, Combustion Engineering TVA	175-Mw unit completed in 1972; has not yet met acceptance tests; many others of greater than 100-Mw under construction	Small scale development units only	Complex, not completely understood; blinding of limestone surface a problem	Demister plugging; poor dependability; low limestone utilization; waste sludge disposal

Source: AEC, 1974: Vol. IV, p. A.2-26.

tubes. Waste disposal is usually accomplished by rapping the tubes and collecting the dust. The performance of a precipitator depends strongly on the amount of sulfur in the dust. For example, if a unit is designed for 95-percent efficiency using 5-percent sulfur coal, it will operate at only 70-percent efficiency with the 0.59-percent sulfur coal. Also, the efficiency of electrostatic precipitators are highly dependent on the stack gas temperature. A system giving 92-percent efficiency at 310^{O}F may only give 55-percent efficiency at 270^{O}F (Soo, 1972: 191). Most electrostatic precipitators are designed to have removal efficiencies of between 92 and 99 percent.

12.2.1.5 Cooling

Selecting a suitable means of dissipating waste heat depends on a number of factors such as the quantity of heat to be dissipated, the availability of water, and local thermal pollution regulations. The four types of cooling systems are:

1. Once-through cooling using fresh or saline water.
2. Cooling ponds.
3. Wet cooling towers.
4. Dry cooling towers.

In once-through systems, water is withdrawn from some source, circulated through the condenser where it is heated, and then returned to the source. Once-through cooling systems are generally used where adequate supplies of water are available and no significant adverse effects on water quality are expected. Sources of water include rivers, lakes, estuaries, and the ocean. Once-through systems are normally more economical than other systems. The only consumptive water uses are those resulting from increased evaporation in the source water bodies because of the addition of heat (Jimeson and Adkins, 1971a).

Where water supplies are limited and suitable sites are available, cooling ponds may be constructed so that water may be recirculated between the condenser and the pond. Sufficient inflow would be needed, either from upstream runoff or by diversion from another stream, to replace the natural evaporation and the evaporation induced by the addition of heat to the pond. A pond surface area of one to two acres per megawatt of plant capacity is normally required to dissipate the heat. Cooling ponds are frequently used for other beneficial purposes, including recreation (Jimeson and Adkins, 1971a).

Where conditions are not favorable for once-through cooling or for the construction of cooling ponds, cooling towers are generally employed for the dissipation of waste heat. Cooling towers may be used to provide full or partial cooling requirements during certain periods or throughout the year.

In wet cooling towers, the warm water is brought in direct contact with a flow of air, and the heat is dissipated principally by evaporation. Cooling towers may be either of natural- or mechanical-draft design. Because of the large structures involved and the added pumping and other costs, wet cooling towers are usually more expensive than once-through systems or cooling ponds (Jimeson and Adkins, 1971a).

Currently, the maximum size of a wet cooling tower employing a natural draft is about 400 feet in diameter and 450 feet high. A tower of this size can provide the cooling requirements for a 500-Mwe nuclear plant or an 800-Mwe fossil-fired plant. Wet cooling towers using mechanical draft are constructed in multiple cells and a plant may contain one or more banks of cells. Forced-draft type fan diameters are limited to 12 feet or less, compared to nearly 60 feet for the induced draft type, which necessitates more cells for a given capacity (Jimeson and Adkins, 1971a).

TABLE 12-3

COOLING WATER REQUIREMENTS FOR 1,000-Mwe PLANT
(ACRE-FEET PER YEAR)

Cooling Method and Plant Type (percent efficiency)	Intake	Consumed (evaporated)	Discharged
Once-through			
Nuclear (32)	1,558,000	0	1,558,000
Coal (38)	925,900	0	925,900
Wet cooling tower			
Nuclear (32)	31,020	19,390	11,630
Coal (38)	18,440	11,520	6,920
Cooling pond			
Nuclear (32)	47,650	28,600	19,050
Coal (38)	28,300	17,000	11,300
Dry cooling[a]			
Nuclear (29.2)	311	0	311
Coal (36.5)	248	0	248

Source: Teknekron, 1973: Chapter 6.

[a]Small quantity of makeup water for circulation.

In a dry cooling tower, the water circulates in a closed system with the cooling provided by a flow of air created either by mechanical or natural draft. This system is much like the radiator in an automobile, and no water is lost by evaporation. Because of the large heat transfer surface area and air volumes required, however, dry cooling towers are substantially more expensive than wet towers. There are no large dry cooling towers at power plants in this country. Recently, a dry cooling tower for a 20-Mwe plant was constructed in Wyoming (Jimeson and Adkins, 1971a).

The amount of water "consumed" by the cooling process will depend on the specific plant design and the affected water-body conditions. Table 12-3 gives the cooling water requirements (intake) and the cooling water consumed (evaporated) for the four cooling types, using both a 32-percent efficient nuclear plant and a 38-percent efficient fossil-fired plant operating at 100-percent load factors (Teknekron, 1973: Chapter 6). The data show that once-through systems require large amounts of water but that none is consumed. Cooling ponds require more intake water and consume more water than do wet cooling towers. However, these data do not agree with another source that indicates wet cooling towers consume 75 percent more water than cooling ponds (Jimeson and Adkins, 1971a).

12.2.2 Energy Efficiencies

The efficiency of any power plant is the amount of electrical energy output per unit of fuel energy input. Modern steam power plants in the 1,000-Mwe size range are capable of efficiencies of approximately 38 to 40 percent. This overall efficiency is the product of the efficiencies of the boiler, turbine, and generator. Typical efficiencies for these components are 85 percent (both conventional and fluidized bed), 50 percent, and 97 percent respectively.

In the boiler, energy is lost through heat in the stack gas, unburned combustibles, radiation and convection from boiler walls, and loss due to hydrogen and moisture in the fuel. Most of these individual losses are small and probably unavoidable. Stack gas temperatures represent the primary loss, but most of the heat energy is removed by the series of superheaters, reheaters, economizers, and air preheaters. Attempts at capturing the remaining heat energy in the stack gas would probably not be economical and, if the stack gases were too cool, they would settle back to earth near the plant rather than being dispersed in the atmosphere.

The conversion of heat energy to mechanical energy performed by the turbine represents the most inefficient component in the electric power generation process. However, the laws of thermodynamics eliminate the possibility for significant improvements. The entire purpose of binary cycle systems is to increase the efficiency of this heat energy-to-mechanical energy conversion step. If the mercury binary cycle is used in conjunction with the LMFBR, net plant efficiencies up to 46 percent might be achieved, as compared to potential LMFBR single-cycle efficiencies of about 42 percent (AEC, 1974: Vol. IV, p. B.5-7).

If the potassium binary cycle is used in a boiler-fired plant, the net plant efficiency is estimated to be 50 to 55 percent or more over a turbine inlet temperature range of 1,400 to 1,800°F (AEC, 1974: Vol. IV, p. B.5-7). This compares with 38 to 40 percent for a plant using a single-steam turbine.

There is little likelihood that the generator efficiency of 96 to 99 percent can be improved.

The type of cooling system used has only a slight effect on overall plant efficiency. The dry cooling system is the most energy consumptive cooling system, requiring approximately 10 percent of the net plant output.

No firm data have been found on the energy required to run stack gas cleaning processes, but a Battelle study "assumed" an overall plant efficiency reduction of two percent (from 37 percent to 35 percent) when various SO_2 scrubbing technologies are applied (Battelle, 1973: 93). The Hittman study listed the efficiencies for "controlled" plants (i.e., those employing stack gas cleaning along with other environmental controls) as 38 percent, which is the same as the efficiency for their "uncontrolled" plants (Hittman, 1974: Vol. I, Table 26).

Improving the efficiency of electric power generation is the focus of major research efforts at the current time, and many of the alternatives described in the following sections are aimed entirely at increasing this efficiency. Improved efficiencies can have a beneficial impact on operating costs (reduced fuel bills), but the primary interest is in conserving limited fossil fuel resources and reducing the environmental impacts of electrical generation. To illustrate the effect, if the efficiency of conversion can be increased from 30 to 40 percent, the chemical pollutants emitted per unit of electricity output will decrease by 25 percent. For thermal pollution, an increase in efficiency from 30 to 40 percent will decrease waste heat by approximately 36 percent.

12.2.3 Environmental Considerations

Table 12-4 lists the residuals for several different boiler-fired power plants burning different fuels. In this table, lines one through three are for a conventional steam power plant with no controls burning coal, oil, and gas, respectively. These data should be considered to have a probable error of less than 50 percent. The coal line assumes a pulverized-feed

Table 12-4. Residuals for Boiler-Fired Power Plants

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)							F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (Tons/10^{12} Btu's)	Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
1 COAL																					
Conventional Steam No controls[b]	25.7	U	U	U	5.81	6.84	2.71	U	U	5.26 x10^{11}	82.2	369.	2020.	6.15	20.5	.103	5050.	8.49/U 8.49	.001	.0106	4.41
2 OIL																					
Conventional Steam No controls[b]	U	U	U	U	7.44	.709	.015	U	U	5.26 x10^{11}	27.2	357.	801.	6.81	.138	3.40	0	2.48/U 2.48	.0006	.06	2.5
3 GAS																					
Conventional Steam No controls[b]	U	U	U	U	7.44	.709	.016	U	U	5.26 x10^{11}	7.34	191.	.293	19.6	.190	3.43	0	1.42/U 1.42	.0006	.057	2.36
4 CENTRAL COAL																					
Atmospheric Fluidized Bed Controlled[b]	0	0	U	U	18.2	0	.003	U	U	0	11.3	70.	378.	242.	2.5	0	6990.	1.62/.18 4.28	U	U	U
5 NORTHERN APPALACHIAN COAL																					
Atmospheric Fluidized Bed Controlled[b]	0	0	U	U	18.2	0	.003	U	U	0	8.52	70.	167.	242.	2.5	0	5880.	1.62/.14 3.82	U	U	U
6 NORTHWEST COAL																					
Atmospheric Fluidized Bed Controlled[b]	0	0	U	U	18.2	0	.003	U	U	0	5.31	70.	56.8	242.	2.5	0	3990.	1.62/.1 3.10	U	U	U

10^4 Btu / Kwh

Table 12-4. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	F/I[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
7 EASTERN COAL																					
Conventional Boiler with wet limestone scrubbing[c]	0	NC	NC	NC	0	12.5	5.5	NC	NC	0	50.	300.	250.	6.5	21.	NC	1.49 x10^4	12.5/U 12.5	.0003	.014	5.1
8 EASTERN COAL																					
Conventional Boiler with Mgo scrubbing[c]	0	NC	NC	NC	0	12.5	5.5	NC	NC	0	50.	300.	250.	6.5	21.	NC	6400.	12.5/U 12.5	.0003	.014	5.1
9 WESTERN COAL																					
Conventional Boiler with wet limestone scrubbing[c]	0	NC	NC	NC	0	12.5	5.5	NC	NC	0	35.	390.	80.	8.	27.	NC	7600.	12.5/U 12.5	.0003	.014	5.1
10 PHYSICALLY CLEANED EASTERN COAL																					
Conventional Boiler with limestone scrubbing[c]	0	NC	NC	NC	0	12.5	5.5	NC	NC	0	22.	275.	100.	5.5	19.	NC	6500.	12.5/U 12.5	.0003	.014	5.1
11 COAL																					
Steam Plant with controls[b]	0	0	U	U	18.2	0	.003	U	U	0	20.6	369.	202.	6.15	20.5	.103	1.46 x10^4	6.9/.2 11.5	.0002	.024	2.6

Table 12-4. (Continued)

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	$^F/_I$ [a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
12 LOW-BTU GAS																					
(Central Coal, BuMines-Atmospheric) Boiler Plant with controls[b]	0	0	U	U	3.4	0	.003	U	U	0	125.	56.9	269.	0	0	0	0	.5/0 .5	.0002	.0188	2.08
13 LOW-BTU GAS																					
(Northern Appalachian Coal, BuMines-Atmospheric) Boiler Plant with controls[b]	0	0	U	U	3.4	0	.003	U	U	0	115.	6.63	488.	0	0	0	0	.48/0 .48	.0002	.0188	2.08
14 LOW-BTU GAS																					
(Northwest Coal BuMines-Atmospheric) Boiler Plant with controls[b]	0	0	U	U	3.4	0	.003	U	U	0	216.	7.76	15.6	0	0	0	0	.42/0 .42	.0002	.0188	2.08
15 RESIDUAL FUEL OIL																					
Steam Power Plant[d]	1.17	NC	.6	NC	66.	5.76	.94	.034	NC	NC	21.1	351.	531.	6.7	.13	3.3	110.	4.66/U U	U	U	U
16 NATURAL GAS																					
Steam Power Plant[d]	1.15	NC	.5	NC	71.	6.95	.925	.033	NC	NC	7.13	185.	.286	21.	NC	1.42	NC	4.66/U U	U	U	U
17 BITUMINOUS COAL																					
Steam Power Plant[d]	1.16	NC	.58	NC	71.	7.	.93	.034	NC	NC	NC	383.	808.	6.36	21.3	.1	5055.	17.8/U U	U	U	U
18 LOW-BTU GAS																					
Steam Power Plant[d]	1.16	NC	.58	NC	65.	7.	.92	.034	NC	NC	NC	168.	9.18	NC	NC	NC	NC	4.24/U U	U	U	U

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement (Acre - year / 10^{12} Btu's) / Incremental Land Impact (Acres / 10^{12} Btu's).

[b]Hittman, 1974, 1975: Tables 4 and 26.

[c]Battelle, 1973: Tables A-13, A-14.

[d]Teknekron, 1973: Figures 3.1, 4.1, 5.1, and 7.1.

furnace burning coal with an ash content of 12.53 percent and a sulfur content of 2.59 percent. The oil line assumes a 1.5-percent sulfur oil. The thermal pollution for these plants is equal, because all have the same conversion efficiencies. The primary chemical pollutants are: particulates, NO_x, SO_2, and solid wastes for coal; NO_x and SO_2 for oil; and NO_x only for gas.

In Table 12-4, lines four through six are for the Pope, Evans, and Robbins Atmospheric Pressure Fluidized-Bed power plant burning three different types of coal: a high-sulfur Central Region coal, a medium-sulfur Northern Appalachian coal, and a low-sulfur Northwestern coal. The air and solid residuals have a probable error of less than 25 percent, while the water residuals have a probable error of less than 100 percent.

Lines 7 through 11 in Table 12-4 give the residuals for steam power plants employing various stack gas scrubbing technologies in combination with different fuel types. Lines 7 through 10 are samples of data from the Battelle study. The two processes considered are throwaway wet limestone scrubbing and magnesium oxide (M_gO) scrubbing with recovery of sulfuric acid (H_2SO_4). Both processes include particulate removal. These data are based on removal efficiencies of 90 percent for SO_2, 20 percent for NO_x, and 99 percent for particulates. The Eastern coal is assumed to be 3.0-percent sulfur and 14.4-percent ash. The Western coal is 0.8-percent sulfur and 8.4-percent ash. The physically cleaned Eastern coal is 1.4-percent sulfur and 7.2-percent ash. Line 11 is from the Hittman study and is for a "controlled" plant burning coal. The "controls" mean that virtually all water effluents can be eliminated except nondegradable organics, cooling towers are used, and a wet limestone scrubber system is employed with SO_x removal efficiencies of 85 percent and particulate removal efficiencies of 99 percent. The coal is assumed to be a national average coal, with 12.53-percent ash and 2.59-percent sulfur.

Lines 12 through 14 are from the Hittman study and are for boiler-fired, "controlled" plants burning low-Btu gas from the Bureau of Mines Atmospheric process for three different coals (Central, Northern Appalachia, and Northwest). These residuals assume that all water effluents can be eliminated and that an electrostatic precipitator with 97-percent efficiency is employed for air emissions. Residuals data on these plants is considered poor, with a probable error of less than 100 percent.

Lines 15 through 18 are from the Teknekron study and are for steam power plants burning four different types of fuel. All four cases assume that wet cooling towers are used. The residual fuel oil case assumes an oil containing one-percent sulfur and 0.5-percent ash, and particulate removal with 84-percent efficiency. The bituminous coal case assumes one-percent sulfur and 12-percent ash, and particulate removal with 99-percent efficiency. The low-Btu gas case is based on clean gas made from coal with three-percent sulfur.

In addition to the residuals listed in Table 12-4, boiler-fired power plants can also be large consumers of water, depending on the type of cooling method used and the plant efficiency. The water requirements for the four major types of cooling were given in Table 12-3.

12.2.4 Economic Considerations

Currently, the conventional boiler-fired steam turbine system is the most economical and technologically developed system available to the electric power industry. Estimates for 1972 capital costs per kilowatt (kw) of installed capacity for plants with no stack gas cleaning are \$180 for coal, \$150 for oil, and \$100 for gas (CEQ, 1973: 44, 50, 54). Presumably, these costs have risen considerably in the

TABLE 12-5

GENERATION COSTS (1971) FOR STEAM POWER PLANTS WITH NO STACK GAS CLEANING (MILLS PER KILOWATT HOUR)

Cost Category	Fuel Source		
	Coal	Oil	Gas
Power plant (capital costs)	4.05	3.38	2.25
Fuel	3.14[a]	4.04[b]	4.58[c]
Fuel storage	.08	.04	NA
Operation and maintenance	.39	.21	.24
TOTAL	7.66	7.67	7.07

NA = not applicable

Source: Olmstead, 1971.

[a]Based on a cost of $.35 per million Btu's.

[b]Based on a cost of $.45 per million Btu's.

[c]Based on a cost of $.51 per million Btu's.

recent past. Table 12-5 shows generation costs determined in a survey of steam plants during 1971 (Olmstead, 1971) and are the same data included in the Hittman study, except that Hittman excluded fuel costs.

Binary cycle plants will clearly have higher capital costs than the conventional steam plant due to the increased complexity, but these costs could be offset by higher plant efficiency. Detailed plant and equipment design studies are needed to develop more reliable cost data.

The Hittman study included cost data for the Pope, Evans, and Robbins Fluidized-Bed Systems on a mills per kilowatt-hour (kwh) basis (excluding fuel). This cost, 2.77 mills per kwh (1972 dollars), appears low in comparison to the costs for a conventional boiler system with no stack gas cleaning, as listed in Table 12-5.

Most of the SO_2 stack gas cleaning technology is at such an early stage of development that it is difficult to make any definitive statements about its cost. The Hittman data places the incremental cost of the wet limestone scrubbing system for coal at 1.8 mills per kwh. Table 12-6 summarizes the estimated economics of several SO_2 control systems (Davis, 1973). These cost estimates include the cost for particulate removal. For comparison purposes, the estimated operating cost for an early wet limestone scrubbing process at Commonwealth Edison's Will County Unit One is 4.5 mills per kwh (Battelle, 1973: 409). Part of this high-cost is attributable to a difficult retrofit task, overtime paid to meet regulatory deadlines, and a relatively expensive sludge disposal system.

In 1972, the Environmental Protection Agency (EPA) estimated, based on certain assumptions concerning clean fuel availability, that stack gas cleaning would be applied to 30 to 50 percent of existing coal- and oil-fired capacity. It was predicted that 80 or 90 percent of the power plants in the Northeastern U.S. could install stack gas desulfurization processes with a kwh cost at or below that which would be required if high-cost clean fuels were used (Battelle, 1973: 409).

The type of cooling system chosen can have an effect on electric power costs. The exact costs for any system will, of course, depend on the design conditions, but a range of capital cost data gathered in a 1971 study is given in Table 12-7. The cooling costs for nuclear systems are generally higher because of lower plant efficiencies.

A further discussion and comparison of the economics of electric power are given in Section 12.9.

12.3 GAS TURBINE POWER PLANTS

The electric utility industry has made increasing use of gas turbines in the last 10 years; they now represent nearly eight percent of the nation's installed generating

TABLE 12-6

SULFUR DIOXIDE AND PARTICULATE CONTROL SYSTEM COST[a]

Process	Throwaway or Recovery	Investment Cost (dollars per kilowatt)	Annual Cost (mills per kilowatt hour)[b]		
			Without Sulfur Recovery Credit	With Sulfur Recovery Credit	Sulfur Dioxide Removal Efficiency Percent
Dry Limestone Injection	Throwaway $CaSO_3/CaSO_4$	17-19	0.6-0.8	U	22-45
Wet Lime/Limestone Scrubbing	Throwaway $CaSO_3/CaSO_4$	27-46	1.1-2.2	U	80-90
Magnesium Oxide Scrubbing	Recovery: Concentrated H_2SO_4 or Sulfur	33-58	1.5-3.0	1.2-2.7	90
Sodium Sulfite Scrubbing	Recovery: Concentrated H_2SO_4 or Sulfur	38-65	1.4-3.0	1.1-2.7	90

U = unknown.

Source: Davis, 1973.

[a]Costs are expressed in 1973 dollars.

[b]Based on 80 percent load factor and fixed charges of 18 percent of capital costs.

capacity. The major use is to accommodate peak loads to which the gas turbines can respond because of their fast start-up time. In addition, they have been attractive because of low initial cost and short delivery times.

This section will describe a simple gas turbine power plant. Other systems that use gas turbines in conjunction with steam turbines (combined cycle plants) are described in Section 12.4.

12.3.1 Technologies

The gas turbine, sketched in Figure 12-7, is essentially the same engine used in jet aircraft. Incoming air is compressed and injected into a combustion chamber with the gaseous or vaporized liquid fuel. The high-temperature, high-pressure combustion gas expands and drives the turbine similar to the process in a steam turbine. The turbine drives both the generator and the compressor. A regenerator may be used to transfer heat from the exhaust gases to the incoming air. Note that no cooling is required since the exhaust gases are vented directly to the atmosphere.

An important characteristic of the gas turbine is the requirement for a clean (no particulates or corrosive components) gas flow through the turbine. This necessitates either a clean burning fuel or a source of high-temperature thermal energy, such as a nuclear reactor, where the fuel-element coolant is the high-pressure, heated gas for the turbine expansion.

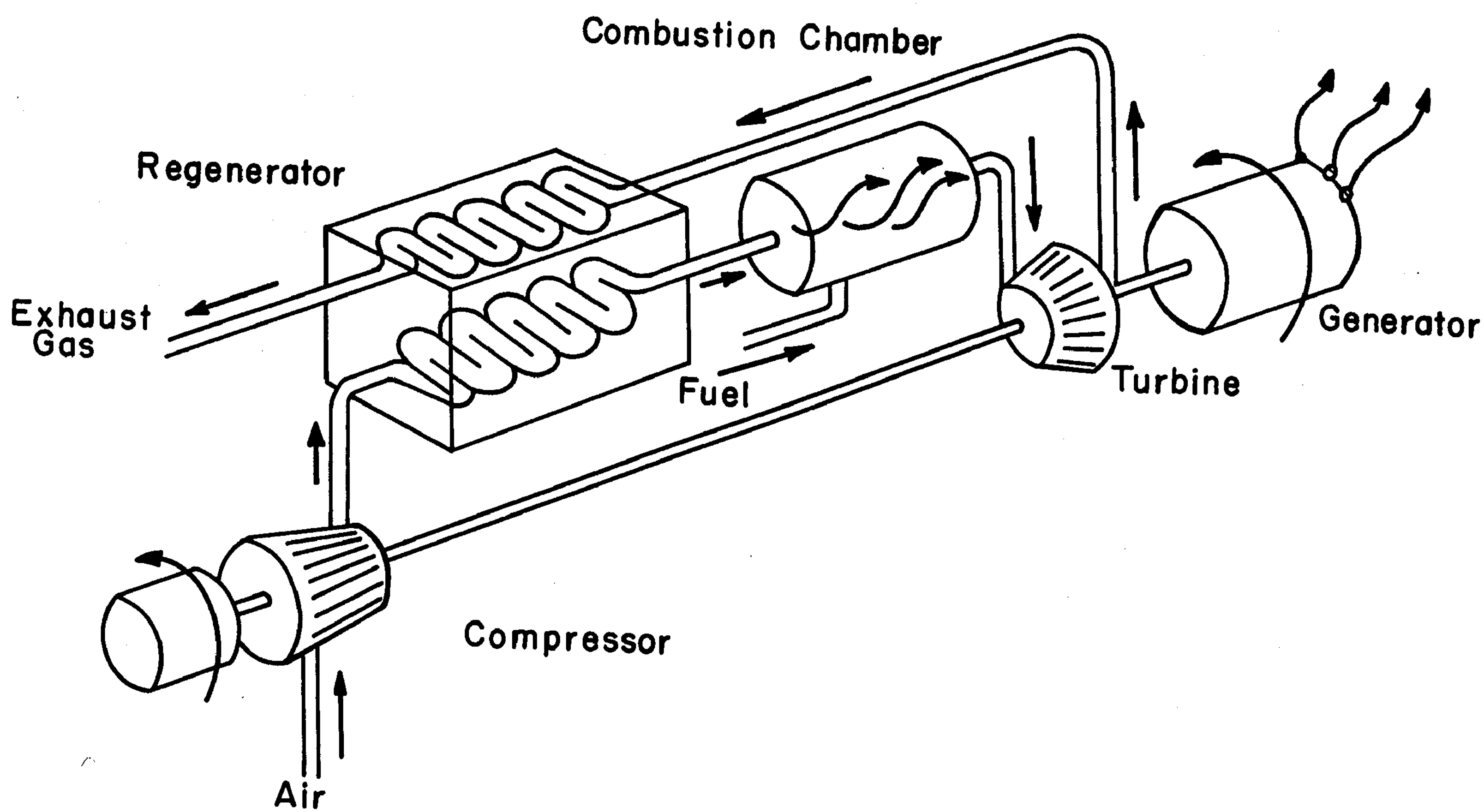


Figure 12-7. Regenerative Cycle Gas Turbine

Source: AEC, 1974: B.4-2.

TABLE 12-7

COSTS OF COOLING SYSTEMS FOR STEAM-ELECTRIC PLANTS

Type of System	Investment Cost (dollars per kilowatt)	
	Fossil-Fueled Plant[a]	Nuclear-Fueled Plant[a]
Once-through[b]	2.00- 3.00	3.00- 5.00
Cooling ponds[c]	4.00- 6.00	6.00- 9.00
Evaporative cooling towers		
Mechanical draft	5.00- 8.00	8.00-11.00
Natural draft	6.00- 9.00	9.00-13.00
Dry cooling towers		
Mechanical draft	18.00-20.00	26.00-28.00
Natural draft	20.00-24.00	28.00-32.00

Source: Jimeson and Adkins, 1971b: 67.

[a]Based on unit sizes of 600 Mwe and larger.

[b]Circulation from lake, stream, or sea and involving no investment in pond or reservoir.

[c]Artificial impoundments designed to dissipate entire heat load to the air. Cost data are for ponds capable of handling 1,200 to 2,000 Mwe of generating capacity.

12.3.2 Energy Efficiencies

Simple-cycle gas turbines without regeneration have overall thermal efficiencies of 27 percent, while those with regeneration can obtain efficiencies of 34 percent (AEC, 1974: Vol. IV, p. B.4-7).

12.3.3 Environmental Considerations

Because gas turbines require clean burning fuels, most of the stack gas emissions (e.g., SO_2, particulates, etc.) are negligible. Although NO_x is a problem area, it is currently being controlled by injecting demineralized water into the combustion chamber. Most gas-turbine manufacturers feel that they will be able to offer combustion chambers that will reduce oxides of nitrogen without the necessity for water injection.

Neither the Hittman, Battelle, nor Teknekron studies has any residual coefficients for gas turbines. However, the Hittman study does have residual data for combined-cycle power plants burning low-Btu gas, as described in Section 12.4. Presumably, the residual data would be similar for the gas turbine system.

12.3.4 Economic Considerations

Capital costs for gas turbine plants are approximately $90 per kw for single cycle and $100 per kw for regeneration cycle plants (1972 dollars) (AEC, 1974: Vol. IV, p. B.4-13). This compares to approximately $180 per kw (1972 dollars) for coal-fired power plants as listed earlier. Thus, gas turbine plants have definite capital cost advantages over the more complex coal-fired steam plants. However, due to their lower efficiency and their need for clean fuels, the fuel costs for gas turbine plants can be much higher.

For example, the Federal Power Commission (FPC) estimated that in 1990, the fossil fuel costs for steam plants would be 3.79 mills per kwh (1968 dollars), while the fuel costs for clean fuels (for gas turbines and diesel) would be 16.1 mills per kwh (1968 dollars) (FPC, 1971: p. I-19-7).

12.3.5 Other Constraints and Opportunities

If a gas turbine plant is constructed, it must have available a clean burning gaseous or liquid fuel. On the other hand, conventional steam plants can be relatively easily converted from one type of fuel to another.

12.4 COMBINED CYCLE POWER PLANTS

In this section, two power systems that combine gas turbine and steam turbine cycles will be described: the gas turbine/steam turbine system and the Westinghouse pressurized fluidized-bed system.

12.4.1 Technologies

A very important variation of the simpler gas turbine system described in Section 12.3 is the combined gas turbine and steam turbine plant. In this plant, the hot exhaust from the gas turbine is used to generate steam in an unfired boiler, and the steam is used to drive a conventional steam turbine. (Some plants have an in-between variation where the gas turbine exhaust generates steam along with a fired boiler, but here only the characteristics of those combined-cycle systems that use unfired boilers will be considered.) For instance, a 1,000-Mwe plant might consist of four gas turbines and their associated electrical generators, plus one steam turbine with its electrical generator.

A sketch of the combined-cycle process is given in Figure 12-8. There are really no technological components required for the combined-cycle system that have not already been covered in the sections on steam turbines or in the preceding discussion of gas turbines. The combined-cycle system is being used currently by some utilities for serving intermediate system loads but presumably could be used in the future for baseloads.

A new concept in combined-cycle systems is Westinghouse's pressurized fluidized-bed system, whose development is being supported by EPA. This system combines the fluidized-bed boiler concept described in Section 12.2 and the gas-turbine system described in Section 12.3. The system is illustrated in Figure 12-9. Essentially, the concept is to burn coal in a dolomite (limestone) bed at 10 atmospheres of pressure. The water is initially heated to steam in the walls of the combustor and is then superheated in the beds. The steam drives a conventional turbine and has one heat cycle. The combustion gases, after particulate removal, are used to drive a gas turbine, and the heat remaining in the gas turbine exhaust is used to preheat the boiler feedwater. The spent dolomite is regenerated.

12.4.2 Energy Efficiencies

Gas turbine/steam turbine plants now available have overall thermal efficiencies in the range of 36 to 38 percent. Commercial design should be available in the 1975 to 1977 period having improved efficiencies, in the range of 40 to 42 percent, making them competitive with the best available conventional steam plants. By 1980, some designers feel further evolutionary developments could yield efficiencies in the range of 43 to 45 percent (AEC, 1974: Vol. IV, p. B.4-7).

The overall efficiency for the Westinghouse system is about 36 percent (Hittman, 1975: Vol. II), but further improvements are projected to obtain an overall efficiency near 45 percent (Keairns and others, 1972).

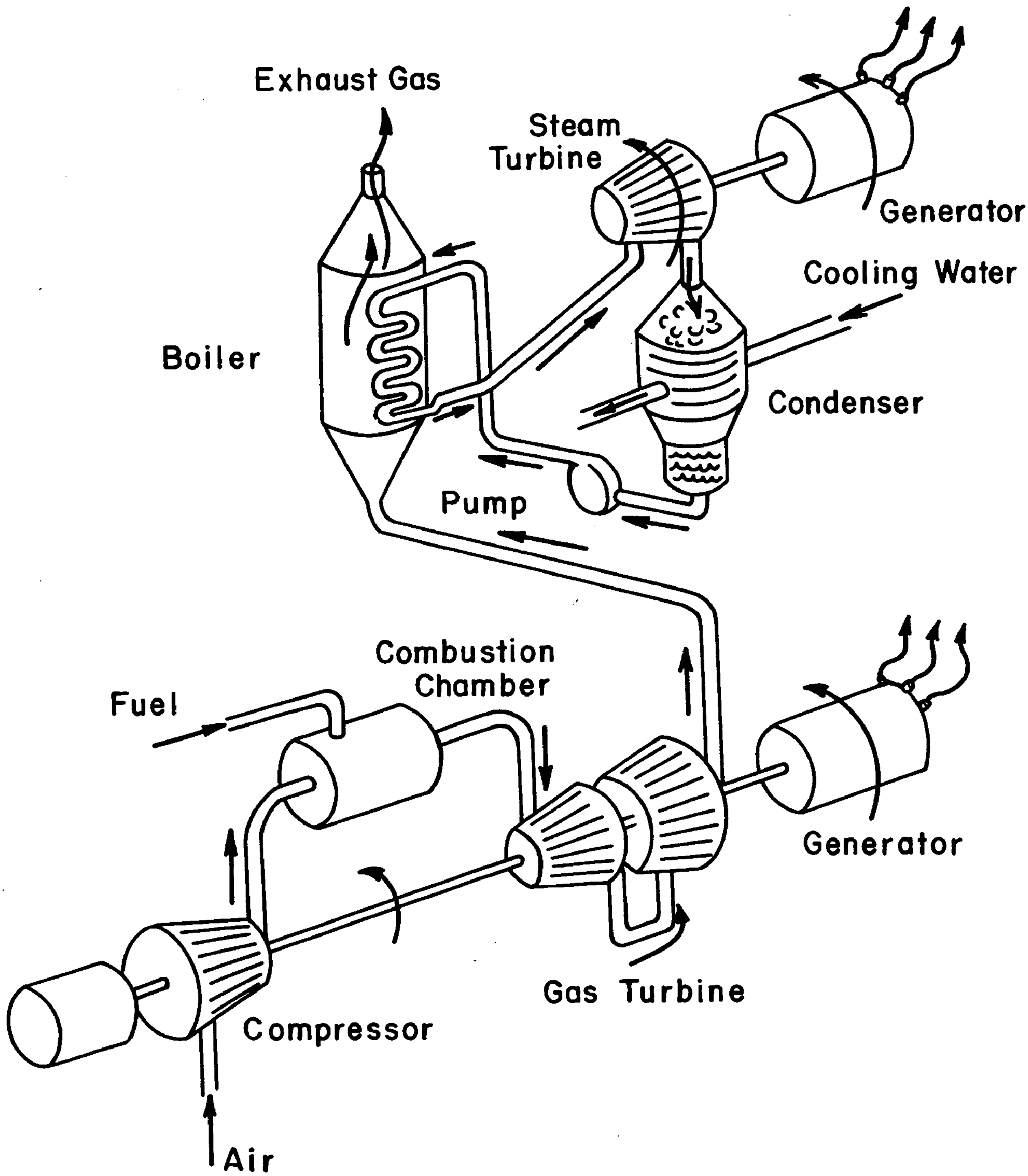


Figure 12-8. Combined Cycle Gas Turbine

Source: AEC, 1974: B.4-5.

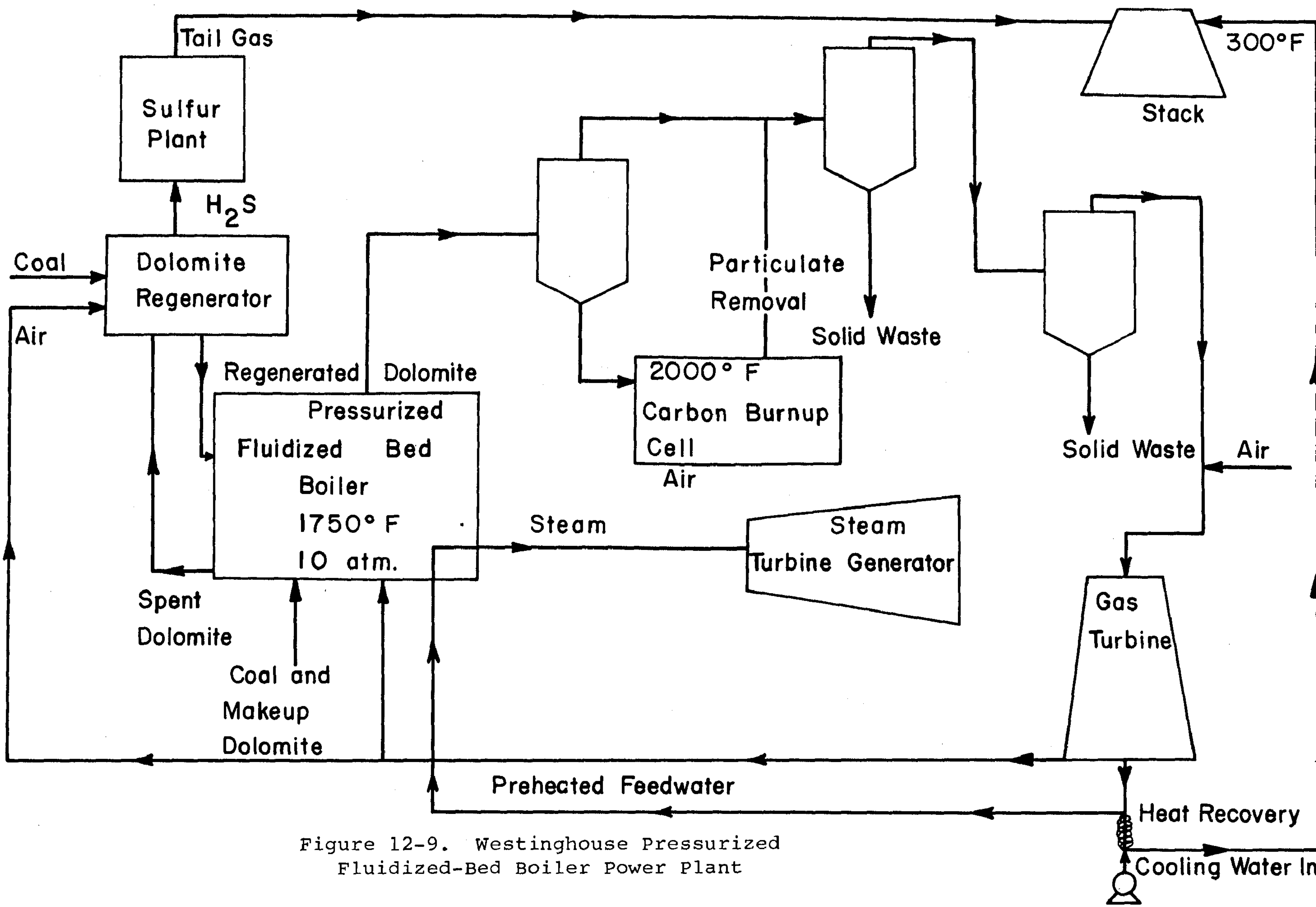


Figure 12-9. Westinghouse Pressurized Fluidized-Bed Boiler Power Plant

Source: Hittman, 1975: Vol. II, p. VI-3.

Table 12-8. Residuals for Environmentally Controlled Combined-Cycle Electricity Generation

SYSTEM	Water Pollutants (Tons/10^{12} Btu's)										Air Pollutants (Tons/10^{12} Btu's)						Solids (Tons/10^{12} Btu's)	$^F/_I$[a]	Occupational Health 10^{12} Btu's		
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/10^{12})	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes		Land Acre-year / 10^{12} Btu's	Deaths	Injuries	Man-Days Lost
CENTRAL																					
1 BuMines-Pressurized Combined-cycle	0	0	U	U	3.4	0	.003	U	U	0	3.75	39.4	278.	0	0	0	0	.217/0 .217	.0002	.0188	2.08
2 Koppers-Totzek Combined-cycle	0	0	U	U	3.4	0	.003	U	U	0	.462	23.7	457.	0	0	0	0	.482/0 .482	.0002	.0188	2.08
NORTHERN APPALACHIA																					
3 BuMines-Pressurized Combined-cycle	0	0	U	U	3.4	0	.003	U	U	0	3.44	10.3	47.4	0	0	0	0	.205/6 .205	.0002	.0188	2.08
4 Koppers-Totzek Combined-cycle	0	0	U	U	3.4	0	.003	U	U	0	.503	19.6	91.2	0	0	0	0	.482/0 .482	.0002	.0188	2.08
NORTHWEST																					
5 BuMines-Pressurized Combined-cycle	0	0	U	U	3.4	0	.003	U	U	0	468.	32.4	165.	0	0	0	0	.181/0 .181	.0002	.0188	2.08
6 Lurgi Combined-cycle	0	0	U	U	3.4	0	.003	U	U	0	14.3	10.	28.6	0	0	0	0	.418/0 .418	.0002	.0188	2.08
7 Koppers-Totzek Combined-cycle	0	0	U	U	3.4	0	.003	U	U	0	.456	15.9	25.9	0	0	0	0	.418/0 .418	.0002	.0188	2.08
CENTRAL COAL																					
8 Combined-cycle Pressurized Fluidized Bed	0	0	U	U	18.2	0	.003	U	U	0	9.29	67.3	441.	0	0	0	6760.	1.62/.17 4.19	U	U	U
NORTHERN APPALACHIAN COAL																					
9 Combined-cycle Pressurized Fluidized Bed	0	0	U	U	18.2	0	.003	U	U	0	12.3	67.3	210.	0	0	0	5780.	1.62/.14 3.78	U	U	U
NORTHWEST COAL																					
10 Combined-cycle Pressurized Fluidized Bed	0	0	U	U	18.2	0	.003	U	U	0	9.70	67.3	71.8	0	0	0	3950.	1.62/.10 3.09	U	U	U

NA = not applicable, NC = not considered, U = unknown.

[a]Fixed Land Requirement $\left(\frac{\text{Acre - year}}{10^{12}\text{ Btu's}}\right)$ / Incremental Land Requirement $\left(\frac{\text{Acres}}{10^{12}\text{ Btu's}}\right)$.

12.4.3 Environmental Considerations

Residuals data for a combined-cycle plant burning low-Btu gas are given in lines 1 through 7 of Table 12-8. These data are considered poor, with a probable error of less than 100 percent. Residuals are given for low-Btu gas from two systems (the Bureau of Mines [BuMines] Pressurized process and the Koppers-Totzek process), for three coals (Central, Northern Appalachia, and Northwest), and for low-Btu gas from the Lurgi process. Note these residuals are for the electric power generation step only and do not include residuals from the low-Btu gasification step.

The residual data for the Westinghouse combined-cycle pressurized fluidized-bed system are given in lines 8 through 10 of Table 12-8 for three different types of coal: a high-sulfur Central Region coal, a medium-sulfur Northern Appalachian coal, and a low-sulfur Northwestern coal. The data are considered good with a probable error of less than 25 percent for air and land data but are considered poor with a probable error of less than 100 percent for water data. These data are discussed and compared to other systems in Section 12.8.

12.4.4 Economic Considerations

The approximate capital cost for a gas turbine/steam turbine plant is $150 per kw (AEC, 1974: Vol. IV, p. B.4-13). No operating cost data are available.

Cost data for the Westinghouse system is included in the Hittman study and is 4.64 mills per kwh (1972 dollars), excluding fuel costs.

Westinghouse's own cost estimates (using different economic assumptions than the Hittman study) for their system are shown in Table 12-9.

For comparison, the economics for a conventional boiler system with stack gas cleaning were calculated by Westinghouse using the same assumptions, and this yielded a cost of 13.20 mills per kwh.

TABLE 12-9

COSTS FOR WESTINGHOUSE COMBINED CYCLE FLUIDIZED-BED SYSTEM

Cost Category	Generation Costs (mills per kilowatt hour)
Fixed charges	6.75
Fuel	4.35
Dolomite or limestone	0.12
Operation and maintenance	0.90
TOTAL	12.12

Source: Keairns and others, 1972: 274.

12.5 FUEL CELL POWER PLANTS

There are no commercially available power plants using fuel cells, and the most optimistic estimates place prototype plants several years in the future. Their theoretical attractiveness, however, appears to justify continued research and development, and they are identified here as a long-term potential option.

12.5.1 Technologies

A fuel cell is a device that produces electrical energy directly from the controlled electrochemical oxidation of fuel. Since fuel cells do not require an intermediate heat cycle, they are not limited by the Carnot efficiency and have a theoretical efficiency approaching 100 percent. The basic components of a simple hydrogen-oxygen fuel cell (illustrated in Figure 12-10) are the electrodes (anode and cathode) and an electrolyte. The electrolyte may be either acidic or basic. The reactants are normally consumed only when the external circuit is completed, allowing electrons to flow and the electrochemical reaction to occur. The result is good fuel efficiency even with low or intermittent loads.

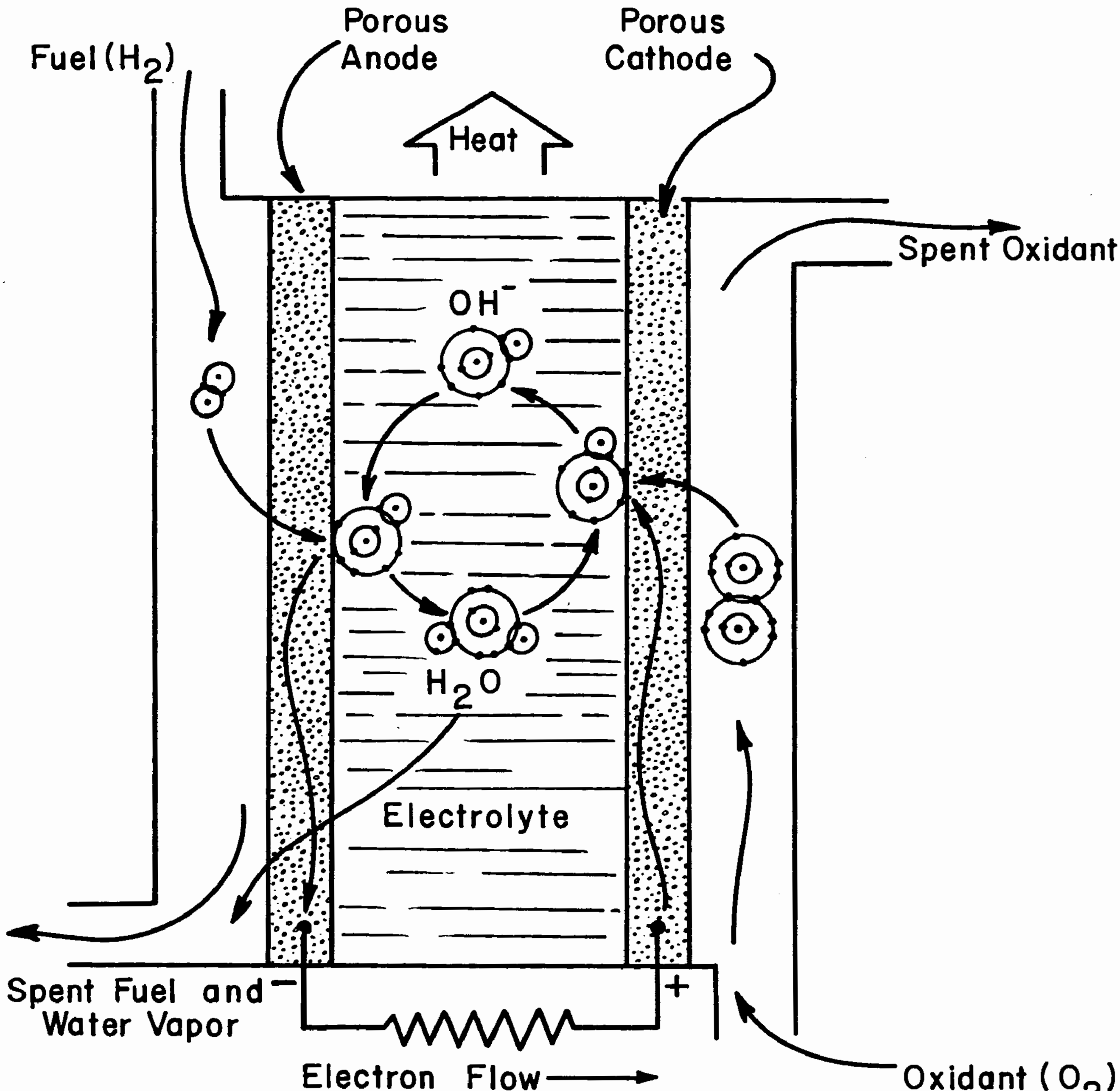


Figure 12-10. Hydrogen-Oxygen Fuel Cell

Source: AEC, 1974: B.6-2.

When the external circuit is completed, an oxidation reaction yielding electrons takes place at the anode and a reduction reaction requiring electrons occurs at the cathode. The electrodes provide electrochemical-reaction sites and also act as conductors for electron flow to the external circuit. Power is produced as long as fuel and oxidant are supplied to the fuel cell and the external electrical circuit is closed, allowing current to flow (AEC, 1974: Vol. IV, p. B.6-1). Continuous operation necessitates the removal of heat, water, and any inert material that enters the cell with the reactants, and reaction kinetics are usually enhanced by the incorporation of a catalyst such as platinum on the high surface area electrode surfaces. The power produced from fuel cells is direct current (DC) and thus must be converted to alternating current (AC) before being usable in conventional electric power systems.

Two routes are being followed with respect to fuel cell development for routine electric power generation: one for central power station application, and the other for dispersed generation of electrical power at substations. For either type of system there are three main classifications of fuel cells, according to the type of fuel used: hydrogen-oxygen, hydrocarbon-oxygen, and reformer. The operation of the hydrogen-oxygen type was described above. The hydrogen fuel would presumably be provided by nuclear or solar energy sources. The hydrocarbon-oxygen cells use gaseous hydrocarbons directly in a phosphoric acid electrolyte fuel cell. The reformer cells actually consist of two stages. First, coal or various hydrocarbons are reformed (reacted with steam) to produce a fuel that consists primarily of hydrogen and carbon monoxide. (Note that this is exactly the low-Btu gasification process described in the chapter on coal.) The hydrogen and carbon monoxide fuel are then used in a high-temperature fuel cell.

Some of the major fuel cell development programs are as follows (AEC, 1974: Vol. IV, Section B.6):

1. Westinghouse is developing a 100-kw system based on low-Btu gasification of coal (to carbon monoxide and hydrogen) and a high-temperature (1,870°F) zirconin electrolyte fuel cell. The development is aimed toward central station power production uses. The total system consists of fuel cell battery tubes assembled into banks, a coal gasifier, and ancillary equipment. Cell banks, which operate at 1,850°F, are physically located in the fluidized-bed coal gasifier for maximum heat recovery.
2. Pratt and Whitney, under the sponsorship of 31 gas utilities, is developing fuel cell systems using reformed natural gas as fuel. This low-temperature (less than 250°F), fuel cell is designed initially for dispersed power generation. In May 1971, a 12.5-kw system was demonstrated and more than 4,000 hours of automatic operation has been achieved. This system will also use gasified coal.
3. The Institute of Gas Technology is doing work complementary to the Pratt and Whitney effort. This group is developing a low-temperature phosphoric acid and higher temperature (2,200°F) molten carbonate electrolyte cell designed to use either natural gas or gasified coal. (It is not clear whether these cells use the fuel directly or whether it is reformed first.)

The further research and development needed for fuel cells is considerable. Although their feasibility has been clearly demonstrated, considerable work still remains to determine whether they offer any advantages in terms of economics, environmental impacts, or energy conversion efficiencies.

12.5.2 Energy Efficiencies

The present published efficiency of conversion of chemical energy from natural gas fuel to AC electrical energy, including the reforming step, is 40 to 45 percent in the 12.5-kw Pratt and Whitney system. The large central station version of this system is projected to have an overall efficiency around 55 percent.

The Westinghouse high-temperature system is designed to operate at a projected efficiency of 58 percent for the 100-kw size and near 70 percent for 1,000-Mwe, based on DC output.

12.5.3 Environmental Considerations

Central station systems using fuel cells will produce chemical pollutants similar to those obtained by conventional combustion of the same fuels, except that NO_x emissions will be reduced because of the reduced temperatures to which air streams are exposed (AEC, 1974: Vol. IV, p. B.6-14). However, the fuel cell is particularly sensitive to pollutants, such as sulfur, now causing concern in conventional steam turbine plants. Thus, the pollutants must be removed prior to the fuel cell system.

If the higher projected efficiencies of fuel cells (as compared to conventional systems) are achieved, this would, of course, yield the primary environmental benefit, as discussed previously with all of those systems aimed at achieving higher conversion efficiencies. Waste-heat rejection is not a significant problem with fuel cell power systems because most of the waste heat is used in the fuel gasification or reforming process. Excess heat is rejected to the atmosphere, and cooling water is not required.

Gas transmission by buried pipeline requires less land for an equivalent amount of energy transmitted, and thus dispersed power generation via fuel cells would have a positive effect on the environment. However, the total environmental impact of overhead transmission lines versus buried pipelines has not been fully evaluated.

12.5.4 Economic Considerations

Since no large fuel cell power systems have been built, an estimate of the costs is somewhat speculative. However, initial economic calculations for the coal-fired Westinghouse system do show that it could produce competitively priced electricity. The projected economics of fossil-fueled fuel cell systems show capital costs comparable to conventional systems but lower operating costs.

Economic estimates for dispersed generation of electrical power are much more complex and speculative. The capability for gaseous fuel storage at the point of usage allows a degree of freedom not found in present electrical distribution systems.

12.5.5 Other Constraints and Opportunities

Dispersed power generation, where the waste heat could be utilized for residential heating and for hot water needs, appears to be a potentially attractive option. However, this requires a drastic change from the current operational mode.

12.6 MAGNETOHYDRODYNAMIC POWER PLANTS

Like the fuel cell option, there are no commercially available power plants using MHD, and the most optimistic estimates place prototype plants many years in the future. However, their theoretical attractiveness appears to justify continued research and development, and they are identified here as a long-term potential option.

12.6.1 Technologies

An MHD generator produces electrical energy directly from thermal energy and has the potential for conversion efficiencies in the range of 50 to 60 percent. The higher conversion efficiency results primarily from the high temperature at which MHD generators operate but also from bypassing the heat energy to mechanical energy conversion step that occurs in steam power plants.

As previously described, a conventional large generator works by spinning a magnet around a stationary conductor. In an MHD generator, the conductor is an electrically conductive fluid. As illustrated in Figure 12-11, the conductive fluid flows through a rectangular duct which is immersed in a magnetic field. As the conductive fluid flows through the duct, a voltage drop is induced across the stream. The electrodes of the MHD generator are normally two opposite walls of the duct to which electrical leads are attached. Note that MHD systems generate DC power which, if used in a conventional central station power plant, must then be transformed to AC power.

Three basic types of MHD systems have been investigated: the open-cycle plasma system, the closed-cycle plasma system, and the liquid metal system.

12.6.1.1 Open-Cycle Plasma System

The open-cycle plasma system has received the most attention to date. In this system, fossil fuel is burned at a sufficiently high temperature (4,000 to 5,000°F) to ionize the product gases. Electrical conductivity is increased by "seeding" the gas with readily ionized material, generally salts of potassium or cesium. These gases then pass through the MHD generator, and the existing hot gas can be used to generate steam for a conventional steam turbine. The seed material must then be extracted from the hot gases before venting to the atmosphere.

The open-cycle plasma system is at the pilot stage in the Union of Soviet Socialist Republics (USSR) where they expect to have a 75-Mwe system (25 Mwe from the MHD generator and 50 Mwe from the steam turbine) in operation by 1975 (AEC, 1974: Vol. IV, p. B.10-5). The technology in the U.S. is somewhere between the bench test and pilot plant stage.

There are still several major problems which must be solved before MHD systems can become a reality for central station power generation, but proponents feel that all of the problems identified thus far are solvable. In any case, it will be at least 10 years before any large-scale MHD plants could be built in the U.S.

12.6.1.2 Closed-Cycle Plasma System

The closed-cycle plasma system uses a seeded noble gas (helium or argon) heated by an indirect heat source such as a nuclear reactor or a fossil fuel boiler. The hot gases pass through the MHD generator and the cooled existing gases are compressed for reheating. These systems would require a heat source operating over the range of 2,300 to 3,500°F.

The closed-cycle plasma system is at the "bench test" level of development, and sufficient experimental and theoretical background exists to permit extrapolation to large sizes with reasonable confidence. The closed-cycle plasma system has basic problems similar to that of the open-cycle system. However, the working conditions of the closed-cycle MHD nonequilibrium duct are much less severe than for the open-cycle system because of a cleaner gas stream and lower temperatures. Therefore, fewer difficulties are anticipated in the development of long-life ducts (AEC, 1974: Vol. IV, B.10-10).

12.6.1.3 Liquid Metal MHD System

In the liquid metal system, there are two fluid circuits, a liquid metal and an inert gas. The liquid metal is heated by a fossil or nuclear heat source, and the inert gas is then dispersed into the liquid metal. As the gas expands, due to being heated by the liquid metal, the two fluids accelerate through the MHD generator, the liquid metal providing the moving conductor

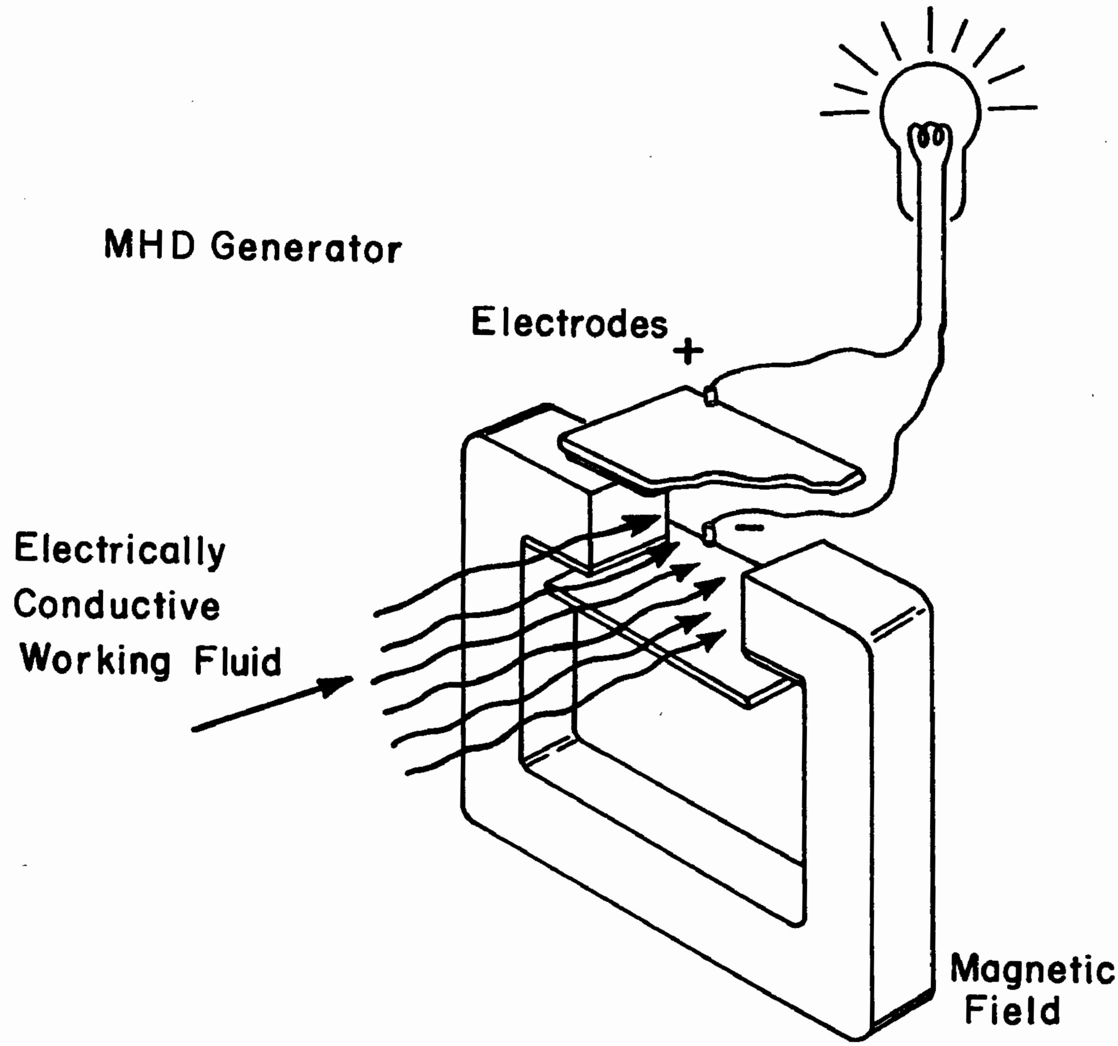


Figure 12-11. MHD Generator Electrical System

Source: AEC, 1974: B.10-3.

capability. At the exit of the MHD generator, the two fluids are separated. The liquid metal is reheated and the gas is cooled and recompressed before being remixed with the liquid metal. Rejected heat from the gas circuit can be used to generate steam or dumped to the atmosphere. Liquid metal MHD systems appear to be compatible with thermal energy sources operating in the range of 1,000 to 2,000°F.

Research on liquid metal systems has been conducted on a much smaller scale than for plasma systems. Generator efficiencies up to 75 percent have been measured for a liquid metal MHD generator at relatively low temperatures with a measured output of about one kw. Tests of larger (5 to 50 kw) and high-temperature (in excess of 1,000°F) liquid metal MHD generators are currently underway or being planned (AEC, 1974: Vol. IV, p. B.10-5).

12.6.2 Energy Efficiencies

MHD power systems have higher potential efficiencies than conventional steam and other expansion-type energy conversion devices. First generation open-cycle plasma systems would operate as a topping cycle on a conventional steam plant and would be expected to give overall plant efficiencies in the range of 46 to 50 percent. Such power plants are projected to have an ultimate efficiency in the range of 55 to 60 percent (AEC, 1974: Vol. IV, p. B.10-8).

The closed-cycle plasma MHD system operating in a binary cycle appears capable of plant efficiencies in excess of 50 percent for heat-source temperatures of 2,900°F (AEC, 1974: Vol. IV, p. B.10-8).

Two-phase, liquid metal MHD power systems are predicted to have overall efficiencies competitive with those of modern steam systems (when operating at the same maximum cycle temperature) and should have efficiencies approaching 50 percent at 1,600°F (AEC, 1974: Vol. IV, p. B.10-8).

Proponents believe that a high-temperature, all-MHD binary power cycle is possible using the open-cycle plasma and the two-phase liquid metal MHD concepts. In such a system, an open-cycle plasma MHD generator obtains thermal energy from a fossil-fired heat source and rejects waste heat to a two-phase liquid metal MHD generator. This dual cycle is projected to have efficiencies in excess of 60 percent for a maximum cycle temperature at 5,000°F (AEC, 1974: Vol. IV, p. B.10-8).

12.6.3 Environmental Considerations

The effluents associated with MHD power plants are associated with the energy source; that is, nuclear or fossil fuels. Since higher conversion efficiencies are expected as compared with conventional steam plants, significant reductions in emissions per unit of power produced should be achieved. However, two special environmental problems associated with the open-cycle system are recovery of seed material and possible increases in NO_x emissions due to the higher combustion temperature.

12.6.4 Economic Considerations

The MHD power plant concepts are still in the early development stage; thus, it is not possible to make accurate assessments of their economic benefits. The higher efficiencies projected for the various MHD systems must provide sufficient fuel and residual clean-up cost savings to compensate for the higher capital costs of the MHD system.

12.6.5 Other Constraints and Opportunities

Since the MHD system generates DC power, the entire system must be analyzed to determine the feasibility of using the DC power directly in certain applications or converting it all to AC power. Costs and efficiencies for this DC to AC conversion must be studied.

12.7 ELECTRICITY TRANSMISSION AND DISTRIBUTION

This section treats those technologies for transporting electrical energy from the generation plant to the point of use. At present, there are approximately 4,000 electric utility companies in the U.S. that operate transmission and/or distribution systems.

12.7.1 Technologies

The system for delivering electrical energy is generally separated into two components: the transmission system which transports the energy at relatively high voltages (69 to 500 kilovolts [kv]) from the electrical generation plant to main substations; and the distribution system which transports the electrical energy, at voltages ranging from 138 kv to 120 volts, from the substations to the point of utilization.

12.7.1.1 Transmission Systems

The transmission system consists of overhead transmission lines and underground cables, terminal equipment (e.g., high voltage transformers, convertors, switchgear, etc.), and control and metering systems (e.g., meters, relays, communications equipment, computers, etc.). In addition to providing transmission within individual utility service areas, transmission systems also generally interconnect adjacent electric utility systems to achieve more reliable and economic service (AEC, 1974: Vol. IV, p. C.5-2).

At present, there are more than 40,000 miles of overhead transmission lines and about 2,000 miles of underground transmission cables. The transmission lines utilize about four million acres of land for right-of-way (Battelle, 1973: 176).

Early transmission lines used wooden poles, wooden cross arms, and solid copper conductors. Voltages on these lines were as low as 69 kv. Today, voltages of 345, 500, and 765 kv are in use, with future planning on the next highest voltage levels of 1,000 and 1,500 kv. As voltages increased, insulators and conductors became bigger and heavier, requiring large steel or aluminum towers (Battelle, 1973: 176).

Because of increased environmental awareness and right-of-way costs, transmission design and technology are the focus of substantial research interest. Major investigative effort is being put into ultrahigh voltage (745 kv and above) and underground transmission lines. The use of higher voltages will enable a given line to carry more power and thus avoid the use of multiple lines or circuits. Also, higher voltages generally result in greater transmission efficiencies.

One of the areas receiving attention in underground transmission is compressed gas insulation. In this method, the wire carrying the power is suspended concentrically in a pipe. Compressed gas (sulfur hexafluoride [SF_6] is a likely candidate) fills the annular space between the pipe and wire, with the advantages of improved heat transfer and low dielectric loss.

Another underground transmission method of interest uses cryogenics. When certain metals are supercooled (to about 4 to 10^o Kelvin [K]), they lose their resistivity entirely, a condition known as superconductivity (Battelle, 1973: 280, 281). Thus, relatively small wires could carry large amounts of power if maintained in a state of superconductivity. Of course, there would be system losses associated with maintaining cryogenic conditions, and it will be several years, if ever, before such systems become economically feasible.

12.7.1.2 Distribution Systems

The typical distribution system consists of subtransmission lines (usually ranging from 69 to 138 kv), primary distribution lines (2.4 to 34.5 kv), distribution transformers, secondary distribution lines

(120 to 240 volts), and service lines to residential and commercial customers. Large commercial and industrial customers are generally supplied at primary distribution or even subtransmission voltages (AEC, 1974: Vol. IV, p. C.5-19).

Distribution systems may either be constructed as overhead or underground systems. Today, the trend is toward more underground installations, especially for the primary and secondary distribution systems feeding suburban loads. Aluminum has been the material most used for conductors in distribution systems because of its physical characteristics and economics.

12.7.2 Energy Efficiencies

The efficiency of the electrical transmission/distribution system is approximately 92 percent, with losses about evenly divided between those systems (AEC, 1974: Vol. IV, p. C.5-1). This 92-percent efficiency is high compared to the 40-percent or less efficiency in the electric power generation stage. Thus, the opportunities for increased efficiencies in transmission and distribution are small compared to those in other parts of the overall electric utility system. Resistance accounts for the majority of transmission/distribution losses.

Of the two, most of the opportunities for increased efficiency are in the transmission system. Here, some of the options are: extra-high and ultrahigh voltage AC transmission systems; high voltage DC systems; compressed gas and cryogenic systems (as described earlier); and improved power system control.

12.7.3 Environmental Considerations

One of the primary environmental impacts of overhead transmission and distribution lines is esthetic. Towers, poles, and their associated cables are not pleasing sights to most people. Of course, the severity of the impact depends on the particular area; for example, the esthetic impacts of transmission lines are greater in heavily timbered areas, over steep slopes, through scenic areas, and across open waters. Obviously, the interest in underground cables is to minimize these esthetic impacts.

The other primary environmental impact associated with transmission lines, and to some extent distribution lines, is the land use and physical destruction of the natural vegetation, which can increase soil erosion. The land use residual is the only nonzero coefficient listed by Hittman and is 778 per 10^{12} Btu's.

Finally, a number of people are concerned about the impact of the extra-high voltage lines that are being proposed. Some evidence suggests that the relatively high electric fields and induced magnetic fields in the vicinity of the line are physically dangerous and can have adverse physiological effects.

12.7.4 Economic Considerations

On a national average basis in 1968, transmission costs were two mills per kwh and distribution costs were 5.7 mills per kwh (FPC, 1971: I-19-2). Generally, the transmission and distribution step is characterized by high capital costs and relatively small operating costs.

Part of the interest in high voltage transmission lines, in addition to the improved efficiency, is the lower per unit transmission cost. The optimum voltage for any transmission line (i.e., the voltage that results in the lowest per kwh transferred) depends on the load to be transferred and the particular economic conditions. For example, using certain economic assumptions, a line transmitting 1,300 Mwe would cost 1.5 mills per kwh for a 345-kv line and only 1.0 mills per kwh for a 500-kv line (FPC, 1971: I-13-8).

Although underground transmission lines are still in an early stage of development, they are estimated to cost about 10 times as much as overhead lines (Battelle, 1973: 278).

12.8 SUMMARY AND COMPARISON OF ENVIRONMENTAL FACTORS

In the previous descriptions of electrical generation alternatives, the residual data based on 10^{12} Btu's input were given. To put some of this residual data in better perspective, the residuals in the following paragraphs are presented on an annual basis for a modern size power plant with a 1,000-Mwe capacity and an average annual load factor of 75 percent.* Such a plant would serve an average population of 900,000.

Table 12-10 lists the total annual output of the residuals of major concern in electric power generation. This table includes data for selected alternative power plants and fuel types previously described. In addition, residuals are listed for two hypothetical plants to illustrate the effect of efficiency. Plant number 14 burns the same coal and in the same manner as plant one but uses an advanced conversion technology (possibly a binary cycle or MHD) to achieve a conversion efficiency of 60 percent. Plant 15 is like plant four (both employ stack gas cleaning) but has a conversion efficiency of 58 percent.

Plant one is a conventional coal-fired steam power plant, burning an average coal with 12.53-percent ash and 2.59-percent sulfur. Assuming an average coal with a heat content of 12,000 Btu's per pound, this plant would consume 2.46 million tons of coal annually. From Table 12-10 the emissions for plant one are approximately 48,500 tons of particulates, 119,200 tons of SO_x, and 21,800 tons of NO_x--a total of 182,200 tons (or 364,400,000 pounds) of air pollutants annually. It also creates nearly 298,000 tons of solid wastes (primarily ash) and produces 31.1×10^{12} Btu's of waste heat. Plants two and three, which burn oil and natural gas respectively, are much cleaner, except that all three plants have essentially the same level of NO_x emission.

For comparison with plant one, note the emissions for plants four, six, seven, and eight which employ throwaway stack gas cleaning systems, and plant five which employs a recovery stack gas cleaning system. The SO_x and particulate emission levels are drastically reduced. However, the solid wastes show a large increase. For example, plant four has 955,000 tons of solid wastes, which are essentially the materials that would have gone into the air plus the reacted limestone. For plant five, the solid waste increase is not as large because the MgO is recycled and thus the solid waste is primarily ash. Based on densities from the Hittman data, the solid wastes from plant four during one year would cover 15 acres to a depth of 35 feet. It is not known what the disposal plans are for such wastes, but transporting them for long distances is presumed to be uneconomical. Also, these sludge wastes will not solidify (thixotropic), and many persons are concerned about their environmental impact.

Plants 9 through 11 are fluidized bed systems, with sulfur recovery (plant 11 having a combined-cycle operation), and they appear to be the most attractive systems for burning coal in terms of environmental residuals. These plants offer definite advantages in terms of NO_x emissions and solid wastes when compared to throwaway stack gas cleaning. However, their differences with plants four through eight in terms of the other residuals are small, being primarily attributable to varying assumptions about efficiencies and physical make-up of the coal.

*A 1,000-Mwe plant operated for one year at an average load factor of 75 percent has an output of 22.43×10^{12} Btu's of electrical energy and, assuming a 38-percent conversion efficiency, requires 59×10^{12} Btu's energy input.

Table 12-10. Major Residuals for 1,000-Mwe Plants at 75 Percent Load Factor

Plant Number	Description	Primary Efficiency	Nitrogen Oxides (10^3 tons)	Sulfur Oxides (10^3 tons)	Particulates (10^3 tons)	Thermal (10^{12} Btu's)	Solid (10^3 tons)
1[a]	Coal: Conventional steam No controls	38	21.8	119.2	48.5	31.1	298
2[a]	Oil: Conventional steam No controls	38	21.1	47.3	1.6	31.1	0
3[a]	Gas: Conventional steam No controls	38	11.2	.02	.43	31.1	0
4[b]	Eastern Coal: Conventional Boiler with wet limestone scrubbing	35	19.2	16.0	3.2	0	955
5[b]	Eastern Coal: Conventional Boiler with magnesium oxide scrubbing	35	19.2	16.0	3.2	0	410
6[b]	Western Coal: Conventional Boiler with wet limestone scrubbing	35	25.0	5.1	2.2	0	487
7[b]	Physically Cleaned Eastern Coal: Conventional Boiler with wet limestone scrubbing	35	17.6	6.4	1.4	0	417
8[a]	Coal: Steam plant with controls	38	23.2	19.1	2.6	0	1,009
9[a]	Northern Appalachian Coal: Atmospheric Fluidized Bed	36.8	4.3	10.2	.5	0	359
10[a]	Northwest Coal: Atmospheric Fluidized Bed	36.8	4.3	3.5	.3	0	243
11[a]	Northern Appalachian Coal: Combined-Cycle Pressurized Fluidized Bed	35.8	4.22	13.2	.8	0	362
12[a]	Low-Btu Gas (Northern Appalachian Coal): BuMines-Atmospheric Boiler plant with controls	38	0.391	28.8	6.78	0	0
13[a]	Low-Btu Gas (Northern Appalachian Coal): BuMines-Pressurized Combined-Cycle plant	40	0.577	2.66	.19	0	0

Table 12-10. Continued.

Plant Number	Description	Primary Efficiency	Nitrogen Oxides (10^3 tons)	Sulfur Oxides (10^3 tons)	Particulates (10^3 tons)	Thermal (10^{12} Btu's)	Solid (10^3 tons)
14	Hypothetical Plant: Similar to #1 but with high conversion efficiency	60	14.0	80.8	130	19.7	41.1
15	Hypothetical Plant: Similar to #4 but with high efficiency	58	11.6	9.7	1.9	0	576

Sources: [a]Hittman, 1974: Vol. I; 1975: Vol. II.

[b]Battelle, 1973.

Plants 12 and 13 are conventional boiler and combined-cycle plants respectively, each burning low-Btu gas made from Northern Appalachian coal. The low-Btu gas is made from the BuMines atmospheric process for plant 12, and the BuMines pressurized process for plant 13. Note that plant 13 has much lower SO_x and particulate emission levels than plant 12, but both appear relatively clean when compared to the other systems. However, it is important to realize that these residuals are only for the electric power generation step and do not include the emissions for the low-Btu gasification process itself.

Comparing plants 14 with one and 15 with four shows the environmental advantages of improved efficiency, although these plants can still yield large amounts of pollutants. However, this is not the entire picture because plant 14 requires only 63 percent as much fuel as plant one and thus all the residuals associated with producing the fuel would be reduced by 37 percent.

Note that the thermal pollution for many of the plants is zero. The assumption here is that these plants would use cooling towers, and thermal pollution is deemed to occur only when the heat goes to nearby bodies of water. However, it is important for comparison to realize that cooling towers "consume" water (by evaporation), and thus the trade-off is generally between heating bodies of water by some amount or consuming some amount of the water. The water consumed annually by a 38-percent efficient, 1,000-Mwe plant varies from zero to approximately 17,000 acre-feet, depending on the cooling system used.

Cooling Process	Water Consumption
Once-through	0 acre-feet
Cooling pond	17,000 acre-feet
Wet cooling towers	11,520 acre-feet
Dry cooling towers	0 acre-feet

For comparison, a 60-percent efficient plant using a wet cooling tower would only consume 4,245 acre-feet annually. For reference, note that the waste heat from a 38-percent efficient, 1,000-Mwe power plant is equivalent to the energy required to heat approximately 250,000 homes.

12.9 SUMMARY OF ECONOMIC CONSIDERATIONS

A brief survey of some of the primary economic considerations that affect electric power production follows. First, general data concerning the costs of the electric power industry are discussed and then the economics of the alternative technologies are summarized.

12.9.1 General Costs of Electric Power

The electric power industry is made up of a great many utility companies. Some of these are owned by private organizations (investor-owned utilities); some are owned by the federal government, municipalities, states, or public utility districts; and some are owned by electric cooperatives. The general structure of the industry is illustrated in Figure 12-12. The investor-owned segment is by far the largest, accounting for 77 percent of the nation's total generating capacity. Nearly all of the approximately 200 major investor-owned utilities operate integrated generation, transmission, and distribution systems. The existence of so many separate and relatively small systems creates a variety of problems. The small systems cannot take advantage of economies of scale, and the large number of systems complicates the job of regional power development.

Historically, the electric utility industry has a record of delivering electric power to the consumer at a continually declining cost. The average price paid by consumers declined from 27 mills per kwh in 1927 to 15.4 mills per kwh in 1968. (In 1968 dollars, this represents a decrease from 52.8 mills per kwh to 15.4 mills per kwh.) Table 12-11 shows U.S. average costs for the three primary functions in electric power supply: generation,

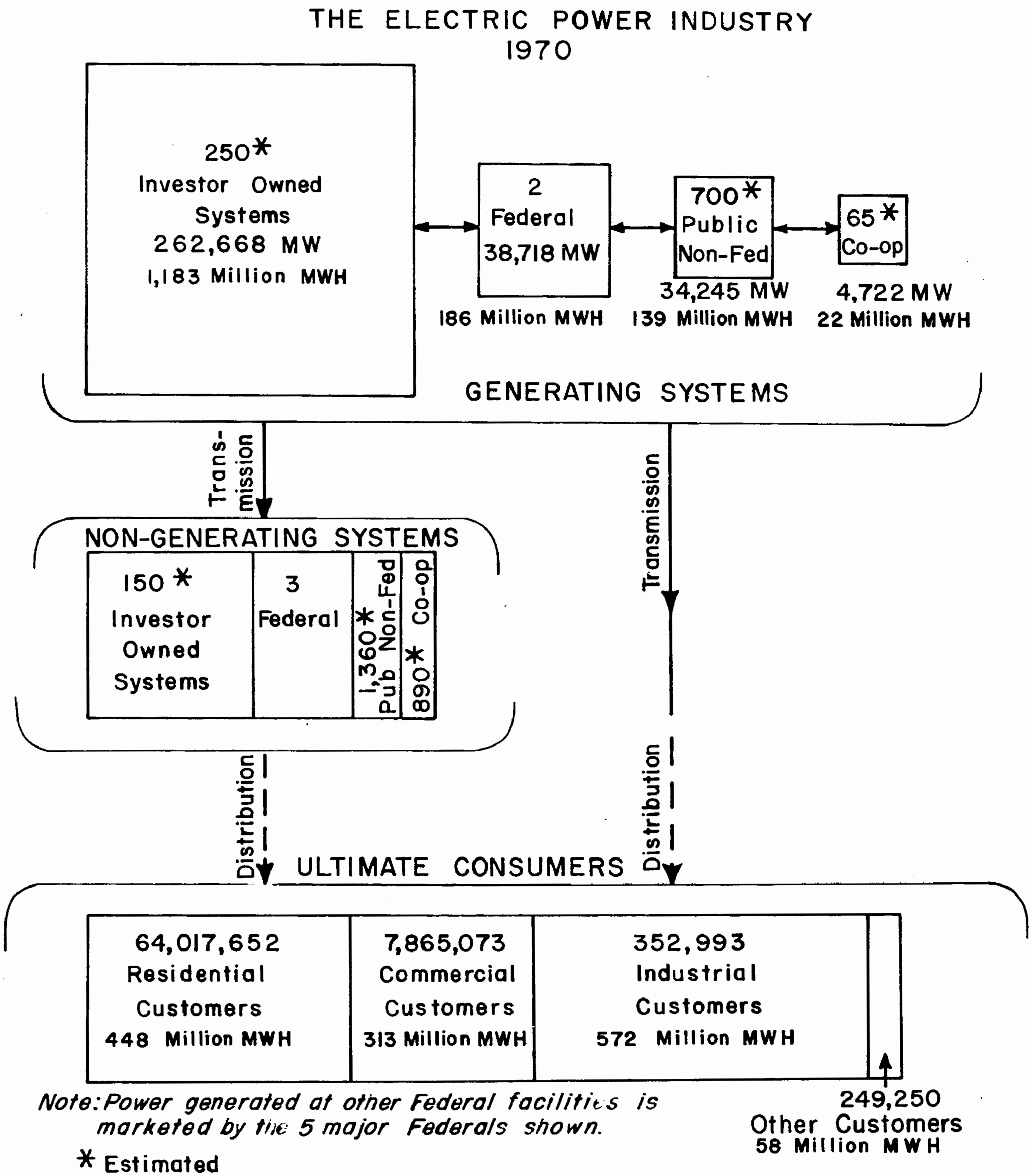


Figure 12-12. The Electric Power Industry

Source: FPC, 1971: I-1-11.

TABLE 12-11

AVERAGE COSTS OF U.S. ELECTRICITY, 1968

Function	Cost (mills per kilowatt hour)	Percent of Total
Generation	7.7	50
Transmission	2.0	13
Distribution	5.7	37
TOTAL	15.4	100

Source: FPC, 1971: I-19-10.

transmission, and distribution. These data indicate that generation alone accounted for one-half of the cost of electricity.

An interesting aspect of electric power is that (for most utilities) the more electricity used by the customers, the cheaper the rate per kwh charged those customers. The rate structures vary from utility to utility and also depend on classification of customers and power needs. As an example, Table 12-12 gives the cost of electricity from a southwestern power company for residential users during two periods of the year.

Any electric power generation plant has three principal cost components: fixed charges on capital investments (including cost of money, depreciation, insurance, taxes, etc.); fuel expenses; and operating and maintenance expenses, excluding fuel, but including allocated administrative and general expenses. (Plants with stack gas cleaning could also add a fourth category for the costs of scrubbing material.)

Although costs of power generation and the relative proportion for each of the three components vary from region to region, the U.S. total for 1968 is given in Table 12-13.

The annual fixed charges can generally be expressed as a percentage of the total capital investment. The percentage used can vary with ownership (private, federal, municipal, etc.) and with the type of equipment, primarily because of differences in service lives but also because of

TABLE 12-12

EXAMPLE OF RESIDENTIAL ELECTRICITY RATE STRUCTURE

On-Peak Season (May-September)		Off-Peak Season (October-April)	
\$1.00	for first 16 kilowatt hours or less	\$1.00	for first 16 kilowatt hours or less
.0380[a]	next 24 kilowatt hours	.0380[a]	next 24 kilowatt hours
.0330[a]	next 100 kilowatt hours	.0330[a]	next 100 kilowatt hours
.0210[a]	next 460 kilowatt hours	.0210[a]	next 460 kilowatt hours
.0185[a]	next 900 kilowatt hours	.0100[a]	next 1,900 kilowatt hours
.0180[a]	next 1,000 kilowatt hours	.0090[a]	all additional kilowatt hours
.0150[a]	all additional kilowatt hours		

Source: Oklahoma Gas and Electric Company.

[a]Dollars per kilowatt hour.

TABLE 12-13

AVERAGE 1968 GENERATION COSTS

Component	Mills per Kilowatt Hour	Percent of Total
Fixed charges	3.71	48
Fuel	2.47	32
Operation and maintenance, allocated administration and general	1.57	20
TOTAL	7.75	100

Source: FPC, 1971: I-19-10.

differences in tax rates and other items. Table 12-14 illustrates the fixed charge rate for a conventional fossil-fueled steam plant with a 30-year life. For this example, a plant with a capital cost of $100 million would have an annual fixed charge cost of $14.2 million (FPC, 1971: I-19-6).

One of the difficulties in comparing many of the cost figures from different sources is that they often use significantly different fixed charge rates, due to different assumptions of service life, interest on borrowed money, etc.

Although fuel costs have increased sharply in recent months and are expected to continue increasing, their percentage of power generation costs may not rise substantially because fixed charges should also increase sharply due to higher interest rates and general inflation.

TABLE 12-14

EXAMPLE OF FIXED CHARGE RATE FOR CONVENTIONAL STEAM PLANT (30-YEAR LIFE)

Component	Annual Fixed Charge Rate (percent of capital investment)
Cost of money	8.2
Depreciation and replacements	1.2
Insurance	0.2
Income taxes	2.2
Other taxes	2.4
TOTAL	14.2

Source: FPC, 1971: I-19-6.

12.9.2 Costs of Alternative Power Plants

For various reasons, it is very difficult to compare the alternative systems based only on a direct comparison of the economic data from the previous sections. First, the estimates are generally made by different sources, each using different assumptions about cost of money, time for construction, future fuel costs, plant operating costs, etc. Second, many of the alternative systems are still in the development stage and thus the cost calculations are based largely on conjecture. However, even though it is difficult to directly compare the data, several important conclusions can be drawn. These are summarized below.

12.9.2.1 Conventional Steam Power Plants

Conventional steam power plants have been the most economical systems to date, with capital cost differences depending on fuel type as shown in Table 12-5. However, the generation costs have been about equal for all fuel systems, as also shown in Table 12-5.

12.9.2.2 Stack Gas Cleaning Technologies

Since stack gas cleaning technologies are still in the early stages of development, their precise cost impact is still somewhat uncertain. It is estimated that the addition of stack gas cleaning systems can cost anywhere from approximately $20 per kw to $65 per kw (1973 dollars), as shown in Table 12-6. This will add from one to two mills per kwh to the cost of electrical generation (Table 12-6), which is from 6 to 15 percent of electricity supply costs (Table 12-11).

12.9.2.3 Fluidized Bed Systems (Including Westinghouse Combined-Cycle System)

Like stack gas cleaning technologies, fluidized bed systems are still in the development stage and thus economics are still uncertain. However, the evidence suggests that fluidized bed systems can generate electric power at or below the cost of steam plants with stack gas cleaning.

12.9.2.4 Gas Turbine Power Plants (Including Combined-Cycles)

The simple gas turbine system has capital cost advantages, but its relatively low efficiency and higher fuel costs make it attractive primarily for peak load purposes. Apparently, combined-cycle power plants can offer capital cost advantages over steam power plants with no loss in overall efficiency, although the precise capital cost differences are not known. Whether these systems will provide lower energy costs will depend on the price and supply of clean gaseous fuels and certain refined liquid fuels in comparison to solid fuels and fuel oils.

12.9.2.5 Other Advanced Conversion Technologies

It is still too early to determine the economic trade-offs of the advanced conversion technologies; i.e., binary cycles, MHD, and fuel cells. However, the trade-offs are generally between the increased capital costs of more complex systems and lower costs for fuel and possible lower costs for pollution control due to increased efficiencies. Of course, it is entirely possible that some of the proposed systems can offer both capital cost and efficiency advantages.

12.9.2.6 Overall Generation Costs

Generation accounts for approximately 50 percent of delivered power cost (Table 12-11), and thus a given percentage increase in generation costs should only increase the total cost of electricity by one-half that percentage.

Fuel costs have ranged from around 33 to 50 percent of generation costs (Tables 12-5 and 12-11). Therefore, even if fuel costs double, total electrical energy costs to the consumer should only increase from 16 to 25 percent.

REFERENCES

Atomic Energy Commission (1974) Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington: Government Printing Office, 4 vols.

Atomic Industrial Forum (1974) "Comparison of Fuels Used in Power Plants." Background INFO, published under the Public Affairs and Information Program. New York: AIF.

Babcock and Wilcox (1972) Steam/Its Generation and Use. New York: The Babcock and Wilcox Company.

Bartock, W., A.R. Crawford, and G.J. Piegari (1972) "Systematic Investigation of Nitrogen Oxide Emissions and Combustion Control Methods for Power Plant Boilers," pp. 66-74 in R.W. Coughlin, A.F. Sarofim, and N.J. Weinstein (eds.) Air Pollution and Its Control, AIChE Symposium Series, Vol. 68, No. 126. New York: American Institute of Chemical Engineers.

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

Council on Environmental Quality (1973) Energy and the Environment: Electric Power. Washington: Government Printing Office.

Davis, John C. (1973) "SO_x Control Held Feasible." Chemical Engineering 80 (October 29, 1973): 76, 77.

Federal Power Commission (1971) 1970 National Power Survey. Washington: Government Printing Office, 5 parts.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975.

Jimeson, R.M., and G.G. Adkins (1971a) "Factors in Waste Heat Disposal Associated with Power Generation." Paper #26a presented at 68th National Meeting of AIChE, Houston, Texas.

Jimeson, R.M., and G.G. Adkins (1971b) "Waste Heat Disposal in Power Plants." Chemical Engineering Progress 67 (July 1971): 64-69.

Keairns, D.L., J.R. Hamm, and D.H. Archer (1972) "Design of a Pressurized Bed Boiler Power Plant," pp. 267-275 in R.W. Coughlin, A.F. Sarofim, and N.J. Weinstein (eds.) Air Pollution and Its Control, AIChE Symposium Series, Vol. 68, No. 126. New York: American Institute of Chemical Engineers.

Nonhebel, Gordon (1964) Gas Purification Processes. London: George Newnes, Ltd.

Olmstead, Leonard M. (1971) "17th Steam Station Cost Survey." Electrical World (November 1, 1971), as cited in Council on Environmental Quality (1973) Energy and the Environment: Electric Power. Washington: Government Printing Office.

Papamarcos, John (1974) "Design Directions for Large Boilers." Power Engineering 78 (July 1974): 34-41.

Shields, Carl D. (1961) Boilers: Types, Characteristics, and Functions. New York: F.W. Dodge Corporation.

Slack, A.V., H.L. Falkenberry, and R.E. Harrington (1972) "Sulfur Oxide Removal from Waste Gases: Lime-Limestone Scrubbing Technology." Journal of the Air Pollution Control Association 22 (March 1972): 159-166.

Soo, S.L. (1972) "A Critical Review on Electrostatic Precipitators," pp. 185-193 in R.W. Coughlin, A.F. Sarofim, and N.J. Weinstein (eds.) Air Pollution and Its Control, AIChE Symposium Series, Vol. 68, No. 126. New York: American Institute of Chemical Engineers.

Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif.: Teknekron.

CHAPTER 13

ENERGY CONSUMPTION

13.1 INTRODUCTION

The preceding chapters reflect the dominant emphasis of this report by describing the nation's alternative energy supplies. However, significant alternatives also exist for energy consumption and, like supplies, these have ranges of efficiencies, environmental residuals, and costs. The energy consumption portion of the U.S. energy system received little public attention until the recent energy shortages and price increases.

Although information on U.S. energy consumption is in an early stage of development, recent studies have provided a more systematic data base. These studies can be divided into three phases. The first phase involved data collection on U.S. energy consumption and classification into meaningful end uses according to various consumption sectors. Phase two involved identification of points within the major consuming sectors where opportunities for energy conservation exist. Phase three, the recent Hittman study, identified the residuals associated with the various end uses found in phase two.

The objectives of this chapter are to: identify quantities of consumption by sector and more specifically by end use (e.g., space heating); identify the environmental residuals associated with the end use; and indicate conservation opportunities resulting either from reduced consumption or increased efficiency. Following a discussion of energy supply and demand, the chapter is divided into three consumption "sectors:" residential and commercial, transportation, and industrial. The first part of each consumption sector describes the applicable technologies (i.e., utilizing devices) and traces the residuals associated with end use. The second part identifies energy conservation alternatives for various end uses, and includes estimates of the potential savings.

Although the end use data format in this chapter is similar to the supply chapters, there are some differences in the data units. The units of residuals for energy consumption are expressed in tons per "measure." The particular "measure" is the unit most appropriate for each end use; examples of measures are passenger-mile, ton, and dwelling-year. A value referred to as the "multiplier" is also included. The "multiplier" is the amount of each end use measure expended in the U.S. for a given year ("multiplier year"). Thus, the product of the energy required for each end use and the multiplier (Column 19 x Column 20) provides an actual yearly energy use expressed in Btu's.

In addition to the above differences, the columns for land use and occupational health are not included in the consumption residuals tables. Land use is not considered the direct result of energy consumption (Hittman, 1974: Vol. I, Table 30, footnote 7026), and, in almost every case, occupational health and safety residuals for energy consumption are identified by Hittman as either not applicable or unknown. The end use residuals data are uncontrolled in

TABLE 13-1

TOTAL AND PER CAPITA U.S. ENERGY CONSUMPTION

Year	Total Energy Consumption (10^{12} Btu's)[a]	Population (millions)	Energy Consumption Per Capita (10^6 Btu's)
1950	34.0	152.3	223.2
1955	39.7	165.9	239.3
1960	44.6	180.7	246.8
1965	53.3	194.2	274.4
1970	67.4	204.8	329.1

Source: Interior, 1972: 11.

[a]Total energy consumption is the sum of inputs into the economy of the primary fuels (petroleum, natural gas, and coal, including imports) or their derivatives, plus the generation of hydro and nuclear power converted to equivalent energy inputs.

that the level of control of environmental impacts is representative of very recent or current practices.

13.1.1 Patterns of Energy Supply and Demand

Since 1950, there has been a growing gap between U.S. energy production and consumption levels. This trend is illustrated in Figure 13-1. Demand for energy in the U.S. grew at an average annual rate of about 3.5 percent from 1950 to 1965, increased to 4.3 percent annually from 1965 to 1970 (Interior, 1972: 12). Concurrently, domestic energy production grew at three percent annually from 1950 to 1970 but has been at a virtual standstill since 1970 (Ford Foundation, 1974: 1). Domestic energy production furnished 84.1 percent of total U.S. energy supplies in 1973, with the remainder supplied by imports (Braddock, Dunn and McDonald, 1974a: III-6). Several projections for the present through 1985 indicate continued domestic supply/demand imbalances in the energy market (BLM, 1973; Interior, 1972; and NPC, 1972).

An important reason for the domestic energy market disparity has been the growth of energy demand during a period when energy was relatively inexpensive. Higher energy usage per capita, compounded by population growth, has resulted in unprecedented levels of energy consumption. Although the U.S. represents only six percent of the world's population, it consumes one-third of the energy used in the world (Cook, 1971: 135). Even though population growth has slowed to about the replacement level, increasing energy use per capita, as shown in Table 13-1, is expected to contribute to an increasing total demand in this country.

13.1.2 Energy Consumption By End Use

Energy consumption by end use in the U.S. is shown in Table 13-2. These estimates were calculated by Stanford Research Institute (SRI) using Bureau of Mines (BuMines) data and other sources. More current energy consumption data, developed by Hittman, are reported in the following sections.

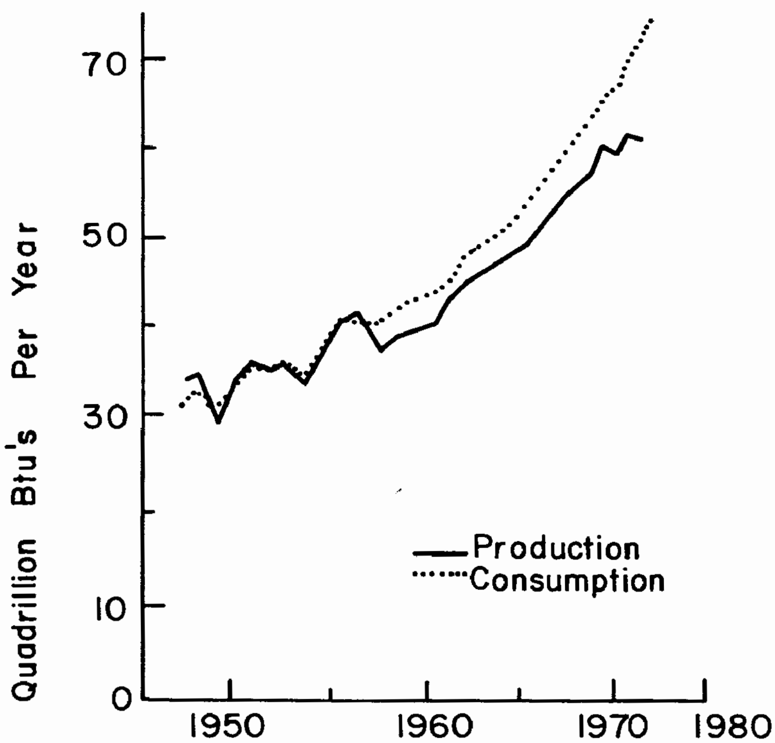


Figure 13-1. Total U.S. Energy Production and Consumption, 1947-1973

Source: Adapted from the Ford Foundation, 1974: 2 (based on Interior, 1972: 11).

TABLE 13-2

ENERGY CONSUMPTION IN THE U.S. BY END USE, 1960-1968

Sector and End Use[a]	Consumption (10^{12} Btu's)		Annual Rate of Growth (percent)	Percentage of National Total	
	1960	1968		1960	1968
Residential					
Space heating	4,848	6,675	4.1	11.3	11.0
Water heating	1,159	1,736	5.2	2.7	2.9
Cooking	556	637	1.7	1.3	1.1
Clothes drying	93	208	10.6	0.2	0.3
Refrigeration	369	692	8.2	0.9	1.1
Air conditioning	134	427	15.6	0.3	0.7
Other[b]	809	1,241	5.5	1.9	2.1
TOTAL	7,968	11,616	4.8	18.6	19.2
Commercial					
Space heating	3,111	4,182	3.8	7.2	6.9
Water heating	544	653	2.3	1.3	1.1
Cooking	98	139	4.5	0.2	0.2
Clothes drying	534	670	2.9	1.2	1.1
Refrigeration[c]	576	1,113	8.6	1.3	1.8
Air conditioning	734	984	3.7	1.7	1.6
Other[d]	145	1,025	28.0	0.3	1.7
TOTAL	5,742	8,766	5.4	13.2	14.4
Industrial					
Process steam	7,646	10,132	3.6	17.8	16.7
Electric drive	3,170	4,794	5.3	7.4	7.9
Electrolytic processes	486	705	4.8	1.1	1.2
Direct heat	5,550	6,929	2.8	12.9	11.5
Feedstock	1,370	2,202	6.1	3.2	3.6
Other	118	198	6.7	0.3	0.3
TOTAL	18,340	24,960	3.9	42.7	41.2
Transportation[e]					
Fuel	10,873	15,038	4.1	25.2	24.9
Raw materials	141	146	0.4	0.3	0.3
TOTAL	11,014	15,184	4.1	25.5	25.2
NATIONAL TOTAL	43,064	60,526	4.3	100.0	100.0

Source: SRI, 1972: 6 (using BuMines and other sources).

[a]Consumption by electric utilities has been allocated to each end use.

[b]Other in residential sector includes lighting, large and small appliances, television, food freezers, etc.

[c]Includes energy consumed for food freezing.

[d]Other in commercial sector is primarily electricity used for lighting and mechanical drives (for computers, elevators, escalators, office machinery, etc.).

[e]See transportation sector discussion for a subdivision of transportation by specific methods.

Several important observations may be made regarding the data in Table 13-2. For example, during the interval 1960 through 1968, annual energy consumption increased from a total of $43{,}064 \times 10^{12}$ Btu's to $60{,}526 \times 10^{12}$ Btu's. The Department of the Interior (Interior) estimated that the total U.S. energy consumption in 1970 had further increased to $67{,}444 \times 10^{12}$ Btu's (Interior, 1972: 40). The table also shows that a relatively few end use categories offer the greatest potential for conservation: residential and commercial space heating and cooling, industrial thermal processes, and transportation fuel usage. Collectively, these activities accounted for approximately 74 percent of the total energy consumption in 1968.

13.1.3 Energy Conservation

Measures to reduce energy demand at the point of end use should be evaluated as a method for achieving a balance between energy production and consumption. That is, conservation might decrease or eliminate some of the requirements that otherwise must be satisfied by new or alternate sources of energy. In addition, slowing the growth rate of energy demand will improve the longevity of domestic supplies, thus allowing more flexibility in developing systems to meet long-term needs (CEQ, 1973: 27).

A number of recent studies have examined ways in which energy demand can be reduced; principal among these is one released by the former Office of Emergency Preparedness (OEP) in 1972. The objective of this study was the suggestion of programs that would either improve the efficiency with which energy is consumed or minimize the consumption of energy while providing the same or similar services to the consumer. OEP divided conservation measures into two broad categories referred to as "belt tightening" and "leak plugging."

Belt tightening is defined as measures that would reduce energy consumption at fixed efficiency levels. If the consumer expended less energy while achieving desired ends (e.g., driving at slower speeds), then energy production could be reduced. Leak plugging is defined as measures that would retain performance while increasing efficiency. In this case, extant technology (e.g., improved insulation in buildings) could be used to improve short- and mid-term energy use (three to eight years). Efficiency improvements in the form of long-term efforts would require new technological developments and/or larger scale application of existing technology (e.g., heat pumps) (OEP, 1972: 5).

13.2 RESIDENTIAL AND COMMERCIAL SECTOR

Energy is consumed in the residential and commercial sector principally for space heating and cooling and water heating. As shown in Table 13-2, these applications for households and commercial establishments required about 24 percent of U.S. energy consumption in 1968. Increasing residential demand is due primarily to more widespread use of electricity-consuming devices for air conditioning, clothes drying, refrigeration, and "other" (primarily lighting, television, and assorted appliances). Growing consumption in the commercial area reflects the expansion of commercial and service activities in the U.S. economy, which have outpaced industrial growth consistently over the last decade (Ford Foundation, 1974: 3). Significant increases in the commercial sector are in air conditioning and "other," which consists of electricity used in lighting, computers, elevators, office machinery, and some electric heat (SRI, 1972: 66).

Table 13-3 is a breakdown of energy consumption by fuel for the major end uses of energy in the residential and commercial sector in 1970. As would be expected, two-thirds of total demand is for natural gas and electricity. Distillate fuel ranks third as a result of its contribution to residential space heating. Coal usage in these two sectors is insignificant except for its use in commercial space heating.

TABLE 13-3

FUEL CONSUMPTION FOR MAJOR END USES IN THE RESIDENTIAL AND COMMERCIAL SECTOR, 1970

End Use Sector	Fuel Type (10^{12} Btu's per year)						Total
	Natural Gas	LPG[a]	Distillate	Residual	Electricity	Coal	
Residential End Use							
Space heating	4,375	476	2,294	NC	708	NC	7,853
Air conditioning	14	NA	NA	NA	570	NA	584
Water heating	945	85	214	NA	744	NA	1,988
Refrigeration (includes freezer)	NC	NA	NA	NA	1,126	NA	1,126
Cooking[b]	328	56	NA	NA	310	NA	694
Commercial End Use							
Space heating	1,857	83	569	1,173	NC	427	4,109
Air conditioning	43	NA	NA	NA	868	NA	911
Water heating	419	18	NC	NA	263	NA	700
Refrigeration (includes freezer)	NC	NA	NA	NA	777	NA	777
Cooking	120	5	NA	NA	26	NA	151
TOTAL	8,099	723	3,076	1,173	5,392	427	18,893

NA = not applicable, NC = not considered.

Source: Calculated from Hittman, 1974: Vol. I, Tables 27 and 28.

[a]Liquefied Petroleum Gas (butane, propane, etc.).

[b]Does not include natural gas, LPG, or electricity consumption for automatic-cleaning oven-ranges.

13.2.1 Space Heating

13.2.1.1 Technologies

Space heating in the residential and commercial sector accounted for approximately 18 percent of the national energy requirement in 1970. This end use represents the largest single energy-consuming function for both homes and commercial buildings. Almost 70 percent of American homes now contain central heating or built-in units which deliver heat to every room in the house. (Battelle, 1973: 603). Energy for space heating, as indicated in Table 13-3, is used either directly as fuel (coal, natural gas, and petroleum products) or as electricity.

13.2.1.1.1 Direct Combustion and Electrical Resistance Heating

Natural gas and petroleum products provide the major energy sources for space heating. However, electricity is increasingly the energy source for this end use. Only 0.7 million homes were electrically heated in 1960, but 4.9 million used electric heat in 1970 (SRI, 1972: 40; Battelle, 1973: 603). Currently, electrical resistance heating is estimated to comprise 20 percent of the installations in new homes. Some electric space heating is probably used by commercial activities, but information is not available on the actual amounts. Likewise, coal usage for residential combustion space heating is significant in some geographic regions but is assumed "nil" in most source studies.

13.2.1.1.2 Heat Pumps

The electric heat pump represents an efficient, alternative technology for space heating because it delivers about two units of heat for each unit of electricity consumed (Hirst and Moyers, 1973a: 1301). The primary application of heat pumps to date has been in space heating and cooling of residential buildings, although some have been installed in larger commercial buildings. In 1970, only 11 percent of electrically heated households in the U.S. had heat pumps (Tansil).

The heat pump is essentially a refrigeration system capable of operating in reverse to provide heating. Economic considerations dictate that heat pumps use the vapor compression refrigeration cycle (Battelle, 1973: 540). In this cycle, the evaporator extracts energy (heat) from a low-temperature source (the outside atmosphere in the heating season and the indoor environment in the cooling season) and rejects this heat to the higher temperature reservoir. Heat is "pumped" outdoors to provide summer cooling and "pumped" indoors for winter heating.

Since heat pump power requirements and thermal energies vary as a function of outside air temperature, overall heat pump efficiency is as much as 50 percent lower in cold regions (Hirst and Moyers, 1973b: 168). As a result, heat pump performance must be evaluated on the basis of seasonal temperature information for different U.S. climatic regions.

Central heat pump systems are manufactured by Carrier, Chrysler, Fedders, General Electric, Singer, Westinghouse, and other corporations. In addition to high capital costs, excessive maintenance costs due to equipment failure have curtailed the widespread use of heat pumps. However, efforts to improve unit reliability are currently being made which should increase heat pump acceptance by homeowners (Hirst and Moyers, 1973b: 169).

13.2.1.1.3 Solar Energy

For a description of on-site solar energy technologies, efficiencies, and related environmental considerations, see Chapter 11.

Solar energy for space heating and cooling and water heating in the residential sector could become economically feasible in some regions of the country (e.g., the Southwest) if the price of fuel increases sufficiently (OEP, 1972: D-5). During the past 30 years, the use of solar energy for heating has developed slowly through the design and construction of about 20 solar collection and storage systems in houses and experimental buildings in the U.S., Japan, Australia, and Italy. Solar space heating and cooling systems are presently available in the U.S. on a custom-built basis (NSF/NASA Solar Energy Panel, 1972: 13).

All solar heating systems have common elements, but their characteristic design and operation vary from one installation to another. Consequently, solar collectors and heat storage systems have not developed the necessary dependability and economy required for mass production and widespread public use. In addition, though solar energy is well distributed, energy storage requirements and seasonal needs would have to be carefully considered for each locality.

13.2.1.2 Energy Efficiencies

For this report, the efficiency with which fuels and energy are utilized is defined as the efficiency of the fuel-using device by itself (e.g., the furnace efficiency of a residential space heating unit).

Some of the differences in space heating efficiencies can be explained by the type of fuel used. Table 13-4 is a breakdown of the estimated efficiencies for space heating by fuel in the residential and commercial sector. These estimates reflect average experience rather than the maximum achievable. It is estimated that

TABLE 13-4

SPACE HEATING EFFICIENCIES BY FUEL FOR THE RESIDENTIAL AND COMMERCIAL SECTOR

Fuel Type	Residential (percent)	Commercial (percent)
Coal	55	70
Natural gas	75	77
Petroleum products	63	76
Electricity	95	95

Source: SRI, 1972: 153.

start-up, shutdown intermittency (temperature control by thermostat on-off operation) of a residential gas-fired furnace can drop the overall efficiency to as low as 50 to 60 percent. Also, equipment maladjustments can reduce the efficiency another 5 to 10 percent (Schurr, 1971: VIII-32, VIII-33). Thus, reported typical end use efficiencies of gas- and oil-burning home heating systems range between 40 and 80 percent.

As shown in Table 13-4, coal efficiency is much higher for commercial establishments than for residences, primarily because of better equipment maintenance and adjustment. Conversely, the efficiency of the larger, more sophisticated commercial natural gas burners is only two percent greater than that of home furnaces. Oil efficiency in commercial establishments is substantially higher than in homes and approaches natural gas efficiency. The efficiencies of coal, gas, and oil heating units are limited primarily by economics. Additional heat exchangers necessary to extract all possible heat from the combustion gases would require substantial capital investment in the heating device.

As indicated in Table 13-4, electric heating is considered 95-percent efficient in both homes and businesses. However, this estimate applies only to the conversion of electricity to heat and does not take into account the conversion of fuel to electricity. In the U.S., the average efficiency for electric power generation plants is about 33 percent (see Chapter 12). Thus, if the efficiency for electrical resistance heating included electricity generation, the total system efficiency would be approximately 30 percent (SRI, 1972: 154).

Table 13-5 lists typical coefficient of performance (C.O.P.) values obtainable for electric heat pumps using various heat sources and sinks. The performance measure for heat pumps is defined as the ratio of useful heat moved to the quantity of energy required to operate the system. Given an electric power generation plant operating at approximately 33-percent efficiency in conjunction with an air-to-air heat pump (C.O.P. of 2.5--average overall performance given certain assumptions about the climate of the region), the total system efficiency is 33 percent times 2.5 or about 82 percent. On the average, this efficiency is better than that required for fueling a typical

TABLE 13-5

COEFFICIENTS OF PERFORMANCE FOR ELECTRICALLY DRIVEN HEAT PUMPS WITH VARIOUS SOURCES AND SINKS

Source and Sink	Coefficient of Performance[a] (C.O.P.)	
	Heating	Cooling
Air	2.5	3.0
Water	5.0	4.0
Earth	3.0	3.0

Source: Battelle, 1973: 540.

[a] C.O.P. is the ratio of heat moved to the quantity of energy needed to operate the system (see text).

house furnace. Note that as the overall operating efficiency of the central power station increases, the heat pump potential relative to other heating systems also increases (Battelle, 1973: 541).

13.2.1.3 Environmental Considerations

Table 13-6 contains the environmental residuals quantified by Hittman for residential and commercial space heating. Impact data corresponds to a particular fuel, and the fuel used serves as the link between the end use and supply portions of the data. Where the end use is electrical, the Btu values represent the energy necessary to generate that electricity. Therefore, these values include the 67-percent energy loss involved in the generation phase. The residuals for electrical space heating devices occur prior to end use; that is, the residuals are at the central power station. The data in Table 13-6 are considered fair, with a probable error of less than 50 percent.

A quick review of Table 13-6 shows that space heating environmental impacts are primarily air pollutants with the principal emissions being particulates, oxides of nitrogen (NO_x), and oxides of sulfur (SO_x). As reported in the technological description, specific air emissions can be affected by fuel type, quality, and other factors such as equipment design, adjustment, and maintenance. The significance of these residuals is directly related to the concentration of residential and commercial activities and to local meteorological and topological circumstances.

13.2.1.4 Economic Considerations

Relatively "cheap" energy (i.e., energy that is inexpensive compared to other components of production cost) discourages investment in more energy-efficient systems. As long as energy was cheap and abundant, the economic trade-off favored low capital investment rather than optimization of long-term maintenance and operating costs. Rising energy prices and the possibility of limited supplies should encourage consumers to consider energy consumption levels and lifetime operating costs as well as the initial cost of heating equipment.

Table 13-7 depicts fuel costs and consumption levels for heating a typical 1,500-square foot house by various methods. The fuel quantity is the Btu equivalent measured at the input to the power plant. The fuel costs for oil and gas heating are essentially the same, while electrical resistance heating costs about twice as much. From a conservation viewpoint, direct combustion heating does not waste as much primary fuel as electrical resistance heating because the electrically heated home requires about twice as much fuel per unit of heat delivered. Because of the higher operating costs of electrical resistance heat, only the more expensive homes would be expected to use it. However, lower installation costs and promotional appeals have resulted in widespread use. Presently, electric rate schedules favor heavy electricity users, which enhances electric heating. However, pressure is increasing to remove or in some manner reduce these advantages because they favor energy wastefulness (Braddock, Dunn and McDonald, 1974b: V-16).

The utilization of heat pumps could equalize the positions of electric, gas, and oil heating systems from a fuel conservation standpoint. As a countrywide average, the heat pump delivers about two units of heat energy for each unit of electrical energy that it consumes (Hirst and Moyers, 1973a: 1301). Also, dual heating/cooling heat pumps are not particularly expensive when compared to conventional central heating/cooling systems because the basic equipment and air handling systems are the same for both heating and cooling. Although the figure seems low, one source estimated that installed in a typical residence, a

Table 13-6. Residuals for Space Heating Energy Use

End Use Sector	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)										
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (tons/measure)	Measure[a,b]	Energy Btu/measure	Multiplier	Multiplier Year
Residential End Use/Fuel																					
SPACE HEAT																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.15×10^{-3}	3.03×10^{-3}	3.45×10^{-5}	4.86×10^{-4}	1.21×10^{-3}	6.05×10^{-4}	NA	Dwelling-year	1.25×10^{8}	3.5×10^{7}	1970
Liquid Petroleum Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.21×10^{-3}	3.92×10^{-3}	7.06×10^{-4}	4.9×10^{-3}	1.28×10^{-3}	6.22×10^{-4}	NA	Dwelling-year	1.25×10^{8}	3.81×10^{6}	1970
Distillate	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	5.01×10^{-3}	6.01×10^{-3}	1.62×10^{-2}	1.5×10^{-3}	2.5×10^{-3}	.001	NA	Dwelling-year	1.39×10^{8}	1.65×10^{7}	1970
Electricity	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Dwelling-year	1.45×10^{8}	4.88×10^{6}	1970
Commercial End Use/Fuel																					
SPACE HEAT																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.32×10^{-6}	1.23×10^{-5}	7.15×10^{-8}	9.78×10^{-7}	2.45×10^{-6}	1.23×10^{-6}	NA	Square foot year	2.52×10^{5}	7.37×10^{9}	1970
Liquid Petroleum Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.45×10^{-6}	1.32×10^{-5}	1.38×10^{-6}	9.87×10^{-7}	2.58×10^{-6}	1.25×10^{-6}	NA	Square foot year	2.52×10^{5}	3.3×10^{8}	1970
Distillate	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	1.38×10^{-5}	5.54×10^{-5}	2.90×10^{-5}	2.76×10^{-6}	1.84×10^{-7}	1.84×10^{-6}	NA	Square foot year	2.55×10^{5}	2.23×10^{9}	1970
Residuals	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	1.96×10^{-5}	5.12×10^{-5}	2.28×10^{-4}	2.56×10^{-6}	1.71×10^{-7}	8.54×10^{-7}	NA	Square foot year	2.55×10^{5}	4.6×10^{9}	1970
Coal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.19×10^{-4}	3.39×10^{-5}	3.43×10^{-4}	1.28×10^{-5}	5.64×10^{-5}	2.09×10^{-7}	U	Square foot year	2.77×10^{5}	1.54×10^{9}	1970

NA = not applicable, NC = not considered, U = unknown.

[a]Dwelling-year is a heated and cooled typical residence operated for one year.

[b]Square foot-year is a heated and cooled typical square foot of commercial space over a period of one year.

TABLE 13-7

ANNUAL FUEL COST AND CONSUMPTION FOR SPACE HEATING[a]

Heating Method	Fuel Cost (dollars)	Fuel Quantity[b] (10^6 Btu's)
Resistance heating	471.3	251.3
Electric heat pump	117.6	62.8
Home combustion, oil	209.0	154.6
Home combustion, natural gas	227.1	134.0

Source: Szego, 1971: Vol. II, Part B, p. F-27.

[a]Represents heating cost and consumption for a typical 1,500-square foot house.

[b]Btu equivalent is measured at the input to the power plant.

three-ton heat pump unit would cost about $1,800 (Battelle, 1973: 541). However, if increased utilization is expected, cost data and unit reliability need to be more firmly established.

Solar energy residential heating in suitable climates could be available even today at costs below those of electrical resistance heat (Tybout and Lof, 1970; Szego, 1971: Vol. II, Part B, p. G-18). Further, as the cost of conventional heating fuels increases and solar economics become more certain, solar heating should compare even more favorably.

13.2.2 Air Conditioning

13.2.2.1 Technologies

In 1970, residential and commercial air conditioning accounted for 3.0 percent of the national energy requirement. More important, air conditioning represents one of the most rapidly growing uses of energy. From 1960 through 1968, residential air conditioning grew at an annual compounded rate of 16 percent (Table 13-2). In addition, approximately 18 percent of the increase in total residential electrical energy consumption between 1960 and 1970 was due to electric-powered "compression-type" air conditioning; more than one-half of this increase was consumed by room units (Large, 1973: 871).

Using averages reported by the SRI (1972: 73), Hittman estimated that about 70 percent of the building space in commercial establishments was air conditioned in 1970 (13 percent used gas as a fuel source with the remainder allotted for electricity). Since electricity meets most of the air conditioning needs and powers the auxiliary equipment for gas units, space cooling is an important factor in summer peak loads of utility systems (Braddock, Dunn and McDonald, 1974b: II-1, II-2).

13.2.2.2 Energy Efficiencies

The efficiencies of heat removal for air conditioning have been estimated at 50 percent for electric equipment and 30 percent for gas equipment (SRI, 1972: 173). Thus, the cooling cycle is much less efficient than the heating cycle.

The conventional measure of efficiency for room air conditioners is the ratio of cooling capacity to power requirements expressed in Btu's per watt-hour. Existing

TABLE 13-8

VARIATIONS IN PERFORMANCE OF SELECTED AIR CONDITIONERS

Rated Cooling Capacity (Btu's)	Rated Current Demand (amperes)	Retail Price (dollars)	Power Consumption (Btu's per watt-hour)	10-Year Total Cost (dollars per 1,000 Btu's)
4,000	8.8	100	3.96	84
	7.5	110	4.65	77.70
	7.5	125	4.65	81.45
	5.0	135	6.96	67.25
5,000	9.5	120	4.58	74.90
	7.5	140	5.80	68.20
	7.5	150	5.80	70.20
	5.0	165	8.70	59.80
6,000	9.1	160	5.34	67.30
	9.1	170	5.24	68.90
	7.5	170	6.96	61.80
	7.5	180	6.96	63.50
8,000	12	200	5.80	67.30
	12	220	5.80	67.80
24,000	13.1	U	8.25	U
	15.4	U	7.10	U
	17.0	U	5.85	U

U = unknown

Source: Federal Council on Science and Technology.

data indicate that room air conditioner efficiencies vary widely from one model to another. Differences of efficiency also occur for different models with the same rated cooling capacity. In a study of units having ratings up to 24,000 Btu's per hour published by the Committee on Energy Research of the Federal Council on Science and Technology (Table 13-8), efficiencies ranged from 3.96 to 8.70 Btu's per watt-hour, with a probable error of less than 50 percent for most of the data. Thus, the least efficient device consumes 2.2 times as much electricity per unit of cooling as the most efficient one. Table 13-8 illustrates that the most expensive units generally offer the best efficiency and the lowest long-term costs.

From the standpoint of primary fuels consumption, electric central air conditioning systems are more efficient than gas in a private household. For large buildings, gas may be more efficient.

13.2.2.3 Environmental Considerations

Estimates of the environmental residuals for natural gas central residential and commercial air conditioning systems are given in Table 13-9. The validity of the data is unknown, with the error probably within or around an order of magnitude. The residuals for the electric equipment occur prior to end use; that is, at the electric power generation plant.

13.2.2.4 Economic Considerations

In general, as noted in Table 13-8, the efficiency of air conditioning equipment correlates with price; units with efficiency improving design features (e.g., larger heat transfer surfaces, more efficient motors, etc.) cost more to build. Due to

Table 13-9. Residuals for Air Conditioning Energy Use

End Use Sector	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)										
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/ measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (tons/measure)	Measure[a,b,c]	Energy Btu/measure	Multiplier	Multiplier Year
Residential End Use/Fuel																					
AIR CONDITIONING: Central																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5.72×10^{-4}	1.66×10^{-3}	1.8×10^{-5}	2.41×10^{-4}	6.02×10^{-4}	3.01×10^{-4}	NA	Dwelling-year	6.2×10^{7}	2.18×10^{5}	1970
Electric	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Dwelling-year	3.69×10^{7}	7.04×10^{6}	1970
Room																					
Electric	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Unit-year	1.42×10^{7}	2.18×10^{7}	1970
Commercial End Use/Fuel																					
AIR CONDITIONING: Central																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2.68×10^{-7}	1.55×10^{-6}	8.23×10^{-9}	1.13×10^{-7}	2.82×10^{-7}	1.41×10^{-7}	NA	Square foot year	2.91×10^{4}	1.46×10^{9}	1970
Electric[d]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Square foot year	3.93×10^{4}	1.46×10^{9}	1970
Electric	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Square foot year	8.28×10^{4}	9.8×10^{9}	1970

NA = not applicable.

[a]Dwelling-year is a heated and cooled typical residence operated for one year (measure assumes central unit with 24,000 Btu's per hour rating).

[b]Unit-year based on average yearly operation of a single consuming device (measure assumes room unit with 10,000 Btu's per hour rating).

[c]Square foot-year is a heated and cooled typical square foot of commercial space over a period of one year (measure assumes 48 Btu's per hour per square foot).

[d]For auxiliary equipment.

the large number of available models and the range of efficiencies (complicated by the fact that efficiency figures have not been given in a meaningful way to the public), the consumer is not likely to select the unit with the best long-term cost. Instead, his decision will likely depend more on first costs, resulting in the purchase of a unit with a lower selling price and, generally, a lower efficiency.

In addition to picking the most energy-efficient unit, it is equally important to accurately determine the needed cooling capacity. A larger than necessary unit will not only draw excess power but also will not cool properly as it tends to cycle off before the room space is sufficiently dehumidified.

In the case of central air conditioners (24,000 to 36,000 Btu's per hour), installation expenses and operating costs vary markedly in the same manner as room units. In general, however, gas units are more expensive to install but may be less expensive to operate.

Finally, most space cooling equipment uses an inefficient and inexpensive throttle valve to expand the fluid used in the system and thus produce the cooling effect. To accommodate for the cooling losses caused by this throttling process, an excess of 20-percent power consumption is designed into the cycle for a given cooling capacity (Berg, 1974: 21). In other words, since market demand is based primarily on first cost, the first-cost economies of throttling valve use are more important in customer sales than the long-term inefficiencies of such units.

13.2.3 Water Heating

13.2.3.1 Technologies

Water heating in the residential and commercial sector accounted for approximately four percent of the national energy demand in 1970. About three-fourths of this amount was used in residences where

TABLE 13-10

WATER HEATING EFFICIENCIES BY FUEL
FOR THE RESIDENTIAL AND COMMERCIAL SECTOR

Fuel Type	Residential (percent)	Commercial (percent)
Coal	15	70
Natural gas	64	64
Petroleum products	50	50
Electricity	92	92

Source: SRI, 1972: 154.

water heating is the second largest energy-consuming function. Currently, increased consumption for both electric and gas water heaters is explained by the increasing numbers of dishwashers and washing machines. Not only do these appliances demand more energy for hot water, but they also require electricity for operation. As per capita affluence increases in this country, the number of appliances using hot water is likewise expected to increase. Some manufacturers offer heat pump energized water heaters, but data are not available for this technology.

13.2.3.2 Energy Efficiencies

The efficiency of heating water varies by fuel as shown in Table 13-10. Most of the data are considered good, with a probable error of less than 25 percent. About 20 percent of the energy used by hot water heaters is required to maintain the desired temperature of the water; that is, to compensate for heat losses to the heater's surroundings and for water that cools off in piping between uses (Hirst and Moyers, 1973b: 174).

13.2.3.3 Environmental Considerations

Table 13-11 contains the environmental residuals for water heating in the

Table 13-11. Residuals for Water Heating Energy Use

End Use Sector	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)										
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/ measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (tons/measure)	Measure[a]	Energy Btu/measure	Multiplier	Multiplier Year
Residential End Use/Fuel																					
WATER HEAT																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	U	2.49×10^{-4}	7.22×10^{-4}	7.86×10^{-6}	1.05×10^{-4}	2.62×10^{-4}	1.31×10^{-4}	NA	Dwelling-year	2.7×10^{7}	3.5×10^{7}	1970
Liquid Petroleum Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	U	2.62×10^{-4}	9.35×10^{-4}	1.53×10^{-4}	1.06×10^{-4}	2.76×10^{-4}	1.34×10^{-4}	NA	Dwelling-year	2.7×10^{7}	3.14×10^{6}	1970
Distillate	NA	NA	NA	NA	NA	NA	0	NA	NA	U	1.25×10^{-3}	1.5×10^{-3}	4.03×10^{-3}	3.92×10^{-4}	6.25×10^{-4}	2.5×10^{-4}	NA	Dwelling-year	3.46×10^{7}	6.2×10^{6}	1970
Electricity	NA	NA	NA	NA	NA	NA	NA	NA	NA	U	NA	NA	NA	NA	NA	NA	NA	Dwelling-year	4.62×10^{7}	1.61×10^{7}	1970
Commercial End Use/Fuel																					
WATER HEAT																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	U	9.58×10^{-9}	5.55×10^{-8}	2.95×10^{-10}	4.03×10^{-9}	1.01×10^{-8}	5.04×10^{-9}	NA	Gallons	1.04×10^{3}	4.03×10^{11}	1970
Liquid Petroleum Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	U	1.01×10^{-8}	$6. \times 10^{-8}$	5.73×10^{-9}	4.09×10^{-9}	1.06×10^{-8}	5.18×10^{-9}	NA	Gallons	1.04×10^{3}	1.7×10^{10}	1970
Electricity	NA	NA	NA	NA	NA	NA	NA	NA	NA	U	NA	NA	NA	NA	NA	NA	NA	Gallons	2.19×10^{3}	1.2×10^{11}	1970

NA = not applicable, NC = not considered, U = unknown.

[a]Dwelling-year is water heated in a typical residence over a period of one year.

residential and commercial sector. The data are considered fair, with a probable error of less than 50 percent. Residuals quantified are for natural gas, liquefied petroleum gas (LPG), and distillate-using devices. The residuals for electric water heaters occur at the electric power generation plant and not at the end use point. Compared to the residuals for space heating, water heating air emissions are relatively small (particularly in the commercial use).

13.2.3.4 Economic Considerations

The use of additional insulation in the jacket surrounding the water storage tank appears to be a promising way of decreasing water heater energy consumption. However, as with space-conditioning devices, the trade-off is in terms of lower initial investments. The cost of two-inch, factory-installed insulation for electric water heaters is about $5.00 per unit cheaper than if three-inch insulation is used. Yet, use of three-inch insulation would result in an operating savings of $1.00 to $2.00 per year, resulting in a net savings over the normal 10-year service life of these water heaters (Hirst and Moyers, 1973b: 174).

13.2.4 Refrigeration

13.2.4.1 Technologies

Refrigeration in the residential and commercial sector accounted for 2.5 percent of the total energy demand in 1970. Estimates report 96 percent of all households had refrigerators in 1969 (SRI, 1972: 46). In the commercial area, supermarkets, public eating places, and institutions have been identified as the major users of refrigeration and food storage.

Increased size and design changes (e.g., automatic ice cube makers, frostfree operation) have contributed to increased unit consumption. Using averages calculated by Hittman, total residential and commercial consumption for refrigeration and freezer use in 1970 was $2,904 \times 10^{12}$ Btu's (Hittman, 1974: Vol. I, Table 27), compared to approximately $1,362 \times 10^{12}$ Btu's in 1968. Part of this increase can be attributed to more widespread use of large, frostfree model refrigerator/freezers which require about two-thirds more energy than smaller, manual defrost units (Ford Foundation, 1974: 2).

13.2.4.2 Energy Efficiencies

The average efficiency of electric refrigeration devices is about 50 percent (SRI, 1972: 155).

13.2.4.3 Environmental Considerations

The environmental residuals for residential and commercial electric refrigeration occur at the central power plant. Although some gas refrigerators are still used in the U.S., their environmental impact is negligible.

13.2.4.4 Economic Considerations

Both the operating and capital costs for frost-free refrigerator/freezers are higher than for standard models. This is an example of how the convenience extras, which are available in many electric appliances, often increase their energy consumption. As a result, there is a need for better labeling (e.g., capacity, fuel consumption, electric power rating, service life expectancy, etc.) of appliances so that consumers can weigh increased operating costs against the added convenience. These trade-offs will become more significant to consumers if electricity costs continue to increase.

13.2.5 Cooking

In 1970, cooking accounted for 1.2 percent of the overall energy consumption in the U.S.

13.2.5.1 Technologies

Gas or electric oven/ranges were found in 96 percent of all U.S. households by 1960.

Although electric range usage increased from 33 percent in 1960 to 40 percent in 1968, the average per-unit energy consumption decreased, probably because of the use of improved heat-transfer materials. As in other appliances, range convenience features such as self-cleaning ovens, automatic timers, and built-in clocks increase energy consumption.

In the commercial sector, energy demand for cooking is affected primarily by the nature, size, and diversity of the equipment. Although insignificant in terms of total national energy consumption, commercial cooking is one of the fastest growing end uses in this sector. Between 1960 and 1968, the annual growth rate of commercial cooking was 4.5 percent, larger than that of commercial space heating (3.8 percent).

13.2.5.2 Energy Efficiencies

Both natural gas and LPG have an efficiency of about 37 percent in cooking, while electricity has 75-percent efficiency (SRI, 1972: 154). Self-cleaning features on ovens have been estimated to increase overall energy consumption by 21 percent. Also, thermal efficiencies vary according to several factors; for example, different utensils and different amounts of water.

Microwave ovens are an important development in cooking technology. American Gas Association studies show that microwave ovens use an average 96.5 percent fewer Btu's than gas ovens and 71.4 percent fewer Btu's than electric ovens (SRI, 1972: 46).

13.2.5.3 Environmental Considerations

Table 13-12 gives the environmental residuals associated with cooking. These residuals are negligible in terms of overall residential and commercial environmental impacts, even considering the probable error of about 100 percent.

Automatic-cleaning oven/ranges used in residences emit higher per-unit levels of air pollutants than standard oven/ranges. For example, a natural gas range with automatic oven cleaner emits 4.67×10^{-4} tons per dwelling-year of air emissions compared to 4.47×10^{-4} tons per dwelling-year for a standard oven/range.

13.2.5.4 Economic Considerations

Like other appliances, ovens waste considerable amounts of energy because market demand is based primarily on initial cost, with operating costs and service life expectancy secondary. In addition, convenience extras increase both capital and long-term appliance costs.

Recently, the price of microwave ovens has reached a competitive level, causing their sales to make headway in the residential market. This factor could enhance conservation goals.

13.2.6 Other

Of the remaining end uses reported by Hittman for the residential and commercial sector, only natural gas yard lights and gasoline-powered lawn and garden equipment have measurable environmental residuals associated with their use.

Each natural gas yard light emits 5.24×10^{-6} tons of SO_x per unit-year. Since approximately 3,800,000 such lights were in use at the end of 1971, almost 20 tons of SO_x were emitted by these lights during that year.

Air pollutants in tons per unit-year for gasoline-powered lawn and garden equipment are: 3.05×10^{-4} for particulates; 2.83×10^{-4} for NO_x; 3.04×10^{-5} for SO_x; 2.49×10^{-2} for hydrocarbons; 2.32×10^{-2} for carbon monoxide (CO); and 3.99×10^{-5} for aldehydes. This represents a total of 2.63×10^{-2} tons per unit-year of air pollutants, the major portion being hydrocarbons and CO.

13.2.7 Conservation Measures for the Residential and Commercial Sector

As discussed in the preceding sections, the principal energy consuming end uses--

Table 13-12. Residuals for Cooking Energy Use

End Use Sector	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)										
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (tons/measure)	Measure[a]	Energy Btu/measure	Multiplier	Multiplier Year
Residential End Use/Fuel																					
COOKING:																					
Standard Oven-Range																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.68×10^{-5}	1.53×10^{-4}	3.06×10^{-6}	4.08×10^{-5}	1.02×10^{-4}	5.09×10^{-5}	NA	Dwelling-year	1.05×10^{7}	3.12×10^{7}	1970
Liquid Petroleum Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.01×10^{-4}	1.98×10^{-4}	5.9×10^{-5}	4.09×10^{-5}	1.06×10^{-4}	5.19×10^{-5}	NA	Dwelling-year	1.05×10^{7}	5.31×10^{6}	1970
Electric	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Dwelling-year	1.2×10^{7}	2.58×10^{7}	1970
Automatic Cleaning Oven-Range																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.01×10^{-4}	1.6×10^{-4}	3.21×10^{-6}	4.27×10^{-5}	1.07×10^{-4}	5.33×10^{-5}	NA	Dwelling-year	1.1×10^{7}	U	U
Liquid Petroleum Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.6×10^{-4}	2.07×10^{-4}	6.19×10^{-5}	4.28×10^{-5}	1.11×10^{-4}	5.44×10^{-5}	NA	Dwelling-year	1.1×10^{7}	U	U
Electric	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Dwelling-year	1.23×10^{7}	U	U
Commercial End Use/Fuel																					
COOKING:																					
Natural Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	3.42×10^{-8}	1.08×10^{-7}	1.05×10^{-9}	1.44×10^{-8}	3.6×10^{-8}	1.8×10^{-8}	NA	Meal	3.7×10^{3}	3.24×10^{10}	1970
Liquid Petroleum Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	3.59×10^{-8}	1.16×10^{-7}	2.03×10^{-8}	1.46×10^{-8}	3.78×10^{-8}	1.84×10^{-8}	NA	Meal	3.7×10^{3}	1.4×10^{9}	1970
Electric	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Meal	5.55×10^{3}	4.62×10^{9}	1970

NA = not applicable.

[a]Dwelling-year is cooking in a typical residence over a period of one year.

space heating, air conditioning, and water heating--are the same for households and commercial establishments. Thus, conservation measures aimed at one are generally applicable to the other. A recent study (Ford Foundation, 1974a: 48) identified two basic criteria for conservation measures: a significant savings in energy should be possible, and the conservation measure must be economical (i.e., save money for the consumer). For example, the installation of electric heat pumps instead of electric resistance heating units in new homes and businesses in some parts of the U.S. would result in a small additional investment but very significant dollar savings per year in electricity bills. Thus, this conservation measure is also economical on a life cycle cost basis.

The OEP study cited in Section 13.1.3 found the greatest potentials for energy savings in the residential and commercial sector to be improved insulation in homes and adoption of more efficient air conditioning systems. Following is a summary of OEP's recommendations (1972: 56-57) for short-, mid-, and long-term measures. The potential savings given for each period are estimates for the last year of the period and are expressed both in Btu's per year and as a percentage of the projected total residential and commercial consumption.

1. Short-Term Measures (1972-1975). Provide tax incentives and insured loans to encourage improved insulation in homes. Encourage use of more efficient appliances and adoption of good conservation practices. Savings: 100×10^{12} Btu's per year (one percent).
2. Mid-Term Measures (1976-1980). Establish upgraded construction standards, tax incentives, and regulations to promote design and construction of energy-efficient dwellings, including the use of the "total energy concept" for multi-family dwellings. Provide tax incentives, R&D funds, and regulations to promote energy-efficient appliances, central air conditioning, water heaters, and lighting. Savings: $5{,}100\times10^{12}$ Btu's per year (14 percent).
3. Long-Term Measures (beyond 1980). Provide tax incentives and regulations to encourage demolition of old buildings and construction of new, energy-efficient buildings. Provide R&D funding to develop new energy sources (e.g., solar and windpower). Savings: $15{,}000\times10^{12}$ Btu's per year (30 percent).

The savings indicated above are in terms of primary source energy inputs before conversion to the energy forms finally utilized. Some of the savings would result in direct reductions in electric energy demand, while others could possibly result in greater electricity consumption. Yet other measures would reduce the direct consumption of fossil fuels at their point of end use. However, in all cases, fuel in some form would be saved contributing to net energy reduction; that is, total demand would be reduced compared to a "no conservation" projection. Some of the alternatives for achieving the energy savings cited above are described in the following sections.

13.2.7.1 Simple Conservation Practices

Some energy demand reduction for space heating and cooling can be achieved through encouraged adoption of simple conservation practices that cause minor or no inconvenience to consumers. Examples are thermostat regulation, turning off lights when not in use, drawing blinds and draperies in unoccupied rooms, installation of awnings and shades, selecting light colors for house paint and roofing, and the use of reflective glass to screen out solar radiation in the summer (OEP, 1972: D-1, D-4). Of course, the potential of such measures is not large when compared to results that might be achieved by "leak plugging" techniques.

13.2.7.2 Improved Thermal Insulation

The most significant potential for energy conservation is in improved home and business insulation. The heat losses or gains that determine the effectiveness of heating and air conditioning in buildings are essentially the same, the major sources of the leaks being inadequate insulation, excessive ventilation, and high rates of air infiltration (Berg, 1973: 553). Decreasing the thermal leakage in buildings would benefit the consumer by both reducing heating and cooling expenditures and reducing the size and capital cost of heating and air conditioning equipment. In addition, improved insulation offers an immediate control measure to reduce the local air pollution emitted by space heating devices (National Mineral Wool Insulation Association, 1972: 3-4).

One measure of the effectiveness of residential building insulation and ventilation is the Federal Housing Administration (FHA) minimum property standards, which in 1965 permitted heat losses of 2,000 Btu's per thousand cubic feet (mcf) per degree day. In 1972, these standards were raised to require that losses by less than 1,000 Btu's per mcf per degree-day. Because few residential buildings are designed to exceed FHA performance standards, it is reasonable to assume that most of the residential buildings in use today require about 40 percent more energy to heat and cool than they would if they were insulated and sealed in accordance with current FHA standards. Similarly, sample field observations indicate that as much as 40 percent of the fuel used to heat and cool commercial buildings could be saved by improved insulation (Berg, 1973a: 553-554).

Techniques to accomplish improved thermal performance of structures include:

1. Fit houses with storm windows and storm doors.
2. Caulk and weatherstrip windows and doors.
3. Insulate attics in existing houses.
4. Insulate walls and ceilings in new homes.

Future standards for insulation and control of air infiltration may offer even greater potential for saving energy. Studies indicate that it is technologically and economically feasible to reduce heating losses from buildings to approximately 700 Btu's per 1,000 cubic feet (cf) per degree-day through improved insulation practices. Implementation of this standard would reduce total energy requirements of buildings by more than 50 percent through well-designed insulation and careful control of ventilation (Berg, 1973a: 554).

13.2.7.3 Building Design and Construction

A measure related to better insulation practice is better design and construction concepts for both residential and commercial buildings. For example, a few of the currently available methods for saving energy are the use of more energy-efficient shapes (circles and cubes), more windows facing north than south, summer shades for windows facing south or west, use of double glazing and heat reflective glass, prescribed heating and cooling of occupied and specialized areas (such as computer centers) rather than entire buildings, and improved building skins (Braddock, Dunn and McDonald, 1974a: L-12).

13.2.7.4 Higher Efficiency Fossil-Fueled Furnaces

Higher efficiency furnaces, including improved design of heat transfer surfaces and better maintenance and adjustment of burners, offer other potential savings in space heating. Battelle Laboratories conducted three residential case studies to determine the effect of combustion equipment adjustment and servicing, plus the effect of increasing thermal insulation, on pollutant emission estimates for various fuels (Battelle, 1973: 606-608). Their results show substantial reduction in emissions for gas, oil, and coal burning devices when the equipment is kept well-tuned and insulation is provided according to FHA specifications, including additional insulation and storm windows.

In conjunction with higher efficiency furnaces, the continuous burning gas pilot light could be replaced with an electric switch-operated ignitor. (One source estimates that the installation of electric ignition systems for gas appliances in residences could result in energy savings in 1980 of 70×10^{12} Btu's per year (Braddock, Dunn and McDonald, 1974b: L-97).

13.2.7.5 Higher Efficiency Room and Central Air Conditioners

Available data suggest substantial latitude for improving the efficiency of air conditioning units. Considering the size distribution for 1970 sales, the average efficiency of existing room air conditioners was estimated to be six Btu's per watt-hour. If the assumed efficiency is improved to 10 Btu's per watt-hour (a level technologically feasible today), overall consumption for this end use could be reduced 15.8 billion kilowatt-hours (kwh) or approximately 40 percent (Hirst and Moyers, 1973a: 1302).

13.2.7.6 Use of Electric Heat Pumps

As noted previously, the use of electric heat pumps could just about equalize the overall efficiencies of electric, gas, and oil heating systems. From the consumer's point of view, heat pump savings must be balanced against higher capital investment and maintenance costs. These costs have tended to retard their widespread use; however, as manufacturers improve component reliability, the heat pump should receive greater market acceptance. One source estimates that if heat pumps were used instead of electrical resistance heating for residential and commercial space heating, the potential energy savings by 1985 could be $2{,}400 \times 10^{12}$ Btu's per year (Ford Foundation, 1974a: 50, 52).

13.2.7.7 Total Energy Systems

Sufficiently higher fuel prices may make total energy systems more attractive. Electricity could be generated on site, allowing the waste heat from the electrical generation process to be used for space heating in the winter and air conditioning in the summer. Such systems could be employed for large commercial establishments and in urban or residential complexes. A total energy system wastes only 20 to 30 percent of the fuel by providing both electricity and heat, unlike the central generating plant where 60 to 70 percent of the fuel's energy is wasted (Ford Foundation, 1973: Chapter XII, p. 15).

13.2.7.8 Solar Energy

Solar radiation provides clean energy without polluting or depleting the earth's resources. Solar energy could be used for space heating, to power heat pumps, to heat water, and for absorption air conditioning (after additional research and development). One source estimates that use of solar energy to provide the above residential needs would result in a total energy savings of almost 20 percent, as well as a substantial overall load reduction on central power stations (Battelle, 1973: 534). Although savings estimated in the next decade from solar energy usage are speculative, the potential (especially for space heating and water heating) is great, given further research and development.

13.2.7.9 Water Heating

Several approaches designed to reduce consumption of energy for water heating can be identified. One such approach is to improve the efficiency of hot water systems through better insulation of heater shells and hot water transporting pipes, recovery of heat from hot water after use (i.e., using the drain flow from washing machines, dishwashers, etc.), and using waste heat from other appliances to preheat the feed-water for hot water tanks.

A second approach is the use of solar water heaters. Solar water heaters are commercially available (NSF/NASA Solar Energy Panel, 1972: 13) and have been used in Florida, California, and a number of foreign countries for years. One source estimates that using solar energy for water heating could reduce U.S. fuel requirements by two percent or more (Berg, 1973a: 559).

A third approach is the one previously mentioned for space heating devices, replacing pilot lights on all fossil-fueled hot water heaters with electric ignitors.

13.2.7.10 Other Potential Energy Savings

In addition to the above, other measures can be taken to conserve energy. Cooking utensils could be made more energy efficient and range burners redesigned or other efforts made to use the heat that currently escapes around the utensil and into the air (OEP, 1972: D-7).

Improved design of electric appliances could significantly enhance their energy utilization efficiency. For example, the energy requirements of the refrigerator could be reduced through such measures as:

1. Increased box insulation.
2. Better unit efficiency for the cooling cycle.
3. Better user maintenance.

Gas yard lights, which have been reported as emitters of SO_x, could be improved or eliminated. Efforts to reduce the proliferation and use of gasoline-powered lawn and garden equipment would reduce local air emissions and energy consumption.

Illumination of residences and commercial buildings also deserves attention. Twenty-four percent of all electricity sold is used for lighting purposes (Large, 1973: 884), with commercial lighting accounting for about 10 percent of total electricity consumption. Light-intensity standards have more than tripled in the last 15 years, and recommended lighting levels in office buildings, which are considered excessive by some, might be reduced in cases where no danger exists to eyesight or worker performance. According to one source, energy used for lighting could be reduced by 50 percent if high levels were concentrated in work areas, rather than throughout entire rooms as in the current design philosophy (Large, 1973: 884). The more extensive use of flourescent lamps would result in additional savings because they are more than three times as efficient as incandescent lamps (OEP, 1972: D-9).

As indicated by the preceding analysis, the effectiveness of energy use in the residential and commercial sector can be improved, and many of the possible improvements appear to be economically justifiable, especially considering that the alternative is to expand the national energy supply. In general, the measures to improve end-use effectiveness are technological; these technologies are either currently extant or can be readily developed.

13.3 INDUSTRIAL SECTOR

The industrial sector is the largest energy consuming sector. In 1971, American industries consumed $22,623 \times 10^{12}$ Btu's or about 33 percent of the nation's total energy requirement for that year (Interior, 1972: 30). More than one-half of that energy was used in industrial thermal processes alone (i.e., the direct burning of fuels or the manufacture of steam), about the same amount as required to supply all residential energy needs. Manufacturing consumes approximately 85 percent of industrial energy and the remainder is equally shared by agriculture and mining.

Industry uses energy in extremely diverse ways and only recently have detailed breakdowns of industrial consumption been attempted (SRI, 1972: 83-143; Braddock, Dunn and McDonald, 1974a: III-11; Hittman, 1974: Vol. I, Table 29, Parts 1, 2, and 3).

This description of industrial consumption is incomplete in that it only addresses use patterns for the following six Standard Industrial Classification (SIC) categories:

SIC 33: Primary Metals
SIC 28: Chemicals and Allied Products
SIC 32: Stone, Clay, Glass, and Concrete
SIC 26: Paper and Allied Products
SIC 20: Food and Kindred Products
SIC 37: Transportation Equipment

Together, however, these industrial groups accounted for almost two-thirds of total industrial energy consumption in 1971.* The specific fuels and amounts used in the six groups are given in Table 13-13. Natural gas has been the largest (about 40 percent) and most rapidly growing energy source consumed directly in industrial plants, followed by coal and coke (27 percent), electricity (22 percent), and petroleum products (11 percent). Electricity is expected to replace natural gas as the growth source of industrial energy in the future.

As shown in Table 13-14, the six industrial groups also include the top five energy intensive industrial groups, as identified by the ratio of input energy to dollar output (Braddock, Dunn, and McDonald, 1974a: III-10). Among the large industrial energy users, only food processing is not energy intensive (Ford Foundation, 1974: 5).

Industrial uses include small amounts of energy for space heating, air conditioning, water heating, lighting, etc., and conservation measures for these as discussed in the residential and commercial sector are applicable here. As noted, half the energy used in the industrial sector is for heating processes. In 1968, industrial use of process steam accounted for about 17 percent of total U.S. energy consumption. Direct heat--that is, heat obtained when fuel is burned directly in an industrial process (e.g., in the manufacture of steel or cement)--comprised almost 13 percent of the nation's energy requirement. Much of the remaining energy use in this sector is for mechanical energy in the form of electric drives (eight percent of national consumption), electrolysis to manufacture primary metals (one percent), and for "non-energy" purposes; that is, as raw materials or feedstocks for manufacturing processes (about four percent) (SRI, 1972: 6).

13.3.1 Technologies

13.3.1.1 Primary Metals

The primary metal industries consume the largest share of coal and coke, and the second largest share of electric energy used in the industrial sector. Energy use in the iron and steel industry is comprised principally of fossil fuels combustion, oxygen, and electricity for firing coke ovens, blast furnaces, and creating steam for compressing blast, generating electricity, and driving mills, forges, and process lines. The energy required to produce a ton of raw steel declined by 13 percent between 1960 and 1968. (This discussion of energy consumption by industrial groups is largely from SRI, 1972: 88-143). This decline was due primarily to more efficient energy use by blast furnaces; for example, the introduction of the "basic oxygen" steel making furnace (OEP, 1972: E-7, E-8).

From 1960 through 1969, aluminum production and processing were the most important energy consuming segments of the primary metal industries. In 1969, primary aluminum production was 88 percent above the 1960 level, resulting in corresponding increases in energy consumption (especially electricity, the basic form required by the industry). In the aluminum industry, electricity is used for electrolytic smelting of aluminum, melting aluminum ingots and

*An additional large industry--SIC 29-Petroleum Refineries and Related Products--is contained implicitly within the oil supply tables (see the refinery discussion in Chapter 3).

TABLE 13-13

ANNUAL FUEL CONSUMPTION FOR SIX MAJOR INDUSTRIAL USES[a]

Industrial Group	Fuel Type (10^{12} Btu's per year)					Total Energy
	Coal and Coke	Natural Gas	Residual	Distillate	Electricity	
Chemical	696	2,335	183	59	1,083	4,356
Primary metals	1,706	1,095	170	77	1,018	4,138[b]
Stone, clay, glass, and concrete	702	1,289	433	180	317	2,921
Paper and allied products	373	420	196	71	304	1,364
Food and kindred products	177	378	65	49	261	930
Transportation equipment	78	84	14	1	146	323
TOTAL	3,732	5,601	1,061	437	3,129	14,032

Source: Calculated from Hittman, 1974: Vol. I, Table 29, Parts 1,2, and 3.

[a]Petroleum refining not included because it is implicitly considered in the energy resource chapter. In general, year associated with data is 1970, the principal exceptions being paper and allied products and transportation equipment numbers which are from 1971.

[b]Includes 72×10^{12} Btu's of petroleum coke used in primary aluminum production.

TABLE 13-14

ENERGY INTENSIVENESS OF MAJOR INDUSTRIAL GROUPS

SIC[a]	Industrial Group	Energy Intensiveness[b]
32	Stone, clay, and glass products	.090
29	Petroleum and coal products	.072
28	Chemicals and allied products	.066
26	Paper and allied products	.063
33	Primary metal industry	.052

Source: Braddock, Dunn and McDonald, 1974a: III-12 (data from Annual Survey of Manufacturers, 1973).

[a]Standard Industrial Classification

[b]Total energy consumed for each dollar of production goods shipped out.

scrap for casting, and other miscellaneous process power and steam generation uses. Additional energy is consumed in the production of secondary aluminum from aluminum scrap and the processing of wrought aluminum (e.g., rolling and extruding).

13.3.1.2 Chemicals and Allied Products

Chemicals and allied products have recently surpassed primary metals as the number one energy consumer in industry.

This group designates the manufacture of basic, intermediate, and end chemicals, including drugs and pharmaceuticals. About 43 percent of the largest industrial corporations in this country participate in some aspect of the manufacture and sale of chemicals. The chemical industry's role has been referred to as that of a "middleman;" that is, "...a purchaser of raw materials and services from numerous supplying industries and a provider of higher value products to a host of consuming industries" (SRI, 1972: 115). Historically, the raw material bases for this group have been coal and coal tar. However, over the past 25 years, coal has been increasingly replaced by petroleum and natural gas as the petrochemical industry has grown.

The petrochemical industry involves the processing of liquids extracted from natural gas or specific products derived from crude oil refining to yield chemical raw materials. Further processing results in a wide range of end use products, including paints, synthetic rubber, upholstery materials, clothing textiles, household goods, building materials, numerous molded and extruded plastic products, and parts for automobiles and industrial equipment.

In 1972, petrochemicals accounted for 30 percent of the tonnage and more than 60 percent of the value of all organic chemicals produced in the U.S. (SRI, 1972: 115,116). Until recently, the petrochemical industry has been able to use plentiful, low-cost natural gas liquids as its primary feedstock. However, the rising costs and shortages of petroleum and natural gas may require changes in the kinds of raw materials used by this industry (Shell, 1973a: 11).

Any attempt to analyze the energy consumption patterns within the chemical industries is complicated because there are hundreds of chemical products, many of these products are produced by more than one process, and different processes use different amounts of energy.

13.3.1.3 Paper and Allied Products

Energy in the paper manufacturing process is typically consumed in two forms, steam and electric power. The electricity is essentially used for mechanical drives. Insignificant amounts of steam may be used for mechanical drives but for the most part, steam is used for heat. Consumption in different mills can vary significantly depending on the pulping process, mill equipment, raw materials, product mix, and outside humidity and temperature. In general, final energy use in this industrial group is estimated at 90 percent for heat and 10 percent for mechanical drive (SRI, 1972: 132).

13.3.1.4 Stone, Clay, Glass, and Concrete

Due to the nature of the raw materials and the required processes, the principal uses of energy in cement manufacture are for mechanical operations (in the form of electric drives) such as crushing, grinding, conveying, and blending, and for direct-fired heating operations to achieve chemical changes. Energy consumption in glass and clay manufacturing is divided between electrical energy for mechanical devices (e.g., blowers, conveyors, and materials handling equipment) and direct process heat in the firing of kilns. The fuel energy required for these products depends on the material being fired, the type of product, and the required formation process, as well as the type of kiln used.

13.3.1.5 Food Processing

The Food and Kindred Products industrial group consists of manufacturers of foods and beverages for human consumption, including certain related products such as manufactured ice, vegetable and animal fats and oils, and prepared feeds for animals and fowl. Although demand for food products has steadily increased during the recent past, the industry's relative share of total energy consumption has been declining. This decline is attributed generally to greater efficiency in operation; that is, closing of inefficient plants, modernization and introduction of more efficient processing systems, and consolidation (SRI, 1972: 138, C-3).

13.3.1.6 Transportation Equipment

The transportation equipment group includes those industries involved in manufacturing equipment for transport of passengers and freight by land, air, and water. The predominant concern here is for manufacturers of motor vehicles (i.e., passenger cars, trucks, truck tractors, chassis, and buses as new units) and motor vehicle parts.

13.3.2 Energy Efficiencies

The average heat transfer efficiency of individual industrial plant equipment items used in the direct heat operations discussed above (e.g., cement kilns, glass furnaces, and similar equipment) ranges from 20 to 30 percent (Berg, 1974: 16). Heat treating furnaces also operate at approximately 30-percent heat transfer efficiency (Berg, 1973b). The overall efficiency of some plant systems (e.g., paper mills, glass factories, and heat treating facilities) has been reported to be even lower than the efficiencies of the individual devices, which are sometimes as low as five percent (Berg, 1974: 16). This lower overall efficiency of thermal processing plants results in part from poor system control and ineffective heat transfer and mixing; that is, plants are not normally operated to make optimal use of energy (Senate Interior Committee 1973a: 588).

The relatively primitive technologies employed to generate process steam in industry generally make inefficient use of the potential energy in fuels. One source estimates the efficiencies of different fuels for process steam production as follows: coal, 70 percent; gas, 64 percent; and oil, 68 percent (SRI, 1972: 155).

To meet its electricity needs, industry either purchases electricity from a central station power plant or generates the electricity on site. If electricity is produced alone, about 30 to 40 percent of the fuel used is converted to electricity. However, if electricity is combined with process steam production, an optimum 80 percent of the potential energy in the fuel can be used to produce both steam and electricity (Ford Foundation, 1974a: 67, 462). Although efficiency can vary to some degree in the industrial use of electricity for the direct drive of machinery and equipment, a reasonable average is reported to be 90 percent (SRI, 1972: 155).

In general, the efficiency of electrolytic processes is much lower than might be expected in an electrical process. The efficiency depends to a large extent on the material being reduced, and losses occur in the circuitry, electrodes, heating and heat loss of the containers, consumption of electrodes, and chemical reactions to contaminants (SRI, 1972: 155,156). For example, in the conversion of alumina to aluminum, the theoretical energy used for that conversion is 35 to 40 percent of the electrical power input and 10 to 15 percent of the energy in the fuel consumed to generate the electricity (SRI, 1972: 156).

13.3.3 Environmental Considerations

Table 13-15 contains environmental residuals that have been quantified for the six industrial groups. The data are considered poor, with a probable error of less than 100 percent. Each industry has been broken into subparts, which essentially correspond to a specific end use (e.g., paper and allied products is broken into pulp and paper mills, and paper products manufacturing). Although the source study (Hittman, 1974: Vol. I: Table 29) does include a breakdown of the end use for each industry by the fuels consumed, the available data on industrial environmental impacts did not justify an attempt at disaggregating the level of the data presented. Thus, contrary to other end use tables in this chapter, the environmental impacts are not allocated to each fuel. Instead, impacts are reported for end uses within the particular industrial group. As a result, the environmental usefulness of the residuals data is limited because impacts cannot be allocated to specific fuels except in a very approximate manner. Also, the impact data are uncontrolled in that the level of control is representative of very recent or current practices.

Industrial facilities generate a range of air pollutants specific to the process involved. The significant pollutants are particulates, SO_x, and NO_x. Industry is the leading producer of particulates and ranks second in the production of SO_x (ACS, 1969: 59). In some cases, other pollutants deserve attention (e.g., CO from integrated steel mills). The major contributors of the pollutants cited above are chemical plants, iron and steel mills, refineries, pulp and paper mills, and nonferrous metal smelters.

Manufacturing is also one of the leading sources of controllable man-made water pollutants in this country. The industrial use of water has increased rapidly over the last two decades and is expected before long to surpass water use for either irrigation or municipal and rural nonirrigation purposes. In 1970, industrial water usage (excluding water used for steam-electric power generation) was estimated at 103 billion gallons per day (gpd), compared to 46 billion gpd in 1950 (Commerce, 1956: 41).

Water is used in industries as a raw material, as a bouyant transporting medium, as a cleansing agent, as a coolant, and as a source of steam in heating and power generation. Since both water quality and quantity requirements vary considerably with industrial use, it is impossible to describe the impact of water use for each of the different industrial purposes.* The general types of industrial water pollutants identified for the six industrial groups are shown in Table 13-15.

Many industries discharge process waters containing compounds not found in natural waters. For example, among the most significant are metal ions (mostly toxic), a spectrum of organic and inorganic chemicals, and many refractory compounds which resist biological degradation. Industrial waste streams with high temperature, turbidity, color, acidity, or alkalinity are also common (Commerce, 1956: 40). Some 66 percent (average value) of industrial water use is for cooling purposes; about half of this water is lost to the atmosphere and the remainder returns to the resource pool with its salt concentration doubled.

Examples of wastewaters that contain significant amounts of mineral impurities are steel-pickling liquors, copper-bearing wastes, electroplating wastes, and gas and coke plant wastes. The most important organic wastes are produced by the meat and

*For a discussion of input water quality requirements which have been quantified for various industries, see McKee and Wolf (1963: 92-106). References estimating the quantity of water used per unit of product for many industries are cited in the above source and in McGauhey (1968: 44,45).

Table 13-15. Residuals for Industrial Energy Use

End Use	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)										
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/ measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (tons/measure)	Measure	Energy Btu/measure	Multiplier	Multiplier year
SIC 26: Paper and Allied Products																					
Pulp and Paper Mills	a	a	U	U	8.75×10^{-2}	2.25×10^{-2}	U	2.46×10^{-2}	4.17×10^{-2}	U	4.53×10^{-2}	5.64×10^{-3}	1.65×10^{-2}	7.26×10^{-4}	2.89×10^{-2}	7.94×10^{-3}	U	Ton	2.32×10^{7}	5.42×10^{7}	1971
Paper Products Manufactured	0	0	0	0	0	0	0	0	0	U	1.63×10^{-4}	1.39×10^{-4}	1.75×10^{-4}	8.32×10^{-6}	1.03×10^{-5}	5.21×10^{-6}	U	Ton	2.18×10^{6}	4.94×10^{7}	1971
SIC 37: Transportation Equipment																					
Motor Vehicles	U	U	U	U	U	1.83×10^{-4}	5.22×10^{-5}	1.28×10^{-4}	3.53×10^{-4}	U	4.74×10^{-3}	1.55×10^{-3}	5.53×10^{-3}	1.51×10^{-4}	1.44×10^{-4}	2.13×10^{-5}	U	Unit	1.36×10^{7}	1.2×10^{7}	1971
Parts	U	U	U	U	U	2.35×10^{-4}	6.56×10^{-5}	1.78×10^{-5}	U	U	2.53×10^{-3}	8.57×10^{-4}	3.14×10^{-3}	8.2×10^{-5}	7.73×10^{-5}	1.17×10^{-5}	U	Ton	8.28×10^{6}	1.93×10^{7}	1971
SIC 32: Stone, Clay, Glass and Concrete																					
Glass Products	U	U	3.2×10^{-4}	0	2.31×10^{-2}	1.36×10^{-3}	1.25×10^{-3}	1.2×10^{-3}	U	U	1.13×10^{-3}	$8.\times10^{-4}$	4.19×10^{-5}	U	U	7.21×10^{-5}	U	Ton	2.88×10^{7}	1.41×10^{7}	1971
Clay Products	U	U	0	0	U	U	U	U	U	U	1.86×10^{-3}	$3.\times10^{-4}$	b	U	U	$4.\times10^{-4}$	U	Ton	7.54×10^{6}	4.41×10^{7}	1971
Cement and Related	U	1.57×10^{-5}	0	0	7.06×10^{-5}	2.81×10^{-5}	U	6.5×10^{-7}	1.2×10^{-7}	U	4.91×10^{-2}	$1.\times10^{-4}$	3.1×10^{-4}	1.79×10^{-5}	4.13×10^{-7}	6.7×10^{-7}	U	Ton	3.62×10^{6}	5.67×10^{8}	1970
Stone and Related	U	U	0	0	2.09×10^{-2}	3.41×10^{-4}	U	3.62×10^{-4}	1.85×10^{-4}	U	1.02×10^{-2}	3.15×10^{-4}	1.94×10^{-4}	6.8×10^{-4}	3.8×10^{-6}	1.17×10^{-5}	U	Ton	8.76×10^{5}	1.47×10^{8}	1970
SIC 28: Chemicals																					
Inorganic	1.72×10^{-2}	4.64×10^{-2}	9.84×10^{-3}	U	.106	.446	2.17×10^{-4}	6.21×10^{-6}	2.42×10^{-5}	U	2.25×10^{-2}	8.64×10^{-4}	.019	4.31×10^{-2}	3.64×10^{-2}	1.18×10^{-2}	1.16×10^{-2}	Ton	1.09×10^{7}	1.71×10^{8}	1970
Organic	.02	U	5.08×10^{-3}	U	2.51×10^{-2}	1.94×10^{-5}	.023	1.96×10^{-5}	5.1×10^{-5}	U	.03	7.91×10^{-3}	4.91×10^{-2}	.189	2.87	9.42×10^{-3}	.011	Ton	2.11×10^{7}	1.18×10^{8}	1970
SIC 20: Food and Kindred Products																					
Meat and Dairy Products	0	U	$8.\times10^{-6}$	8.75×10^{-7}	4.14×10^{-4}	5.69×10^{-4}	1.89×10^{-4}	4.66×10^{-3}	4.5×10^{-3}	U	1.14×10^{-3}	1.58×10^{-4}	7.66×10^{-4}	2.71×10^{-5}	1.23×10^{-5}	5.3×10^{-6}	U	Ton	2.64×10^{6}	8.88×10^{7}	1970
Bakery, Sugar, and Confectionary	0	5.57×10^{-3}	2.5×10^{-3}	4.35×10^{-3}	.252	.595	U	3.2×10^{-3}	.223	U	3.9×10^{-3}	4.63×10^{-4}	2.45×10^{-4}	7.21×10^{-5}	3.84×10^{-5}	1.35×10^{-5}	U	Ton	5.66×10^{6}	3.12×10^{7}	1970

Table 13-15. (Continued)

End Use	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)										
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (tons/measure)	Measure	Energy Btu/measure	Multiplier	Multiplier year
Beverage, Can, Cured, and Frozen	U	2.64×10^{-4}	1.47×10^{-5}	5.97×10^{-5}	8.12×10^{-2}	7.42×10^{-4}	2.44×10^{-4}	3.16×10^{-2}	3.28×10^{-2}	U	5.54×10^{-3}	3.42×10^{-4}	1.98×10^{-3}	4.91×10^{-5}	3.16×10^{-5}	8.47×10^{-6}	.825	Ton	4.48×10^{6}	4.93×10^{7}	1970
Grain Mill and Miscellaneous	U	U	U	U	U	U	U	U	U	U	2.42×10^{-2}	1.48×10^{-4}	6.47×10^{-4}	1.17×10^{-5}	1.03×10^{-5}	5.52×10^{-4}	U	Ton	9.45×10^{5}	3.17×10^{8}	1970
SIC 33: Primary Metals																					
Iron and Steel Making	U	U	U	U	U	1.21×10^{-3}	4.5×10^{-4}	U	U	c	1.02×10^{-2}	4.54×10^{-2}	4.63×10^{-4}	0	8.64×10^{-3}	0	d	Ton	2.23×10^{7}	1.33×10^{8}	1972
Iron and Steel Castings	U	U	0	0	U	1.37×10^{-2}	U	3.69×10^{-3}	2.29×10^{-2}	U	3.95×10^{-4}	3.74×10^{-6}	e	e	4.5×10^{-3}	e	U	Ton	1.31×10^{7}	1.88×10^{7}	1969
Primary Aluminum	U	U	0	0	U	.005	2.5×10^{-3}	1.62×10^{-4}	1.37×10^{-2}	U	.126	b	b	b	b	2.12×10^{-2}	U	Ton	1.96×10^{8}	3.98×10^{6}	1970
Primary Copper	U	U	U	0	U	1.74×10^{-2}	U	U	2.18×10^{-3}	U	2.02×10^{-4}	U	6.25×10^{-2}	U	U	U	U	Ton	4.43×10^{7}	1.77×10^{6}	1970
Primary Zinc	U	U	U	U	U	U	U	U	U	U	.01	U	2.02×10^{-2}	U	U	U	U	Ton	7.25×10^{7}	9.55×10^{5}	1970

U = unknown.

[a] Ph values of wastewaters are reported to range from 3.4 to 12.0.

[b] Considered small or negligible.

[c] Because of many outfalls for each steel mill, average temperature rise is not available.

[d] Slag produced in the blast furnace process is readily salable as a general rule and is not considered a solid waste.

[e] Hydrocarbon, SOx, aldehydes and metallics are emitted but are highly variable.

dairy products industries, breweries and distilleries, and canneries. The biological wastes from industry are particularly significant because of the exceptionally high biochemical oxygen demand (BOD) of many such discharges. Examples of wastes containing both organic and mineral impurities are those of the paper mills.

13.3.4 Economic Considerations

In industries, such as chemical refining, where the function of the industry is to convert the energy content of fuel to some readily marketable form, the design of large plants is based on an optimal consideration of initial costs and operating costs, especially fuel costs (Berg, 1973a: 556). In the past, other industries constructed plants that minimized total costs, not clearly emphasizing the role of energy as an essential ingredient. As long as energy was plentiful and inexpensive relative to other components of production cost (energy has accounted for only five percent of value added on the average [Ford Foundation, 1974a: 63]), investment in more energy-efficient equipment and processes was not of major concern. Despite the advantage of having competent engineering staffs capable of understanding and analyzing all the costs of owning equipment, industry often buys inefficient devices because it desires a "quick payout" (two to five years) on its initial expenditures (OEP, 1972: E-16). This practice of seeking quick recovery of capital expenditures often results in low-cost plants that are large energy consumers. Of course, not all industrial concerns take this attitude but, in some cases, industry has found that because energy was inexpensive, "it has been cheaper to permit a leak of energy than to modify or replace inefficient equipment" (Berg, 1973a: 556). As energy costs rise, industry may find the trade-offs favor more efficient energy utilization; that is, reduced fuel consumption.

Due to the extreme diversity among industries, it is not possible to generalize about economic considerations for specific industrial groups. In almost every case, however, investment in more efficient equipment, coupled with the introduction of more efficient processes, should reduce fuel consumption. Further, price is not the only influencing factor. In some parts of the country, gas suppliers have placed fuel quotas on industries that may not be exceeded. Industries affected by such measures are already seeking to improve their plant efficiencies (Berg, 1973a: 556).

13.3.5 Conservation Measures for the Industrial Sector

The following discussion of conservation measures is organized around energy use in generic manufacturing processes rather than around the specific industrial groups or end uses. This approach reflects the manner in which industrial conservation proposals most often appear in the literature. Such a focus reflects the complexity and diversity of the industrial sector. As a result, conservation discussions have focused more generally on energy uses and practices common to more than one industry.

The conservation study by the OEP reported that, with the exception of the primary metals group, all the energy intensive industries could cut energy demand by 10 to 15 percent (and probably more) over a period of time by accelerated retirement of old equipment, optimal energy process design, and upgraded and increased adjustment and maintenance of existing equipment (OEP, 1972: E-14). OEP outlined the following recommendations, including possible sector savings corresponding to different time parameters (OEP, 1972: 56,57):

1. Short-Term Measures (1972-1975). Increase energy price to encourage improvement of processes and replacement of inefficient equipment. Provide tax incentives to encourage recycling and reusing of component materials. Savings: 1,900 to $3{,}500 \times 10^{12}$ Btu's per year (6 to 11 percent).

2. Mid-Term Measures (1976-1980). Establish energy use tax to provide incentive to upgrade processes and replace inefficient equipment. Promote research for more efficient technologies. Provide tax incentives to encourage recycling and reusing component materials. Savings: 4,500 to $6,400 \times 10^{12}$ Btu's per year (12 to 17 percent).

3. Long-Term Measures (beyond 1980). Establish energy use tax to provide incentive for upgrading processes and replacing inefficient equipment. Promote research in efficient technologies. Provide tax incentives to encourage recycling and reusing component materials. Savings: 9,000 to $12,000 \times 10^{12}$ Btu's per year (15 to 20 percent).

As indicated in the preceding discussion, energy consumption in this sector could be reduced through changes in the processes for the manufacture of products. The responsibility for such changes lies almost entirely within the various individual industrial groups. In addition, process research is almost always proprietary.

13.3.5.1 Industrial Thermal Processes

As indicated in the technological description, the overall efficiency of thermal processing plants is not high. Approximately 30 percent of the energy used in industrial processes could be saved by applying existing conservation techniques that are economically justifiable given present fuel prices (Berg, 1973a: 556). Certain examples of improved equipment that would more effectively utilize energy deserve attention.

Gas-fired vacuum furnaces have recently been developed for industry, and one source reports that under ideal circumstances such furnaces, used in conjunction with well-designed vacuum insulation and modern heat transfer and combustion techniques, could operate with 25 percent of the total fuel consumption of previous vacuum furnaces (Berg, 1973a: 556).

The effectiveness of industrial fuel utilization could also be improved through the application of fluidized-bed processing to cement kilns and similar apparatus.* Estimates indicate that recent advances in fluidized-bed equipment design may increase the heat transfer efficiency from present levels to about 50 percent. Also, the reaction completion time in the kiln may be significantly reduced, resulting in improved productivity in, for example, cement making (AEC, 1974: Vol. IV, p. C.6-11).

Another device that offers the prospect of reduced fuel demand is the heat pipe. This device allows rapid and highly controllable heat transfer over long distances with minimal drop in temperature. Heat pipes can be used as heat sources for vacuum furnaces, and indications are favorable for their application to glass furnaces. They can also be used to extract heat from stack gases, thus recovering heat that would otherwise be wasted (AEC, 1974: Vol. IV, p. C.6-11).

13.3.5.2 Process Steam Generation

One technological option offering potential energy savings is combined electric power/steam generation systems (also discussed in Chapter 12). In combined systems, approximately 80 percent of the fuel energy is converted to steam and electricity; when electricity alone is produced, only 30 to 40 percent of the fuel is converted to electricity. The savings result because the electricity generated in combined systems can displace electricity that would otherwise be generated inefficiently. The net savings in total energy requirements for steam and electricity can be about 30 percent (Ford Foundation, 1974a: 67).

13.3.5.3 Increased Efficiency of Industrial Processes

More efficient management of systems and improved efficiency of industrial processes (e.g., petroleum refining, chemical

---

*A discussion on fluidized-bed boiler systems is given in Chapter 12.

processing, and metal manufacturing) can produce substantial energy savings. For example, the Shell Oil Company has made substantial progress toward a goal of reducing energy consumption in its refineries by 10 percent over a two- to four-year period (amounting to 3.5 to 4 million barrels [bbl] of fuel oil per year) (Shell, 1973b: 15). The DuPont and Dow chemical companies suggest that savings of 10 to 15 percent on fuel are possible in almost every chemical complex (Shell, 1973b: 15). A process developed to reduce water requirements fourfold in the paper industry also cuts energy requirements in half. In the aluminum industry, a new Alcoa electrolytic "chloride" process, called the Alcoa Smelting Process, has been estimated to reduce energy needs for primary aluminum production by 30 percent (Senate Interior Committee, 1973a: 661). Presumably, the successes of these programs do not represent isolated examples of possible industrial savings through process changes.

13.3.5.4 Heat Recuperation

Better waste heat management can be expected to yield industrial energy savings. A substantial fraction of the process heat requirements (other than steam) is presently lost to exhaust gases or to materials in process. Few chemical or mechanical processes can utilize very low-grade heat; however, the use of heat recuperators or regenerators that return some of this otherwise wasted energy to various processing steps could reduce fuel consumption by 20 to 25 percent (Ford Foundation, 1974a: 67).

There are applications for process steam extracted at higher temperatures that use waste heat. For example, the Dow Chemical Company will make use of steam extracted from a nuclear power plant under construction in Midland, Michigan for the production of chemicals (Battelle, 1973: 620). Also, combustion air could be preheated with exhaust gases. One source indicated that the use of such devices is economically feasible, even for backfitting plants already in existence (Ford Foundation, 1974a: 67). At present, however, there are few examples of clear financial incentives for exploitation of this possible conservation measure.

13.3.5.5 Recycling and Reusing

One area where clear financial incentives exist for energy conservation is in the reuse and recycling of materials, especially primary metals and paper. Recycled aluminum requires only two to five percent of the energy required for the production of primary aluminum (Senate Interior Committee, 1973a: 656). An exception is recycled glass, which requires about as much energy to recycle as glass produced from virgin raw materials (sand). However, the reuse of glass containers is only one-fifth as energy intensive as using disposable glass containers (Senate Interior Committee, 1973b: 141). Thus, energy could be conserved by designing equipment to facilitate recycling or by reusing component parts and materials; that is, standardizing product components to encourage reuse.

Most of the recycle-reuse measures are currently economical. One study reported (Hannon, 1972: E-18) that, in the container industry, the total resource system energy use is significantly higher for the throwaway system. In fact, dollar costs for the soft drink glass throwaway container system were about twice as expensive as the returnable system.

Another area that has received considerable attention for recycling potential is the auto industry (cf. OEP, 1972: E-18, E-19). If cars were properly designed for recycling, a substantial amount of metal and other materials could be recovered from junked automobiles.

There are numerous measures, besides the savings opportunities discussed here, that can be implemented over the short-term requiring little, if any, capital investment. "Leak plugging" tactics that would improve present practices can result in energy savings generally in the range of 10 to 15 percent in the short-term (Ford Foundation, 1974a: 68). In all cases, an analysis of energy use should enhance the possibility of implementing, where practical, conservation measures in the industrial sector.

13.4 TRANSPORTATION SECTOR

The transportation sector accounts for a significant percentage of total U.S. energy consumption,* averaging about 24 percent since 1950. Thus, like total energy consumption, U.S. transportation energy requirements almost doubled from 1950 to 1970 (i.e., from $8{,}724 \times 10^{12}$ Btu's in 1950 [Hirst, 1972: 3] to $15{,}843 \times 10^{12}$ Btu's in 1970).** Most of this increase was in the form of petroleum products used in cars, trucks, and aircraft. In fact, transportation currently accounts for more than half of the total U.S. petroleum use and continues to increase its share (SRI, 1972: B-8). Table 13-16 shows a breakdown by fuel type of the gross consumption of energy in this sector.

The following discussion is organized around two general transportation categories, freight and passenger. Two other categories, feedstocks*** and military and government, were identified by Hittman and will be included in this description only in terms of their environmental residuals. Energy consumption for each category is shown in Table 13-17.

*This description does not deal with the energy required to build transportation systems, only with the energy used to operate them.

**Year associated with 1970 estimate is actually a 12-month period during 1970/1971 as reported by Hittman (1974: Vol. I, Table 30). BuMines data, which includes military fuel, give a total of $17{,}080 \times 10^{12}$ Btu's for 1971 and $16{,}490 \times 10^{12}$ Btu's for 1970.

***Feedstocks are automotive and aviation lubricants.

TABLE 13-16

FUEL SOURCES FOR TRANSPORTATION, 1970[a]

Fuel Type	10^{12} Btu's per year	Percent of Total
Gasoline	11,522	72.6
Distillate	1,613	10.2
Residual	455	2.9
Jet fuel	2,059	13.0
Electricity	41	0.3
Feedstocks (lubricants)	153	1.0
TOTAL	15,843	100.0

Source: Calculated from Hittman, 1974: Vol. I, Table 30.

[a]12-month period during 1970-1971.

TABLE 13-17

CATEGORIES OF TRANSPORTATION USE[a]

Category	10^{12} Btu's	Percentage of Total
Freight	4,822	30.4
Passenger	10,167	64.2
Feedstocks	153	1.0
Military and government	701	4.4

Source: Hittman, 1974: Vol. I, Table 30.

[a]12-month period during 1970-1971.

Table 13-18 shows the transportation end use distribution in 1970. Automobiles were the leading consumer, using more than 52 percent of the overall transportation energy. Trucks were second, consuming approximately 22 percent. The percentage of energy used by domestic commercial aircraft increased substantially, from 4.1 percent in 1960 (Hirst, 1972: 27) to 7.3 percent in 1970 (Hittman, 1974: Vol. I, Table 30).

TABLE 13-18

END USE OF ENERGY WITHIN THE TRANSPORTATION SECTOR, 1970[a]

Use	Percent of Total Transportation Energy	Total
Automobiles		
Urban	32.5	
Intercity	19.8	52.3
Aircraft (domestic/international)		
Freight	1.1	
Passenger	8.8	9.9
Railroads		
Freight	3.3	
Passenger (including urban rapid transit)	0.4	3.7
Trucks (freight)		21.8
Ships and Barges (freight)		4.1
Buses		
Urban	0.5	
Intercity	0.4	0.9
Military/Government		
Aircraft	3.8	
Ground vehicles	0.3	
Ships	0.4	4.5
Feedstocks (lubricants)		1.0
Other[b]		1.8
OVERALL TOTAL		100.0

Source: Calculated from Hittman, 1974: Vol. I, Table 30.

[a]12-month period during 1970-1971.

[b]Includes passenger traffic by motorcycle, and recreational boating.

During that same period, the railroads' percentage of total energy usage declined.

Increasing consumption in the transportation sector is due primarily to growth in traffic levels, shifts to less energy-efficient modes, and declines in energy efficiency for individual modes of transportation (Hirst and Moyers, 1973a: 1299). Growth projections suggest that pressure on fossil fuel resources will continue from this sector (OEP, 1972: 14).

13.4.1 Freight

13.4.1.1 Technologies

Primary transport for freight includes waterways (barges, ships), trucks, railroads, and domestic and international jet airplanes. (For a discussion of pipelines see Chapter 3). Table 13-19 shows that a shift has occurred in intercity freight transport usage over the past 20 years. Railroads now haul a smaller percentage

TABLE 13-19

METHODS OF INTER-CITY FREIGHT TRAFFIC

Year	Ton-Miles Freight (10^9)	Percentage of Total Ton-Miles				
		Railroads	Trucks	Waterways	Pipelines	Airways
1950	1,090	57.4	15.8	14.9	11.8	0.03
1955	1,300	50.4	17.2	16.7	15.7	0.04
1960	1,330	44.7	21.5	16.6	17.2	0.06
1965	1,650	43.7	21.8	15.9	18.6	0.12
1970	1,930	40.1	21.4	15.9	22.4	0.18

Source: Hirst, 1972: 6 (data from Statistical Abstract, 1970, and from Transportation Facts and Trends, 1971).

of total ton-miles, while all other transportation methods carry a larger share. Although air freight remains relatively small (0.18 percent), it did steadily increase its percentage share of total ton-miles during 1950 to 1970.

13.4.1.1.1 Ships

Over the last few years ship usage has shown a slight increase and is expected to continue growing at a slow rate (Szego, 1971: Vol. II, Part B, pp. N-10, N-26). In the recent past, the fuel supply for ships has switched from coal to residual oil. For freight movement, domestic waterborne traffic is composed primarily of barges pushed by diesel-powered towboats.

13.4.1.1.2 Trucks

Trucks are large users of gasoline and diesel fuel. Because they are not substantially limited in the kinds of materials they can move, and due to the flexibility of their pickup and delivery points, trucks have considerably increased their share of the freight market. Approximately 95 percent of truck ton-mileage is concentrated in hauls greater than 100 miles, and 35 percent is for hauls more than 200 miles (Ford Foundation, 1973: Chapter XII, p. 31).

13.4.1.1.3 Railroads

Railroad energy consumption for freight transport has continually declined over the last 20 years, from 57.4 percent of total ton-miles in 1950 to 40.1 percent in 1970. This reduction is the result of a change in fuels used and more efficient engines. During 1950 to 1970, most railroad locomotives were changed from coal to residual fuel oil (steam engines) and then were replaced by distillate-burning diesel-electric engines. Since the diesel-electric engines are more efficient, more freight was moved with less energy consumption. Yet, as noted in Table 13-19, freight shipment by rail has declined even as the energy efficiency of railroads has increased.

This trend is explained in part by the increase in freight shipment by trucks. The attractiveness of trucks over railroads apparently reflects differential regulation of the two industries, as well as better and more dependable service by trucks. Customer preference is illustrated by the fact that approximately 40 percent of all freight tonnage in 1967 could have been moved by either truck or rail, yet trucks hauled over 80 percent of this "competitive" cargo (Ford Foundation, 1974a: 60).

13.4.1.1.4 Airplanes

Air transportation energy demand is increasing at a rapid rate, yet is still a small percentage of total freight traffic. Between 1965 and 1970, air freight experienced an average annual growth rate of 13 percent (DOT, 1972: 1031). If this growth rate continues, air cargo demand will double about every six years, resulting in increased (although not necessarily corresponding) energy demand. This implies that air freight transportation, though insignificant over the last two decades, could eventually become a primary energy consuming end use.

The predicted exponential growth in air freight is due largely to such factors as speed, convenience, and kinds of materials shipped. Air cargo falls into three categories: emergency (unplanned); routine perishable (planned); and routine surface divertible (planned) (NASA/ASEE, 1973: 77). As energy becomes more expensive, the latter category might experience a significant diversion to other modes, lowering the expected overall growth rate of air freight.

13.4.1.2 Energy Efficiencies

Fuel consumption through the use of a particular mode of transport is directly proportional to the energy intensiveness of that mode. Energy intensiveness is defined as the amount of energy required to move one unit (one passenger or one ton of cargo) a distance of one mile. The measure is expressed in Btu's per passenger-mile or Btu's per ton-mile.

Table 13-20 shows energy intensiveness for the movement of freight by various transport modes. The energy data is considered good, with a probable error of less than 25 percent. Pipelines and waterways represent a very efficient means of freight transport; however, they are limited in the kinds of materials they can carry and in the flexibility of their pick-up and delivery points. Railroads are more than four times as efficient as large trucks (diesel trucks are more efficient than gasoline-powered trucks) and almost 63 times as efficient as air transportation. Generally, in freight transportation, increased fuel consumption pays for speed, flexibility, and scheduling.

TABLE 13-20

ENERGY INTENSIVENESS OF FREIGHT TRAFFIC

Mode	Btu's per Ton-Mile[a]
Aircraft	42,000
Trucks	2,800
Waterway	680
Rail	670
Pipeline	450

Source: Hirst and Moyers, 1973a: 1300.

[a]Assuming 136,000 Btu's per gallon.

13.4.1.3 Environmental Considerations

The environmental residuals quantified for freight transportation are given in Table 13-21. The measure of use for all freight modes is the ton-mile. As in the residential and commercial sector, all end use impact data correspond to a particular fuel. A quick review of Table 13-21 shows that the primary environmental residuals from transportation are air emissions; these data are considered fair, with a probable error of less than 50 percent. Environmental consequences, such as solid and liquid wastes, are not quantified due to insufficient data, incomplete knowledge of effects and consequences, and the wide variability of liquid and solid by-product discharges.

As in the other tables, the not applicable designation (NA) means either that any environmental impacts which may occur are not energy related or that no rational

Table 13-21. Residuals for Freight Transportation Energy Use

End Use/Fuel	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)										
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (tons/measure)	Measure[a]	Energy Btu/measure	Multiplier	Multiplier Year
FREIGHT TRANSPORTATION																					
Barge/Distillate	NA	NA	NA	NA	0	NA	NA	NA	NA	0	1.51×10^{-7}	4.78×10^{-7}	6.73×10^{-8}	3.15×10^{-8}	1.91×10^{-7}	NA	b	Ton-Mile	3.78×10^{2}	5.78×10^{11}	1972
Ship-Foreign Trade/ Residual	NA	NA	NA	NA	0	NA	NA	NA	NA	0	1.98×10^{-7}	1.03×10^{-7}	1.96×10^{-7}	1.68×10^{-8}	1.96×10^{-7}	NA	b	Ton-Mile	3.98×10^{2}	1.08×10^{12}	1972
Truck/Distillate	NA	NA	NA	NA	NA	NA	0	NA	NA	0	1.2×10^{-7}	3.4×10^{-6}	2.5×10^{-7}	3.4×10^{-8}	2.08×10^{-6}	5.5×10^{-8}	b	Ton-Mile	2.42×10^{3}	3.13×10^{11}	1971
Truck/Gasoline	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	2.25×10^{-7}	4.35×10^{-6}	1.35×10^{-7}	7.15×10^{-6}	4.87×10^{-5}	3.7×10^{-7}	b	Ton-Mile	9.38×10^{3}	2.89×10^{11}	1971
Rail/Distillate	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	6.5×10^{-8}	1.95×10^{-7}	1.69×10^{-7}	1.3×10^{-7}	1.82×10^{-7}	2.85×10^{-8}	b	Ton-Mile	6.9×10^{2}	7.65×10^{11}	1970
Airplane-Domestic/Jet	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	7.5×10^{-7}	3.95×10^{-7}	1.58×10^{-7}	1.69×10^{-6}	1.98×10^{-6}	5.92×10^{-8}	b	Ton-Mile	4.2×10^{4}	3.4×10^{9}	1970
Airplane-International/ Jet	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	7.5×10^{-7}	3.95×10^{-7}	1.58×10^{-7}	1.69×10^{-6}	1.98×10^{-6}	5.92×10^{-8}	b	Ton-Mile	4.2×10^{4}	8.36×10^{8}	1970

NA = not applicable.

[a] Ton-Mile is one ton of cargo moved a distance of one mile.

[b] Solid waste is not attributable to transportation energy consumption except for the secondary impacts of discarded propulsion systems.

technique exists to distinguish what portion of the total impact is energy related. For example, no effort is made to relate auto accident deaths to energy use (Hittman, 1974: Vol. I, p. II-18).

The U.S. Office of Science and Technology (OST) reported that, in 1969, motor vehicles accounted for almost half the nation's total air pollution by weight (OST, 1972). Pollutants of particular significance in vehicle use are NO_x, hydrocarbons, and CO. Since the establishment of Environmental Protection Agency (EPA) standards, government and industry have been investigating a number of techniques by which these pollutants can be kept below levels required by the standards. Of the three pollutants, NO_x (formed by the nitrogen-oxygen reaction at high combustion temperatures) is the more difficult to control. Modifications to control emissions may take several forms such as the current use of catalytic beds (the new "mufflers") which convert the unburned hydrocarbons and CO contaminants to water and CO_2, acceptable effluent products (Hittman, 1974a: 5). Proposed solutions to the NO_x problem are based on exhaust gas recirculation, catalysis, changes in compression ratios, and other methods.

While studies show that emission control engineering changes have resulted in reduced emissions, they have also adversely affected fuel economy. This point is discussed in more detail in Section 13.4.2.1.1.

13.4.1.4 Economic Considerations

Table 13-22 gives (approximate) average prices for the movement of inter-city freight by various methods in 1970. This table closely resembles the variation in energy intensiveness (Table 13-20); that is, the price per ton-mile increases for the less efficient modes, reflecting their greater speed, flexibility, and reliability. For example, the truck is four times less efficient than the railroad, and costs 5.35 times more. Consequently, there is no great difference between relative economic and energy costs. In general, the public has been willing to pay higher operating costs in return for greater convenience.

TABLE 13-22

INTER-CITY FREIGHT
TRANSPORTATION PRICE DATA (1970)

Mode	Price (cents per ton-mile)
Pipeline	0.27
Railroad	1.4
Waterway	0.30
Truck	7.5
Airplane	21.9

Source: Hirst and Moyers, 1973a: 1300.

13.4.2 Passenger Travel

13.4.2.1 Technologies

Table 13-23 shows that, over the past 20 years, the automobile traffic share of total inter-city passenger-miles has remained relatively constant, accounting for 86.8 percent of the total in 1950 and 87.0 percent in 1970. During this period, railroads declined from 6.4 percent to less than one percent of the total passenger-miles, while the airplane increased its share nearly five-fold. In 1970, air transportation accounted for almost 10 percent of the total inter-city passenger-miles. These data clearly illustrate the degree to which the automobile and airplane presently dominate the inter-city passenger sector.

The urban passenger sector is dominated by the automobile. As population growth is increasingly concentrated in the suburbs, a further demand for automobiles and roads is created. Much of this urban travel results from the separation of residential areas and work places, shopping

TABLE 13-23

METHODS OF INTER-CITY PASSENGER TRAFFIC

Year	Total Passenger-Miles (10^9)	Percentage of Total Passenger-Miles			
		Automobile	Airplane	Bus	Railroad
1950	510	86.8	2.0	5.2	6.4
1955	720	89.5	3.2	3.6	4.0
1960	780	90.1	4.3	2.5	2.8
1965	920	88.8	6.3	2.6	1.9
1970	1,180	87.0	9.7	2.1	0.9

Source: Hirst, 1972: 10 (data from Statistical Abstract, 1970, and from Transportation Facts and Trends, 1971).

centers, and recreational facilities. To date, public transportation (i.e., buses and rapid transit modes) has not competed effectively with growing automobile usage, even though such transit systems could potentially alleviate congestion and pollution problems.

13.4.2.1.1 Automobiles

The largest single energy consumer in the transportation sector is the passenger car. Automobiles account for more than half of the total transportation energy needs. Eight out of 10 American households presently own at least one car while 3 in 10 have two cars (Washington Center for Metropolitan studies, 1974). The automobile's use is related to rising affluence, suburban development, and shifting employment patterns. Essentially, the car is very much a part of the American lifestyle, reflecting mobility and independence. It offers distinct advantages over competing modes of transportation, such as privacy, speed, personal comfort, and freedom to choose one's own route of travel. As a consequence, Americans have tended to ignore many of the energy trade-offs involved in their transportation decisions.

Presently, most automobiles are heavy, high-powered, and very inefficient. Calculations for the 1973 average American car indicate a fuel economy of less than 12 miles per gallon (mpg) (EPA, 1972). This figure represents about a 20-percent decline from the 1968 nationwide average. Until recently, the primary reasons for this declining fuel economy were steady increases in engine displacement, weight, and average operating speed, in conjunction with the use of energy consuming accessories such as air conditioners, power steering, and automatic transmissions (Hirst and Herendeen, 1973). Although the recent imposition of the national 55-miles per hour (mph) limit has reduced the average speed and EPA standards have caused some reduction in engine size, fuel economy has continued to decline because of lowered engine efficiencies (higher power-to-weight ratios), emission control devices, and continued use of power accessories.

The above factors--combined with low average car occupancy (one passenger for urban use, two passengers for average use [Rice, 1972: 34]), the growing use of cars for short distance trips, and an increase in total miles driven (Figure 13-2)--have

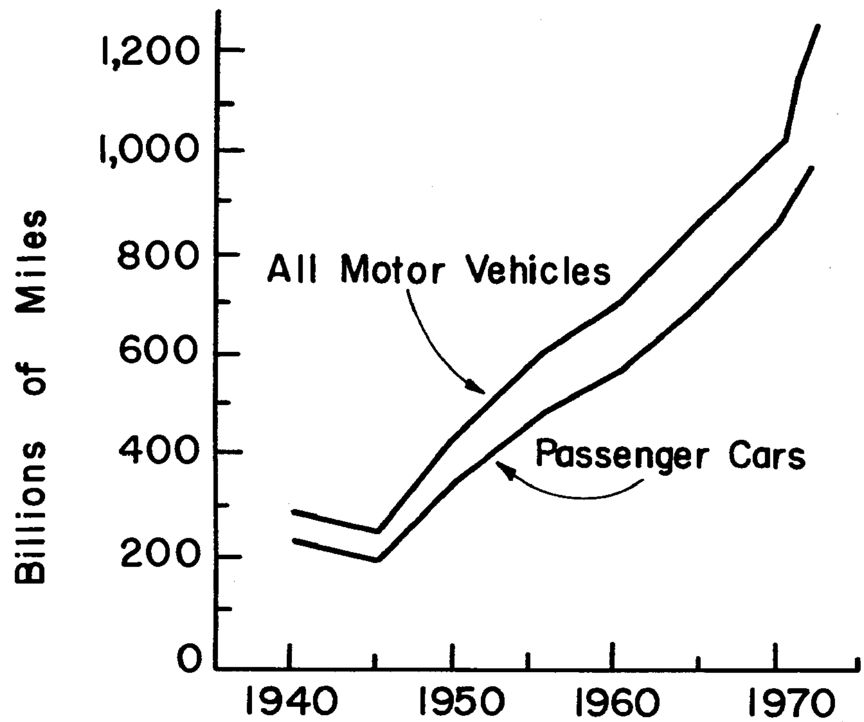


Figure 13-2. Growth in Vehicle Miles, 1940-1972

Source: The Ford Foundation, 1974: 5
(from Motor Vehicle Manufacturers Association).

not only increased fuel consumption but contributed significantly to environmental pollution.

13.4.2.1.2 Buses

Although buses are a highly efficient method of transportation, both in terms of energy and cost, they have not been able to effectively compete with either the automobile or the airplane. From 1950 through 1970, buses' percentage of the total passenger-miles declined from 5.2 to 2.1 percent. Demands for mobility, speed, comfort, convenience, and reliability have caused buses to lose customers to other, more energy intensive modes. In addition, traffic congestion has contributed to the buses' reputation as a time consumer. A considerable amount of current research and development funds are being expended by the Department of Transportation (DOT) to make bus transport more attractive to the public and reverse the negative growth trend (DOT, 1972: 1031).

Buses generally fall into three categories: urban bus, highway (inter-city) bus, or microbus. The average passenger loads for these categories are 12, 22, and 7 respectively (Rice, 1972: 34). Urban buses have recently received more attention in several large U.S. cities (Los Angeles, New York City, and Washington, D.C.) where special lanes have been provided for their travel, thereby increasing their speed and reliability. An interesting variant over the more conventional urban bus is the "Dial-a-Ride" bus that holds 10 to 20 passengers, is dispatched in response to a phone call, and provides door-to-door service.

13.4.2.1.3 Airplanes

Between 1965 and 1970, passenger air travel experienced a dramatic average annual growth rate of 14 percent (DOT, 1972: 1031). This is the fastest growing mode of inter-city passenger travel, increasing its share of the total passenger-miles from two percent in 1950 to 9.9 percent in 1970. Most earlier estimates projected this trend to continue for some time. Recent estimates assume the passenger air transportation industry is maturing while air freight is only beginning to grow (Ford Foundation, 1974a: 446).

For most Americans, the airplane represents the fastest method to a given destination, thus is a way to save time. Despite other delays (e.g., airport and ground congestion), the airplane is considered the standard to be used in judging all other modes of transportation. In addition, as the automobile market becomes essentially saturated within the next few decades, increasing amounts of per capita real disposable income will probably be used for common carrier transportation. In fact, one source attributes part of the increase in air travel to just that influence--money available to be used in air rather than automobile travel (DOT, 1972: 1032).

13.4.2.1.4 Railroads

Between 1965 and 1970, railroads were rapidly losing their small share of the inter-city passenger market. During this five-year period, passenger service dropped 9.3 percent annually (DOT, 1972: 1036). As a result, railroads were eliminating their remaining passenger services until recently. This decline in service is expected to stop, or at least slow down, because of a federal commitment to help rail transportation.

Passenger trains use either distillate fuel or electrical energy. U.S. railroads are predominately diesel; for example, only seven of the 20 billion passenger-miles carried by mass transit in 1970 were handled by electric-powered systems.

Rapid transit systems operating on electrical energy are proposed as a method for substantially reducing the number of commuters using automobiles. However, economic problems associated with these systems have delayed their implementation. For example, the San Francisco Bay Area Rapid Transit (BART) District was founded in 1958. Construction of the system began in 1966, and the expected completion date was 1974. During this period, costs increased from the $700 million original estimate to $1.5 billion. On completion, the system is expected to carry only one percent of the total surface travel and 10 to 15 percent of the commuters in the bay area (Shell, 1973a: 9).

13.4.2.2 Energy Efficiencies

Approximate energy requirements for various passenger modes of inter-city and urban travel are given in Table 13-24. The data are considered good, with a probable error of less than 25 percent. Like the trends reported for freight, passenger transport has also shifted to more energy intensive modes. For example, airplanes are less energy efficient for passenger movement than autos, which in turn are less efficient than buses and railroads. Since efficiency rises dramatically as more passengers are accommodated, the load factor assumptions in the table are crucial in determining the most efficient modes. For example, consider the efficiency of the automobile in inter-city transportation, where the load factor is about double that for urban transportation.

TABLE 13-24

ENERGY INTENSIVENESS OF
INTER-CITY AND URBAN PASSENGER TRAVEL

Mode	Average Load Factor (percent)	Btu's per Passenger-Mile
		INTER-CITY
Aircraft	50	8,400
Automobile	48	3,400
Railroad	35	2,900
Bus	45	1,600
		URBAN
Automobile	28	8,100
Mass transit	20	3,800

Source: Hirst and Moyers, 1973a: 1300.

The effective overall thermal efficiency of the average automobile is only 8.3 percent, compared to 22 to 25 percent theoretical efficiency of the internal combustion engine. This theoretical to actual difference is the result of losses due to engine design, emission controls, aerodynamic drag, rolling resistance, parasitic and transmission losses, constraints imposed on the driver and vehicle by traffic conditions such as stop-and-go driving, and others. (Szego, 1971: Vol. II, Part B, pp. N-8, K-22). Significant improvements in automobile efficiencies will probably require a transition from the present internal combustion engine to more advanced engines. (See Section 13.4.4 for an example).

Table 13-21 indicates that, for inter-city traffic, buses and trains are the most efficient modes. Cars are less than half as energy efficient as buses but more than twice as efficient as airplanes.

Urban efficiencies are lower than those for inter-city travel due to lower average miles per gallon and fewer passengers per vehicle (load factor). Mass transit systems--60 percent are bus systems--are more than twice as efficient as cars for urban travel.

13.4.2.3 Environmental Considerations

Table 13-25 contains the environmental residuals that have been quantified for passenger transportation. The data are considered fair, with a probable error of less than 50 percent. The pollutants of significance are air emissions. The automobile

Table 13-25. Residuals for Passenger Transportation Energy Use

End Use/Fuel	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)						Solids (tons/measure)	Measure[a]	Energy Btu/measure	Multiplier	Multiplier Year
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/ measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes					
PASSENGER TRANSPORTATION																					
Auto-Intercity/Gasoline	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	1.05×10^{-7}	1.44×10^{-6}	6.2×10^{-8}	3.53×10^{-6}	2.25×10^{-5}	1.69×10^{-7}	b	Passenger-Mile	3520.	8.95×10^{11}	1970
Auto-Urban/Gasoline	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	1.95×10^{-7}	1.44×10^{-6}	1.18×10^{-7}	4.78×10^{-7}	$4. \times 10^{-5}$	3.21×10^{-7}	b	Passenger-Mile	4730.	1.09×10^{12}	1970
Bus-Intercity/Distillate	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	4.85×10^{-8}	1.39×10^{-6}	$1. \times 10^{-7}$	1.36×10^{-7}	8.45×10^{-7}	2.21×10^{-8}	b	Passenger-Mile	1070.	2.35×10^{10}	1971
Bus-Intercity/Gasoline	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	1.08×10^{-8}	2.53×10^{-7}	6.25×10^{-8}	3.2×10^{-7}	2.05×10^{-6}	1.7×10^{-8}	b	Passenger-Mile	757.	4.31×10^{10}	1971
Bus-Urban/Distillate	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	1.05×10^{-7}	2.98×10^{-6}	2.18×10^{-7}	2.93×10^{-7}	1.81×10^{-6}	4.75×10^{-8}	b	Passenger-Mile	2300.	1.84×10^{10}	1971
Bus-Urban/Gasoline	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	2.15×10^{-8}	3.24×10^{-7}	1.39×10^{-8}	5.55×10^{-7}	4.65×10^{-6}	3.5×10^{-8}	b	Passenger-Mile	1440.	1.81×10^{10}	1971
Air-Civil-Domestic/Jet	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	1.45×10^{-7}	1.05×10^{-7}	4.2×10^{-8}	3.5×10^{-7}	3.3×10^{-7}	1.05×10^{-8}	b	Passenger-Mile	9320.	1.1×10^{11}	1970
Air-Civil/ International/Jet	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	7.53×10^{-8}	4.6×10^{-8}	1.67×10^{-8}	8.36×10^{-8}	2.2×10^{-8}	4.2×10^{-9}	b	Passenger-Mile	5660.	4.88×10^{10}	1970
Rail-Urban Rapid Transit/Electric	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	b	Passenger-Mile	3390.	7.75×10^{9}	1970
Rail-Intercity/ Electric	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	b	Passenger-Mile	2360.	6.07×10^{9}	1970
Rail-Intercity/ Distillate	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	2.21×10^{-7}	6.65×10^{-7}	5.72×10^{-7}	4.43×10^{-7}	6.2×10^{-7}	9.75×10^{-8}	b	Passenger-Mile	2900.	6.1×10^{9}	1969
General Aviation-Piston/ Gasoline	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	$1. \times 10^{-4}$	$1. \times 10^{-4}$	$5. \times 10^{-6}$	$2. \times 10^{-4}$	$6. \times 10^{-3}$	$5. \times 10^{-5}$	b	Hour	2.75×10^{6}	2.4×10^{7}	1970
General Aviation- Turbine/Jet	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	U	2.49×10^{-4}	5.65×10^{-5}	2.72×10^{-4}	9.5×10^{-4}	U	b	Hour	1.51×10^{7}	1.5×10^{6}	1970

NA = not applicable.

[a]Passenger-Mile is one passenger moved a distance of one mile.

[b]Solid waste is not attributable to transportation energy consumption except for the secondary impacts of discarded propulsion systems.

is shown to be a major contributor to the man-made emissions of CO, unburned hydrocarbons, and NO_x. One source estimated that, in cities, motor vehicles emitted 50 to 90 percent of the above pollutants in 1973 (EPA, 1973: 156).

Current pollution abatement efforts of the automotive industry have increased consumption of gasoline and petroleum products for motor vehicles, but not as much as often reported. A recent EPA study estimates that the loss in fuel economy for 1973 model year vehicles over those with no emission controls is in the range of seven to eight percent (EPA, 1972: 141).* Indications suggest that the fuel economy of 1975 vehicles with their additional controls should remain unchanged from 1973. The imposition of the initial 1976 NO_x emission standards could have caused a further reduction in fuel economy of 10 percent to 12 percent; however, due to recent developments in air quality data, the emission standards for 1976 are being reconsidered. In terms of operating costs, a fuel economy loss of seven to eight percent is estimated to increase the average driver's fuel bill by less than $25 a year (1973 prices). The increased initial cost of a 1975 model year vehicle due to emission controls should be in the range of $150 to $300 (approximately two to three percent of the total cost) (EPA, 1973: 160,161).

In addition to the air emissions resulting from the operation of vehicles, gaseous, liquid, and solid wastes are generated by the manufacture, maintenance, and scrapping of vehicles. Though these impacts are beyond the scope of this description (in that they are not attributed directly to the end use of energy for transportation), they should be considered at least qualitatively in an overall assessment of the environmental impacts of any one transportation mode (cf. Hittman, 1974b: Appendix C).

13.4.2.4 Economic Considerations

Table 13-26 shows approximate 1970 prices for passenger travel by various methods. Although not as strongly correlated as for freight movement, passenger travel modes also show a direct relationship between energy intensiveness and price. In other words, price per passenger-mile increases for the less efficient modes, reflecting their speed, convenience, comfort, flexibility, and reliability. However, user costs do not always reflect relative energy costs. For example, comparing the energy intensiveness figures, Table 13-24 shows that, although the urban automobile consumes 2.24 times more energy per

TABLE 13-26

PASSENGER TRANSPORTATION PRICES (1970)

Mode	Price (cents per passenger-mile)
	INTER-CITY
Bus	3.6
Railroad	4.0
Automobile	4.0
Airplane	6.0
	URBAN
Mass transit	8.3
Automobile	9.6

Source: Hirst and Moyers, 1973a: 1300.

*To put these numbers in perspective, the fuel penalty associated with consumer choices such as auto air conditioning and automatic transmissions have been reported respectively as nine and five or six percent. On the other hand, high vehicle weights can result in fuel penalties up to 50 percent, especially when they result in very low power-to-weight ratios.

passenger-mile than a bus, the economic cost is only 1.15 times greater.

Massive commitments in terms of energy and money are made to the automobile in our society. During 1970, 8.4 million cars (both domestic and foreign) were sold by retail dealers, and 87 million passenger cars were registered in the U.S. Approximately 10 percent of the Gross National Product (GNP) and 16 percent of the American work force can be directly traced to the automotive industry (Hittman, 1974a: 21,23). Obviously, the production and use of the automobile constitutes a significant part of the national economy. In addition, owning an automobile constitutes a major part of each family's budget. The average new car price for 1970, excluding taxes, was $3,190 (Hirst and Herendeen, 1973: 973), and until recent price increases, the total cost for auto transportation was about 14 cents per vehicle mile (Ford Foundation, 1973: Chapter XII, p. 23).

13.4.3 Military-Government and Feedstocks

As previously noted, Hittman provided estimates for two additional transportation categories: consumption and related residual data for military and government transportation (based on records maintained by the Department of Defense Fuel Supply Center), and the total gallons of lubricants for automotive and aviation transportation (a separate feedstocks category).

Table 13-27 gives estimates of the environmental residuals that have been quantified for the above two categories. Most of the data is considered poor, with a probable error of 100 percent. Feedstocks for transportation services are a source of nondegradable organic water pollutants, contributing about 7.42×10^4 tons per year to the environment. The residuals associated with military and government transportation use are similar to those for freight and passenger vehicle modes; that is, air pollutants.

13.4.4 Conservation Measures for the Transportation Sector

As demonstrated in the preceding technological description, U.S. transportation is dominated by the least efficient (in terms of energy consumption) methods. Government policies appear preferential to the development of air and highway transportation and have contributed to declining energy use efficiency. Further, the present mix of transport modes is determined by personal preference, private economics, convenience, speed, and reliability (Hirst and Moyers, 1973a: 1300)--factors that often ignore energy consumption rates.

Conservation strategies for the transportation sector must take into account national and social factors so that changes do not result in excessive damage to transportation-dependent industries or appreciably disrupt the quality of transportation services. Energy demand in this sector could be reduced by shifting to more energy efficient transportation modes; increasing load factors; and improving the efficiency of the different transport modes. Of these measures, only the latter would require additional research and development (e.g., to determine improvements or alternatives to the internal combustion engine).

A conservation study by the OEP found the greatest potential for transportation energy savings in the shift of inter-city freight from highway to rail, inter-city passengers from air to ground travel, urban passengers from automobiles to mass transit, freight consolidation in urban freight movement, and longer term improvements through the introduction of more efficient equipment. OEP outlined the following specific recommendations (1972: 56,57), including estimated sector savings if the measures were implemented:

1. Short-Term Measures (1972-1975). Conduct educational programs to stimulate public awareness of energy conservation in the transportation sector. Establish government energy efficiency standards.

Table 13-27. Residuals for Military and Government and Feedstocks Transportation Energy Use

End Use/Fuel	Water Pollutants (Tons/measure)										Air Pollutants (Tons/measure)										
	Acids	Bases	PO_4	NO_3	Total Dissolved Solids	Suspended Solids	Organics	BOD	COD	Thermal (Btu's/measure)	Particulates	NO_x	SO_x	Hydrocarbons	CO	Aldehydes	Solids (tons/measure)	Measure	Energy Btu/measure	Multiplier	Multiplier year
MILITARY AND GOVERNMENT TRANSPORTATION																					
Aircraft-Piston/Gasoline	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	5.55×10^{-6}	4.45×10^{-7}	1.45×10^{-7}	4.5×10^{-5}	3.37×10^{-4}	2.22×10^{-7}	a	Gallons	1.25×10^{5}	4.18×10^{8}	1972
Aircraft-Turbine/Jet	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	2.5×10^{-6}	1.14×10^{-6}	4.5×10^{-7}	5.9×10^{-6}	5.5×10^{-6}	2.28×10^{-7}	a	Gallons	1.33×10^{5}	4.19×10^{9}	1972
Ground Vehicles/Gasoline	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	4.14×10^{-6}	7.95×10^{-5}	2.49×10^{-6}	1.3×10^{-4}	8.6×10^{-4}	6.8×10^{-6}	a	Gallons	1.25×10^{5}	3.29×10^{8}	1972
Ships/Distillate	NA	NA	NA	NA	0	NA	NA	NA	NA	0	5.55×10^{-5}	1.75×10^{-4}	2.45×10^{-5}	1.16×10^{-5}	$7.\times10^{-5}$	U	a	Gallons	1.39×10^{5}	1.78×10^{8}	1972
Ships/Residual	NA	NA	NA	NA	0	NA	NA	NA	NA	0	1.12×10^{-5}	3.35×10^{-5}	7.35×10^{-5}	6.3×10^{-6}	7.4×10^{-5}	U	a	Gallons	1.5×10^{5}	1.7×10^{8}	1972
TRANSPORTATION FEEDSTOCKS																					
Lubricants	NA	NA	NA	NA	NA	NA	$7.\times10^{-5}$	NA	NA	NA	0	0	0	0	0	0	NA	Gallons	1.44×10^{5}	1.06×10^{9}	1969

NA = not applicable, U = unknown.

[a]Solid waste is not attributable to transportation energy consumption except for the secondary impacts of discarded propulsion systems.

Improve traffic flow. Improve mass transit and inter-city rail and air transport. Promote automobile energy efficiency through low-loss tires and engine tuning. Savings: $1{,}900 \times 10^{12}$ Btu's per year (10 percent).

2. Mid-Term Measures (1976-1980). Improve freight handling systems. Support pilot implementation of most promising alternatives to internal combustion engine. Set tax on size and power of autos. Support improved truck engines. Require energy efficient operating procedures for airplanes. Provide subsidies and matching grants for mass transit. Ban autos within the inner city. Provide subsidies for inter-city rail networks. Decrease transportation demand through urban refurbishing projects and long-range urban/suburban planning. Savings: $4{,}800 \times 10^{12}$ Btu's per year (21 percent).

3. Long-Term Measures (beyond 1980). Provide R&D support for hybrid engines, nonpetroleum engines, advanced traffic control systems, dual mode personal rapid transit, high speed transit, new freight systems, and people movers. Decrease demand through rationing and financial support for urban development and reconstruction. Savings: $8{,}000 \times 10^{12}$ Btu's per year (25 percent).

The remainder of this discussion specifically identifies several of the more promising energy conservation alternatives for various end uses within the transportation sector. Public awareness of these measures should help foster an understanding of the energy implications of transportation decisions.

13.4.4.1 Automobiles

The consumer should be made aware of the energy and dollar cost implications of his decisions concerning the expected fuel economy of new cars, as well as the long-term costs associated with accessories (e.g., air conditioners, automatic transmissions, etc.).

The Ford Foundation energy study estimated that about 75 percent of the potential transportation energy savings in 1985 can come from improving the fuel economy of the automobile to 20 mpg (Ford Foundation, 1973: Chapter XII, p. 23). This could be accomplished by shifting to smaller, lighter-weight or medium-sized cars which in many cases already achieve or surpass the 20-mpg average. Short-term fuel economy could be favorably affected by some rather simple, economically feasible engineering improvements as listed in Table 13-28. Improvements like the above might increase auto capital costs up to $450 but the fuel savings would more than compensate for the added investment (Ford Foundation, 1974a: 59).

TABLE 13-28

EFFECT OF AUTO DESIGN ON FUEL ECONOMY

Design Feature	Fuel Economy Improvement (percent)
Body redesign to reduce aerodynamic drag	5
Use of radial tires to reduce rolling resistance	10
Better load-to-engine match	10 to 15
Substitution of 300 pounds of aluminum for 750 pounds of steel	18

Source: Ford Foundation, 1974a: 59.

Another conservation opportunity is car pooling, which increases the average occupancy (load factor) of automobiles. The impact of car pooling is difficult to estimate because of variations in geographic locations, size of metropolitan areas, business types, and residential densities. However, increased load factors represent a source of immediate savings.

The development of efficient, convenient, and reliable mass transit systems to be used in place of more energy intensive automobiles could significantly reduce the traffic congestion and the need for additional highways. Although mass transit systems have very long lead times and high capital costs, urban transportation is a primary target for this action.

To illustrate possible energy savings through use of more energy efficient modes, one study (Hirst and Moyers, 1973a: 1300) compared two transportation models (an actual and a hypothetical case), one based on historic growth trends and the other on a steady shift toward more energy efficient modes. This comparison revealed that adoption of the hypothetical case would require only 78 percent as much energy to move the same traffic as the actual case.

Assumptions underlying the hypothetical model include:

1. Half the freight traffic carried by conventional methods (truck and air) is assumed to be carried by rail.
2. Half the inter-city passenger traffic carried by air and one-third the traffic carried by auto is assumed to be carried by bus and train.
3. Half the urban automobile traffic is assumed to be carried by bus.

For this scenario's potential to be realized, changes must occur in public attitudes concerning mass transit. The balance among transportation modes is constrained by various socio-economic factors that might inhibit shifts to more energy efficient modes. Such factors include: existing land use patterns, capital costs, changes in energy efficiency within a given mode, substitutability among modes, new technologies, transportation ownership patterns, and other institutional arrangements. However, fuel scarcities, rising energy prices, dependence on foreign petroleum, urban land-use problems, and environmental considerations may provide the incentives necessary to alter current transportation practices (Hirst and Moyers, 1973a: 1300).

Further improvements for the long-term can be achieved through research and development in motor vehicle engine design. Possible improvements range from modification of conventional engines, with add-on devices like catalytic beds, to systems based on thermodynamic cycles different than the conventional internal combustion engine. Hittman performed a technology assessment of advanced automotive propulsion systems in an effort to define and study the interrelationships and impacts resulting from a transition from the current internal combustion engine to alternate propulsion systems (1974b). The stratified-charge engine (developed by Honda) appears to be especially promising for the automobile. Hittman concluded that stratified-charge engine design had progressed to the point that full-size vehicles, compacts, and subcompacts could be developed with significantly improved fuel economy, low-emissions without catalysts, and minor materials and economic impact (Hittman, 1974a: 102).

Another alternative is the lightweight diesel engine. (Presently, the Mercedes-Benz 220D is the leading diesel-powered auto available in the U.S.) The advantage of the diesel-powered auto is fuel economy. Figure 13-3 illustrates this engine's high fuel economy in relation to three gasoline engines at the low speeds characteristic of urban driving. Additional advantages of the diesel engine are its low level of pollutant emissions, low maintenance requirements, and high mileage between overhaul capability. However, present customer acceptance of diesel-powered cars is low and future levels are very uncertain because of the engine's characteristic high noise level, smoke, odor, difficult cold starting, low performance, and particulate emissions (Hittman, 1974a: 29-31).

13.4.4.2 Airplanes

Energy use for air travel can be reduced either by shifting to alternative modes or by improving the operating efficiencies. The Ford Foundation energy study

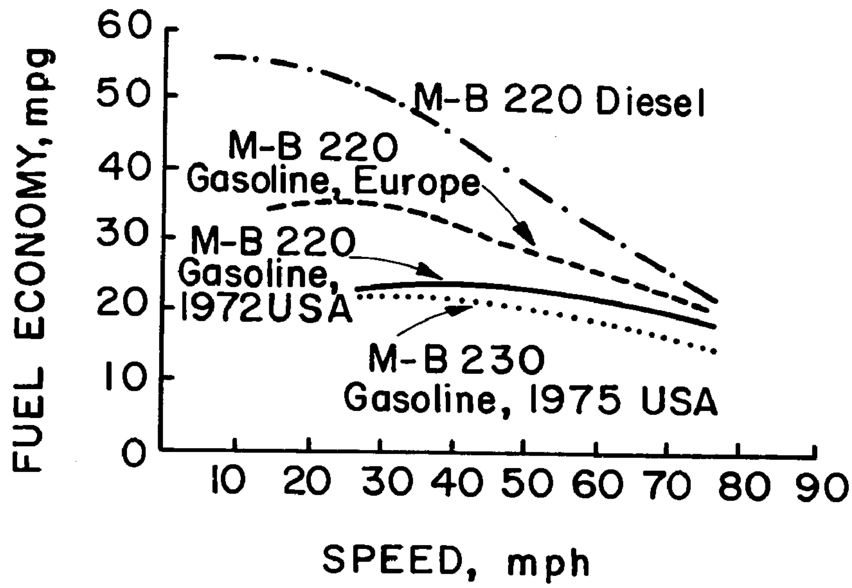


Figure 13-3. Comparison of Fuel Economy for Four Engines

Source: Wakefield, 1973: 67 (Courtesy Road & Track Magazine).

reported the most important single measure for reducing energy requirements for this transport mode would be to increase the load factor for passengers (Ford Foundation, 1974a: 61). As the public and the federal government become more aware that air travel is not energy efficient when seats are vacant, the possibility that load factors will change becomes greater. Load factors depend to a large degree on the rate at which the Civil Aeronautics Board (CAB) authorizes competitive routes. Recently, airlines have been authorized by the CAB to discuss the elimination of competing flights.

It has been estimated that load factors could be increased to 67 percent without appreciably reducing a passenger's chances of losing his reservation. Such an improvement is calculated to result in a 18-percent direct fuel savings for domestic flights and an eight-percent savings for international flights, which are already loaded to a greater capacity (Ford Foundation, 1973: Chapter XII, p. 29).

Further improvements could come from reducing speeds of airplanes to the level where fuel consumption in minimal. Reducing speeds to this level would result in a 4.5-percent fuel savings and would increase flight times only six percent (Ford Foundation, 1974a: 61).

In an attempt to achieve a more optimal balance in terms of energy efficiency, short-haul air freight (up to 150 miles) should be shifted to truck, and intermediate-haul air freight (250 to 450 miles) should be shifted to rail. As rapid rail transport systems are developed, it might even become feasible to shift short-haul air traffic to rail.

13.4.4.3 Trucks and Rail

Energy demand for trucks and railroads can be reduced by:

1. Loading trucks more efficiently.
2. Switching gasoline-powered trucks to diesel or equally efficient engines.
3. Changing truck configurations.
4. Shifting many truck shipments to rail.

The Ford Foundation estimates that savings of 10 to 30 percent are possible through improved loading practices. In addition, about 30-percent savings could be achieved by switching freight-hauling trucks from gasoline to diesel engines (Ford Foundation, 1974a: 60).

Although several changes in truck configuration are possible, the most promising is probably a change in the truck body shell to reduce aerodynamic drag. One source indicated that a modest design program, completed in the short-term, could result in design capable of achieving a five-percent reduction in energy consumption (Seidel and others, 1973: 94).

The use of railroads instead of trucks for freight was suggested earlier as a potential energy saving measure. To the present, the difference in efficiency has not been great enough to outweigh the positive features of trucks. This situation could change with rising fuel costs. There are indications that with changed government policies, some upgrading of rail service, and the adoption of marginal cost pricing, the economics of a switch to rail would be favorable for more than half the freight now moving by truck (Ford Foundation, 1973: Chapter XII, p. 31). If 20 percent of the large truck traffic (corresponding to hauls longer than 600 miles) is shifted to rail, the Ford Foundation estimates savings by 1985 to be 300×10^{12} Btu's.

13.4.4.4 Other

Inter-city buses and short- and medium-distance high-speed trains are another potential for reducing the number of persons using private automobiles and commercial airplanes. An example is the Metroliner train between New York and Washington. However, these transport modes depend to a large extent on major financial assistance and changes in the attitudes of the general public. Without such support, these transportation modes will not be used to their maximum.

Energy conservation strategies within the transportation sector are highly interactive, and any conservation measure will tend to shift the structure of the transport market to which it is applied (Seidel and others, 1973: 91,92). Thus, studies of the competition between transport modes should be an integral part of any assessment of energy conservation strategies.

REFERENCES

American Chemical Society (1969) Cleaning Our Environment: The Chemical Basis for Action. Washington: American Chemical Society.

Atomic Energy Commission (1974) Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington: Government Printing Office, 4 vols.

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

Berg, Charles A. (1973a) "Energy Conservation Through Effective Utilization," Reprinted in Senate Interior Committee (1973a): 552-561.

Berg, Charles A. (1974) "A Technical Basis for Energy Conservation." Technology Review 76 (February 1974): 14-23.

Berg, Charles A. (1973b) "A Brief Report on Technology for Energy Consumption in Industrial Thermal Processes," draft dated June 13, 1973, for the Technical Advisory Committee on Research and Development of the National Power Survey, as cited in AEC (1974): Vol. IV, pp. C.6-C.10.

Braddock, Dunn and McDonald, Inc. (1974a) Study of Alternative Strategies and Methods of Conserving Energy, First Interim Technical Status Report. Vienna, Va.: BDM, Inc.

Braddock, Dunn and McDonald, Inc. (1974b) Technology Assessment of Energy Conservation Through Electricity Peak Load Demand Leveling. Vienna, Va.: BDM, Inc.

Bureau of Land Management (1973) Energy Alternatives and Their Related Environmental Impacts. Washington: Government Printing Office.

Cook, Earl (1971) "The Flow of Energy in an Industrial Society." Scientific American 224 (September 1971): 134-144.

Council on Environmental Quality (1973) Energy and the Environment: Electric Power. Washington: Government Printing Office.

Department of Commerce (1956) "Water Use in the United States, 1960-1975," as reported in McGauhey (1968).

Department of the Interior (1972) United States Energy Through the Year 2000, by Walter G. Dupree, Jr., and James A. West. Washington: Government Printing Office.

Department of Transportation (1972) Research and Development Opportunities for Improved Transportation Energy Usage, DOT-TSC-OST-73-74-14 (September 1972). Reprinted in Senate Interior Committee (1973a: 1005-1097).

Environmental Protection Agency (1972) Fuel Economy and Emission Control. Reprinted in Conservation and Efficient Use of Energy, Joint Hearings before Subcommittees of the Committees on Government Operations and Science and Astronautics, House of Representatives, 93rd Cong., 1st sess., July 11, 1973, Part 1, pp. 131-135.

Environmental Protection Agency (1973) "The Federal Automobile Emission Standards: Their Purpose, Their Need, Their Impact." Reprinted in Conservation and Efficient Use of Energy, Joint Hearings before Subcommittees of the Committees on Government Operations and Science and Astronautics, House of Representatives, 93rd Cong., 1st sess., July 11, 1973, Part 1, pp. 156-162.

Federal Council on Science and Technology, Committee on Energy Research, as cited in Berg (1974): 21.

The Ford Foundation, Energy Policy Project (1973) Energy Study Draft Report.

The Ford Foundation, Energy Policy Project (1974) Exploring Energy Choices: A Preliminary Report. Washington: The Ford Foundation.

The Ford Foundation, Energy Policy Project (1974a) A Time to Choose: America's Energy Future. Cambridge, Mass.: Ballinger Publishing Company.

Hannon, Bruce (1972) System Energy and Recycling: A Study of the Container Industry, as cited in OEP (1972).

Hirst, Eric (1972) Energy Consumption for Transportation in the U.S., Oak Ridge National Laboratory Report ORNL-NSF-EP-15. Oak Ridge, Tenn.: ORNL.

Hirst, Eric, and Robert Herendeen (1973) Total Energy Demand for Automobiles. New York: Society of Automotive Engineers. Reprinted in Senate Interior Committee (1973a): 970-976.

Hirst, Eric, and John C. Moyers (1973a) "Efficiency of Energy Use in the United States," Science 179 (March 30, 1973): 1299-1304.

Hirst, Eric, and John C. Moyers (1973b) "Potential for Energy Conservation Through Increased Efficiency of Use," pp. 155-176 in Energy Conservation, Hearings before the Committee on Interior and Insular Affairs, Senate, 93rd Cong., 1st sess., March 22-23, 1973.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

Hittman Associates, Inc. (1974a) The Automobile--Energy and the Environment: A Technology Assessment of Advanced Automotive Propulsion Systems. Columbia, Md.: Hittman Associates, Inc.

Hittman Associates, Inc. (1974b) A Technology Assessment of the Transition to Advanced Automotive Propulsion Systems. Columbia, Md.: Hittman Associates, Inc.

Large, David B., ed. (1973) Hidden Waste: Potentials for Energy Conservation. Washington: The Conservation Foundation. Reprinted in Conservation and Efficient Use of Energy, Joint Hearings before Subcommittees of the Committees on Government Operations and Science and Astronautics, House of Representatives, 93rd Cong., 1st sess., July 11, 1973, Part 3, pp. 836-978.

McGauhey, P.H. (1968) Engineering Management of Water Quality. New York: McGraw-Hill Book Co.

McKee, Jack Edward, and Harold W. Wolf (1963) Water Quality Criteria. Sacramento, Calif.: State of California.

National Aeronautics and Space Administration/American Society for Engineering Education (1973) The Energy Dilemma and Its Impacts on Air Transportation. Norfolk, Va.: Old Dominion University.

National Mineral Wool Insulation Association, Inc., Technical Committee (1972) Impact of Improved Thermal Performance in Conserving Energy. New York: National Mineral Wool Insulation Association, Inc.

National Petroleum Council, Committee on U.S. Energy Outlook (1972) U.S. Energy Outlook. Washington: NPC.

National Science Foundation/National Aeronautics and Space Administration Solar Energy Panel (1972) An Assessment of Solar Energy As a National Energy Resource. College Park, Md.: University of Maryland.

Office of Emergency Preparedness (1972) The Potential for Energy Conservation. Washington: Government Printing Office.

Office of Science and Technology (1972) Cumulative Regulatory Effects on the Cost of Automotive Transportation, Final Report of the Ad Hoc Committee as cited in Shell Oil Company (1972) Oil and the Environment: The Prospect. Houston: Shell Oil Company, p. 7.

Rice, Richard A. (1972) "System Energy and Future Transportation," Technology Review 74 (January 1972): 31-37.

Schurr, Sam H. (1971) Energy Research Needs. Washington: Resources for the Future, Inc.

Seidel, Marquis R., Steven E. Plotkin, and Robert O. Reck (1973) Energy Conservation Strategies. Washington: Environmental Protection Agency.

Senate Committee on Interior and Insular Affairs (1973a) Energy Conservation and S. 2176, Hearings, 93rd Cong., 1st sess., August 1973.

Senate Committee on Interior and Insular Affairs (1973b) Energy Research and Development--Problems and Prospects, by Harry Perry. Washington: Government Printing Office.

Shell Oil Company (1973a) The National Energy Problem: Implications for the Petrochemical Industry. Houston: Shell Oil Company.

Shell Oil Company (1973b) The National Energy Problem: Potential Energy Savings. Houston: Shell Oil Company.

Stanford Research Institute (1972) Patterns of Energy Consumption in the United States. Washington: Government Printing Office.

Szego, G.C. (1971) The U.S. Energy Problem. Warrenton, Va.: InterTechnology Corporation.

Tansil, J., Residential Consumption of Electricity: 1950-1970, Oak Ridge National Laboratory Report ORNL-NSF-EP, as cited by Hirst and Moyers (1973b): 169.

Tybout, Richard A., and George O.G. Lof (1970) "Solar House Heating" Natural Resources 10 (April 1970): 268-326.

Wakefield, R. (1973) "The Diesel." Road and Track 25 (September 1973).

Washington Center for Metropolitan Studies (1974), as cited in the Ford Foundation (1974).

PART II: PROCEDURES FOR EVALUATING AND COMPARING ENERGY ALTERNATIVES

INTRODUCTION

Guidelines issued by the Council on Environmental Quality (CEQ) and court interpretations of the National Environmental Policy Act (88 Stat. 842, 42 U.S.C. Sec. 4321) emphasize certain content requirements for environmental impact statements (EIS), including the evaluation of both primary and secondary effects, the consideration and balancing of both advantages and disadvantages, and a thorough exploration of all reasonable alternatives. Reasonable persons can and have disagreed on whether these requirements have been met in particular impact statements. As a consequence, most agencies have made a considerable effort to improve the quality of the EIS they prepare and to make them less susceptible to challenge. However, EIS are often uneven in quality, largely because there is no satisfactory methodology for systematically identifying, measuring, interpreting, and/or replicating the evaluation of the proposed action and reasonable alternatives to it. The environmental impact statement process has now evolved to a point where it is both desirable and possible to suggest procedures for making more systematic evaluations and comparisons. The primary purpose of this part of the report is to suggest procedures for using CEQ's Matrix of Environmental Residuals for Energy Systems (MERES) data and the University of Oklahoma (OU) resource systems descriptions in Part I of this report.

By themselves, these procedures and data will not satisfy current requirements for evaluating and comparing energy alternatives in an EIS. For example, while accounting for many of the significant residuals, the procedures do not provide for a comprehensive analysis of the impacts of a proposed action on the environment; they do not provide guidelines for identifying which alternatives should be evaluated and compared as "reasonable" alternatives, including non-energy uses of affected lands; they do not specify evaluative criteria; and they do not provide answers to questions regarding policy alternatives such as the impact of deregulating the wellhead price of natural gas. In short, these procedures are primarily a tool to be used in planning and preparing an energy EIS, a tool for making certain limited kinds of calculations and comparisons that can be supported by the MERES data base and the OU resource systems descriptions.* However, Part II does suggest general procedures for relating residuals to ambient conditions, extending the examination of energy efficiencies to a more comprehensive energy balance analysis, and upgrading the economic analysis to include a consideration of prices as well as economic costs. All three of these analyses require data not available in either MERES or the OU resource systems descriptions; they also require an explicit identification of goals, objectives, and evaluative criteria at a level of specificity beyond that possible within the limitations imposed for this report generally and Part II specifically.

---

*Three broad classes of EIS have evolved to date--an EIS for: a specific project; a particular geographical area or region; and an overall program. The examples used in this report fit the specific project category.

Both the OU resource systems descriptions and MERES incorporate residuals, energy efficiency, and economic cost data reported in Hittman Associates' Environmental Impacts, Efficiency and Cost of Energy Supply and End Use (1974: Vol. 1; 1975: Vol. 2). MERES presently contains only data on four fossil fuels: coal, crude oil, natural gas, and oil shale.* The OU resource systems descriptions also contain data drawn from Battelle's Environmental Considerations in Future Energy Growth (1973), Teknekron's Fuel Cycles for Electrical Power Generation (1973), the Federal Energy Administration's Project Independence Blueprint (1974), and miscellaneous other sources published by agencies such as the Atomic Energy Commission, Bureau of Mines, U.S. Geological Survey, and other government agencies with responsibilities in the energy area. In addition to the four fossil fuels covered by MERES, Part I of this report describes geothermal, hydroelectric, nuclear fission, nuclear fusion, organic wastes, solar, tar sands, electric power generation, and energy consumption.

MERES data have also been incorporated into a computerized data system, the Energy Model Data Base (EMDB), developed by the Energy/Environmental Data Group of the Brookhaven National Laboratory. Detailed information on data and documentation files and the methods of accessing the EMDB are contained in Brookhaven's Energy Model Data Base User Manual (1975).

Note that the proposed procedures are affected by data quality. As noted in the General Introduction, both the OU descriptions and MERES data are incomplete because they are limited to what can be quantified. Although the OU descriptions do identify and discuss certain qualitative residuals, data contained in all three sources must be considered incomplete. This gap is especially significant when these data and procedures are used in planning and EIS preparation.

While both the OU descriptions and MERES incorporate only the most accurate data currently available, some of the data are of questionable quality. In part, this is due to disagreements within the scientific and technological communities, and in part it is due to the quality of data included in MERES and the OU descriptions. MERES data have been reviewed systematically and have been assigned "hardness" numbers to indicate their reliability. As noted earlier, these numbers show that reliability ranges from very good (an error of 10 percent or less) to very poor (an error of perhaps as much as an order of magnitude). These numbers are also used in the OU descriptions of energy resource systems to identify data quality.*

Plans for MERES include continuously updating and improving data quality. Users of MERES and this report can help by calling to the attention of CEQ, OU's Science and Public Policy Program, and Brookhaven's Energy/Environmental Data Group errors in the present data, the existence of more reliable data, and when more current data become available.

Part II consists of three chapters that describe and demonstrate procedures for using MERES data and the energy resource descriptions in Part I of this report. Chapter 14 focuses on the calculation and comparison of residuals and suggests procedures for analyzing impacts. Chapter 15 deals with energy efficiencies and energy balances. Chapter 16 discusses economic costs and prices. Analyses and comparisons in all three chapters are based on the following hypothetical proposed major federal action and selected alternatives to it. The alternatives are

---

*Data for other energy resources will soon be added.

*When technological activities are combined, the error of the combination is reported by OU as the hardness number for the lowest quality data.

intended to be illustrative only and should not be considered _the_ "reasonable" alternatives to the hypothetical proposed action.

Hypothetical Proposed Major Federal Action

The Secretary of the Interior is considering an application of the Synthetic Energy Company to construct and operate a coal mine and coal gasification facility on leased federal lands near Colstrip, Montana. It is assumed that the company leased the lands to be mined and upon which the processing facility is to be located in a competitive lease sale. Under the conditions of the sale, the winning bidder was required to submit an application to the Secretary within 30 days after the lease was awarded. That application, which includes a mine and facilities development plan and an assessment of the environmental impact of the planned development, was submitted to the Secretary and is now being reviewed by the Department. These plans call for an area surface mine, a Synthane high-Btu gasification facility, and introduction of the produced gas into an existing interstate pipeline that transports natural gas to the Pacific Northwest. Approval of this application is interpreted to constitute a major federal action within the meaning of Section 102 (2) (C) of the National Environmental Policy Act of 1969 (88 Stat. 842, 42 U.S.C. Sec. 4321).

In an EIS, it may be legally necessary to consider a number of alternatives to the proposed action, including "no action". For example, different technologies might be chosen (the Lurgi rather than Synthane high-Btu gasification process); a different location could be chosen for the Synthane plant (the Pacific Northwest rather than Montana); an alternative source of high-Btu gas might be considered (the Alaskan North Slope); and a different fuel might be substituted (electricity generated by an oil or nuclear-powered facility). Again, not all "reasonable" or possible alternatives that it would be necessary to consider in an EIS analysis are compared in Chapters 14 through 16; the following alternatives have been selected only to illustrate the use of MERES and OU descriptions:

1. Technological Alternative. Substitution of Lurgi for Synthane.
2. Locational Alternative. Relocate the high-Btu gasification facility from the mine-mouth to the demand center.
3. Alternative Sources of High-Btu Gas.
   a. Alaskan natural gas via a Canadian pipeline.
   b. Alaskan natural gas via pipeline to Valdez and by LNG tanker to the west coast.
   c. Increased domestic production offshore.
   d. Imported foreign LNG.

The residuals, energy efficiencies, and economic costs of each of these alternatives and the hypothetical proposed major federal action are calculated and compared in the following three chapters.

REFERENCES

Battelle Columbus and Pacific Northwest Laboratories (1973) _Environmental Considerations in Future Energy Growth_, Vol. I: _Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens_, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

Brookhaven National Laboratory, Associated Universities, Inc., Energy/Environmental Data Group (1975) _Energy Model Data Base User Manual_, BNL 19200.

Federal Energy Administration (1975) _Project Independence Blueprint_. Washington: Government Printing Office.

Hittman Assosiates, Inc. (1974 and 1975) _Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use_, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc. (NTIS numbers: Vol. I, PB-238 784; Vol. II, PB-239 158).

"National Environmental Policy Act", _Statutes at Large_ 88, Sec. 842; _U.S. Code_, Title 42, Sec. 4321.

CHAPTER 14

PROCEDURES FOR COMPARING THE RESIDUALS OF ENERGY ALTERNATIVES

14.1 INTRODUCTION

Residuals are by-products that an activity, process, or technological alternative produces in addition to its primary product. Residuals include particulates, gases, solid and liquid wastes, accidents and death, and land consumption, all or some of which might produce significant environmental impacts where they occur.

This chapter describes the residuals data contained in Matrix of Environmental Residuals for Energy Systems (MERES) and the University of Oklahoma (OU) resource system description and demonstrates methods by which these data can be used in the comparison of energy alternatives. Residuals data are divided into five categories: air, water, solids, land, and occupational health. Air pollutant residuals include particulates, oxides of nitrogen, oxides of sulfur, hydrocarbons, carbon monoxide, and aldehydes. Water pollutant residuals include acids, bases, phosphates, nitrates, dissolved solids, suspended solids, nondegradable organics, thermal pollution, and increased biochemical and chemical oxygen demands.* Solids include various kinds of solid wastes such as processed (spent) oil shale and the overburden that has to be removed to surface mine coal, oil shale, tar sands, etc.

In the OU report, the land residual includes three numbers: fixed land use, incremental land use, and a time-averaged total. Only the time-averaged total is given in MERES. Fixed land use refers to the land required for facilities; for example, a gasification plant, a settling pond, water treatment plant, etc. This requirement is given in acres for a typical size facility. Incremental land use refers to such items as the number of acres mined to produce a given amount of coal or the acres required to dispose of a given amount of solid waste. This requirement is stated in acres per 10^{12} Btu's input to the process. The time-averaged value is the total land impact for the life of the facility (assumed to be either 25 or 30 years, depending on the facility, for a facility which processes 10^{12} Btu's per year). This value is obtained by summing (1) the fixed value obtained by linearly interpolating to a size of operations equivalent to processing 10^{12} Btu's per year and (2) the time average obtained by multiplying the incremental value by half the number of years the facility will operate. This requirement is expressed in acre-years per 10^{12} Btu's.

Occupational health includes deaths, injuries, and man-days lost. These values and the air, water, and solids residuals are quantified in MERES on the basis of

---

*These data are limited to those included in Hittman (1974 and 1975) and, as indicated earlier, may not be complete. For example, heavy metals are not included as air and/or water pollutants. The purpose of this report was not to make the data base all inclusive; rather, the report should be viewed as a step toward developing a comprehensive data base and a methodology for using it in evaluating and comparing energy alternatives.

energy inputs per 10^{12} Btu's. Many of the OU data are quantified in the same units as the MERES data, but the OU data include some qualitative residuals as well (such as noise and esthetics). OU data also include impact producing inputs (e.g., requirements for water, catalysts, etc.). When broadly defined, the term "residual" encompasses inputs of this type.

In the OU resource systems descriptions (Chapters 1 through 13), residuals data are reported in an "Environmental Considerations" section following the description of each technological activity. Brookhaven's Energy/Environmental Data Group has prepared an Energy Model Data Base User Manual (1975) which describes the Energy Model Data Base (EMDB) data and documentation files as well as the programs that have been written for using the data in energy modeling. The EMDB can be accessed from remote terminals. Information on procedures may be obtained from either the Council on Environmental Quality (CEQ) or Brookhaven.

14.2 GENERAL PROCEDURES FOR OBTAINING AND USING RESIDUALS DATA

The steps for calculating and comparing the residuals of energy alternatives, including the action being proposed in the environmental impact statement (EIS) requiring the comparisons to be made, are:

1. Identify, describe, and calculate residuals for the process, activity, partial trajectory, or trajectory* to be evaluated and compared.
   a. Identify the alternative activities and/or processes to be evaluated and compared by referring to Figure 1 in each of the OU resource system descriptions. (Some alternatives may be eliminated as unreasonable without going through the entire evaluation and comparison procedure. For example, some coal gasification processes could be eliminated from further consideration if they are not compatible with the kind of coal that is to be gasified.)
   b. Access MERES data and documentation files following procedures described in Brookhaven's User Manual. Residual amounts for each process, activity, partial trajectory, or trajectory will be calculated for the size of operation being considered. For example, if high-Btu coal gasification processes are to be compared, residuals can be based on either the energy value of the coal that goes in or the gas that comes out (e.g., if the HYGAS process produces 6.88 tons of particulates per 10^{12} Btu's of coal input, 3.02 tons of particulates will be produced by a facility producing 250 million cubic feet [mmcf] of gas daily*).
   c. To obtain supplemental data included in the OU descriptions and information on the assumptions made concerning the data, data quality, and descriptions of qualitative residuals, read the sections on "Environmental Considerations" that follow the descriptions of processes for each activity in the OU resource systems descriptions. Information on assumptions and data quality can also be obtained from MERES.
   d. For those resource systems not included in MERES, obtain both quantitative and qualitative residuals data from the "Environmental Considerations" sections of the OU resource systems descriptions. As when using MERES, the size of operations to be compared should be specified.
   e. If the quantities for each process, activity, partial trajectory, or trajectory have not been summed, sum them and list all quantitative residuals. Caution: the residual quantities are first converted (from those in the data base) to correspond to the size operation or trajectory output specified. For example, the hypothetical proposed high-Btu gasification facility produces 250 mmcf daily.
2. Make the desired comparisons. These can include:
   a. A comparison of specific

*These terms are defined in the Introduction to this part of the report.

*250 mmcf = 2.6×10^{11} Btu's of gas. Based on a HYGAS primary efficiency of 59 percent, this is 4.4×10^{11} Btu's of coal input.

residuals, such as oxides of nitrogen, or categories of residuals, such as water pollutants* (e.g., from source to end use).

b. A comparison of complete trajectories or of any part of a trajectory (e.g., by geographic location).

3. In comparing the proposed action and alternative sources, the feasible options can be determined by referring to the OU descriptions. (These descriptions include only technologies that have the possibility of being available in prototype form in 10 years, that are the subject of major research support, that have the potential for producing hydrocarbons, or that can be substituted to meet specified end use requirements. If these descriptions are not used, the user must specify his own criteria for determining feasibility; for example, economic costs, a fixed level of air or water pollutants, etc.) Those source alternatives determined to be feasible can then be compared with the proposed action and the technological and locational alternatives on the basis of a fixed amount or a fixed reference point such as input or output energy. However, evaluators should be alert to the possible effects of scale, the addition of new point sources at a given location, and possible cumulative and synergistic effects. All three of these cautions will be discussed in the demonstration that follows.

The three procedural steps for evaluating and comparing the residuals of energy alternatives are summarized in Exhibit 14-1.

These procedures are applicable to the calculation and comparison of technological, locational, source, and substitute fuels alternatives. However, the criteria for determining feasible alternatives may vary between categories, as might the comparison bases. For example, in the case of locational alternatives, complete trajectories can be compared on the basis of where they will or would be produced. This becomes most important when impacts are being evaluated and compared since impact analysis requires that residuals be related to ambient conditions. (Impact analysis is discussed in Section 14.5.)

*Residuals categories include air pollutants, water pollutants, solids, land, occupational health, aesthetics, inputs, and outputs.

14.3 A DEMONSTRATION OF HOW TO CALCULATE RESIDUALS OF ENERGY ALTERNATIVES

In demonstrating the use of the proposed system, calculations and comparisons are based on the proposed action, a technological alternative, a locational alternative, and the four source alternatives outlined in the Part II Introduction.

14.3.1 The Proposed Major Federal Action

The trajectory for the hypothetical proposed major federal action consists of five activities: mining and reclamation, within and near mine transportation, beneficiation, processing/conversion, and transportation. In illustrating the calculation of residuals for this action, MERES data and the OU resource systems descriptions are used. However, in many instances these data are averages and thus, often will not be directly applicable to a specific action. For example, MERES data for coal are reported as though they were national averages for five regions.* Also, the data for a particular process, such as Synthane, assume a configuration that may not be the same as that called for in the proposed action. As a consequence, these data should be used only for planning purposes. New site-specific data should be gathered for specific proposed actions.

The action agency (or anyone) wishing to evaluate a particular proposal might begin by calculating the residuals for that action and selected alternatives using the OU resource systems descriptions. If, after these calculations, the action is still considered desirable and an EIS is to be

*Regional coal data contained in MERES are actually based on one or more mines within the region: that is, they are not averages of all coal resources within that region.

EXHIBIT 14-1

SUMMARY PROCEDURES FOR COMPARING THE RESIDUALS OF ENERGY ALTERNATIVES

STEP I	IDENTIFY, DESCRIBE, AND CALCULATE RESIDUALS Identify the alternatives to be evaluated by referring to the technologies flow charts in the OU descriptions. Obtain residuals using MERES data. Supplement with additional quantitative and qualitative residuals data from the OU descriptions. Summarize and tabulate all residuals data for each alternative to be evaluated.

STEP II	COMPARE THE RESIDUALS OF ALTERNATIVES Compare either particular residuals or categories of residuals. Compare either partial or complete trajectories.

STEP III	DECIDE WHICH ALTERNATIVES ARE FEASIBLE AND WARRANT FURTHER EVALUATION

prepared, the residuals calculations for the EIS should be based on new site specific data. Although basing calcuations for all possible alternatives on specific site data is neither necessary nor feasible, comparing the proposed action and alternatives may indicate that certain alternatives should be examined more closely, including perhaps the recalculation of residuals for specific sites and configurations.*

Note that the three data sources and the procedures described in this report may be used:

1. As a planning tool for initially appraising an energy alternative.
2. To determine whether the residuals that would be produced warrant preparation of an EIS.
3. To identify feasible (reasonable) alternatives and allow a comparison on a process, activity, partial trajectory, and/or complete trajectory basis.

For purposes of this demonstration, a printout of the residuals for each individual process and total amounts of residuals for the hypothetical proposed action's trajectory was requested. The results reported in Table 14-1 are based on a daily energy output of $2.62x10^{11}$ Btu's (250 mmcf at 1,050 Btu's per cubic foot [cf]) from the Synthane gasification facility. Note that the residuals to be produced at or near the same location have been grouped together; that is, residuals have been combined on a geographical basis as well as for the total trajectory. In the proposed trajectory, all residuals except those associated with the transmission and distribution pipeline occur at or near the mine.

*An evaluation of the residuals of a project may lead to cancellation, but it also may lead to design modification.

14.3.2 A Technological Alternative

For purposes of illustration, only one technological alternative, Lurgi high-Btu gasification, has been considered (see Table 14-2). However, three other high-Btu gasification processes are included in the OU descriptions, each of which could be evaluated as an alternative to Synthane.* As Chapter 1 illustrates, there are technological alternatives for almost all of the other activities as well.

14.3.3 A Locational Alternative

Residuals for a trajectory moving the Synthane plant from near the mine site in southeastern Montana to the Pacific Northwest are reported in Table 14-3. Note that this trajectory also requires changing from natural gas pipeline to unit train transportation. (Another transportation technological alternative would be to pulverize the coal at or near the mine site and transport it by a slurry pipeline.) Again, residuals have been grouped and totaled by the area where they would be produced. In the example, this results in three groups of residuals: those that occur at or near the mine site, those associated with unit train transportation, and those that would be produced at or near the demand center location of the Synthane facility.

14.3.4 Source Alternatives

Four separate source alternatives will be calculated and compared: Alaskan natural gas to be transported to the U.S. upper midwest by a pipeline through Canada;** Alaskan

*As noted in Chapter 1, several of the coal conversion technologies are still in the development stage. This should be kept in mind when data for these processes are used.

**It is assumed that this alternative will displace pipeline quality gas from other sources currently being consumed in the upper midwest, and the 250 mmcf per day to be supplied to the Pacific Northwest could be drawn from one of these sources.

Table 14-1. Residuals of the Proposed Action: Synthane High-Btu Gasification ($2.62x10^{11}$ Btu's Per Day Output)

Activity/Process	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)							Solids (tons/day)	Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Organics	Total	Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants		Fixed (acres)[a]	Incremental (acres/year)	Total (acres)[b]	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
MINING AND RECLAMATION:																			
Strip 15° or less slope	NA	NA	0	.443	.544	.0398	.0544	.332	.00883	1.42	386.	15.	0	747.	.483	11.	272.	0	0
WITHIN OR NEAR MINE TRANSPORTATION:																			
Trucking	NA	NA	0	.00471	.134	.00974	.0134	.0906	.00109	.254	0	10.6	0	57.	0	5.28	128.	0	0
BENEFICIATION:																			
Breaking and Sizing	NA	0	0	0	0	0	0	0	0	0	1.77	35.	0	189.	0	.545	28.	0	0
PROCESSING/ CONVERSION:																			
Synthane	0	0	0	6.73	59.6	4.99	.989	3.3	.183	75.6	1980.	330.	0	749.	U	U	U	25.	.00411
TRANSPORTATION:																			
Feeder Pipeline[c]	NA	NA	NA	0	.802	0	83.8	0	0	84.7	0	U	0	2410.	0	.117	2.73	0	0
Subtotal[d]	0	0	0	7.18	61.	5.04	84.8	3.72	.193	162.	2370.	U	0	4150.	U	U	U	25.	.00411
TRANSPORTATION:																			
Transmission Pipeline	NA	NA	NA	0	27.8	0	0	0	0	27.8	0	U	0	8980.	.004	1.36	31.9	0	0
TOTAL	0	0	0	7.18	88.8	5.04	84.8	3.72	.193	190.	2370.	U	0	13100.	U	U	U	25.	.00411

NA = not applicable, NC = not considered, U = unknown.

[a]For a synthane facility processing 22,550 tons per day; feeder and transmission pipelines require 62.5 feet of right-of-way and a 25 acre compresser station every 187 miles.

[b]Time-averaged total land impact for the life of the facility.

[c]MERES data for gathering pipelines is used.

[d]Subtotal is for all residuals that will be produced at or near the mine. Transmission pipeline residuals will be spread over the length of the pipeline. Certain residuals, as for pumping stations, for example, could be localized.

Table 14-2. Residuals of a Technological Alternative: Lurgi High-Btu Gasification
(2.62×10^{11} Btu's Per Day Output)

Activity/Process	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)							Solids (tons/day)	Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Organics	Total	Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants		Fixed (acres)	Incremental (acres/year)	Total (acres)	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
MINING AND RECLAMATION:																			
Strip 15° or less slope	NA	NA	0	.428	.526	.038	.0526	.32	.00852	1.37	372.	15.	0	721.	.466	10.6	263.	0	0
WITHIN OR NEAR MINE TRANSPORTATION:																			
Trucking	NA	NA	0	.00455	.129	.00945	.0129	.0875	.00105	.245	0	10.6	0	55.3	0	5.1	123.	0	0
BENEFICIATION:																			
Breaking and Sizing	NA	0	0	0	0	0	0	0	0	0	1.71	35.	0	182.	0	.526	27.	0	0
PROCESSING/ CONVERSION:																			
Lurgi	0	0	0	1.02	38.4	2.79	.64	2.13	.146	45.2	1860.	330.	0	690.	U	U	U	18.	.004
TRANSPORTATION:																			
Feeder Pipeline[c]	NA	NA	NA	0	.802	0	83.8	0	0	84.7	0	U	0	2410.	0	.117	2.73	0	0
Subtotal[d]	0	0	0	1.46	39.9	2.84	84.5	2.54	.156	131.	2240.	U	0	4060.	U	U	U	18.	.004
TRANSPORTATION:																			
Transmission Pipeline	NA	NA	NA	0	27.8	0	0	0	0	27.8	0	U	0	8980.	.0039	1.36	31.9	0	0
TOTAL	0	0	0	1.46	67.7	2.84	84.5	2.54	.156	159.	2240.	U	0	13000.	U	U	U	18.	.004

NA = not applicable, NC = not considered, U = unknown.

[a]For a Lurgi facility processing 23,654 tons per day; feeder and transmission pipelines require 62.5 feet of right-of-way and a 25 acre compressor station every 187 miles.

[b]Time-averaged total land impact for the life of the facility.

[c]MERES data for gathering pipelines is used.

[d]Subtotal is for all residuals that will be produced at or near the mine. Transmission pipeline residuals will be spread over the length of the pipeline. Certain residuals, as for pumping stations, for example, will be localized.

Table 14-3. Residuals of a Locational Alternative: Synthane Facility Moved To Demand Center (2.62×10^{11} Btu's Per Day Output)

	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)								Land			Occupational Health			Inputs	
Activity/Process	Thermal (10^9 Btu's)	Organics	Total	Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants	Solids (tons/day)	Fixed (acres)	Incremental (acres/year)	Total (acres)	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
MINING AND RECLAMATION:																			
Strip 15° or less slope	NA	NA	0	.384	.472	.0345	.0472	.287	.00765	1.23	334.	15.	0	647.	.418	9.51	236.	0	0
Within or Near Mine TRANSPORTATION:																			
Trucking	NA	NA	0	.00408	.116	.00848	.0116	.0785	.000942	.22	0	10.6	0	49.7	0	4.57	110.	0	0
BENEFICIATION:																			
Breaking and Sizing	NA	0	0	0	0	0	0	0	0	0	1.53	35.	0	163.	0	.472	24.3	0	0
Subtotal[c]	0	0	0	.388	.588	.043	.0588	.366	.0086	1.45	336.	60.6	0	860.	.418	14.6	370.	0	0
TRANSPORTATION:																			
Unit Train[d]	NA	NA	NA	10.6	7.99	6.95	5.34	7.49	1.17	39.6	0	U	0	82100.	81.9	654.	6080.	0	0
PROCESSING/ CONVERSION:																			
Synthane	0	0	0	5.83	51.6	4.32	.857	2.86	.159	65.5	1720.	330.	0	649.	U	U	U	25.	.00411
TOTAL	0	0	0	16.9	60.2	11.3	6.25	10.7	1.34	107.	2050.	U	0	83600.	U	U	U	25.	.00411

NA = not applicable, NC = not considered, U = unknown.

[a]For a Synthane facility processing 22,550 tons per day; train right-of-way is 6 acres per mile.

[b]Time-averaged total land for the life of the facility.

[c]Subtotal is for the residuals that would be produced at or near the mine, unit train residuals would be spread over the route of the train. Processing/ Conversion residuals would be produced at the facilities site at or near the demand center.

[d]MERES data are adjusted for mileage since those data are based on an average hauling distance of 150 miles. The assumed value here is 1,000 miles and all coefficients, except those for occupational health, have been multiplied by 6.67.

natural gas to be pipelined to Valdez, Alaska, and transported from there to the U.S. west coast by liquefied natural gas (LNG) tanker; increased offshore production of natural gas; and foreign LNG imports. Together with coal gasification, these appear to be the feasible alternative supplies of large quantities of pipeline quality gas during the next 10 to 15 years.*

The residuals associated with each of the four source alternatives are identified and calculated in Tables 14-4 through 14-7. The evaluation is on the basis of 250 mmcf per day, but neither Alaskan gas (either through Canada or Valdez) nor foreign LNG imports alternatives would be undertaken on so limited a scale, primarily because neither would be economical on this scale. This consideration is discussed in Chapter 16.

14.3.5 Substitute Fuels Alternatives

Although not included in this demonstration, the procedures used to calculate the residuals for technological, locational, and source alternatives can be used to calculate the residuals for substituting other fuels for pipeline quality gas. In addition to the data used in the examination of other sources of pipeline quality gas, MERES and the OU resource systems descriptions include residuals data for coal, crude oil, natural gas, and oil shale,** and the OU descriptions include <u>some</u> residuals data for geothermal, nuclear fission, organic, electric power generation, and conservation (consumption). However, substitute fuels are not included in the demonstration of procedures presented in this chapter.

14.4 A DEMONSTRATION OF HOW TO COMPARE THE RESIDUALS OF ENERGY ALTERNATIVES

Energy alternatives can be compared on the basis of the residuals they produce in a variety of ways, ranging from a comparison of particular processes to a comparison of complete trajectories* and from a comparison of particular residuals (such as oxides of nitrogen) to categories of residuals (air pollutants).** For illustration purposes, the following comparisons are made:

1. Totals by categories of residuals for each of the seven trajectories being evaluated (Table 14-8 and Figures 14-1 and 14-2).
2. Totals by categories of residuals on the basis of where the residuals will be produced: at or near the mine-site, over the length of the transportation corridor, at or near the demand center, etc. (Table 14-9 and Figure 14-3).
3. Totals for specific residuals for each of the seven trajectories evaluated (Table 14-8 and Figures 14-4, 14-5, and 14-6).
4. Totals for specific residuals on the basis of where the residuals would be produced (Table 14-9 and Figure 14-7).

14.4.1 A Comparison of Residuals by Category and Trajectory

Figures 14-1 and 14-2 indicate total air emissions are highest for the offshore natural gas source alternative. LNG imports produce only small quantities of all residuals,

---

*"Large quantities" does not refer to the 250 mmcf per day for this specific case but rather to the amount of pipeline quality gas that will be required in addition to the amounts from current onshore and offshore domestic sources. At best, increased onshore production is expected to be small, and alternative synthetic sources are not expected to be available in large quantities.

**As noted earlier, data on other energy resources will soon be added to MERES.

*Although residuals can be combined by category, they should be combined only with great care since residuals within any category, such as air pollutants, can vary widely as to their potential effects.

**Note that the "complete" trajectories used here extend from extraction to placing 250 mmcf per day of pipeline quality gas in the Pacific Northwest. These trajectories could actually be extended to include end uses such as residential space heating, for example.

Table 14-4. Residuals of a Source Alternative: Alaskan Natural Gas via Canadian Pipeline
(2.62×10^{11} Btu's Per Day Output)

Activity/Process	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)							Solids (tons/day)	Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Organics	Total Water Pollutants	Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants		Fixed (acres) [a]	Incremental (acres/year)	Total (acres) [b]	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
EXTRACTION:																			
Onshore Extraction	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.	0	250.	.0329	1.45	51.2	U	NA
NEAR SITE TRANSPORTATION:																			
Gathering Pipeline	NA	NA	NA	0	.885	0	92.5	0	0	93.5	NA	U	0	2660.	.0004	.129	3.01	0	NA
Subtotal [c]	NA	NA	NA	0	.885	0	92.5	0	0	93.5	NA	U	0	2910.	.0333	1.58	54.2	U	NA
TRANSPORTATION:																			
Transmission Pipeline [d]	NA	NA	NA	0	123.	0	0	0	0	123.	NA	U	0	39600.	.0174	6.	141.	0	NA
TOTAL	NA	NA	NA	0	124.	0	92.5	0	0	216.	NA	U	0	42500.	.0507	7.58	196.	U	NA

NA = not applicable, U = unknown.

[a] For extraction, fixed represents acres per well, for the gathering and transmission pipeline, the right-of-way along the pipeline is 62.5 feet, and 25 acres are required for a compressor station every 187 miles.

[b] Time-increased total land for the life of the facility.

[c] Subtotal is for onshore extraction and gathering pipelines, residuals for which would occur at or near the extraction site.

[d] It was assumed that MERES data were based on an average U.S. transmission distance of 500 miles. The value in this case was 2,000 miles, 1,500 miles through Canada and 500 miles in the U.S.

Table 14-5. Residuals of a Source Alternative: Alaskan Natural Gas via Alaskan Pipeline and LNG Tanker ($2.62x10^{11}$ Btu's Per Day Output)

Activity/Process	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)							Solids (tons/day)	Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Organics	Total Water Pollutants	Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants		Fixed (acres)[a]	Incremental (acres/year)	Total (acres)[b]	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
EXTRACTION:																			
Onshore Extraction	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.	0	31000.	.0408	1.8	63.5	U	NA
NEAR SITE TRANSPORTATION:																			
Gathering Pipeline	NA	NA	NA	0	1.10	0	115.	0	0	116.	NA	U	0	3300.	0	.16	3.74	0	NA
Subtotal[c]	NA	NA	NA	0	1.10	0	115.	0	0	116.	NA	U	0	34300.	.0408	1.96	67.2	U	NA
TRANSPORTATION:																			
Transmission Pipeline	NA	NA	NA	0	38.	0	0	0	0	38.	NA	U	0	12300.	.0054	1.86	43.7	0	NA
PROCESSING:																			
Liquefaction	3.69	NA	NA	0	127.	0	0	0	0	127.	NA	250.	0	1.64	U	U	U	U	NA
TRANSPORTATION:																			
Liquid Natural Gas Tanker	0	1.89	1.89	.281	3.9	3.01	.138	.0551	.039	7.41	NA	0	0	53.3	U	U	U	U	NA
PROCESSING:																			
Storage	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	NA	U	0	205.	U	U	U	U	NA
PROCESSING:																			
Vaporization	NA	NA	NA	.0515	.275	.00162	.0216	.054	.0297	.432	NA	250.	0	13.4	U	U	U	U	NA
Subtotal[d]	NA	NA	NA	.0515	.275	.00162	.0216	.054	.0297	.432	NA	U	0	218.	U	U	U	U	NA

Table 14-5. (Continued)

Activity/Process	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)							Solids (tons/day)	Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Organics	Total Water Pollutants	Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants		Fixed (acres)[a]	Incremental (acres/year)	Total (acres)[b]	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
TRANSPORTATION:																			
Transmission Pipeline	NA	NA	NA	0	27.8	0	0	0	0	27.8	NA	U	0	8980.	.00394	1.36	31.9	U	NA
TOTAL	3.69	1.89	1.89	.333	198.	3.01	115.	.109	.069	317.	NA	U	0	25100.	U	U	U	U	NA

NA = not applicable, U = unknown.

[a]For extraction, fixed represents acres per well; for the gathering and transmission pipeline, the right-of-way along the pipeline is 62.5 feet, and 25 acres are required for compressor stations every 187 miles; the 250 acres represents the requirement for a typical port facility including docks, storage, and liquefaction or vaporization.

[b]Time-averaged total land for the life of the facility.

[c]Subtotal for onshore extraction and gathering pipelines, residuals for which would occur at or near the extraction site.

[d]Subtotal for LNG storage and vaporization, residuals for which would occur at or near the port site.

Table 14-6. Residuals of a Source Alternative: Offshore Natural Gas
(2.62×10^{11} Btu's Per Day Output)

Activity/Process	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)							Solids (tons/day)	Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Organic	Total Water Pollutants	Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants		Fixed (acres)[a]	Incremental (acres/year)	Total (acres)[b]	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
EXTRACTION:																			
Offshore Extraction	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1.	0	42.9	.003	.112	4.03	U	NA
NEAR SITE TRANSPORTATION:																			
Gathering Pipeline[c]	NA	NA	NA	0	3.25	0	340.	0	0	343.	NA	U	0	9770.	.001	.475	11.1	0	NA
Subtotal[d]	NA	NA	NA	0	3.25	0	340.	0	0	343.	NA	U	0	9810.	.004	.587	15.1	U	NA
TRANSPORTATION:																			
Transmission Pipeline	NA	NA	NA	0	27.8	0	0	0	0	27.8	NA	U	0	8980.	.004	1.36	31.9	0	NA
TOTAL	NA	NA	NA	0	31.	0	340.	0	0	371.	NA	U	0	18800.	.008	1.95	47.	U	NA

NA = not considered, U = unknown.

[a]For extraction, fixed represents 1 acre per well; for the gathering and transmission pipeline, the right-of-way along the pipeline is 62.5 feet and 25 acres are required for compressor stations every 187 miles.

[b]Time-averaged total land for the life of the facility.

[c]Mileage note: All the coefficients have been multiplied by a factor of 4.

[d]Subtotal is for offshore extraction and gathering pipelines, residuals for which would be produced at or near the site of extraction.

Table 14-7. Residuals of a Source Alternative: Imported LNG
(2.62×10^{11} Btu's Per Day Output)

Activity/Process	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)							Solids (tons/day)	Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Organics	Total Water Pollutants	Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants		Fixed (acres)[a]	Incremental (acres/year)	Total (acres)[b]	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
TRANSPORTATION:																			
Liquefied Natural Gas Tanker (LNG)	0	.066	.066	.009	.125	.096	.0044	.00177	.00124	.237	NA	U	0	51.1	U	U	U	U	NA
PROCESSING: LNG																			
Storage	NA	NA	NA	NA	NA	NA	0	NA	NA	NA	NA	U	0	205.	U	U	U	U	NA
PROCESSING: LNG																			
Vaporization	NA	NA	NA	.0515	.275	.00162	.0216	.054	.0297	.432	NA	250.	0	13.4	U	U	U	U	NA
Subtotal[c]	0	.066	.066	.0605	.4	.0976	.026	.0558	.0309	.669	NA	250.	0	270.	U	U	U	U	NA
TRANSPORTATION:																			
Transmission Pipeline	NA	NA	NA	0	27.8	0	0	0	0	27.8	NA	U	0	8980.	.004	1.36	31.9	0	NA
TOTAL	0	.066	.066	.0665	28.2	.0976	.026	.0557	.031	28.5	NA	U	0	9250.	U	U	U	U	NA

NA = not applicable, U = unknown.

[a]The 250 acres includes facilities for tankers, storage, and vaporization; the right-of-way along a transmission pipeline is 62.5 feet, and 25 acres are required for compressor stations every 187 miles.

[b]Time-averaged total land for the life of the facility.

[c]Subtotal for LNG tanker residuals in U.S. coastal waters, LNG storage, and LNG vaporization, residuals of which would occur at or near the port site.

Table 14-8. Totals by Trajectory for Categories of Residuals (2.62×10^{11} Btu's Per Day Output)

	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)								Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Total Water Pollutants		Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants	Solids (tons/day)	Fixed (acres)	Incremental (acres/year)	Total (acres)	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
PROPOSED ACTION:																			
Synthane High-Btu Gasification	0	0		7.18	88.8	5.04	84.8	3.72	.193	190.	2370.	U	0	13100.	U	U	U	25.	.00411
TECHNOLOGICAL ALTERNATIVE:																			
Lurgi High-Btu Gasification	0	0		1.46	67.7	2.84	84.5	2.54	.156	159.	2240.	U	0	13000.	U	U	U	18.	.00411
LOCATION ALTERNATIVE:																			
Synthane Facility at Demand Center	0	0		16.9	60.2	11.3	6.25	10.7	1.34	107.	2050.	U	0	83600.	U	U	U	25.	.00411
SOURCE ALTERNATIVE:																			
Alaskan Natural Gas Pipeline	NA	NA		0	124.	0	92.5	0	0	216.	NA	U	0	42500.	.0507	7.58	196.	U	NA
SOURCE ALTERNATIVE:																			
Alaskan Natural Gas Pipeline and Tanker	3.69	1.89		.333	.198	3.01	115.	.109	.069	317.	NA	U	0	25100.	U	U	U	U	NA
SOURCE ALTERNATIVE:																			
Offshore Natural Gas	NA	NA		0	31.	0	340.	0	0	371.	NA	U	0	18800.	.00799	1.95	47.	U	NA
SOURCE ALTERNATIVE:																			
Imported Liquefied Natural Gas (LNG)	0	.066		.065	28.2	.098	.026	.056	.031	28.5	NA	U	0	9250.	U	U	U	U	NA

NA = not applicable, U = unknown.

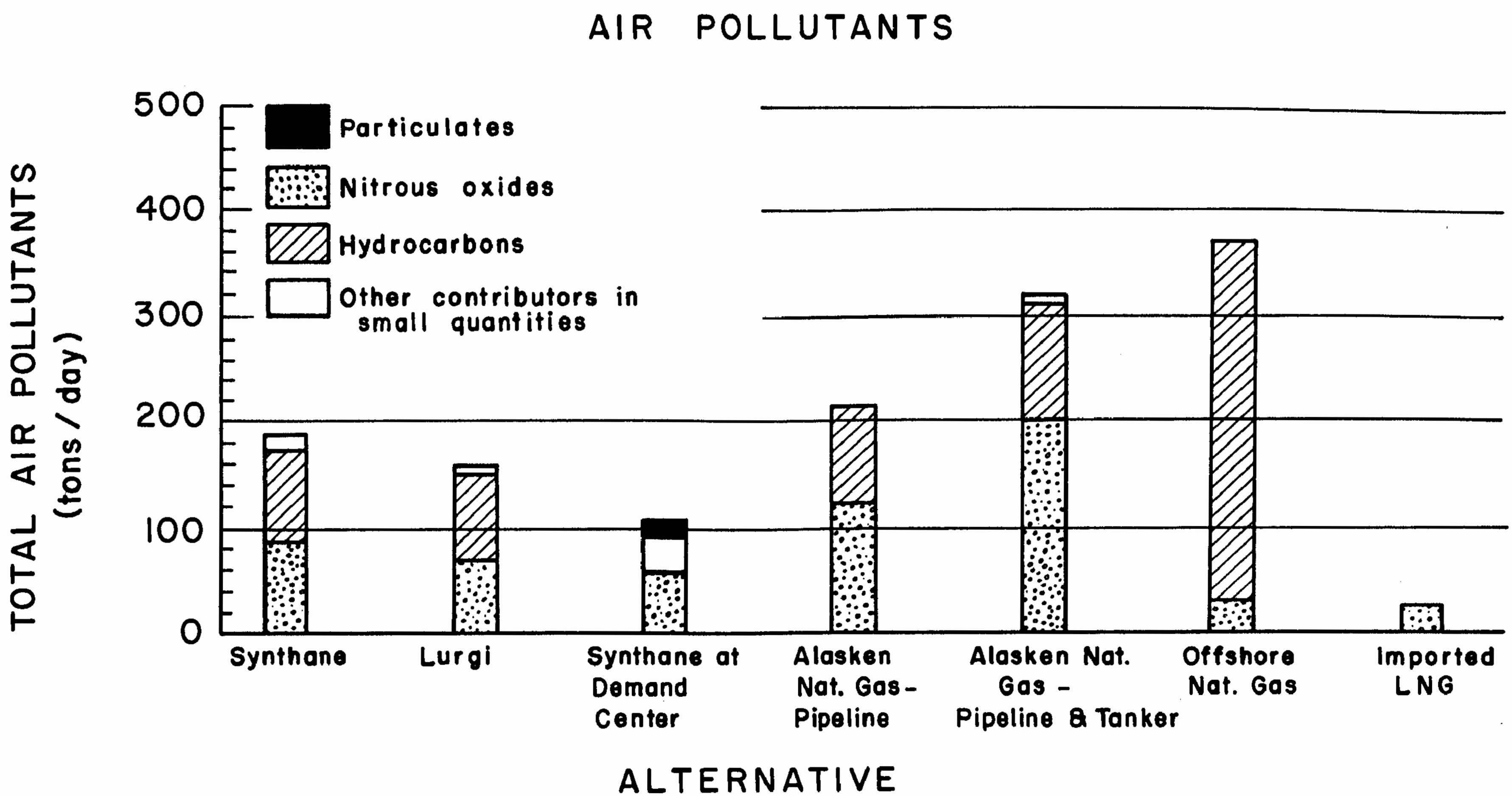
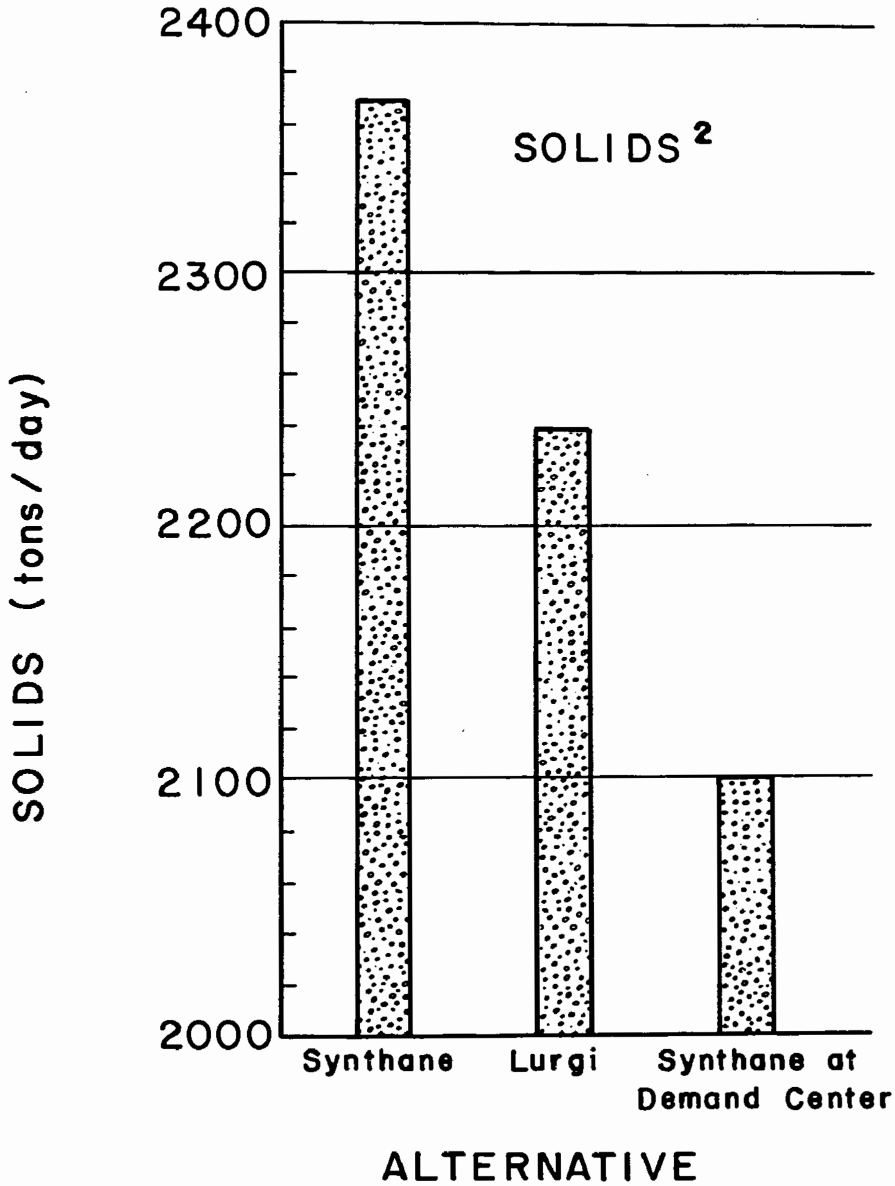


Figure 14-1. Totals by Trajectory for Categories of Residuals (Table 14-8)



[2] No solid residuals are produced by the source alternatives.

Figure 14-2. Totals by Trajectory for Categories of Residuals (Table 14-8)

Table 14-9. Totals by Location for Categories of Residuals
(2.62×10^{11} Btu's Per Day Output)

	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)								Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Total Water Pollutants		Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants	Solids (tons/day)	Fixed (acres)	Incremental (acres/year)	Total (acres)	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
PROPOSED ACTION:																			
Synthane High-Btu Gasification																			
At or Near Mine Site	0	0		7.18	61.	5.04	84.8	3.72	.193	162.	2370.	U	0	4150.	U	U	U	25.	.00411
Transportation Corridor	NA	NA		0	27.8	0	0	0	0	27.8	0	U	0	8980.	.004	1.36	31.9	0	0
TECHNOLOGICAL ALTERNATIVE:																			
Lurgi High-Btu Gasification																			
At or Near Mine Site	0	0		1.46	39.9	2.84	84.5	2.54	.156	131.	2240.	U	0	4060.	U	U	U	18.	.00411
Transportation Corridor	NA	NA		0	27.8	0	0	0	27.8	27.8	0	U	0	8980.	.0039	1.36	31.9	0	0
LOCATIONAL ALTERNATIVE:																			
Synthane Facility at Demand Center																			
At or Near Mine Site	0	0		.388	.588	.043	.059	.366	.009	1.45	336.	60.6	0	860.	.418	14.6	370.	0	0
Transportation Corridor	NA	NA		10.6	7.99	6.95	5.34	7.49	1.17	39.6	0	U	0	82100.	81.9	654.	6040.	0	0
Demand Center	0	0		5.83	51.6	4.32	.857	2.86	.159	65.5	1720.	330.	0	649.	U	U	U	25.	.00411
SOURCE ALTERNATIVE:																			
Alaskan Natural Gas Pipeline																			
At or Near Extraction Site	NA	NA		0	.885	0	92.5	0	0	93.5	NA	U	0	2910.	.0333	1.58	54.2	U	0
Transportation Corridor	NA	NA		0	123.	0	0	0	0	123.	NA	U	0	39600.	.0174	6.	141.	0	0

Table 14-9. (Continued)

	Water Pollutants (Tons/day)			Air Pollutants (Tons/day)							Solids (tons/day)	Land			Occupational Health			Inputs	
	Thermal (10^9 Btu's)	Total Water Pollutants		Particulates	NO_x	SO_2	Hydrocarbons	CO	Aldehydes	Total Air Pollutants		Fixed (acres)	Incremental (acres/year)	Total (acres)	Deaths/year	Injuries/year	Man-Days Lost per year	Water (millions of gallons/day)	Nickel (pounds/day)
SOURCE ALTERNATIVE:																			
Alaskan Natural Gas Pipeline and Liquefied Natural Gas Tanker (LNG)																			
At or Near Extraction Site	NA	NA		0	1.1	0	115.	0	0	116.	NA	U	0	34300.	.0408	1.96	67.2	U	NA
Transportation Corridor 1	NA	NA		0	38.	0	0	0	0	38.	NA	U	0	12300.	.0054	1.86	43.7	0	NA
Port Site 1	3.69	NA		0	127.	0	0	0	0	127.	NA	250.	0	1.64	U	U	U	U	NA
Transportation Corridor 2	0	1.89		.281	3.9	3.01	.138	.005	.039	7.41	NA	U	0	53.3	U	U	U	0	NA
Port Site 2	NA	NA		.0515	.275	.002	.022	.054	.03	.432	NA	U	0	218.	U	U	U	U	NA
Transportation Corridor 3	NA	NA		0	27.8	0	0	0	0	27.8	NA	U	0	8980.	.00344	1.36	31.9	0	NA
SOURCE ALTERNATIVE:																			
Offshore Natural Gas																			
At or Near Extraction Site	NA			0	3.25	340.	0	0	0	343.	NA	U	0	9810.	.00401	.587	15.1	U	NA
Transportation Corridor	NA			0	27.8	0	0	0	0	27.8	NA	U	0	8980.	.00394	1.36	31.9	0	NA
SOURCE ALTERNATIVE:																			
Imported Liquefied Natural Gas (LNG)																			
Port Site	0	.0660		.06	.4	.098	.026	.056	.031	.669	NA	250.	0	270.	U	U	U	U	NA
Transportation Corridor	NA	NA		0	27.8	0	0	0	0	27.8	NA	U	0	8980.	.00394	1.36	31.9	0	NA

NA = not applicable, U = unknown.

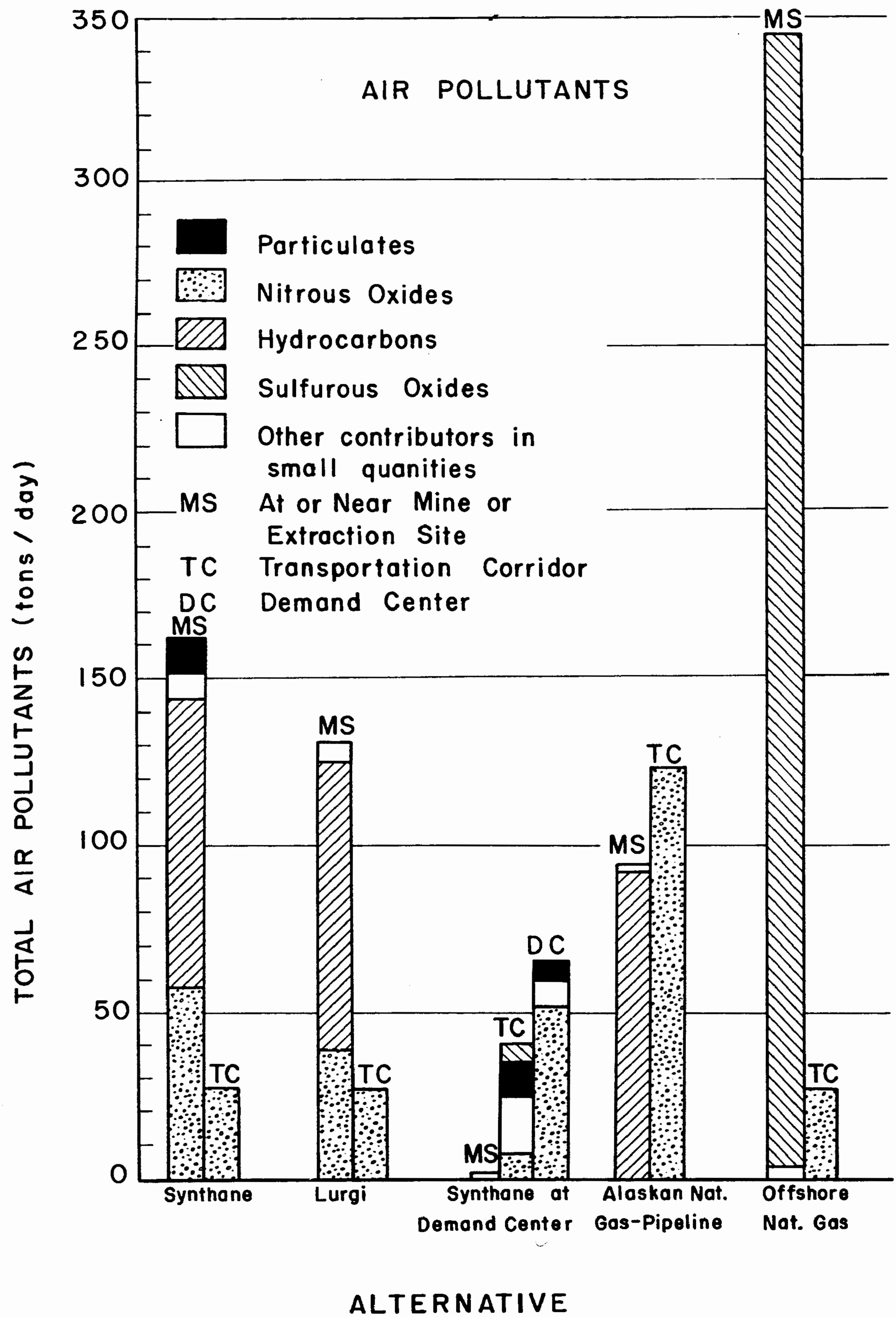


Figure 14-3. Totals by Location for Air Pollutants (Table 14-9)

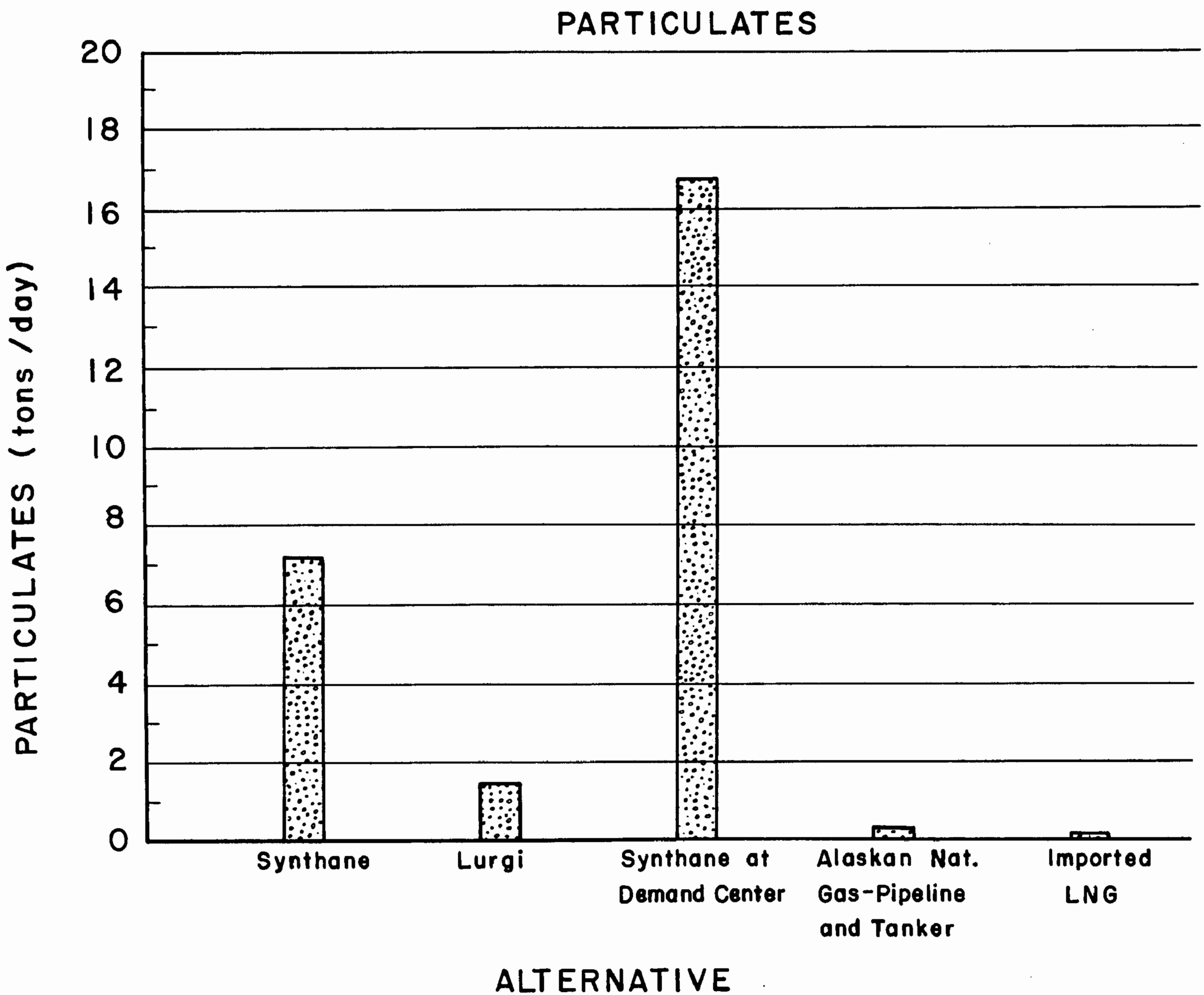


Figure 14-4. Totals by Trajectory for Specific Air Pollutants (Table 14-8)

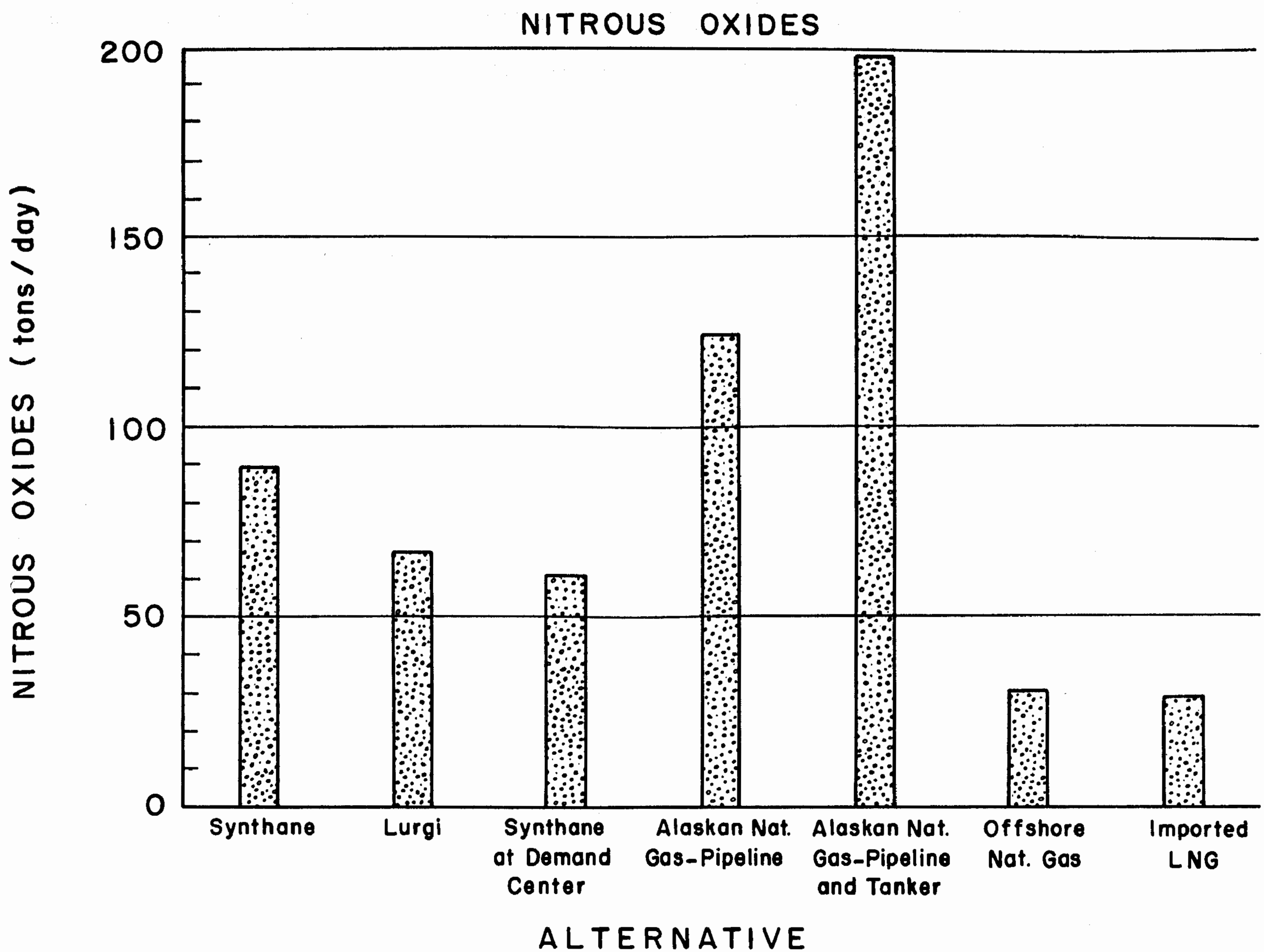


Figure 14-5. Totals by Trajectory for Specific Air Pollutants (Table 14-8)

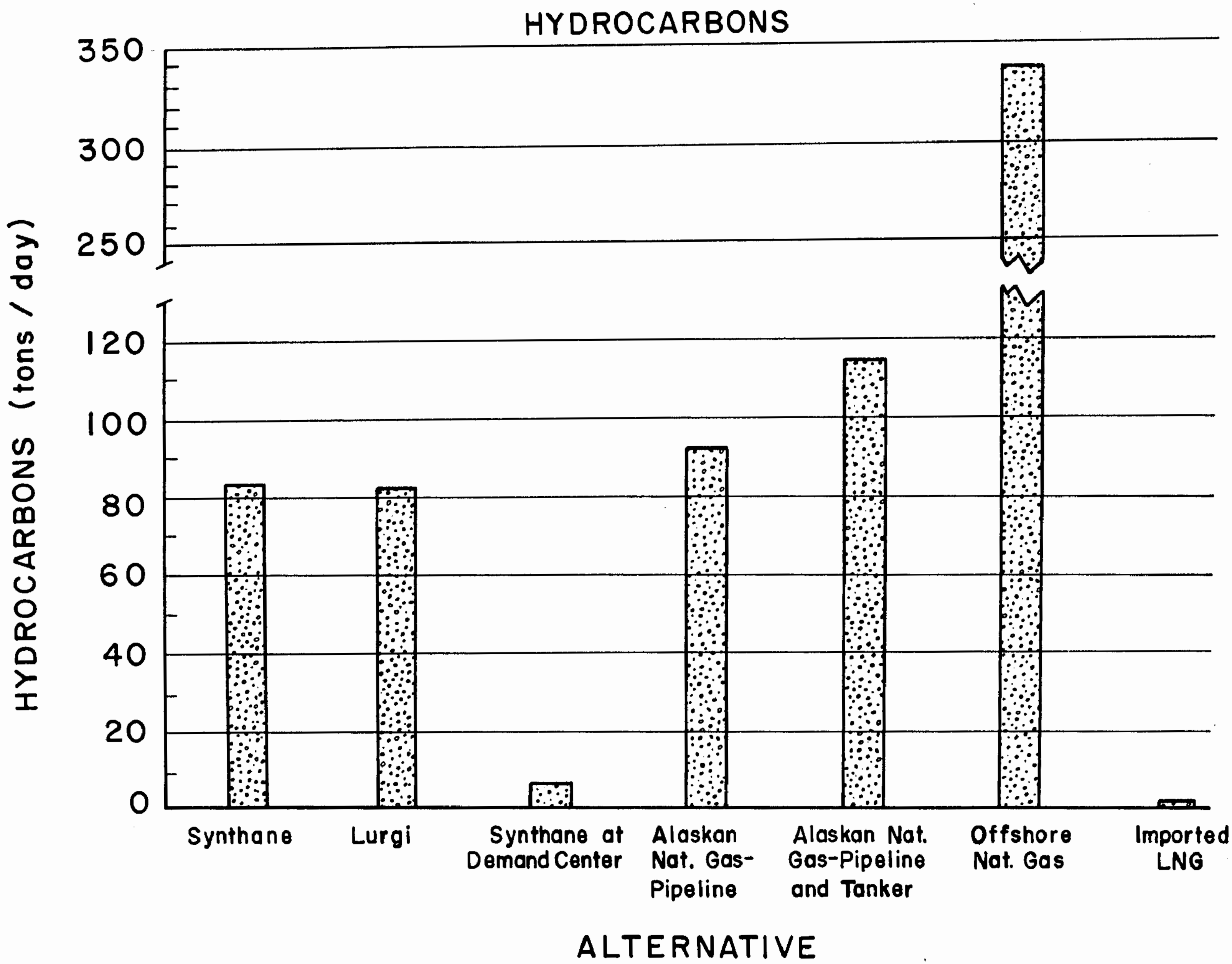


Figure 14-6. Totals by Trajectory for Specific Air Pollutants (Table 14-8)

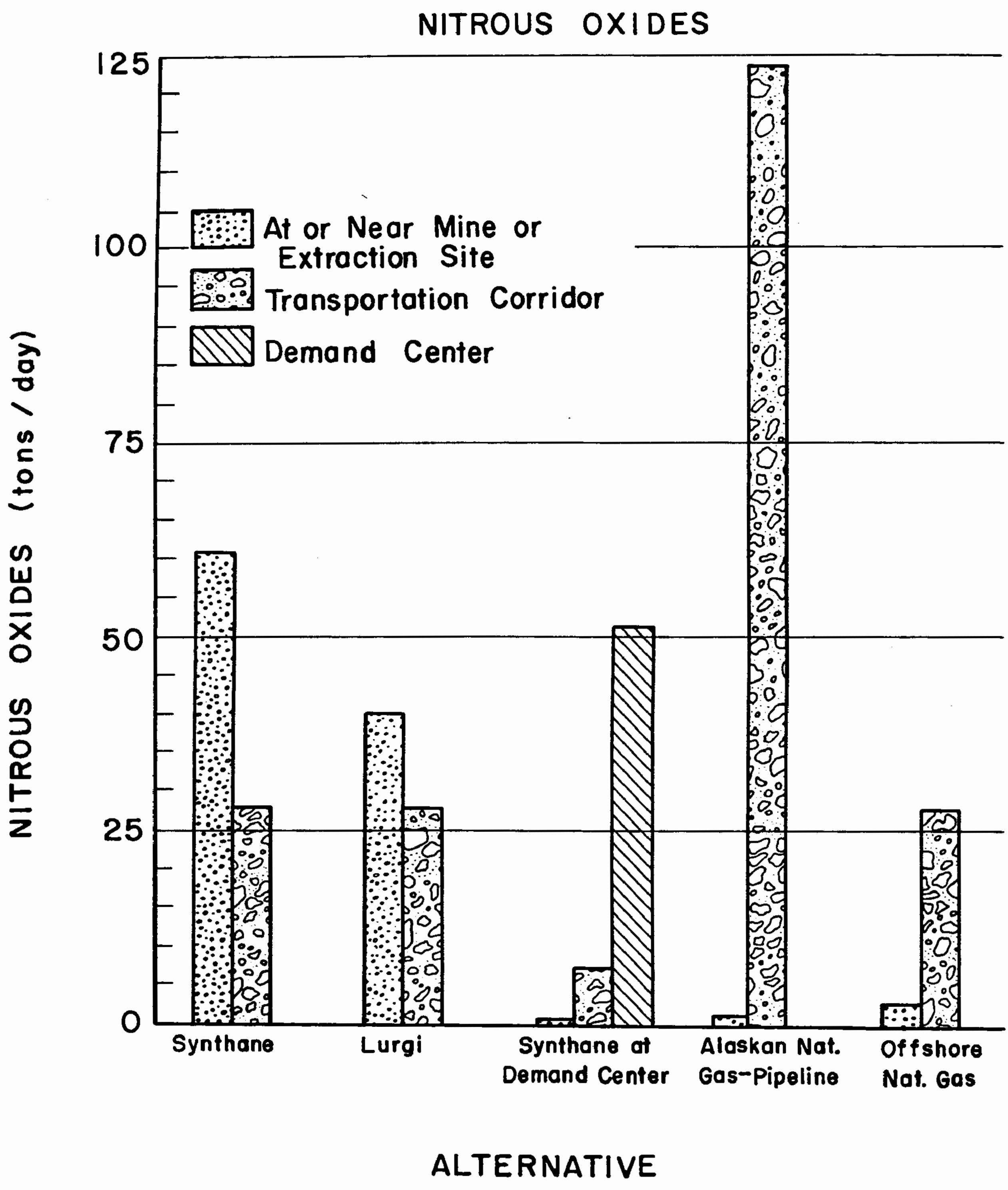


Figure 14-7. Totals by Location for Specific Air Pollutants (Table 14-9)

primary because only those emissions that would occur within the U.S. are reported here.

14.4.2 A Comparison of Residuals by Category and Location

Figure 14-3 indicates that air pollutants are highest (300 tons per day) at the extraction site of natural gas in Alaska and offshore. The air pollutants are mostly hydrocarbons.

14.4.3 A Comparison of Residuals by Particular Residual and Trajectory

Figures 14-4, 14-5, and 14-6 indicate that particulate emissions are highest for the locational alternative (train transport of coal). Nitrous oxide emissions are highest for the Alaskan pipeline/tanker transport source alternative. Hydrocarbon emissions are highest for the offshore natural gas alternative. All types are lowest for importing LNG, again because only a portion of the trajectory is within the U.S.

14.4.4 A Comparison of Residuals by Particular Residual and Location

Figure 14-7 indicates that nitrous oxide emissions are highest along the transportation corridor for the Alaskan pipeline source alternative. They are lowest at the extraction (mine) site for the locational alternative. In general, nitrogen oxides are highest wherever combustion occurs (at the mine site for the proposed action and technological alternative and at the demand center for the locational alternative) and in all transportation activities.

14.4.5 Summary

In Section 14.4, residuals of selected alternatives have been calculated and compared. Although these calculations and comparisons are only illustrations, they show how MERES data and the data in Chapters 1 through 13 of this report can be used in comparing energy alternatives. Chapters 1 through 13 can be considered as a catalog from which an analyst can select residuals data for individual technological activities or combinations of technological activities. Although the combinations or trajectories used as illustrations here stop with the production of a gaseous fuel, Chapters 1 through 11 can be combined with Chapter 12 to include the generation of electricity. Also, data contained in Chapter 13 permit calculations of trajectories that include an end use.

14.5 SUGGESTIONS CONCERNING IMPACT ANALYSIS

The evaluation and comparison of energy alternatives will be incomplete if they are restricted to the kinds of residuals analysis demonstrated to this point. To be complete, evaluation and comparison should include an effort to determine what the <u>impact</u> of residuals will be. This involves relating residuals to ambient conditions; that is, impact analysis requires evaluating the effect of residuals on environmental conditions at the place where they occur.*
Unfortunately, there are no obviously correct procedures or method for conducting this type of impact analysis.

The lack of a single analytical method is not due to a lack of developmental efforts.

Since the National Environmental Policy Act (NEPA) became law, numerous attempts have been made to develop a methodology for environmental impact assessment. In a recent review for the Environmental Protection Agency (EPA), Maurice L. Warner and Edward H. Preston (1974) found that impact assessment methodologies can be divided into five

*Place or location in this sense goes beyond the term <u>site</u>. Some residuals may produce impacts that are, indeed, site-specific, but others may produce local, state, or even national impacts. The characteristics of the residual dictate the scope of the evaluation of its impact. This is taken into account in the procedures suggested here.

types based on the way impacts are identified. They describe the five as (Warner and Preston, 1974: 3-4):

1. Ad hoc. These methodologies provide minimal guidance to impact assessment beyond suggesting broad areas of possible impacts (e.g., impacts on flora and fauna, impacts on lakes, forests, etc.), rather than defining specific parameters to be investigated. (For example, Western Systems Coordinating Council, 1971.)

2. Overlays. These methodologies rely on a set of maps of environmental characteristics (physical, social, ecological, aesthetic) for a project area. The maps are overlaid to produce a composite characterization of the regional environment. Impacts are identified by noting the impacted environmental characteristics lying within the project boundaries. (For example, Krauskopf and Bunde, 1972; McHarg, 1969.)

3. Checklists. These methodologies present a specific list of environmental parameters to be investigated for possible impacts but do not require the establishment of direct cause/effect links to project activities. They may or may not include guidelines on how parameter data are to be measured and interpreted. (For example, Adkins and Burke, 1971; Dee and others, 1972 and 1973; Institute of Ecology, University of Georgia, 1971; Arthur D. Little, 1971; Smith, n.d.; Stover, 1972; Multiagency Task Force, 1972; Tulsa District, U.S. Army Corps of Engineers, 1972; and Walton and Lewis, 1971.)

4. Matrices. These methodologies incorporate a list of project activities in addition to a checklist of potentially impacted environmental characteristics. These two lists are related in a matrix which identifies cause/effect relationships between specific activities and impacts. Matrix methodologies may specify which actions impact which environmental characteristics or may simply list the range of possible actions and characteristics in an open matrix to be completed by the analyst. (For example, Dee and others, 1973; Leopold and others, 1971; Moore and others, 1969; and Central New York Regional Planning and Development Board, 1972.)

5. Networks. These methodologies work from a list of project activities to establish cause/condition/effect networks. They are an attempt to recognize that a series of impacts may be triggered by a project action. These approaches generally define a set of possible networks and allow the user to identify impacts by selecting and tracing out the appropriate project actions. (For example, Sorensen, 1970: and Sorensen and Pepper, 1973.)

Among these five, the most comprehensive and systematic methodologies also tend to be the most cumbersome and costly to use. This is because any attempt to be comprehensive tends to reflect the complexity of the task of relating residuals to the natural setting and social system within which impacts will occur. For example, in the matrix approach, the tendency is to have extended lists of the activities, processes, technologies, etc. that might produce impacts as well as lists of the environmental characteristics that might be impacted. Such an approach often leads to unnecessary data and analyses being included in impact statements. Thus, the network or "relevance tree" offers the best approach for a concise but adequate impact assessment, and the following suggestions generally fit into the network category.

Analytical procedures should be as simple and straightforward as possible but should permit a response to the need for more details and greater complexity when necessary. That is, the amount of detail and degree of complexity should build from the less detailed and complex to the more detailed and complex on the basis of analytical need. This is in direct contrast to methods or procedures that call for describing complex activities, natural settings, and social systems in advance of any actual analysis of impacts.*

The following suggestions are not intended to be comprehensive. The objective

---

*The level of detail required is probably directly related to the credibility of the agency preparing the EIS; that is, agencies which develop high credibility may be able successfully to employ a more concise approach to impact analysis than can agencies with low credibility.

is to suggest and illustrate an approach, not to produce an analysis that will satisfy all requirements of an adequate EIS. Although categories of evaluative criteria are suggested, no attempt is made to provide the detailed criteria appropriate for an agency preparing an EIS.

The impact analysis suggested here begins with the residuals data obtained using the procedures described in Section 14.2. Since, as indicated earlier, this type of analysis requires data not included in either MERES or the OU descriptions, the analysis requires that goals, objectives, and evaluative criteria be made explicit. Given the limitations imposed here, this example cannot be that explicit and thus can only provide general guidelines.

Residuals can be evaluated individually or by categories: air pollutants, water pollutants, solids, land, health and safety, aesthetics, inputs, and outputs. Residuals can impact individually or in combination and directly or indirectly on two major systems:

1. Natural setting: air, water, land, and biological productivity and diversity.
2. Social system: health, safety, and welfare; economics; land use; and the environment (e.g., aesthetics and recreation).

As indicated, these two impact categories can be subdivided into a few major subcategories and, if need be, can be subdivided even further.

The criteria for evaluating the impact of residuals on the natural setting and/or the social system can be divided into at least three general categories:

1. Legal requirements.
2. Scientific standards or expert judgment.
3. Public acceptability as indicated by public attitudes and/or reactions.

Regardless of how it is conducted, an impact analysis basically consists of interrelating residuals, environmental characteristics, and evaluative criteria.

Since no present or future method of impact analysis is likely to eliminate all uncertainties, questionable judgments will continue to be made, regardless of the criteria applied. As a consequence, analytical procedures should provide for broad participation, both to guard against inadequately based judgments and to insure the broad acceptability (the legitimacy) of the analytical results. To this end, the impact analysis portion of an EIS should be prepared by an interdisciplinary team of experts.*

14.5.1 General Procedures

The first procedural step of an impact analysis should be to determine whether residuals would be generated in any location that violate national, state, or local laws. Since pollution standards vary by area as well as discharge types and quantities, a comparison of the allowable statute levels with process estimates should determine whether any obviously illegal impacts will result. If so, then the proposed action could be altered or the proposal withdrawn before the expense of a complete impact analysis is incurred.

Following this preliminary step, impact analysis should proceed in two phases. Phase I should attempt to identify potential impacts as a basis for delineating the ambient data required to determine actual impacts. Phase II should attempt to determine the actual impacts. The sequence of

*When there is a great deal of uncertainty concerning the likely impact of a significant residual or category of residuals, public participation in the existing hearings process may well be inadequate to legitimate the team's analysis and the team may wish to seek the advice of a consultive committee whose membership should include both germane expertise and interests. When such a committee is appointed, a variety of interests as well as expertise should be represented, both to comply with the admonition to increase public participation and as a means of anticipating what is publicly acceptable.

steps involved in each phase is shown diagrammatically in Figures 14-8 and 14-9.

In Phase I, each residual or category of residuals to be evaluated should be related to the natural setting and the social system to determine:

1. Whether the residual or category of residuals would produce a primary impact.
2. If so, what ambient data would be required to determine the significance of the impact in terms of legal requirements, scientific standards and expert judgments, and public acceptability.

The required ambient data should then be collected. As the examples of ambient data categories listed in Figures 14-8 and 14-9 indicate, these data can be quite diverse, ranging across both the physical and social spectra of the place of the proposed action.

In Phase II, specific residuals or categories of residuals should be evaluated against specific ambient data, and the impact of these residuals on the natural setting or social system should be determined on the basis of the specified evaluative criteria (see Figure 14-8). The quality of judgments made at this procedural point will depend directly on the quality and breadth of the expertise built into the interdisciplinary team responsible for preparing the EIS. (At this point in the procedures, a broadly based consultive committee may be used to enhance the credibility of evaluations and to legitimate the EIS process.)

Note that the process is iterative. For example, when a primary impact is identified, it should be subjected to both Phase I and Phase II impact analyses. This procedural step is intended to include effects often called "secondary impacts" in the analysis.

As a final step, residuals and impacts of residuals should be evaluated to determine, if possible, whether there are likely to be synergistic and/or additive impacts when they are combined. Procedurally, little more can be done than to suggest that questions about these two possible effects be raised explicitly during the impact analysis. The attempt to evaluate synergistic impacts should begin with a review of the residuals to be produced rather than with an extensive inventory of existing ambient conditions. This review should attempt to determine whether some of the residuals, under certain conditions, might produce significant synergistic impacts. If so, then the next step is to determine whether the synergistic-producing conditions exist at the location where the residuals will be produced.

Additive impacts, on the other hand, will generally require that a point source inventory be conducted to determine existing ambient loadings. Also, such assessment tools as diffusion models may be required for these analyses.

Finally, the results of various impact analyses should be compared on the bases of specific impacts or impact categories and partial or complete trajectories.

The suggested procedures for conducting impact analyses can be summarized as in Exhibit 2.

14.5.2 An Illustration of Impact Analysis

Two examples illustrate how to use the suggested procedures for conducting impact analyses: the impact of the water input requirements for the Synthane and Lurgi high-Btu coal gasification facilities and the impact of the air pollutant residuals produced by the same two processes. For purposes of identifying ambient data, both examples assume that the hypothetical gasification facility will be located near Colstrip, Montana.

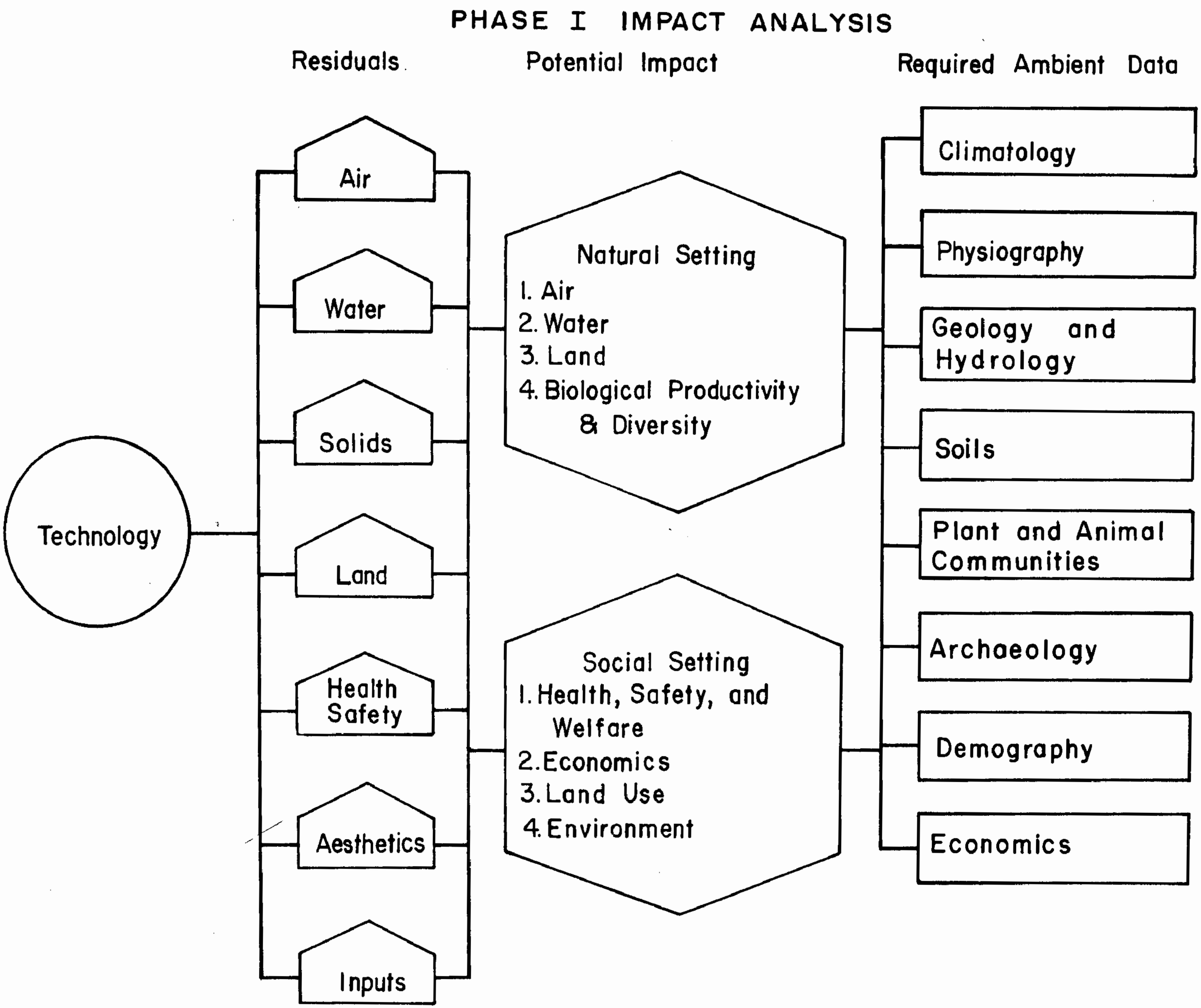


Figure 14-8. Impact Analysis for Energy Alternatives, Phase I

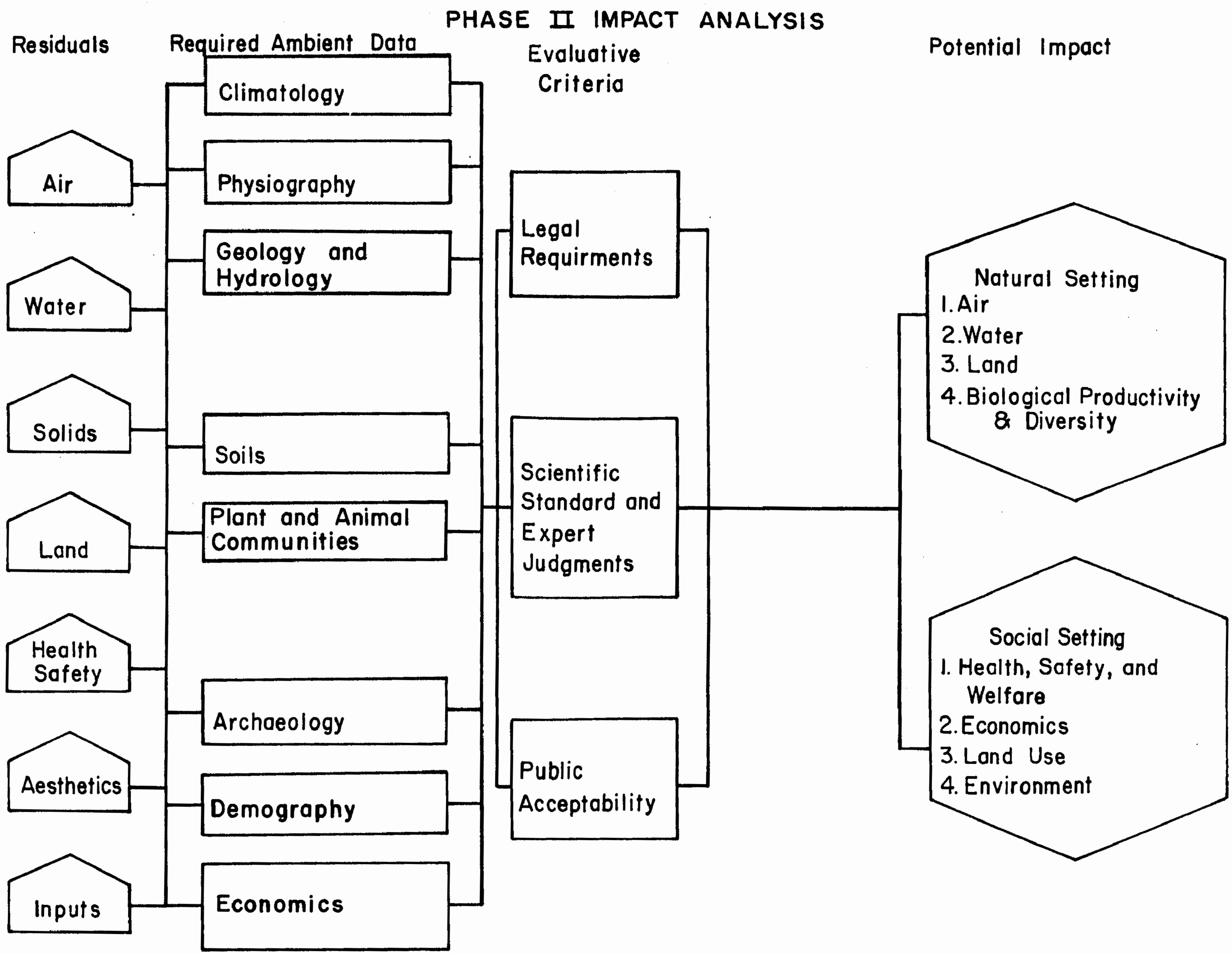


Figure 14-9. Impact Analysis for Energy Alternatives, Phase II

EXHIBIT 14-2

SUMMARY OF IMPACT ANALYSIS PROCEDURES

IDENTIFY UNLAWFUL EMISSIONS, AMBIENT CONDITIONS, AND IMPACTS, AND COMPARE ALTERNATIVES

Determine whether there are residuals that, regardless of where they occur, will produce unlawful impacts.

Determine what the potential impacts of residuals are likely to be and what ambient data will be required to assess actual impacts.

Using the ambient data collected, determine impacts by evaluating residuals in relation to specific natural setting and social system conditions.

Attempt to determine whether there are likely to be synergistic or additive effects.

Compare the impacts of alternatives on the bases of particular impacts or impact categories and partial or complete trajectories.

14.5.2.1 Impact of Particulates, Sulfur Dioxide, and Nitrous Oxide Emissions

Residuals data for Synthane (Table 14-1) and Lurgi (Table 14-2) are:

Residuals	Synthane (tons per day)	Lurgi (tons per day)
Particulates	6.73	1.02
Sulfur dioxide	4.49	2.79
Nitrous oxide	59.6	38.4

Following the procedures described in Section 14.5.1, the analysis would be as follows:

Step 1. Do residuals produce unlawful impacts regardless of where they occur? Although federal standards have not been established for coal gasifiers, EPA's New Stationary Source Emission Standards for Fossil Fuel-Fired Steam Generators can be used to illustrate this procedural step. Table 14-10 gives the amounts and types of expected emissions from Synthane and Lurgi, none of which would violate existing new source standards for fossil-fired steam generators.

Step 2. What are possible impacts and what ambient data are required to assess them? The possible impacts are summarized in Table 14-11, and the impact categories are shown in Figures 14-8 and 14-9. Many of the potential impacts described in Table 14-11 may be insignificant, and most are impossible to predict quantatively. Not all the ambient data tested in Table 14-11 has been collected, but the procedures are illustrated by an example: evaluation of the impact of air residuals on air quality.

Step 3. Determination of impacts. A diffusion model of the site could be developed to predict new ambient air concentrations.*

*Bases for diffusion models and equations for predicting ambient air quality can be found in Pasquill, 1962; Gifford, 1961; Miller and Holzworth, 1967; and Turner, 1969.

For stack gas emission control, each of the technologies under consideration employ an electrostatic precipitator, a Wellman Lord scrubbing unit, and, for sulfur removal and recovery, a Claus plant and an ammonia still. As a result, emissions are low, averaging an order of magnitude less than new source emission standards for power plants. Thus, for the Montana location (where other urban sources of air pollutants are minimal), the probability of exceeding ambient air quality standards is small. Consequently, a site-specific diffusion model (a process perhaps requiring a consultant) may not be needed. Approximations using general formulas could substitute. One example is given below.

Example:

For a particulate emission of 6.73 tons per day (Synthane facility, Table 14-1), ground level concentrations are calculated for the worst possible meteorological conditions and a stack height and downwind distance combination yielding the highest concentration. Thus, the data in Table 14-12 represent the worst cases or maximum possible concentrations for various stack heights and two wind speeds.

The EPA primary ambient air standard for particulates (40 CFR 50) sets an upper limit of 75 micrograms per cubic meter (annual geometric mean). Since the instantaneous, worst case concentrations presented in Table 14-12 exceed the standard, further calculations were made.

Table 14-13 gives concentrations at various distances downwind for a constant effective stack height of 328 feet (100 meters) and windspeed of 6.7 miles per hour (mph) (3 meters per second). Results indicate little chance in the annual geometric mean exceeding 75 micrograms per cubic meter.

TABLE 14-10

COMPARISON OF ENVIRONMENTAL PROTECTION AGENCY
SOURCE STANDARDS AND EXPECTED EMISSIONS
(POUNDS PER MILLION BTU'S INPUT)

Air Residual	Environmental Protection Agency[a]	Synthane[b]	Lurgi[c]
Particulates	0.1	0.026	0.004
Sulfur dioxide	1.2	0.017	0.011
Nitrous oxides	0.7	0.230	0.154

[a]Maximum two-hour average source standard for burning solid fossil fuel (40 CFR 60).

[b]Daily energy inflow to the gasifier is 5.18×10^{11} Btu's.

[c]Daily energy inflow to the gasifier is 5.00×10^{11} Btu's.

TABLE 14-11

POTENTIAL IMPACTS OF AIR POLLUTANTS AND AMBIENT DATA
REQUIRED TO EVALUATE THEM

Potential Impact Category and Subcategory	Ambient Data Required for Impact Evaluation
Air Quality Exceed legal standards for ambient conditions Change in ambient air quality Percent this new input is of all other input Quantity carried downwind Aerosol[a] formation	Concentration of the pollutant at the point of emission, other pollutant sources, diffusion characteristics at the site and surrounding area (topography, velocity, direction of prevailing wind, frequency and duration of temperature inversions), existing ambient air quality, Environmental Protection Agency air quality standards
Water Quality and Quantity Aerosols impinging on water bodies Change in pH of rain Change in pH of existing water bodies Change in other water quality parameters due to pollutants in rainout	Amount of rain Location and size of water bodies (lakes, rivers, estuaries) Water quality of existing water bodies Other sources of water pollutants
Biological Communities and Diversity Direct damage to species; relationship of damaged species to food web Reduction in crop growth and productivity Change in plant and animal diversity Specific species possibly affected Possible chemical and physical changes in plant cells or interference with plant enzyme system Effect on biogeochemical cycles of oxygen, sulfur, carbon, nitrogen, phosphorus	Characterization of each ecosystem present in terms of productivity, diversity, bioenergetics Species present and any data on their tolerance levels Identification of rare and endangered species

TABLE 14-11 (Continued)

Potential Impact Category and Subcategory	Ambient Data Required for Impact Evaluation
Land Use Patterns	
Change in ecosystems due to plant, animal, or crop damage Relocation of suburbs away from pollutant source	Current land use patterns Population characteristics which may stimulate changes
Economics	
Material damage due to rainout	Experience in other areas
Environment	
Smog formation Increased dust in homes	Content and diffusion characteristics of the plume
Health and Safety	
Respiratory ailment rate Accident rate due to high carbon monoxide levels	Demographic characteristics of the population--number of elderly people, etc. Past history in other places with the expected ambient air quality in this location

[a]Aerosol refers to droplets of air pollutants in the air as when sulfur dioxide is converted to sulfuric acid droplets.

TABLE 14-12

GROUND LEVEL AMBIENT AIR CONCENTRATIONS OF PARTICULATES FOR WORST CASES[a]

Combination Yielding Highest Possible Concentrations		Ground Level Concentration (Micrograms Per Cubic Meter)	
Effective Stack Height[b] (feet)	Distance Downwind (miles)	Wind Speed of 6.7 Miles Per Hour	Wind Speed of 11.2 Miles Per Hour
98	0.09	4,710	2,826
164	0.15	1,130	678
230	0.22	777	466
328	0.28	424	254
492	0.34	235	141
656	0.40	162	97

Source: Calculated using Figure 3-51 of Turner (1969), p. 11.

[a]Stack emission is 6.73 tons per day = 70.66×10^6 micrograms per second.

[b]Effective stack height is actual stack height plus plume rise before leveling.

TABLE 14-13

GROUND LEVEL AMBIENT AIR CONCENTRATIONS OF PARTICULATES FOR TWO METEOROLOGICAL CONDITIONS[a]

Distance Downwind (miles)	Ground Level Concentration (Micrograms Per Cubic Meter)	
	Stability Class A[b]	Stability Class D[b]
0.09	0.1	0
0.19	235.0	0
0.62	70.6	23.5
0.93	0	94.2
3.11	0	153.0
6.21	0	77.7
31.07	0	9.4

Source: Calculated using Figures 3-5A and 3-5D of Turner (1969): 11 and 14.

[a]Stack emission is 6.73 tons per day = 70.66×10^6 micrograms per second.

[b]Class A refers to very unstable air; Class D is the neutral class, being neither stable not unstable.

Step 4. Possible synergistic effects. From a practical standpoint, the question is not whether interaction effects exist--they almost certainly do--but whether they are of sufficient magnitude to cause impacts in other categories.

The current level of understanding of synergistic effects is minimal. For example, nitrogen dioxide is known to be the trigger for the photochemical reactions (with hydrocarbons) which produce smog. However, predicting the extent of smog producing reactions from residual data is not yet possible. For insight, data on the mean mixing depths and history of inversions at Colstrip, Montana (Table 14-14) has been incorporated into the example analysis. The conclusion from these data is that, since ambient air quality concentrations are predicted to be acceptable and dispersion potential at the site is good, smog will not be a significant problem.

Step 5. Comparison of impacts of alternatives. Air residuals produced by both Lurgi and Synthane are insignificant on the basis of new source standards. In all cases, Lurgi produces lesser amounts than does the Synthane process.

14.5.2.2 Impact of Water Inputs

Residuals from Tables 14-1 and 14-2 are:

1. Synthane: 25 million gallons of water per day consumed.
2. Lurgi: 18 million gallons of water per day consumed.

Following the procedures described in Section 14.5.1 the analysis would be as follows:

Step 1. Do residuals produce unlawful impacts regardless of where they occur? There are no non-site specific laws governing water use and consumption.

Step 2. What are possible impacts and what ambient data are required to access them? Potential impacts of increased water consumption were evaluated against the impact categories and a partial list of impacts and the

TABLE 14-14

FREQUENCY OF HIGH AIR POLLUTION POTENTIAL AT COLSTRIP, MONTANA

Data obtained from the Colstrip area during November 1971 to November 1972 were used to provide a measure of thermodynamic stability and a means for characterizing atmospheric dispersion potential. Vertical temperature profiles indicate that there were 250 inversions during the year, an average of 18 per month. Most of those inversions were short (lasting from several hours to 24 hours), but 14 lasted for periods longer than 24 hours. The short inversions were most common in August, September, and October while those exceeding 24 hours occurred during the winter months (seven in December, three in January, and four in February). The longest inversion recorded during the year lasted 67 hours and occurred in December. Data on tops of ground-based inversions indicate the mean top of the inversion occurs about 1,000 feet above the ground during the summer and the fall tops may occur up to 3,000 feet above the ground.

Mean maximum mixing depths range from about 3,800 feet in the winter to about 6,500 feet in the summer (Table 14-17). Fall and spring seasons show means of 5,600 and 6,000 feet respectively. In Table 14-15, the last column in the table provides mean mixing depths as estimated by Holzworth (1971). This estimation of the mean mixing depth is lower during the wintertime periods than the actual measurements made at Colstrip during the one-year period.

Holzworth (1971) data on the frequency of high air pollution potential (HAPP) caused by low mixing depth and light winds indicate that from 1960 to 1965 the Colstrip region experienced no HAPP cases occurring where wind speed was around 13.5 miles per hour. Mixing heights less than 3,280 feet coupled with winds less than 9 miles per hour lasting 2 days or more occurred about 70 times in the 5-year period. Similar conditions lasting 5 days or more occurred about 10 times. These data indicate that southeastern Montana is in a region which experiences extended periods of high air pollution potential. Holzworth's calculations, however, were based mainly on information gathered from weather stations in Wyoming where stagnant air masses are somewhat more frequent. The data from Colstrip indicate that this portion of southeastern Montana is a moderately good dispersion region.

Source: Westinghouse, 1973: 2-12.

TABLE 14-15

MID-AFTERNOON MIXING DEPTHS AT COLSTRIP

Month	Mixing Depth, feet			Mixing Depth, feet
	Maximum[a]	Mean	Minimum	Mean (Holzworth)
December	6,770	3,000	0	NC
January	6,770	4,740	0	NC
February	6,770	4,460	0	NC
WINTER	6,770	3,800	0	2,950
March	6,770	4,930	1,870	NC
April	6,770	6,180	3,770	NC
May	6,770	6,690	5,770	NC
SPRING	6,770	6,030	3,800	7,550
June	6,770	5,640	3,370	NC
July	6,770	6,770	6,770	NC
August	6,770	6,770	6,770	NC
SUMMER	6,770	6,490	5,640	8,860
September	6,770	6,440	4,170	NC
October	6,770	4,980	1,970	NC
November	6,770	5,610	500	NC
FALL	6,770	5,620	2,210	5,250
MEAN	NA	5,250	NA	5,900

NA = not applicable, NC = not considered

Source: Westinghouse, 1973: 2-12.

[a]Maximum height of aircraft.

TABLE 14-16

POTENTIAL IMPACTS OF WATER DEMAND
AND DATA REQUIRED FOR ITS EVALUATION

Potential Impact Category	Ambient Data Required for Impact Evaluation
Water Quality and Quantity	
Change in river flow Change in quality parameters	River flow distribution through the year Present water quality of rivers
Air Quality	
Fogging and microclimate changes due to thermal loading from the evaporative cooling tower	Temperature, humidity, dew point distribution throughout the year
Biological Productivity and Diversity	
Changes in the river aquatic communities and terrestrial communities linked to the river	Present aquatic and terrestrial communities with emphasis on terrestrial animal population levels and their water needs
Land Use	
If land use for agriculture or urban areas is water dependent, what changes could be expected?	Present land use patterns and their source and level of water consumption Present legal distribution of the water

data required for their evaluation drawn (Table 14-16). For example, only the impact of direct water demand or primary water demand on existing water quantity is considered. The ambient data collected for this evaluation are given in Table 14-17. As indicated in Table 14-17, see page 14-36, the consumptive use of surface water dominates that of groundwater, and surface water sources are responsible for 98.6 percent of that diverted. The greatest diversion of water is for irrigation of crops, and about 98 percent of the consumed water is for irrigation. Only a small quantity of groundwater, less than one percent of the total irrigation diversion, comes from wells.

Step 3. Determination of impact. Table 14-18 gives the percent of each of the two river flows required by the Synthane and Lurgi processes. Percent of existing consumption in Montana is also given. Both Synthane and Lurgi demand a very small percent of the Yellowstone River but a significant percentage of the Tongue River (7 to 10 percent). When the Tongue River is at low flow, the gasification facility could conceivably demand the entire flow. Consequently, data on the seasonal flow of the river should be obtained.

Step 4. Determination of synergistic and additive effects. Impacts in this category require knowledge of the other uses and demands on the river flow. This information was not available.

TABLE 14-17

AMBIENT DATA NEEDED TO EVALUATE IMPACT
OF WATER REQUIREMENT ON WATER QUANTITY

1. Surface Water Availability: Two rivers are close enough to Colstrip to be water sources. The Yellowstone River has an annual average flow of 10,460 cubic feet per second. The Tongue River has an annual average flow of 405 cubic feet per second with a range of 0 to 13,300 cubic feet per second (Westinghouse, 1973: 2-41; 2-46).

2. Groundwater Availability: Within the Yellowstone Basin, river water is virtually the sole source of water for all uses. In Rosebud County, groundwater is available at less than 50 feet at rates between 50 and 500 gallons per minute per well; however, this source is considered an extension of the river in that depletion is recharged at the expense of river discharge, not by aquifers fed from other sources. At locations three or more miles distant from the river, soil infiltration rate ability is less than 0.05 mile per hour at saturation, and availability per well is less than 50 gallons per minute. Within the entire Yellowstone Basin, groundwater is practical only for limited use (Westinghouse, 1973: 2-47).

3. Present Water Consumption and Diversion in Montana per year.

Use	Volume (10^3 acre-feet)				Total Water Consumption (percent)
	Surface Water		Groundwater		
	Diverted	Consumed	Diverted	Consumed	
Crop production	10,000.0	3,750.0	45.0	20.0	98.8
Public supplies	79.0	8.0	33.0	3.0	0.3
Industrial	169.0	17.0	31.0	3.0	0.5
Rural domestic	1.0	0.1	11.0	1.0	0.0
Stock	18.0	6.0	20.0	7.0	0.4

Source: Westinghouse, 1973: 2-47.

TABLE 14-18

PERCENT OF RIVER FLOW AND CONSUMPTIVE
USE IN MONTANA REPRESENTED BY GASIFICATION WATER DEMAND

Gasification Water Demand (million gallons per day)	Yellowstone River[a] (percent)	Tongue River[b] (percent)	Current Consumptive Use in Montana[c] (percent)
Synthane - 25	0.37	9.55	0.73
Lurgi - 18	0.27	6.88	0.53

[a]Average flow of 10,460 cubic feet per second = 6,757.2 million gallons per day.

[b]Average flow of 405 cubic feet per second = 261.6 million gallons per day.

[c]Current consumption of 3,812,100 acre-feet per year = 3,402.9 million gallons per day.

Step 5. Compare alternatives. Gasification using the Lurgi process consumes 18 percent less water than gasification using the Synthane process. Both would exert a major demand on the Tongue River flow but a minor demand on the Yellowstone River flow.

14.6 SUMMARY

Two levels of analysis (residuals and impacts) have been described in this discussion of how to evaluate and compare energy alternatives. As indicated, MERES and the OU resource systems descriptions provide the basic data required for calculating and comparing residuals. The procedures presented in Sections 14.2 through 14.4 are a guide to systematic analysis at this level. Impact analysis is of a higher order and is much more difficult to achieve. In Section 14.5, procedures were suggested for progressing to this higher level of analysis, employing a network or relevance tree approach designed to contribute to the systematic analysis of the impacts of the residuals peoduced by energy alternatives.

REFERENCES

Adkins, William G., and Dock Burke, Jr. (1971) Interim Report: Social, Economic, and Environmental Factors in Highway Decision Making, for the Texas Highway Department in cooperation with the U.S. Department of Transportation, Federal Highway Administration. College Station, Tex.: Texas A&M University, Texas Transportation Institute.

Arthur D. Little, Inc. (1971) Transportation and Environment: Synthesis for Action: Impact of National Environmental Policy Act of 1969 on the Department of Transportation, Vol. 3, Options for Environmental Management, for Department of Transportation.

Brookhaven National Laboratory, Associated Universities, Inc., Energy/Environmental Data Group (1975) Energy Model Data Base User Manual, BNL 19200.

Central New York Regional Planning and Development Board (1972) Environmental Resources Management, for Department of Housing and Urban Development. Springfield, Va.: National Technical Information Service.

Code of Federal Regulations (1973a) Title 40, Protection of Environment, Section 60, "New Stationary Sources."

Code of Federal Regulations (1973b) Title 40, Protection of Environment, Section 50, "National Ambient Air Quality Standards."

Dee, Norbert, Janet K. Baker, Neil L. Drobny, Kenneth M. Duke and David C. Fahringer (1972) Environmental Evaluation System for Water Resources Planning, report to U.S. Bureau of Reclamation. Columbus, Ohio: Battelle Memorial Institute.

Dee, Norbert, and others (1973) Planning Methodology for Water Quality Management: Environmental Evaluation System. Columbus, Ohio: Battelle Memorial Institute.

Gifford, F.A. (1961) "Uses of Routine Meteorological Observations for Estimation of Atmospheric Dispersion." Nuclear Safety 2 (April 1961): 47-51.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

Holzworth, G.C. (1971) "Mixing Heights, Wind Speeds and Potential for Urban Air Pollution Throughout the Contiguous United States." Washington: Environmental Protection Agency.

Institute of Ecology, University of Georgia (1971) Optimum Pathway Matrix Analysis Approach to the Environmental Decision Making Process: Test Case: Relative Impact of Proposed Highway Alternatives. Athens, Ga.: University of Georgia, Institute of Ecology (mimeographed).

Krauskopf, Thomas M., and Dennis C. Bunde (1972) "Evaluation of Environmental Impact Through a Computer Modeling Process," pp. 107-125 in Robert Ditton and Thomas Goodale (eds.) Environmental Impact Analysis: Philosophy and Methods. Madison, Wis.: University of Wisconsin Sea Grant Program.

Leopold, Luna B., and others (1971) A Procedure for Evaluating Environmental Impact, USGS Circular 645. Washington: Government Printing Office.

McHarg, Ian (1969) Design with Nature. Garden City, N.Y.: Natural History Press, pp. 31-41.

Miller, Marvin E., and George C. Holzworth (1967) "An Atmospheric Diffusion Model for Metropolitan Areas." Journal of the Air Pollution Control Association 17 (January 1967): 46-50.

Moore, John L. and others (1973) A Methodology for Evaluating Manufacturing Environmental Impact Statements for Delaware's Coastal Zone, report to the State of Delaware. Columbus, Ohio: Battelle Memorial Institute.

Multiagency Task Force (1972) Guidelines for Implementing Principles and Standards for Multiobjective Planning of Water Resources, review draft. Washington: Bureau of Reclamation.

Pasquill, F. (1962) Atmospheric Diffusion. New York: D. Van Nostrand Co., Ltd.

Smith, William L. (n.d.) Quantifying the Environmental Impact of Transportation Systems. Topeka, Kans.: Van Deren-Hazard-Stallings-Schnacke (mimeographed).

Sorensen, Jens (1970) A Framework for Identification and Control of Resource Degradation and Conflict in the Multiple Use of the Coastal Zone. Berkeley, Calif.: University of California, Department of Landscape Agriculture.

Sorensen, Jens, and James E. Pepper (1973) Procedures for Regional Clearinghouse Review of Environmental Impact Statements--Phase Two, report to the Association of Bay Area Governments.

Stover, Lloyd V. (1972) Environmental Impact Assessment: A Procedure. Miami, Fla.: Sanders and Thomas, Inc.

Tulsa District, U.S. Army Corps of Engineers (1972) Matrix Analysis of Alternatives for Water Resource Development, draft technical paper.

Turner, D.B. (1969) Workbook of Atmospheric Diffusion Estimates, U.S. Department of Health, Education, and Welfare, Environmental Health Series. Washington: Government Printing Office.

Walton, L. Ellis, Jr., and James E. Lewis (1971) A Manual for Conducting Environmental Impact Studies, Virginia Highway Research Council. Springfield, Va.: National Technical Information Service.

Warner, Maurice L., and Edward N. Preston (1974) A Review of Environmental Impact Assessment Methodologies, EPA Socioeconomic Environmental Studies Series. Washington: Government Printing Office.

Western Systems Coordinating Council, Environmental Committee (1971) Environmental Guidelines.

Westinghouse Electric Corporation, Environmental Systems (1973) Colstrip Generation and Transmission Project: Applicant: Environmental Analysis. Pittsburgh: Westinghouse.

CHAPTER 15

PROCEDURES FOR COMPARING THE ENERGY EFFICIENCIES OF ENERGY ALTERNATIVES

15.1 INTRODUCTION

Matrix of Environmental Residuals for Energy Systems (MERES) and the University of Oklahoma (OU) resource systems descriptions provide two measures of the energy intensiveness of a technology: primary efficiency (the ratio of output to input energy) and ancillary energy requirements (the amount of energy required to fuel trucks, power draglines, etc.).* As shown in Figure 15-1, primary efficiency (expressed as a percentage) measures the unavoidable losses which all energy alternatives suffer as a consequence of physical, thermal, and/or chemical processes. Ancillary energy (reported in Btu's per 10^{12} Btu's of energy input) measures the direct energy subsidy required to deliver energy from a particular activity of process.**

Neither primary efficiency nor ancillary energy can be used as the single measure for comparing the energy intensiveness of technologies. For example, there may be no overall difference in terms of direct energy consumption between a technology that has a high primary efficiency but requires large amounts of ancillary energy and an alternative technology that has a low primary efficiency but requires little ancillary energy. Thus, in comparing alternatives, an overall efficiency should be calculated from the primary efficiency and ancillary energy requirements. In this calculation, output energy is divided by total input energy (including ancillary energy) to obtain the overall efficiency. As expressed in Figure 15-1, overall efficiency is $\frac{Y}{X + U}$.***

---

*Where energy for process heat is taken from the fuel being processed (refinery gas in a refinery or coal in a coal gasification facility), it is calculated as part of the primary efficiency, thus making the process appear to be less efficient.

**All energy alternatives are also subsidized by the energy required to manufacture materials and equipment (e.g., steel and aluminum, and trucks and draglines). Although a comprehensive calculation of energy efficiencies would require that these materials and equipment subsidizes be taken into account, adequate data are not available and they are omitted from the calculations made in this chapter. An increasing number of researchers undertaking environmental and technology assessments now advocate that all external inputs or subsidies be evaluated on an energy basis (Bayley, 1973; Boynton, 1974; Odum, 1973; and Slesser, 1974).

Net energy analysis as introduced by Howard T. Odum (1971) for impact assessment is being evaluated by the Office of Planning and Analysis of Energy Research Development Administration (ERDA) (with the actual analysis being done at Brookhaven National Laboratory), the Office of Energy Policy of National Science Foundation (NSF), and the Office of Research and Development of the Department of Interior. The ERDA, NSF, and Interior studies are intended to provide a systematic critique of Odum's work.

***In any calculation, the same energy quality units should be used. The quality of energy is a measure of its ability to do work. That is, one Btu of electricity can do more work than one Btu of coal; thus, electricity is a higher quality energy. As a result, Btu's of electricity should not be added to Btu's of coal, oil, or gas without first converting the electricity by the heat rate (approximately 10,500 Btu's per kilowatt hour [kwh]) to the equivalent quality.

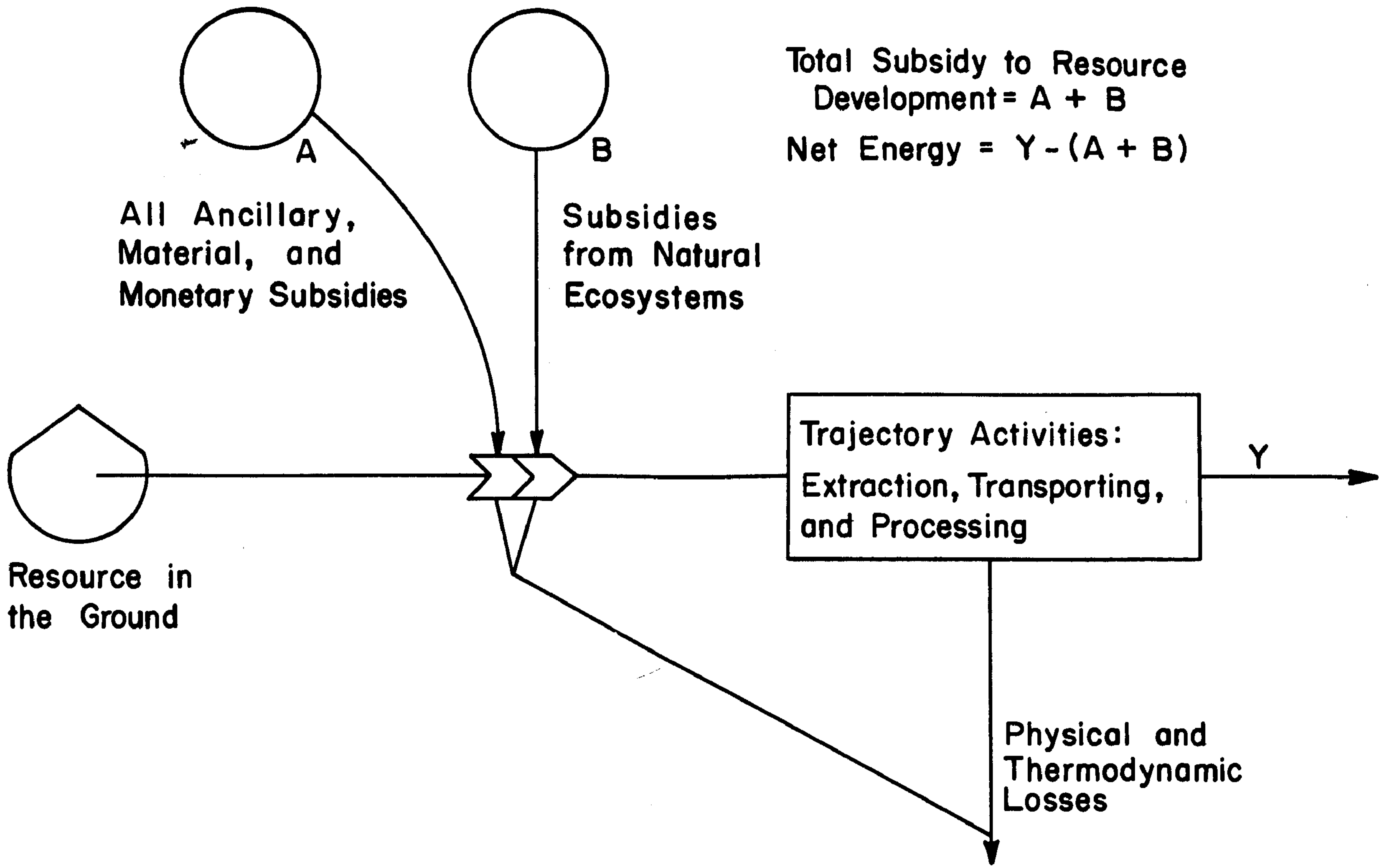


Figure 15-1. Energy Efficiency Measures

The remainder of this chapter is a demonstration of how energy efficiency data in MERES and the OU resource systems descriptions can be used to calculate and compare the energy efficiencies of energy alternatives. Procedures are suggested that account for all external inputs (including materials and equipment) in terms of energy units.

15.2 GENERAL PROCEDURES FOR OBTAINING AND USING ENERGY EFFICIENCY DATA

The steps for evaluating and comparing efficiencies of energy alternatives are essentially the same as those described in Chapter 14 for residuals. They are:

1. Identify, describe, and calculate energy efficiencies for the process, activity, partial trajectory, or trajectory to be evaluated and compared.

   a. Identify the alternative activities and/or processes to be evaluated and compared by referring to Figure 1 in the appropriate chapter(s) of the OU resource system description.

   b. Access the MERES data by means of the computer programs described in Brookhaven's Users Manual (1975). This will provide a printout of the primary efficiency and ancillary energy for each process, activity, partial trajectory, or trajectory for which a request is entered. Ancillary energy requirements will be calculated for the size of operation specified in the request. For example, the ancillary energy requirement for gasifying 10^{12} Btu's of coal in a Lurgi low-gas unit is 27.8×10^{9} Btu's (see Chapter 1). For a Lurgi facility synthesizing 250 million cubic feet (mmcf) of low-Btu gas a day, the ancillary energy requirement is 1.83×10^{9} Btu's per day.* Note that all ancillary energies given in MERES and OU data have been converted to the same energy quality.

   c. To obtain supplemental data included in the OU descriptions, to obtain information on the assumptions made concerning the efficiency data, and to obtain descriptions of the type ancillary energy required, read the sections on "Energy Efficiencies" that follow the process descriptions in the OU resource systems descriptions. Information on assumptions can also be obtained from the MERES when footnotes are requested with the efficiency data.

   d. For those resource systems not included in MERES, obtain efficiency data from the "Energy Efficiencies" sections of the OU resource systems descriptions. The size of operations to be compared should be specified and adjustments in ancillary energy made accordingly.

   e. Calculate an overall efficiency for each process, activity, partial trajectory, or trajectory and list primary efficiencies, ancillary energies, and overall efficiencies for each.

      (1) To calculate the primary efficiency of a trajectory, multiply all process primary efficiencies together. Exclude the recovery efficiency (the primary efficiency for extraction) which is the amount of energy not recovered from the mine or reservoir. For example, an underground coal mining recovery efficiency of 57-percent or an oil reservoir recovery efficiency of 30-percent is not a measure of overall energy intensiveness or consumption.

      (2) To calculate the ancillary energy requirement for a trajectory, add the ancillary energy requirements for all processes. Remember that ancillary energies are first converted (from those in the data base) to correspond to the size of operation specified.

      (3) To calculate an overall efficiency for a process, add the ancillary energy value to input energy value and divide the resulting sum into the amount of energy output from the process.

      (4) To calculate a trajectory's overall efficiency, multiply all process overall efficiencies together.

---

*250×10^{6} cubic feet (cf) x 200 Btu's per cf = 5×10^{10} Btu's out as gas. 5×10^{10} Btu's divided by 0.758 primary efficiency = 6.6×10^{10} Btu's input as coal. If 27.8×10^{9} Btu's are required to process 10^{12} Btu's of coal, then 1.83×10^{9} Btu's are required to process 6.6×10^{10} Btu's.

2. Make the desired comparisons. Comparisons of energy efficiencies for energy alternatives should be made based on:

   a. Primary efficiencies, ancillary energy requirements, and overall efficiency for processes.

   b. Primary efficiencies, ancillary energy requirements, and overall efficiency for the trajectory.

3. At this point, specify some criteria for feasible alternatives, thus narrowing the total number to be compared. Chapter 14 gives examples of criteria.

These three procedural steps for evaluating and comparing the energy efficiencies of energy alternatives are summarized in Exhibit 15-1. These procedures are applicable for comparing technological, locational, source, and substitution alternatives. The implications of energy efficiencies for energy development are discussed in Section 15.5.

15.3 A DEMONSTRATION OF HOW TO CALCULATE ENERGY EFFICIENCIES

Primary efficiencies, ancillary energy requirements, and overall efficiencies are given for each activity for the proposed action and each of the six alternatives to the proposed action in Tables 15-1 through 15-7.* In addition, pertinent information and assumptions relating to the data (as discussed in the "Energy Efficiencies" sections which follow the process descriptions Chapters 1 through 13) are listed. Table 15-8 gives trajectory totals for the seven alternatives. Each trajectory delivers 2.62×10^{11} Btu's per day (or 250 mmcf at 1,050 Btu's per cf) to the consumer.

15.3.1 The Proposed Major Federal Action

As noted in Chapter 14, MERES data are based on configurations that may differ from that proposed for a particular action. These data are, in a sense, averages. Consequently, when calculations are made for a proposed action, they should be based on the configuration proposed; for example, the particular sulfur recovery process, stack gas cleaner, wastewater unit processes, etc. to be used (see Section 14.3.1). For this demonstration, data were taken from the OU descriptions and are presented in Table 15-1 for each activity in the trajectory.

The following information pertains to the data in Table 15-1:

1. Ancillary energy is zero for high-Btu gasification because process heat requirements are generated on-site using some of the coal. The loss is reflected in the primary efficiency.
2. The ancillary energy for extraction is about half diesel fuel and half electricity.
3. The ancillary energy for trucking is supplied by diesel fuel and represents an average haul distance of 1.5 miles.
4. The ancillary energy for breaking and sizing is about 80 to 85 percent as electricity and 15 to 20 percent as oil.
5. Ancillary energies for pipeline gathering and distribution are zero because part of the gas is used for the compressors with the loss being reflected in the primary efficiency.

15.3.2 A Technological Alternative

In addition to Synthane, four high-Btu gasification alternatives are discussed in the OU descriptions. Only one, Lurgi, is used here as an example. Efficiency data for the trajectory that includes the Lurgi process are given in Table 15-2.

Concerning the data in Table 15-2, note that:

1. The same five facts listed above for the proposed action data in Section 15.3.1 apply to the data in this trajectory.
2. Although the table indicates that Lurgi is a more efficient process than Synthane, the level of data accuracy (error less than 25 percent, Hittman, 1975 Vol. II) may mean that the difference is not real.

---

*For convenience, these tables have been placed where they are explained in the text.

EXHIBIT 15-1

SUMMARY PROCEDURES FOR EVALUATING AND COMPARING THE ENERGY EFFICIENCIES OF ENERGY ALTERNATIVES

STEP I	IDENTIFY, DESCRIBE, AND CALCULATE EFFICIENCIES Identify the alternatives to be evaluated by referring to the technologies flow charts in the OU description. Obtain efficiency data from MERES and/or the OU descriptions. Summarize and tabulate all efficiency data for each alternative to be evaluated, calculating the overall efficiency.
STEP II	COMPARE ALTERNATIVES Compare primary efficiencies, ancillary energy requirements, and overall efficiencies. Compare either processes or complete trajectories.

TABLE 15-1

EFFICIENCIES OF THE PROPOSED ACTION:
SYNTHANE HIGH-BTU GASIFICATION

Activity	Primary Efficiency (percent)	Ancillary Energy[a] (Btu's)	Overall Efficiency (percent)
Extraction	NA	1.02×10^9	NA
Mine transportation (trucking)	100.0	0.100×10^9	100.0
Breaking and sizing	100.0	1.13×10^9	99.8
High-Btu gasification	58.4	0	58.4
Pipeline gathering	89.2	0	89.2
Pipeline distribution	97.1	0	97.1
Trajectory	50.5	2.25×10^9	50.4

NA = not applicable

[a]Based on a trajectory outflow of 2.62×10^{11} Btu's per day or 250 mmcf per day.

TABLE 15-2

EFFICIENCIES OF A TECHNOLOGICAL ALTERNATIVE:
LURGI HIGH-BTU GASIFICATION

Activity	Primary Efficiency (percent)	Ancillary Energy[a] (Btu's)	Overall Efficiency (percent)
Extraction	NA	0.985×10^9	NA
Mine transportation (trucking)	100.0	0.097×10^9	100.0
Breaking and sizing	100.0	1.09×10^9	99.8
High-Btu gasification	60.5	0	60.5
Pipeline gathering	89.2	0	89.2
Pipeline distribution	97.1	0	97.1
Trajectory	52.4	2.18×10^9	52.2

NA = not applicable

[a]Based on a trajectory outflow of 2.62×10^{11} Btu's per day or 250 mmcf per day.

TABLE 15-3

EFFICIENCIES OF A LOCATIONAL ALTERNATIVE: SYNTHANE FACILITY MOVED TO DEMAND CENTER

Activity	Primary Efficiency (percent)	Ancillary Energy[a] (Btu's)	Overall Efficiency (percent)
Extraction	NA	0.884×10^9	NA
Mine transportation	100.0	0.087×10^9	100.0[b]
Breaking and sizing	100.0	0.982×10^9	99.8
Unit train transportation	100.0	29.6×10^9	93.8
High-Btu gasification	58.4	0	58.4
Trajectory	58.4	31.6×10^9	54.5

NA = not applicable

[a]Based on a trajectory outflow of 2.62×10^{11} Btu's per day or 250 mmcf per day.

[b]The exact efficiency is 99.96 percent because there is a 0.04 percent loss during transport.

15.3.3 A Locational Alternative

The high-Btu gasification facility can be located at the demand center, in which case the coal is transported from the mine to the processing plant and transmission of the natural gas is not required. Energy efficiency data for the locational alternative are given in Table 15-3.

For the data in Table 15-3:

1. The facts listed as numbers 1 through 4 in Section 15.3.2 apply to this trajectory.
2. Unit train transportation is assumed to be over a distance of 1,000 miles.
3. The primary efficiency of a unit train reflects wind losses.

15.3.4 Source Alternatives

An alternative to producing synthetic gas from coal is to obtain more natural gas from natural reservoirs. However, increased onshore production does not appear to be a feasible alternative. The alternatives considered here are: Alaskan natural gas piped directly to the U.S. via Canadian pipeline or liquefied and shipped by tanker from Valdez; increased offshore production of natural gas; and imported liquefied natural gas (LNG). Tables 15-4 through 15-7 give the efficiency data for the activities in each of these processes.

Pertinent information about the data in Tables 15-4 through 15-7 includes:

1. The primary efficiency of natural gas extraction reflects losses due to escaping gas.
2. The primary efficiencies for storage and pipeline distribution reflect the use of part of the gas as fuel for compressors.
3. The primary efficiencies for liquefaction and vaporization reflect the use of part of the incoming gas to fuel the vaporizer and liquefaction plant.
4. Ancillary energy for tanker transport of LNG is diesel fuel.

15.3.5 Substitute Fuel Alternatives

Although not included here, the energy efficiencies for substituting other fuels for pipeline quality gas could also be calculated using the procedures described above.

TABLE 15-4

EFFICIENCIES OF A SOURCE ALTERNATIVE:
ALASKAN NATURAL GAS VIA CANADIAN PIPELINE

Activity	Primary Efficiency (percent)	Ancillary Energy[a] (Btu's)	Overall Efficiency (percent)
Extraction-onshore	NA	0	NA
Gathering pipeline	89.2	0	89.2
Pipeline distribution	88.0	0	88.0
Trajectory	78.5	0	78.5

NA = not applicable

[a]Based on a trajectory outflow of 2.62×10^{11} Btu's per day or 250 mmcf per day.

TABLE 15-5

EFFICIENCIES OF A SOURCE ALTERNATIVE:
ALASKAN NATURAL GAS VIA ALASKAN PIPELINE AND LNG TANKER

Activity	Primary Efficiency (percent)	Ancillary Energy[a] (Btu's)	Overall Efficiency (percent)
Extraction-onshore	NA	0	NA
Gathering--pipeline	89.2	0	89.2
Transmission--pipeline	97.1	0	97.1
LNG liquefaction	83.0	0	83.0
LNG tanker transportation	92.5	14.5×10^9	88.2
LNG storage	100.0	0.77×10^9	99.7
LNG vaporization	98.0	0.20×10^9	97.9
Pipeline distribution	97.1	0	97.1
Trajectory	63.3	15.4×10^9	61.0

NA = not applicable

[a]Based on a trajectory outflow of 2.62×10^{11} Btu's per day or 250 mmcf per day.

TABLE 15-6

EFFICIENCIES OF A SOURCE ALTERNATIVE: OFFSHORE NATURAL GAS

Activity	Primary Efficiency (percent)	Ancillary Energy[a] (Btu's)	Overall Efficiency (percent)
Extraction-offshore	NA	0	NA
Pipeline gathering	88.0	0	88.0
Pipeline distribution	97.1	0	97.1
Trajectory	85.4	0	85.4

NA = not applicable

[a]Based on a trajectory outflow of 2.62×10^{11} Btu's per day or 250 mmcf per day.

TABLE 15-7

EFFICIENCIES OF A SOURCE ALTERNATIVE: IMPORTED LNG

Activity	Primary Efficiency (percent)	Ancillary Energy[a] (Btu's)	Overall Efficiency (percent)
LNG tanker on U.S. coastal waters	96.4	6.94×10^9	94.1
Storage--LNG tank	100.0	0.77×10^9	99.7
LNG vaporization	98.0	0.20×10^9	97.9
Pipeline distribution	97.1	0	97.1
Trajectory	91.7	7.91×10^9	89.3

[a]Based on a trajectory outflow of 2.62×10^{11} Btu's per day or 250 mmcf per day.

15.4 A DEMONSTRATION OF HOW TO COMPARE THE EFFICIENCIES OF ENERGY ALTERNATIVES

Efficiency data for the proposed action trajectory and six alternatives are summarized in Table 15-8 and compared graphically in Figure 15-2. The high energy cost of converting coal to natural gas is evident. Primary efficiencies range from 63 to 92 percent for alternative sources of natural gas. The most efficient is imported gas because that trajectory begins in U.S. ports and does not include extraction or transportation to the U.S.

Ancillary energy requirements are highest for trajectories involving transportation over long distances other than by a pipeline. The train transport of coal in the locational alternative and the tanker transport of LNG from Alaska raises the trajectory ancillary energy to 31.6×10^9 and 15.4×10^9 Btu's respectively. Since 2.62×10^{11} Btu's of natural gas are delivered at the end of the trajectories, these ancillary energy requirements represent 12.1 percent and 5.9 percent of delivered energy respectively.

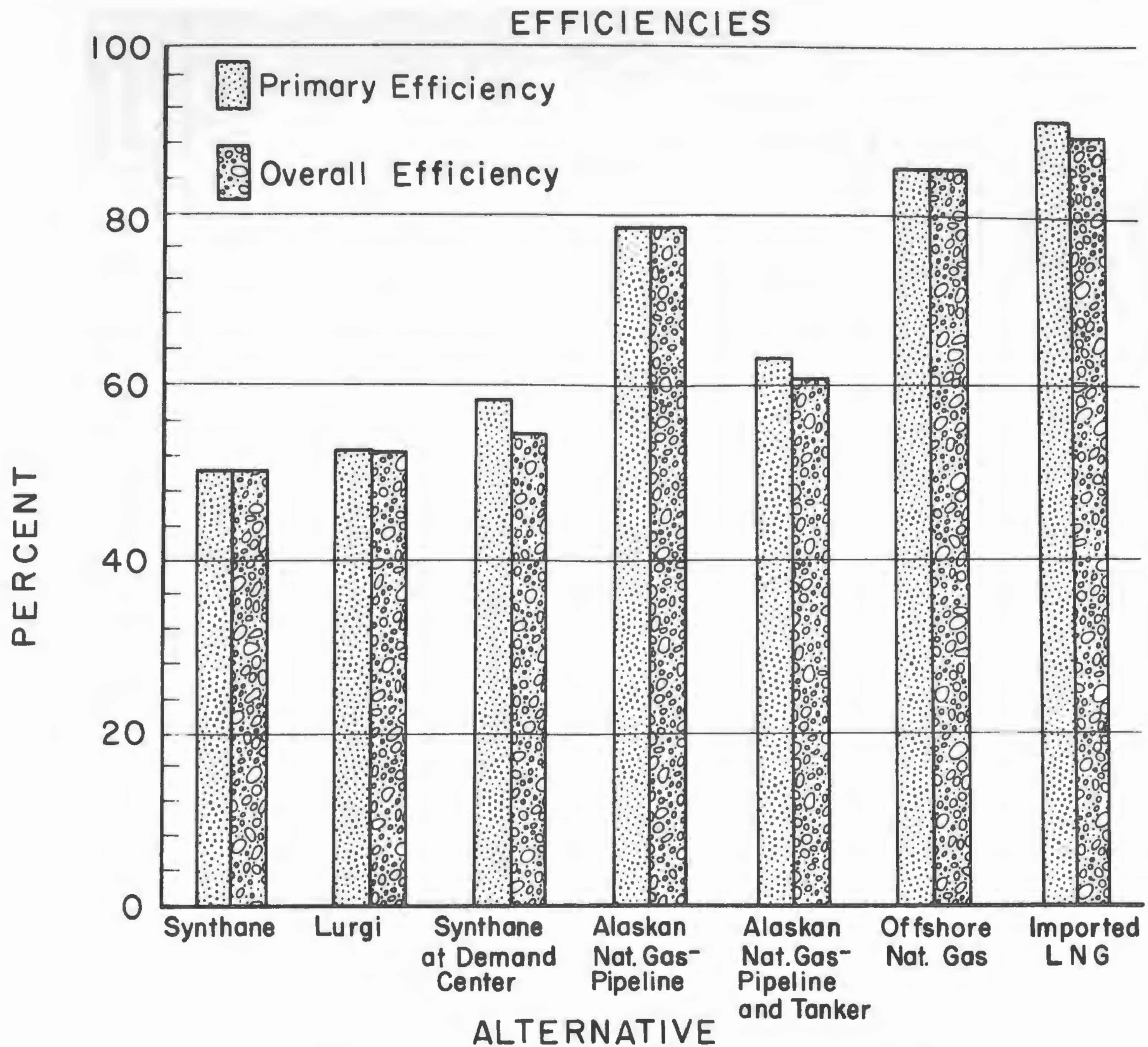


Figure 15-2. Comparison of Energy Efficiencies

TABLE 15-8

ENERGY COST OF DELIVERING 2.62×10^{12} BTU'S OF NATURAL GAS USING SEVEN ALTERNATIVE TRAJECTORIES

Trajectory	Primary Efficiency (percent)	Ancillary Energy (10^9 Btu's)	Overall Efficiency (percent)
Synthane high-Btu gasification	50.5	2.25	50.4
Lurgi high-Btu gasification	52.4	2.18	52.3
Synthane facility at demand center	58.4	31.6	54.6
Alaskan natural gas--pipeline	78.5	0	78.5
Alaskan natural gas--pipeline and LNG tanker	63.3	15.4	60.1
Offshore natural gas	85.4	0	85.4
Imported LNG	91.7	7.91	89.2

Overall efficiencies follow the same pattern as primary efficiencies, with conversion of coal to natural gas being less efficient than direct production of natural gas. The large ancillary energy requirements for the locational alternative (train transport of coal) and the Alaska-LNG tanker alternative depress the overall efficiencies of these two trajectories.

The appendix to this chapter suggests methods for using Odum's energy accounting approach to extend the analysis of energy efficiency beyond what has been discussed above. References for both the chapter and the appendix follow the appendix.

APPENDIX TO CHAPTER 15

SUGGESTIONS CONCERNING IMPACT ANALYSIS

A.1 INTRODUCTION

The ancillary energies given and compared in the preceding sections of this chapter are only those used directly in each activity. As noted earlier, this represents only part of the total subsidy to the trajectory. In the development and operation of any activity, energy is utilized in constructing the equipment, supporting the people and supply systems, providing the raw materials other than energy (such as water and catalysts), and supporting the research for its development. These are all subsidies from other fuel sectors to developing and operating the process. At present, all nonfossil fuel energy resources require fossil fuel subsidies to provide the technology, machines, and direct ancillary energy for their development. Many new forms of energy are, in effect, low-grade because we have to drill or dig deeper, go offshore, or concentrate dilute forms. Thus, there is increasing interest in evaluating these sources in terms of how much energy is required to deliver the product to the consumer.*

A.2 CATEGORIES OF EXTERNAL INPUTS

There are two principal categories of external inputs or "subsidies" in the development of an energy resource. The first includes the ancillary energy as well as material requirements. The second includes the required inputs from the natural sector which allow for resource development.

Material and capital requirements are most often measured in terms of economic costs. However, estimates of the energy values (in Btu's) of these inputs can be determined by evaluating the fuels needed for manufacturing materials and by transforming the dollar cost of items and activities into energy units.

Table A-1 gives examples of the Btu content of selected materials. (Details on the development of these types of figures can be found in Berry and Fels, 1972 and Makino and Berry, 1973.) A preliminary estimate of Btu's expended per dollar cost can be obtained by dividing total U.S. energy consumption by the Gross National Product in a given year. (The Btu-to-dollar conversion in 1973 was 68,000 Btu's per dollar and in 1958 was 93,000 Btu's per dollar [Klystra, 1974].) This value can be used when the cost item covers a spectrum of activities. For example, exploration includes personnel, equipment, information, and fuel. In addition, the Office of Energy Research and Planning of the State of Oregon has developed estimates for some specific categories of activities. These are given in Table A-2. Oregon's Office of Research and Planning recently calculated net energy for 14 energy supply trajectories (Oregon Office of Research and Planning, 1974).

When the external inputs from nature are added, the accounting of subsidies is completed. The natural systems which are

*Recall that this approach, pioneered by Howard T. Odum (1971), is currently being systematically evaluated by ERDA, NSF, and Interior.

TABLE A-1

EXAMPLES OF ENERGY CONTENT OF MATERIALS

Material	Energy Content (10^6 Btu's per ton)
Carbon steel: forged	76.0
pipe	52.6
Alloy steel: forged	78.6
pipe	55.2
Stainless steel: forged	102.1
pipe	78.7
Iron casting	25.0
Aluminum-forged	75.0
Copper-rolled	128.0
Zinc-rolled	79.2
Nickel	374.7
Lead	31.1
Paper	40.6

Source: Oregon Office of Research and Planning, 1974: 201-202.

TABLE A-2

ENERGY VALUE OF A DOLLAR IN 1973 FOR SEVERAL CATEGORIES OF MATERIALS

Material	1973[a] Btu's per dollar
General industrial machinery (16 categories including pumps, compressors, transmission lines)	49,955
Construction machinery (18 sectors including mining equipment, and oil field equipment)	43,800
Engines and turbines	40,900
Petroleum--diesel (purchases by 10 manufacturing sectors)	1,000,000
Natural gas (purchases by 10 manufacturing sectors)	1,717,000

Source: Oregon Office of Research and Planning, 1974: 203.

[a]The numbers for 1973 were updated from 1967 data. They assume that Btu consumption per unit product has remained fairly constant; thus, Btu-per-dollar changes from year to year are caused by inflation. Since the ratio changes slightly each year, this ratio should be used for 1973 dollars only.

stressed by resource development have an energy value. They are part of man's life support because they produce useful products and recycle wastes, without economic cost. Only when the biosphere is overstressed does society realize the existence of such natural services, as the recycling of sewage and the absorption and dilution of air pollutants. Nature also provides water supply systems, microclimate control, and recreational and aesthetic opportunities. Recently, society has had to funnel large amounts of money and energy into so-called "environmental technology" to help the natural system absorb residuals. Thus, the loss of parts of natural ecosystems due to the development of an energy activity is an energy cost or subsidy. This too must be subtracted from the gross energy to obtain net energy available to society over and above the expenditures and losses in free services. Examples of changed natural energy value due to energy development are: the land taken out of biological production* during strip mining, decreased production due to plant damage from air pollution, and the change in aquatic production due to wastewater disposal.

An analysis that includes all these external inputs (as represented in Figure A-1) has been called an "energy cost/benefit analysis" (Odum, 1974a). Examples of using this type of analysis for evaluating alternative energy sources are: Lem and others, 1974, "Some Considerations that Affect the Net Yield from Nuclear Power;" Ballantine, 1974, A Net Energy Analysis of Surface Mining, Electrical Power Production, and Coal Gasification; and Odum, 1974b, "Energy Cost/Benefit Approach to Evaluating Power Plant Alternatives."

A.3 AN ILLUSTRATION OF ENERGY ACCOUNTING

The technology alternative, which includes a Lurgi high-Btu gasification facility located at the strip mine in Colstrip, Montana, was chosen for this illustration. High-quality energy in the form of petroleum, electricity, and machinery is required to deliver the synthetic gas to the consumer and reclaim the land. In addition, the land produced crops and supported livestock before being disturbed. These external inputs to the trajectory are summarized in Table A-3. As indicated in that table, the energy subsidy for delivering 262 billion Btu's of energy as high-Btu gas to the customer is 28.21 billion Btu's.

The first column in Table A-3 represents the ancillary energy calculated from MERES data. For the trajectory evaluated, ancillary energy is a small portion (6.8 percent) of the total energy subsidy. The second column represents energy required in constructing facilities, manufacturing materials, and supporting the labor force required by each activity. Exploration activity includes the energy cost of exploring, testing, siting, land leasing, and initial clearing. For extraction, the value represents the energy cost of reclamation (estimated at $10,000 per acre) and of constructing the equipment for large strip mining operations (see Table A-1 for examples of energy cost of material construction). Cleaning and gasification values represent construction materials, materials hauling, maintenance energy, and water pumping. The value for pipeline distribution includes the energy equivalent of pipeline materials (see Table A-1) and pipeline construction energy. The pipeline construction energy for a 1,000-mile pipeline has been estimated at 8.4×10^{12} Btu's. However, since this pipe would carry considerably more than the gas produced by this trajectory, the value was scaled linearly to this size operation.

The third column represents the losses in natural photosynthetic energy caused by land disruption. The number of acres disrupted to supply the daily trajectory requirement of 262×10^{9} Btu's was calculated.

*The rate at which solar energy is stored by the photosynthetic activity of plants.

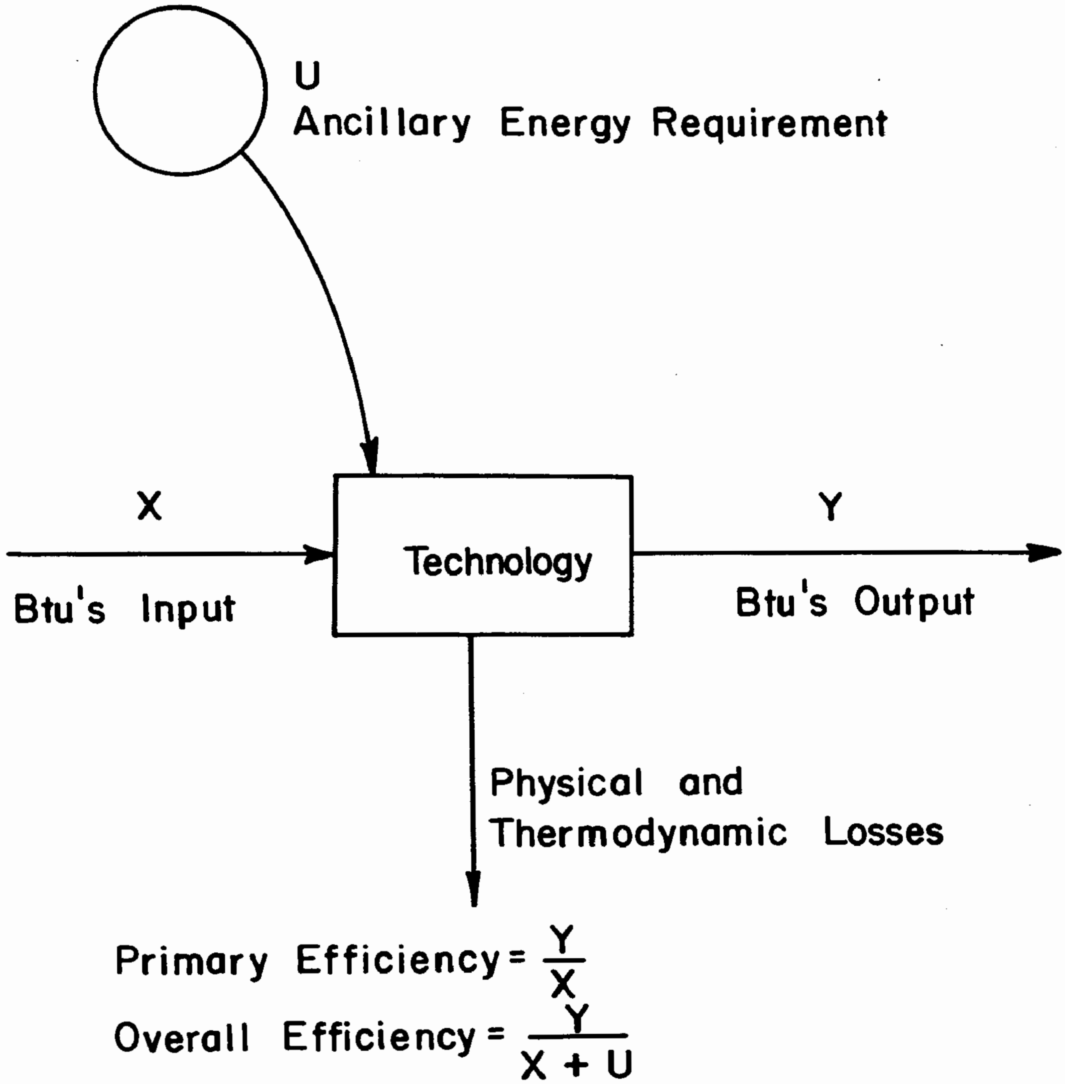


Figure A-1. Dependence of Energy Development on External Inputs and Evaluation of Net Energy

TABLE A-3

EXTERNAL INPUTS TO LURGI HIGH-BTU GASIFICATION[a]
(10^9 Btu's)

Activity	Ancillary Energy	Energy Value of Construction and Materials[b]	Energy Value of Natural Sector
Exploration	0	0.14	0
Extraction (includes reclamation)	0.99	16.74	0.02
Mine transportation	0.10	0.14	0
Breaking and sizing	1.09	0.94	0.05
Gasification--Lurgi	0	4.01	0.55
Gathering pipeline	0	0	0
Distribution pipeline	0	3.77	0
TOTAL	2.18	25.74	0.62

[a]The trajectory energy outflow is 262.0×10^9 Btu's.

[b]Calculated from: Oregon Office of Research and Planning, 1974. The original data were expressed in dollars.

In addition, there are losses in natural production due to the acreage requirement of the facilities: 35 acres for a breaking and sizing plant and loading facility and 515 acres for the gasification facility including storage, preparation, gasifier, and evaporation ponds to handle wastewater streams (Hittman 1975: Vol. II, p. IV-27).

The energy subsidy to the trajectory due to lost photosynthetic productivity was calculated as follows: the gross primary productivity* of this Montana grasslands (approximately two grams per square meter per day) was multiplied by the number of acres disrupted** and converted to the same energy quality as coal (20 Btu's sugar per Btu coal). The assumption was that this productivity would be lost completely for 10 years. In reality, there would be no productivity for several years (until the plants reestablished themselves), and a much longer period than 10 years would be required for the grasslands to reach their original level of productivity.

The total of the three columns in Table A-3 is 28.6×10^9 Btu's. This is 11 percent of the energy delivered to the consumer. In this hypothetical case then, the trajectory yields nine times as much energy as it consumes (its net energy). However, the values in this calculation are not precise; several calculations are estimates. For example, the conversion from dollars to Btu's is approximate and several effects within the natural sector have not been accounted for. These include the effect on other water users (man and nature) of elimination of aquifers within the coal beds and the effect, if any, on crops and natural vegetation due to air emissions.

*Gross primary productivity is a measure of the amount of sunlight caught and concentrated by plants.

**For the hypothetical Colstrip mine with a 25-foot seam thickness, there are 43,000 tons extracted per acre of coal.

REFERENCES

Ballantine, T. (1974) A Net Energy Analysis of Surface Mining, Electrical Power Production, and Coal Gasification. AEC Research Proposal, Environmental Engineering Sciences, University of Florida, Gainesville.

Bayley, S. (1973) Energy Evaluation of Water Management Alternatives in the Upper St. Johns River Basin of Florida. Report of EPA Water Program, Region IV Office, Atlanta, Georgia.

Berry, S. and M. Fels (1972) The Production and Consumption of Automobiles. Illinois Institute for Environmental Quality.

Boynton, W.R. (1974) "Regional Modeling and Energy Cost-Benefit Calculations Regarding Proposed U.S. Army Corps of Engineers Dam on the Appalachicola River at Blountstown, Florida," in C. Hall and J. Day (eds.) Models as Ecological Tools: Theory and Case Histories. (In press).

Brookhaven National Laboratory, Associated Universities, Inc., Energy/Environment Data Group (1975) Energy Model Data Base User Manual, BNL 19200.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc. (NTIS numbers: Vol. I, PB-238 784; Vol. II, PB-239 158).

Klystra, C.D. (1974) "Energy Analysis as a Common Basis for Optimally Combining Man's Activities and Nature." Presented to the National Symposium on Corporate Social Policy, Chicago, Illinois.

Lem, P.N., H.T. Odum, and W.E. Bolch (1974) "Some Considerations that Affect the Net Yield from Nuclear Power." Paper presented at Health Physics Society 19th Annual Meeting, Houston, Texas.

Makino, H. and S. Berry (1973) Consumer Goods: A Thermodynamic Analysis of Packaging, Transport, and Storage. Illinois Institute for Environmental Quality.

Odum, H.T. (1971) Environment, Power, and Society. Wiley-Interscience.

Odum, H.T. (1973) The Role of the Power Plants at Crystal River in the Coastal System of Florida. Florida Power Corporation.

Odum, H.T. (1974a) "Energy, Value, and Money," in C. Hall and J. Day (eds.) Models as Ecological Tools: Theory and Case Histories. (In press).

Odum, H.T. (1974b) "Energy Cost Benefit Approach to Evaluating Power Plant Alternatives." Environmental Engineering Sciences and Center for Wetlands, University of Florida, Gainesville.

Oregon Office of Energy Research and Planning (1974) Energy Study: Interim Report. Salem, Ore.: State of Oregon.

Slesser, M. (1974) "Energy Analysis in Technology Assessment." Technology Assessment 2: 201-208.

CHAPTER 16

COMPARING THE ECONOMIC COSTS OF ENERGY ALTERNATIVES

16.1 INTRODUCTION

As noted in the Part II Introduction, the Matrix of Environmental Residuals for Energy Systems (MERES) data bank presently contains data on coal, crude oil, natural gas, and oil shale.* The University of Oklahoma resource descriptions also contain data on these energy sources and on geothermal, hydroelectric, nuclear fission, nuclear fusion, organic wastes, solar, tar sands, electric power generation, and energy consumption.

Economic data in the OU resource systems descriptions are limited to publicly available information on fixed, operating, and total costs** (estimated for a trillion Btu's [10^{12} Btu's] of energy input***). MERES also contains these types of data plus such additional information as fixed investments and labor and maintenance costs. Except for electric energy costs (which are generally estimated for plants producing 1,000 megawatts-electric [Mwe]), cost estimates in the OU descriptions are based on trillions (10^{12}) of Btu's of energy inputs. Additional information on fixed investment, labor costs, etc. are included in the "Economic Considerations" section of each OU resource system description.

The user should be aware of certain limitations and cautions when using both data bases, including:

1. Annual fixed costs per Btu of energy are considered to be constant over the entire lifetime of an activity.* For example, in evaluating a high-Btu gasification facility, fixed costs are assumed to be the same for the first and last year during which the facility is to be operated. In practice, fixed costs may change considerably from year to year. Fixed costs are calculated as follows:

$$\text{Fixed Cost per Btu} = \frac{(\text{Fixed Investment})\times(\text{Fixed Charge Rate})^{**}}{(\text{Btu's of input energy})}$$

2. By-products have been treated as a cost credit rather than as a source of revenue; that is, revenue obtained from the sale of by-products has been used to offset costs rather than to augment revenue.
3. Plant output is assumed to be 90 percent of rated capacity.

---

*Data on other resources will be added soon.

**Fixed costs are those that continue at set levels regardless of the level of production; for example, interest on debt, repayment of debt, insurance payments, and property taxes. Operating costs vary with level of production; for example, labor and materials costs.

***It is more conventional to base costs on output. Output costs can be obtained by dividing the cost per unit of input by the primary efficiency of the activity.

*Note that cost data are discussed on an annual basis. Both residuals (Chapter 14) and energy efficiency data (Chapter 15) were considered on a daily basis.

**MERES data are based on a fixed charge rate of 10 percent and, in most cases, a 25-year life on capital equipment. The fixed charge rate is defined as interest plus depreciation plus yearly recurring costs such as insurance, property taxes, and interim replacements of short-lived equipment.

4. Cost estimates for each activity are based on a specified scale of operations. As a consequence, linear extrapolations should be treated with caution.
5. Transportation costs are generally based on a fuel of a given Btu content and a given haulage distance (usually the national average for each transportation mode). Since freight rates for energy products are usually based on tonnage and miles, they cannot be accurately scaled up or down on a per-Btu basis. As a consequence, Btu and distance adjustments will generally be required.
6. Transportation costs for natural gas combine both transmission and distribution.*
7. The cost estimates for activities beyond extraction do not include the cost of energy used as a raw material. For example, the cost of coal gasification in the MERES data bank does not include the value of the coal that is gasified.
8. Cost estimates generally assume ideal circumstances such as the absence of construction delays, work stoppages, technical problems with new technologies, etc.
9. Cost data are static, for a single year (1972), and already seriously out of date.
10. The cost estimates generally do not include the cost of working capital requirements; that is, the cost of the firm's investment in short-term assets such as cash, short-term securities, accounts receivable, and inventories.

As with both residuals and energy efficiencies, procedures for gaining access to MERES economic data are described in Brookhaven's User Manual (1975). OU economic data are reported in an "Economic Considerations" section following the description of each technological activity.

This chapter demonstrates the use of these cost data in calculating and comparing energy alternatives, explains ways to modify the data to improve analytical quality, and suggests methods for extending the level of analysis to include an assessment of economic impacts.

*Separating these costs is frequently useful. Distribution costs are 46 percent of fixed costs, 60 percent of operating costs, and 50 percent of the total.

16.2 GENERAL PROCEDURES FOR OBTAINING AND USING THE COST DATA

Direct, unaugmented use of economic data in MERES and the OU descriptions is limited to a relatively simple, static cost analysis. The general procedures listed below and the cost calculations contained in the next section illustrate this type of analysis, which should be regarded as only a first step in the economic analysis of energy alternatives.

The general procedures for calculating and comparing the costs of energy alternatives are:

1. Identify, describe and calculate costs for the process, activity, partial trajectory, or trajectory to be evaluated and compared.
   a. Identify the alternative activities and/or processes to be evaluated and compared by referring to Figure 1 in the appropriate OU resource systems descriptions. (At this point, some alternatives may be obviously unfeasible. For example, some coal gasification processes are designed to be used only with certain kinds of coal.)
   b. Access MERES data by means of the computer programs described in Brookhaven's User Manual (1975). This will provide a printout of the costs for each process, activity, partial trajectory, or trajectory for which a request is entered.* Costs will be calculated for the size of operation specified in the request. (For example, if high-Btu coal gasification processes are to be compared, costs can be based on either the energy value of the input coal or the output gas; that is, if the HYGAS total costs are \$258,000 per 10^{12} Btu's of coal input, then total costs will be \$100,620.

*Costs for transportation activities will generally require a distance adjustment and in some cases a Btu adjustment. The user must compute this adjustment and enter the new cost figures per 10^{12} Btu's before continuing the analysis.

for a facility producing 250 million cubic feet [mmcf] of gas daily.*)

c. To obtain supplemental cost data included in the OU descriptions, information on the assumptions made concerning the data, and descriptions of qualitative costs, read the "Economic Considerations" sections that follow the process descriptions for each activity in the OU resource systems descriptions. As when using MERES, the size of operations to be compared should be specified.

d. If the costs for each process, activity, partial trajectory, or trajectory have not been summed, sum them and list all quantitative and qualitative costs. Note that all of the activities in a trajectory must be balanced in terms of operational size before summing.

2. Make the desired comparisons. These can include:

a. A comparison of fixed costs, operating costs, and/or total costs.

b. A comparison of costs for complete trajectories or for any part of a trajectory.

c. A feasibility comparison of the proposed action and alternative sources. In this comparison, the feasible options can be determined by referring to the OU descriptions or by specifying criteria for determining feasibility; for example, economic costs, a fixed level of air or water pollutants, etc. Those source alternatives determined to be feasible can then be compared with the technological and locational alternatives on the basis of a fixed amount or a fixed reference point such as input or output energy or total costs. However, evaluators should be alert to possible effects of scale, to possible cost changes through time, and to possible synergistic effects, particularly external economies or diseconomies. All these cautions are discussed in Section 16.3

A summary of the procedures for comparing the economic costs of energy alternatives is given in Exhibit 16-1. As discussed in this section, the procedures in Exhibit 16-1 can be used to calculate economic costs for a variety of alternatives, including other technologies, locations and sources, and fuels.

16.3 A DEMONSTRATION OF HOW TO COMPARE THE ECONOMIC COSTS OF ENERGY ALTERNATIVES

This section demonstrates economic cost calculations using the general procedures described in Section 16.2. Total costs for each of the seven trajectories described in Chapter 14 are listed in Tables 16-1 through 16-7. All the cost figures in these tables are based on MERES data except for the coal mining activities (extraction, mine trucking, and breaking and sizing) which were obtained from Chapter 1 of the OU resource descriptions.

Each of the trajectories assumes controlled environmental conditions and the delivery of 95.7 trillion (95.7×10^{12}) Btu's per year of pipeline quality gas to the Seattle market. All the cost figures include the normal linear magnitude or scale adjustment.* Natural gas pipeline transmission and distribution costs have been separated because several of the trajectories do not require any pipeline transmission.

*The production of 250 mmcf of gas daily requires 3.9×10^{11} Btu's of coal input when the efficiency of the process is considered. Total costs may then be calculated as:

$$\frac{3.9 \times 10^{11}}{1 \times 10^{12}} \times \$258{,}000 = \$100{,}620$$

*As stated in Section 16.3, each of the activities is assumed to have been organized into identical operations, all having the scale assumed in the MERES or OU cost estimates. Note that natural gas liquids (NGL) separation and hydrogen sulfide (H_2S) removal have been assumed to be unnecessary for any of the trajectories.

EXHIBIT 16-1

SUMMARY PROCEDURES FOR COMPARING
THE ECONOMIC COSTS OF ENERGY ALTERNATIVES

STEP I	IDENTIFY, DESCRIBE, AND CALCULATE ECONOMIC COSTS Identify the alternatives to be evaluated by referring to the technologies flow charts in the OU descriptions. Obtain economic cost data from MERES. Supplement with additional quantitative and qualitative economic cost data from the OU descriptions. Summarize the economic cost data for each alternative.
STEP II	COMPARE FIXED COSTS, OPERATING COSTS, AND/OR TOTAL COSTS FOR EITHER PARTIAL OR COMPLETE TRAJECTORIES FOR EACH ALTERNATIVE
STEP III	DECIDE WHICH ALTERNATIVES ARE FEASIBLE AND WARRANT FURTHER ATTENTION

TABLE 16-1

THE PROPOSED ACTION: SYNTHANE HIGH-BTU GASIFICATION[a]

Activity	Fixed Cost (millions of dollars per year)	Operating Cost (millions of dollars per year)	Total Cost (millions of dollars per year)
Extraction (strip mining, <15° slope, Powder River Basin, Mountain); Mine transportation (trucking); Processing (breaking and sizing)	3.03	15.50	18.53
High-Btu gasification (mine mouth, Synthane process)	31.80	18.70	50.50
Gathering (pipeline)	2.54	0.71	3.25
Transmission (pipeline)	9.02	2.36	11.41
Distribution (pipeline)	7.68	3.77	11.41
TOTAL	54.0	41.1	95.1

[a]Based on 1972 cost data.

TABLE 16-2

COSTS OF A TECHNOLOGICAL ALTERNATIVE: LURGI HIGH-BTU GASIFICATION[a]

Activity	Fixed Cost (millions of dollars per year)	Operating Cost (millions of dollars per year)	Total Cost (millions of dollars per year)
Extraction (strip mining, <15° slope, Powder River Basin, Mountain); Mine transportation (trucking); Processing (breaking and sizing)	2.93	15.00	17.93
High-Btu gasification (mine mouth, Lurgi process)	43.10	18.60	61.70
Gathering (pipeline)	2.54	0.71	3.25
Transmission (pipeline)	9.02	2.36	11.41
Distribution (pipeline)	7.68	3.77	11.41
TOTAL	65.2	40.4	105.6

[a]Based on 1972 cost data.

TABLE 16-3

COSTS OF A LOCATIONAL ALTERNATIVE:
SYNTHANE FACILITY MOVED TO DEMAND CENTER[a]

Activity	Fixed Cost (millions of dollars per year)	Operating Cost (millions of dollars per year)	Total Cost (millions of dollars per year)
Extraction (strip mining, <15° slope, Powder River Basin, Mountain); Mine transportation (trucking); Processing (breaking and sizing)	2.63	13.40	16.03
Unit train transportation to Synthane plant	3.79	58.50	62.30
High-Btu gasification (Synthane process, Seattle area)	27.50	16.20	43.80
Gathering (pipeline)	2.28	0.64	2.92
Distribution (pipeline)	7.68	3.77	11.41
TOTAL	43.9	92.5	136.4

[a]Based on 1972 cost data.

TABLE 16-4

COSTS OF A SOURCE ALTERNATIVE:
ALASKAN NATURAL GAS VIA CANADIAN PIPELINE[a]

Activity	Fixed Cost (millions of dollars per year)	Operating Cost (millions of dollars per year)	Total Cost (millions of dollars per year)
Extraction (on-shore)	18.70	1.83	20.53
Gathering (pipeline)	2.80	0.78	3.58
Transmission (pipeline)	65.80	23.40	89.20
Distribution (pipeline)	7.68	3.77	11.41
TOTAL	95.0	29.8	124.8

[a]Based on 1972 cost data.

TABLE 16-5

COSTS OF A SOURCE ALTERNATIVE:
ALASKAN NATURAL GAS VIA ALASKAN PIPELINE AND LNG TANKER[a]

Activity	Fixed Cost (millions of dollars per year)	Operating Cost (millions of dollars per year)	Total Cost (millions of dollars per year)
Extraction (on-shore)	23.10	2.27	25.40
Gathering (pipeline)	3.40	0.97	4.45
Transmission/Distribution (pipeline)	22.80	8.39	31.20
Processing (LNG liquefaction)	13.50	11.60	25.20
Transmission/Distribution (LNG tanker)	12.40	5.48	17.80
Storage (LNG tank in Seattle area)	1.56	0.89	2.44
Conversion (LNG vaporization)	0.11	1.56	1.67
Distribution (pipeline)	7.68	3.77	11.41
TOTAL	84.6	34.9	119.5

[a]Based on 1972 cost data.

TABLE 16-6

COSTS OF A SOURCE ALTERNATIVE: OFFSHORE NATURAL GAS[a]

Activity	Fixed Cost (millions of dollars per year)	Operating Cost (millions of dollars per year)	Total Cost (millions of dollars per year)
Extraction (offshore)	8.14	10.60	18.70
Gathering (pipeline)	10.30	2.87	13.17
Transmission (pipeline)	9.02	2.36	11.41
Distribution (pipeline)	7.68	3.77	11.41
TOTAL	35.1	19.6	54.7

[a]Based on 1972 cost data.

TABLE 16-7

COSTS OF A SOURCE ALTERNATIVE: IMPORTED LNG[a]

Activity	Fixed Cost (millions of dollars per year)	Operating Cost (millions of dollars per year)	Total Cost (millions of dollars per year)
Transmission/Distribution (LNG tanker in U.S. coastal waters)	11.90	5.26	17.10
Storage (LNG tank in Seattle area)	1.56	0.89	2.44
Conversion (LNG vaporization)	0.11	1.56	1.67
Distribution (pipeline)	7.68	3.77	11.41
Subtotal	21.2	11.4	32.6
Purchase price (104×10^{12} Btu's per year at \$1.25 per 10^9 Btu's on long-term contract)	0.0	130.0	130.0
TOTAL	21.2	143.9	165.1

[a]Based on 1972 cost data.

16.3.1 The Hypothetical Proposed Major Federal Action

The trajectory of the hypothetical proposed major federal action begins with a strip mine located in the Powder River Basin of Montana. Data for the coal mine activities were obtained from the OU descriptions because MERES does not now include cost data for a particular Northwest coal mine. The mining cost estimates shown in Table 16-1 are based on a strip mine scale of five million tons per year and a 10-percent fixed charge rate.* (The 10-percent rate was used for the OU data because this rate was used for all MERES cost estimates.) A Synthane gasification plant is located at the mine mouth, and plant cost estimates assume that all the solid wastes are returned to the mine for disposal.

*The costs of extraction, mine transportation, and processing have been combined in Tables 16-1 and 16-2 because the OU descriptions do not show the costs for each of these activities separately.

Transmission and distribution costs have been separated, as explained in Section 16.1 above, to facilitate comparisons with other trajectories. Since distance adjustments cannot be made for pipeline costs,* the estimates for transmission and distribution activities are probably only rough indicators of these costs. Total estimated costs for this trajectory are \$95.1 million, 57 percent of which are fixed costs.

16.3.2 A Technological Alternative

When Synthane is replaced with Lurgi, the cost estimates for the mining activities are lower because the primary efficiency of the Lurgi process (60.5 percent) is slightly higher than that of the Synthane process (58.4 percent). Thus, a smaller coal input is required. The Lurgi gasification plant is located at the mine mouth, and its solid

*Distance and Btu adjustments are explained in Section 16.5.2.

wastes are returned to the mine for disposal. Pipeline costs (for gathering, transmission, and distribution) are identical to those of the hypothetical proposed major federal action. Total estimated costs using Lurgi are $105.6 million, 62 percent of which are fixed costs.

16.3.3 A Locational Alternative

Cost estimates for mining activities (Table 16-3) are slightly different when the Synthane facility is moved to the Pacific Northwest because of slight differences in efficiency over each trajectory. By locating the Synthane gasification plant in the Seattle area instead of at the mine mouth, the coal must be transported 1,000 miles by unit train, an additional activity. The unit train transportation costs include adjustments for both distance and the Btu content of the coal (8,800 Btu's per pound).*

Since the gasification plant is not located at the mine mouth, the assumption that its solid wastes are returned to the mine for disposal cannot be met and no costs for an alternate disposal method have been included. (This type of simplification should be avoided in actual use because disposing of solid wastes would be an additional operating cost.) Locating the Synthane plant in the Seattle area also obviates any need for pipeline transmission; thus, only the costs for gathering and distribution activities are included. Total estimated costs for this trajectory are $136.4 million, 32 percent of which are fixed costs.

*The unit train cost estimates in the MERES assumed that 12,000-Btu's-per-pound coal was hauled 300 miles. The cost per Btu for hauling 8,800-Btu's-per-pound-coal 1,000 miles is 4.52 times the MERES estimates:

$$\frac{12,000}{8,800} \times \frac{1,000}{300} = 4.52.$$

16.3.4 Source Alternatives

The costs for delivering Alaskan natural gas via a trans-Canadian pipeline are shown in Table 16-4.* Total estimated costs for this trajectory are $124.8 million, 76 percent of which are fixed costs.

Alaskan natural gas could also be routed by pipeline to Valdez and from there to the U.S. west coast by tanker. Estimated costs for this trajectory are presented in Table 16-5. The primary efficiency of this trajectory is lower than that for the Canadian pipeline alternative, and, as a consequence, costs are slightly higher. Pipeline transmission is via an Alaskan pipeline to Valdez. (Again, the scale of this trajectory alone would not justify building such a pipeline.) Transportation of the gas from Valdez to Seattle is via LNG tanker. Storage and conversion are necessary in the Seattle area (LNG is to be revaporized there), but there is no need for pipeline transmission within the continental U.S. Total estimated costs for this trajectory are $119.5 million, 71 percent of which are fixed costs.

Another alternative source of natural gas is increased production offshore. Gathering, transmission, and distribution costs have been separated in Table 16-6, but, since no distance adjustments can be made for pipeline transportation, these estimates should only be regarded as rough estimates.** Total estimated costs for this trajectory are $54.7 million, 64 percent of which are fixed costs.

*Cost data include exploration and leasing, but it is not clear whether the costs of dry-holes are included. The scale of this trajectory is insufficient to justify the construction of a trans-Canadian pipeline; thus, an existing pipeline must be assumed if this alternative is to be feasible.

**See Section 16.5.2 for an explanation of distance adjustments.

A final source alternative is to import LNG produced overseas. The trajectory for this alternative does not include an extraction activity; therefore, some resource cost or purchase price for the imported LNG has to be introduced. Since many long-term contracts for Russian and Algerian gas have involved prices of approximately \$1.25 per 10^6 Btu's, this figure was used. No escalation of the contract price was considered in this analysis, and all purchase costs are assumed to be operating costs.

Since the LNG is stored and vaporized in the Seattle area, no pipeline transmission is required. Total estimated costs for this trajectory are \$162.6 million, 13 percent of which are fixed costs.

16.4 A COMPARISON OF THE ECONOMIC COSTS OF ENERGY ALTERNATIVES

As cited in Section 16.3, the trajectories for the hypothetical proposed action and the six alternatives provide for the delivery of 95.7×10^{12} Btu's per year (2.62×10^{11} Btu's or 250 mmcf per day) of pipeline quality gas to the Seattle market. Total estimated costs for each trajectory are listed in Table 16-8 and charted in Figure 16-1. Based on these figures, offshore continental U.S. production is the least costly, coal gasification at the mine mouth ranks second, Alaskan gas is third, and the total cost of coal gasification in the Seattle area is exceeded only by the cost of importing LNG. Except for the two highest cost trajectories, fixed costs increase as total costs increase. Operating costs are roughly comparable for the first five trajectories but are markedly higher for the two highest cost trajectories.

Section 16.1 noted that these cost estimates are static and that they represent, at best, costs in only the initial years of the economic life of a trajectory. Changes in costs through time are not included in these estimates, but the sensitivity of a trajectory to cost changes can be assessed by assuming that significant changes will occur only in operating costs. Using this assumption, the ratio of fixed to total costs in Table 16-8 indicates the percentage of a trajectory's cost structure that would not be exposed to rising costs through time. The first five trajectories in the ranking have at least 57 percent of their cost structure unexposed to rising costs while the last two are heavily exposed.* In addition, qualitative cost considerations indicate that imported LNG has additional exposure to rising costs because of the risk that energy exporting countries will raise LNG prices through time regardless of contractual obligations.

Other qualitative cost considerations include balance of payments and foreign trade effects. Imported LNG rates particularly low on this criterion because of adverse balance of payment effects, the exporting of jobs overseas, and the risks associated with cutoff of LNG imports and dollar devaluations. The trajectory routing Alaskan natural gas via Canadian pipeline also has these problems although to a lesser degree than does the imported LNG trajectory. The remaining five trajectories have none of these effects.

The trajectories substituting Lurgi for Synthane, moving the liquefication facility to the demand center, and the hypothetical proposed action are the only trajectories for which the final price to the consumer would not be determined primarily by the Federal Power Commission (FPC). Current FPC policy is not to regulate the price of synthetic gas until it enters a pipeline under FPC jurisdiction, but both

*The fixed costs for gasification in the Pacific Northwest are probably understated because the fixed costs for unit trains are estimated in the MERES data as six percent of total operating costs (based on the fact that depreciation amounts to six percent of total operating expenses for rail freight service).

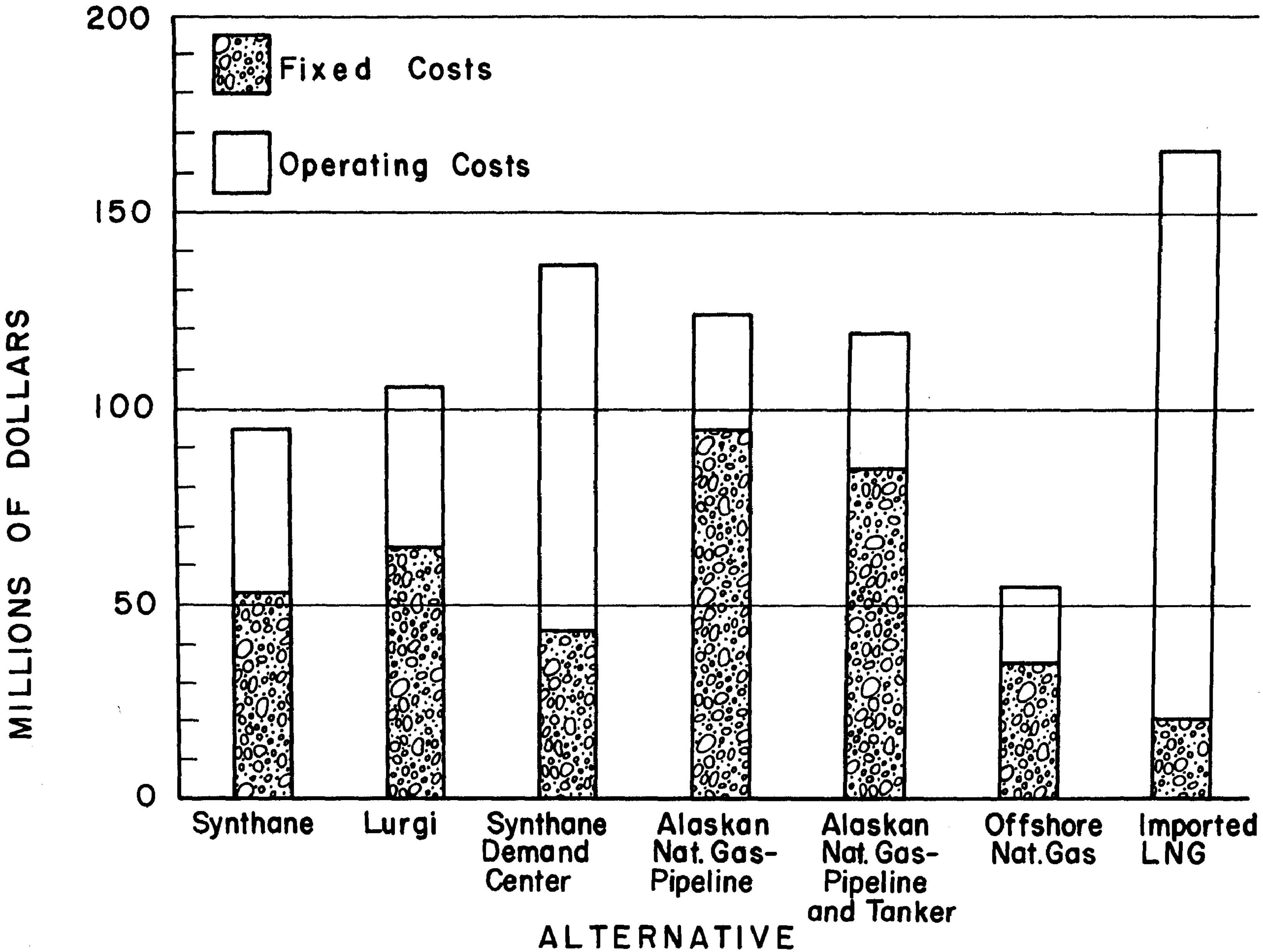


Figure 16-1. Fixed and Operating Costs by Alternative

TABLE 16-8

TRAJECTORIES RANKED BY TOTAL COSTS[a]

Trajectory	Total Costs (millions of dollars per year)	Fixed Costs (percent of total costs per year)	Fixed Costs (millions of dollars per year)	Operating Costs (millions of dollars per year)
Offshore Natural gas	54.7	64	35.1	19.6
Synthane high-Btu gasification	95.1	57	54.0	41.1
Lurgi high-Btu gasification	105.6	62	65.2	40.4
Alaskan natural gas-pipeline and LNG tanker	119.5	71	84.6	34.9
Alaskan natural gas-pipeline	124.8	76	95.0	29.8
Synthane facility at demand center	136.4	32	43.9	92.5
Imported LNG	162.6	13	21.2	141.4

[a]Based on 1972 cost data.

the proposed action and the trajectory which substitutes the Lurgi process could fall under increased FPC control if this policy is altered. Moving the Synthane facility to the demand center involves intrastate sale of gas; thus, there is less risk of increased FPC price regulation. However, this reduction in risk is obtained by a $41-million increase in total cost over the hypothetical proposed action, primarily because of the high cost of unit train transportation.

16.5 EVALUATION OF ECONOMIC COSTS: SUGGESTED IMPROVEMENTS

The cost estimates presented above represent costs as of 1972 and reflect the technological, scale, economic, and legal assumptions that underlie them. The user might well wish to update the cost estimates so that they more closely reflect current conditions. The user might also find it either necessary or desirable to make assumptions that conflict with the assumptions built into the MERES data base. And, most importantly, the user may wish to shift from a completely static to a more dynamic framework of analysis. Each of these adjustments for improving the evaluation of economic costs is discussed below.

16.5.1 Updating the Cost Data

Several types of updating adjustments might be considered by the user, including adjustments for changes in scale, improvements in technology, and alternatives in the legal environment, particularly in the area of environmental legislation. However, the most pressing reasons for updating will probably result from changes in costs, by-product credits, or both. For example, unit train rates have nearly doubled since 1972.

Since cost indexes will undoubtedly be one of the tools used for such adjustments, the user should be aware that these indexes do not adequately account for technological changes and substitution possibilities. Thus, the indexes are most accurate when the time interval considered is short and the magnitude of the cost change is small. The Survey of Current Business (published monthly by the U.S. Department of Commerce) is a good source for cost indexes.

16.5.2 Conflicting Assumptions

In practice, the user will frequently need to make assumptions that conflict with those made for the data included in MERES and the OU descriptions. Several examples of this occurred in the analysis of the seven trajectories listed in Table 16-8. Perhaps the best example of this type of assumption is the need to adjust transportation costs for distance and Btu factors.

As noted in Section 16.1, freight rates for energy products are generally based on tonnage and miles; thus, the data base costs cannot be merely scaled up or down as the size of the activity (in terms of Btu's) changes. First, a new cost figure per 10^{12} Btu's must be calculated for the particular Btu content of the fuel and for the haulage distance being considered. This cost figure is then adjusted up or down as the scale of the activity (in terms of Btu's) changes. For example, in the analysis of the trajectory locating the Synthane plant in the Seattle area (section 16.3), the coal had a Btu content of 8,800 Btu's per pound and was to be hauled 1,000 miles. The fixed, operating, and total cost figures for unit train distribution were all increased by a factor of 4.52 to adjust for these changes (note that these are the costs per 10^{12} Btu's). Distribution of coal by mine train, river barge, slurry pipeline, truck, or conveyor would all require similar cost adjustments.

Similar problems will also be encountered in natural gas and oil transmission/distribution; however, in most cases a distance adjustment cannot be made because no distance information is provided in the MERES data. In particular, no distance adjustment can be made for either crude oil or petroleum product transportation by pipeline, tanker, supertanker, or tank truck. For similar reasons, distance adjustments cannot be made for natural gas transportation by either pipeline or tanker or for either crude oil or natural gas gathering pipeline. Although Btu adjustments can be made, they will usually be unnecessary unless, for example, low-Btu gas (below pipeline quality) is introduced into a pipeline.

16.5.3 Shifting from a Static to a Dynamic Framework of Analysis

As mentioned earlier, cost estimates in the data bases are static and likely only to represent costs during the initial years of the economic life of an activity. The need to reflect dynamic conditions goes beyond simply allowing for the time value of money* and requires that the user consider likely cost changes through time, including those resulting from continued expansion or changes in the industry under study, expansion or changes in either the industries supplying or competing for the resource, or changes in the general economic or legal environment in which the industry operates. Although difficult, this type of analysis is most useful.

16.5.4 Cost Effectiveness Analysis

The absence of any price-, value-, or demand-oriented information for the seven trajectories given in Table 16-8, can be circumvented by a cost effectiveness analysis which compares the costs of trajectories with identical physical end points. For example, all the trajectories resulted in the delivery of 95.7×10^{12} Btu's of pipeline

---

*The time value of money recognizes the fact that $1.00 to be received in the future has less value than $1.00 received today because an amount less than $1.00 could always be invested now and allowed to grow to $1.00 in the future. This concept should not be confused with inflationary or deflationary effects on the purchasing power of the dollar.

quality gas to the Seattle market. Thus, an argument could be made that a cost effectiveness analysis would be appropriate and that the cost analyses illustrated above are a sufficient basis of comparison for these trajectories. However, this type of analysis would be misleading because the economic ramifications of each trajectory are markedly different, particularly with respect to final consumer price but also in terms of balance of payment effects, government tax revenues, impacts on input markets, and local or regional economic impacts. These factors severely limit economic analyses based exclusively on cost data.

16.6 SUGGESTIONS FOR ECONOMIC IMPACT ANALYSIS

Section 16.5.4 suggested that the economic impacts of an action are not effectively measured by trajectory costs alone. In fact, several types of economic impacts should be analyzed, including effects on: input markets; final consumer prices or output markets; local, regional, national, and international (balance of payments) economies; and tax revenues at all levels of government.

The diversity of these potential effects makes a single starting point for the impact analyses desirable. A net present value (NPV) analysis can serve this purpose. However, since an NPV analysis will generally require an evaluation of energy demand factors, the reasons why market prices often deviate from production costs, causing profits to expand or contract, are discussed before the NPV analysis is explained.

16.6.1 Production Costs and Market Prices

Although, by definition, total unit cost plus profit per unit equals market price, profit margins (profit as a percentage of unit price) are not constant across industries, products, or even time. Profit margins vary as a result of at least three factors.

First, profit margins are not the same as actual profits in economic terms. Economic theory has always held that under conditions of workable competition (particularly free exit and entry of competitors into industries) profits across industries would tend to equalize (allowing for differences in risk and assuming that no unexpected events occur). However, this theory applies only to return on investment, not to profit margins among industries.* In fact, there is no tendency for profit margins to equalize across industries because of differences in fixed and operating costs. High fixed cost industries tend to have a low ratio of sales to total investment while the opposite is true for industries that have low fixed costs. For example, grocery stores with an annual sales-to-total investment ratio of 12 can survive on a profit margin as low as one percent because the product of the two is a 12-percent return on total investment before taxes. On the other hand, the electric power industry has an annual sales-to-total investment ratio of one-third; thus, its profit margin of 36 percent (of sales) is necessary if it is to earn a 12-percent return on investment before taxes. The point is that profit margins may be somewhat similar within industries, particularly for firms with similar cost structures, but they will differ among industries.

A second factor is the occurrence of unexpected events that, at least temporarily, can disrupt any tendency for return on investment to equalize. Unexpected events can lead to lower than normal profits (or even losses) or to higher than normal profits and thus magnify existing differences in profit margins. For example, the

*The discussion in this section assumes that firms have no debt and, therefore, that returns on equity and total investment are identical. This restriction on a firm's capital structure simplifies the analysis and can be relaxed without affecting the results.

TABLE 16-9

CHARACTERISTICS OF VARIOUS MARKET STRUCTURES

Type of Market	Characteristics			
	Number of Competitors	Barriers to Entry	Nature of Product	Control Over Price
Competitive	very large	none	homogeneous	none
Monopolistic competition	many	minor	some differentiation	minor
Oligopoly	few	high	differentiated	high
Unregulated monopoly or cartel	none	total	highly differentiated	total
Regulated monopoly	none	total	highly differentiated	minor

unexpected increases in imported oil prices by the Organization of Petroleum Exporting Countries (OPEC) caused the domestic price of "new" oil* to rise to the delivered price of imported oil (approximately $11 per barrel). Since domestic oil companies differ widely in their dependence on imported oil and in their proportionate mix of new versus old oil, profit margins within the oil industry should diverge. (The Federal Energy Administration's entitlement program was designed to counter this problem, at least for refining profits.)

This example also indicates that events in one industry can spread to other industries because of substitution possibilities. New domestic oil is the only perfect substitute for imported oil; thus, its price should have equalized with that of imported oil. Low-sulfur coal is also a good substitute, and its spot market price plus delivery costs has risen to a level comparable to that of imported oil on a per-Btu basis.

A third factor is the different market structures in which goods are traded. Economists have identified at least five distinct market structures, each containing various gradations. These market structures and the various characteristics associated with each are summarized in Table 16-9.

"Competitive markets" constitute one extreme and are characterized by a very large number of competitors producing a homogeneous product in an industry that allows very easy entry or exit. Under these conditions, each competitor has an infinitesimal share of the market and no control over market price. Market price is determined by the interaction of industry supply and demand, and each competitor sells as much as he can at the market price. Agricultural markets are perhaps the best examples of competitive markets.

"Monopolistic competition" describes a market in which there is some product differentiation created by style, brand

*"New" oil is oil produced from domestic reserves added after January 1, 1974.

name, advertising, location, etc. These markets have many competitors and minor barriers to entry (licensing requirements, advertising expenses, etc.). Each competitor has some control over price and can vary price within a small range without a substantial loss of customers because of brand loyalty and other factors. Retail gasoline outlets are examples of this type of market.

"Oligopolistic markets" differ from monopolistic competitive markets only in degree and in the interdependence of the competitors. In oligopolistic markets, each competitor must consider the potential reactions of his counterparts to any price changes. Examples of this type market include many important manufacturing industries such as the steel, automobile, chemical, and oil refining industries.

"Unregulated monopolies" are characterized by highly differentiated products for which there are no close substitutes. Entry into the industry is completely blocked (usually by law); thus, there are no competitors and the unregulated monopolist has complete control over market price. Recent examples of unregulated monoplies include both the Xerox and Polaroid companies, which were granted temporary market monopolies during the life of their patents.

In "regulated monopolies," prices and profits are limited by government regulatory commissions, and the monopolist has, in effect, a cost-plus contract. Examples of regulated monopolies include: electric power generation, transmission, and distribution; interstate natural gas production, transmission, and distribution; and crude oil and petroleum product pipelines.

Market structure is important because, in theory, return on investment should increase as the market moves from competition toward unregulated monopoly.* In addition, temporary increases in return on investment caused by unexpected events should endure longer as the market moves in this direction. Empirical results are mixed but do tend to support these theories.

This section has discussed three of the more important reasons why profit margins should differ substantially across and within industries. For these reasons, the total unit cost of a particular production process is not as accurate an indicator of market price for energy as might be expected, particularly when other lower cost techniques may emerge to determine the market price and when extended periods of time are being considered.

16.6.2 Calculation of Final Consumer Prices

Section 16.6.1 discussed the reasons why, in a market economy, production costs are often poor indicators of market prices. Frequently, however, prices calculated on production costs and an assumed rate of return on stockholders equity can be useful. These prices (cost-plus prices) do not accurately predict future market price (because market price would be determined by a wider array of supply and demand forces) but are indicative of the minimum market price necessary to make a given activity attractive to private investors. Cost-plus prices can also be used to compare alternatives based on the minimum output prices required for their adoption or to rank alternatives in order of economic desirability.

---

*Profit on total investment is not as sensitive to market structure as is profit on equity, indicating that more concentrated industries (i.e., industries with fewer competitors) tend to be more highly leveraged (i.e., have a higher proportion of debt in their capital structure). These factors suggest that the increased profitability of more highly concentrated industries may be due more to financial power than to pricing power.

In general, calculation of cost-plus price requires that annual revenue be identified and divided by annual output. The essential feature of a cost-plus price is that profits are treated as the cost of attracting equity capital and usually estimated as some percentage return on equity times the amount of equity required. Profits and all other costs may then be summed to determine annual revenue requirements.

In the remainder of this section, cost-plus output prices are calculated for each of the seven trajectories listed in Table 16-8. To simplify these calculations, several assumptions were made:

1. There is no depletion allowance.
2. All capital facilities have a 25-year life and zero salvage value.
3. Straight line depreciation is used.
4. State, federal, and local corporate income taxes are 50 percent of taxable income.
5. Price computations are to be made for the year 1972 (which eliminates the need to update the MERES and OU cost estimates).

Five additional assumptions regarding financial structure were made based on typical financial relationships for gas utilities, large corporations, and coal companies:

6. Fifty percent of the capital structure is debt (both long and short term), and 50 percent is equity.
7. The average cost of debt is eight percent.*
8. Stockholders require an eight-percent, after tax, rate of return on equity.
9. Working capital is equal to seven percent of fixed investment.**
10. Property taxes and insurance costs are two percent of total investment.

*The eight percent includes interest charges, underwriting costs, etc.

**Working capital is defined as the firm's investment in cash, short-term securities, accounts receivable, and inventories. The MERES and OU cost estimates generally do not include working capital requirements.

Given these 10 assumptions and the cost information in MERES and the OU descriptions, cost-plus price calculations for each of the seven trajectories can be based on the equations given in Table 16-10. Equation 1 indicates that cost-plus price, P, is equal to annual revenue, R, divided by annual output, Q.* Quantity is known since each trajectory delivers 95.7×10^{12} Btu's or 92.8 mmcf of pipeline quality gas per year. Revenue requirements may be computed by summing the costs of the five components listed in equation 2 of Table 16-10.

The first component, operating costs (C_o), for a given trajectory may be obtained from MERES using the procedures described in Section 16.2. These calculations have already been done for the seven trajectories in Table 16-8.

Fixed costs, C_f, should not be obtained directly from MERES because of the need to include working capital and to consider separately the costs of depreciation, equity, and debt.** Fixed costs consist of the cost of debt, i, and insurance and property taxes, T_p, since depreciation has been identified as a separate item. As defined in equation 3, fixed costs are equal to six percent of total investment, I, which is assumed to be 107 percent of fixed investment (equation 4). To compute fixed costs, the user must first determine fixed investment by obtaining the MERES fixed cost estimate and multiplying this

*Costs, revenues, profits, and output all have time dimensions and are expressed as rates; that is, so many dollars per year. Total investment, fixed investment, and working capital investment do not have a time dimension and are expressed as amounts; that is, $1 million.

**The fixed costs, C_f, can be found by multiplying the MERES fixed costs by 1.9 but this 1.9:1 relationship is a result of assumptions 5 through 10 made at the start of this section. A change in any of these six assumptions and the 1.9:1 relationship will also be changed.

TABLE 16-10

EQUATIONS FOR COST-PLUS PRICE COMPUTATIONS

Equation 1. $P = R/Q$

Where P = annual average price
R = annual revenue
Q = annual output of gas in thousands of cubic feet

Equation 2. $R = C_o + C_f + \pi + D + T_i$

Where C_o = annual operating costs of each trajectory (obtained from the OU or MERES cost estimates in Table 16-8)
C_f = annual fixed costs (computed from equation 3 and not obtained directly from the OU or MERES cost estimates)
π = annual after tax profits
D = annual straight line depreciation computed as 1/25 of fixed investment
T_i = annual federal, state, and local corporate income taxes

Equation 3. $C_f = i + T_p = 0.06\ I$

Where i = annual cost of debt (by assumptions 6 and 7 on page 16-17, this equals 0.04 I)
T_p = annual property taxes and insurance costs (by assumption 10 on page 16-17, this equals 0.02 I)[a]
I = total investment

Equation 4. $I = I_f + I_w = 1.07\ I_f$

Where I_f = fixed investment (obtained from the OU and MERES descriptions or by multiplying the OU or MERES fixed cost estimates by 10)[b]
I_w = working capital investment (by assumption 9 on page 16-17, this equals $0.07\ I_f$)

Equation 5. $\pi = 0.08\ (0.5\ I) = 0.04\ I$ (by assumptions 6 and 8 on page 16-17)

Equation 6. $D = 0.04\ I_f$ (by assumptions 2 and 3 on page 16-17)

Equation 7. $T_i = (R - C_o - C_f - D)\ 0.5 = \pi$ (by assumptions 1 and 4 on page 16-17)

[a]Property taxes would include all federal, state, and local non-income taxes. In actual practice, the insurance and property tax base may not be the same.

[b]Since the OU and MERES descriptions computed fixed costs as 10 percent of fixed investment, fixed investment may be found by multiplying their fixed cost estimates by 10.

number by 10 (MERES and the OU descriptions computed fixed costs as 10 percent of fixed investment). Equation 4 may then be used to calculate total investment, I, and equation 3 to compute the new fixed cost estimates.

After tax profits, π, are assumed to be eight percent of equity. Since equity is assumed to be half of the capital structure, after tax profits (equation 5) amount to four percent of the total investment calculated in the above paragraph.

Depreciation, D, is defined as four percent of fixed investment (equation 6). Fixed investment, as noted above, is calculated as 10 times the MERES or OU fixed cost estimates.

Corporate income taxes, T_i, are assumed to be 50 percent of income before taxes. As defined in equation 7, income before taxes is revenue less operating costs, fixed costs, and depreciation.

The sum of the above five components yields required revenue, R. Calculation of each of these components and of cost-plus price for the offshore natural gas trajectory is illustrated in Table 16-11. Similar calculations for each of the seven trajectories have been summarized in Table 16-12 and Figure 16-2.

16.6.3 Comparison of Price and Cost Rankings

The seven trajectories have been ranked in order of increasing output price in Table 16-12. The prices range from a low of $0.93 per thousand cubic feet of gas (mcf) to a high of $2.26 per mcf. Under the assumptions made, these prices represent the minimum average price at which natural gas from a given trajectory would be available in the Seattle area. The average 1972 market price for natural gas in the State of Washington was $0.76 per mcf.* The cost-plus price for all trajectories exceeded this average price, and only the offshore natural gas trajectory delivers gas at a roughly comparable price.

The rank ordering of each trajectory in terms of annual total cost, as shown in Table 16-8, differs from the rank ordering by consumer price (calculated on a cost-plus basis) as shown in Table 16-12. The cost and price rankings are identical for the first three trajectories in Table 16-12, but in Table 16-8 the fourth through seventh ranked trajectories were, in order: Alaskan gas via LNG tanker, Alaskan gas via Canadian pipeline, Synthane facility at demand center, and imported LNG.

Two additional points concerning Table 16-12 should be made. First, the cost-plus price computations are based on 1972 cost estimates with no cost escalations through time; thus, alterations in costs could produce changes in the rankings. Second, the profit margins also vary with the cost structure from a high of 19.4 percent for Alaskan natural gas via Canada (the highest ratio of fixed costs to total costs) to a low of 5.0 percent for imported LNG (the lowest ratio of fixed costs to total costs). This variation in profit margins is caused by differences in cost structure and not by the rate of return on equity, which is eight percent for all seven trajectories.

The basic difference between Tables 16-8 (trajectories ranked by total costs) and 16-12 (trajectories ranked by cost-plus price) is that Table 16-12 has a broader scope because it includes the cost of

---

*This average included residential, commercial, and industrial prices as follows:

Residential Price:	$1.44 per mcf.
Commercial Price:	$1.19 per mcf.
Industrial Price:	$0.48 per mcf.
Average Price:	$0.76 per mcf.

TABLE 16-11

SAMPLE COST-PLUS PRICE CALCULATIONS
FOR THE OFFSHORE NATURAL GAS TRAJECTORY

1. C_o = <u>\$19.6 million</u> (from Table 16-8).

2. $C_f = 0.06\ I = 0.0642\ I_f$

   since $I = 1.07\ I_f$

   The MERES fixed costs for this trajectory in Table 16-8 are \$35.1 million, therefore I_f = 10 (\$35.1 million) = \$351 million.

   The new fixed cost estimate, C_f, is:

   $C_f = 0.642\ I_f$ = 0.0642 (\$351 million) = <u>\$22.53 million</u>

3. $\pi = 0.04\ I = 0.04\ (1.07\ I_f) = 0.0428\ I_f$

   = 0.0428 (\$351 million) = <u>\$15.02 million</u>

4. $D = 0.04\ I_f$ = 0.04 (\$351 million) = <u>\$14.04 million</u>

5. $T_i = \pi$ = <u>\$15.02 million</u>

6. $R = C_o + C_f + \pi + D + T_i$ = <u>\$86.21 million</u>

7. Q = <u>92.8 million mcf</u>

8. P = R/Q = \$86.21 million/92.8 million mcf = <u>\$0.93 per mcf</u>

TABLE 16-12

TRAJECTORIES RANKED BY COST-PLUS PRICE[a]

Trajectory	Operating Cost[b]	Fixed Cost[b]	After Tax Profits[b]	Depreciation[b]	State, Federal and Local Corporate Income Taxes[b]	Profit Margin[c]	Required Revenue[b]	Required Output Price[d]
Offshore natural gas	19.6	22.53	15.02	14.04	15.02	17.4	86.21	0.93
Synthane high-Btu gasification	41.1	34.67	23.11	21.60	23.11	16.1	143.59	1.55
Lurgi high-Btu gasification	40.4	41.86	27.91	26.08	27.91	17.0	164.16	1.77
Synthane facility at demand center	92.5	28.18	18.79	17.56	18.79	10.7	175.82	1.89
Imported LNG	141.4	13.61	9.07	8.48	9.07	5.0	181.63	1.96
Alaskan natural gas pipeline and LNG tanker	34.9	54.31	36.21	33.84	36.21	18.5	195.47	2.11
Alaskan natural gas pipeline	29.8	60.99	40.66	38.00	40.66	19.4	210.11	2.26

[a]Based on 1972 cost data and an eight-percent after tax return on equity. See text for assumptions. Each trajectory delivers 92.8×10^6 thousand cubic feet of gas per year to the Seattle market assuming that each cubic foot of gas contains 1,031 Btu's. The total cost figures in this table differ slightly from those of Table 16-8 due to the addition of working capital requirements and the explicit treatment of the costs of debt and equity.

[b]Millions of dollars per year.

[c]Profit as a percentage of revenue.

[d]Dollars per thousand cubic feet.

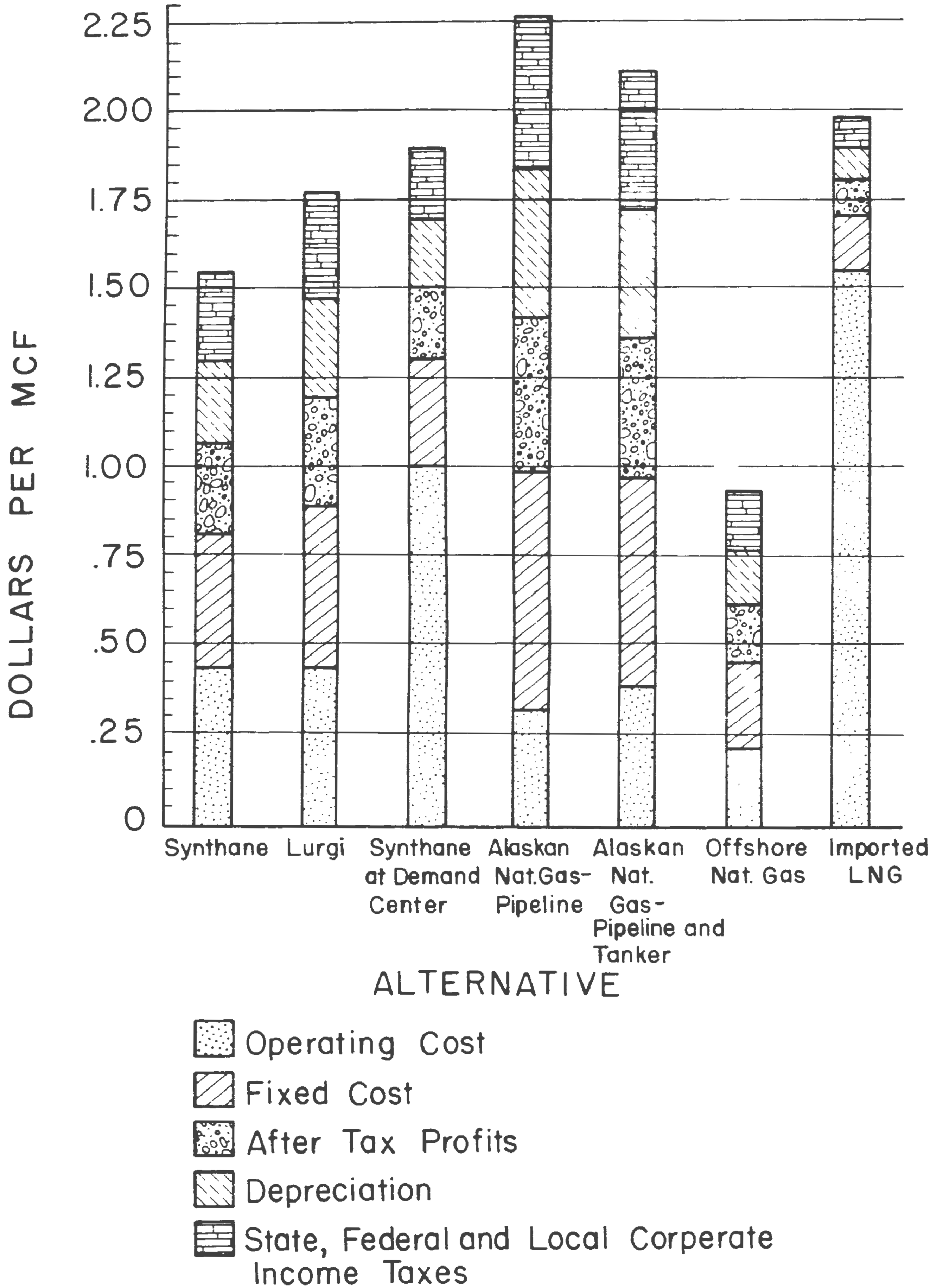


Figure 16-2. Cost-Plus Price by Alternative

raising working capital, equity, and tax revenue. These additional factors must be considered whether a trajectory is financed by public or private means. Thus, the cost-plus price rankings in Table 16-12 are more useful than those in Table 16-8 for public policy decisions. Although these cost-plus prices do not predict future market prices, they do indicate the minimum output price necessary to make a trajectory economically attractive and therefore are one method of ordering alternatives, assuming risks and other factors are comparable.

Although rankings made in this manner have the advantage of involving relatively simple computations, they ignore demand forces and cannot easily accommodate such factors as the time value of money and future economic considerations. For these reasons, the more sophisticated (and complex) analysis of the next section is often used to rank alternatives in order of economic desirability.

16.6.4 Net Present Value Analysis

Although many volumes have been written about the best economic criterion for evaluating a proposed investment activity, most of the methods employed in both the public and private sectors are related to the concept of net present value (NPV) or discounted cash flow (DCF) analyses. In essence, the net present value criterion states that revenues should exceed costs when adjusted for their sequence in time; that is, when the time value of money is properly accounted for.

NPV is essentially a method for determining the profitability of an investment over its life. The numbers calculated by use of equation 8 in Table 16-13 can vary from negative (unprofitable) to positive (profitable). Since a doubling of all revenue and cost figures on the right hand side of equation 8 would double the NPV of an investment, the NPV concept should be interpreted carefully when investments of differing magnitudes are being compared. Because of this, the user may wish to compute the NPV of an investment per dollar of total investment when comparing investments of differing magnitudes.

To make a NPV calculation, the user should identify the prices and quantities of all inputs and outputs for each time period over the life of the investment.* Inputs include land, buildings, labor, raw materials, management skills, financing, etc. Outputs include products, by-products, and services. Once this price and quantity information is assembled, costs for any given time period, C_t, may be found by multiplying price times quantity and summing over all inputs (equation 9). Similarly, revenue for any given time period, R_t, may be found by multiplying price times quantity and summing over all outputs (equation 10). These revenue and cost estimates plus an appropriate discount or interest rate may then be used to compute the net present value of the investment (equation 8).**

Note that time, t, is generally expressed in years and that revenue may be zero in the initial time periods and may include salvage value in the final time period. Costs in the initial time periods generally represent outlays for plant and equipment*** (fixed investment), while costs

---

*Price and quantity information for each input are not always given in the OU and MERES descriptions since some costs, such as maintenance costs, are estimated as a percent of operating costs. It would be useful to have the information on prices and quantities for each input as this would facilitate evaluation of local employment effects, balance of payments effects, etc.

**While there is general agreement that the selection of an appropriate discount rate is a critical factor, there is little general agreement on the numerical rate to be used. In addition, higher discount rates are frequently used for higher risk investments.

***Assuming that the plant and equipment are purchased and not leased.

TABLE 16-13

COMPUTATION FORMULA FOR NET PRESENT VALUE (NPV)

Equation 8. $$NPV = (R_o - C_o) + \frac{(R_1 - C_1)}{(1+r)} + \frac{(R_2 - C_2)}{(1+r)^2} + \ldots + \frac{(R_t - C_t)}{(1+r)^t}$$

Where C_t is cost in the t^{th} time period

R_t is revenue in the t^{th} time period

r is the discount rate or percent

and, T is the economic life of the proposed activity, and t is an integer so that $0 \leq t \leq T$.

Furthermore,

Equation 9. $$C_t = \sum_{j=0}^{J} P_{jt} Q_{jt}$$

where Pjt is the price of the j^{th} input at time t

and, Q_{jt} is the quantity of the j^{th} input at time t

and, J is the number of inputs and j is an integer.

and;

Equation 10. $$R_t = \sum_{m=0}^{M} P_{mt} Q_{mt}$$

where P_{mt} is the price of the m^{th} output at time t

and, Q_{mt} is the quantity of the m^{th} output at time t

and, M is the number of outputs and m is an integer.

<u>Example</u>

Assume:

1) $R_o = o$	3) $R_t - C_t = \$10$	5) T = 25 years
2) $C_o = \$100$	4) r = 10 percent	6) t = 1, 2, . . ., 25

Then:

$$NPV = (0-100) + \frac{(10)}{(1+0.1)^1} + \frac{(10)}{(1+0.1)^2} + \frac{(10)}{(1+0.1)^{25}} = - \$9.23$$

The negative NPV indicates that the investment will not be profitable.

in subsequent periods are composed of both operating and fixed costs.* Working capital requirements may also be introduced as a cash outflow in the initial periods (a cost) and as a cash inflow in the final period (a revenue).

NPV may be computed either before or after taxes. For private sector activities, it is generally preferable to compute NPV after taxes. This may be done simply by considering depreciation, tax credits, and all federal, state, and local taxes in a separate computation and then introducing the annual results for each time period into equation 8 as an additional cost or revenue, depending on whether the tax credits outweigh the tax payments. Tax calculations do not generally enter an NPV analysis of public sector activities unless some change in tax revenues is expected.**

The principal value of the NPV approach is that it forces the user to consider present as well as future economic factors that may affect the action he takes now. This type of consideration is lacking in the estimates discussed in Sections 16.3 and 16.6.2.

Although the net present value of an activity is one of the more useful summary measures of its economic desirability, it is clearly a simplification of reality because NPV is only one factor to be considered when evaluating an investment. For this reason, decision makers frequently consider other aspects or impacts of the activity such as availability of skilled manpower, risks, local economic impacts, etc.

One value of NPV analysis is that the price and quantity information for each input and output should serve as a starting point for an analysis of any particular economic impact of interest. For example, the local economic impact of a plant could be assessed by starting with information on state and local tax payments, the number of employees, their wage rates, etc. and estimating housing needs, consumption expenditures, schooling needs, etc. Balance of payments impacts, both present and future, could also be assessed by identifying inputs and outputs that are now, or might be in the future, either imported or exported.

Finally, the terms NPV and DCF are sometimes applied to private sector investments, and the terms "cost-benefit analysis" or "cost effectiveness analysis" are frequently used for non-profit or public sector investments. All these analyses are essentially the same and, with appropriate care, equation 8 can be used for all.* For example, cost benefit analysis generally requires the assigning of values to non-market outputs of an investment such as the value of the recreation and conservation outputs of a government hydroelectric project. These annual values may then be treated as revenues along with the revenues obtained from the sale of electricity. When there are alternative methods of producing identical benefits,** a cost benefit

---

*Fixed investment and fixed costs are related but dissimilar concepts. Fixed investment represents cash outlays for land, plant, and equipment in the initial time periods. Most companies use debt to finance their fixed investments and some fixed obligation or costs over future time periods are created including interest on debt and repayment of debt. Fixed costs also include annual insurance costs, property taxes, etc. Fixed costs are sometimes estimated as fixed investment times a fixed change rate (FCR) where the FCR is expressed as a percent per year.

**For example, a decision by the federal government to construct an office building rather than to rent office space would reduce both property and income tax payments in the city or state affected.

*The internal rate of return can also be calculated from equation 8 by setting NPV = 0 and solving for the value of r that satisfies this relationship; that is, the discount rate that equates discounted revenues and discounted costs.

**In other words, the revenue flows in equation 8 are identical for each alternative; thus, the analysis can be narrowed to consideration of only the cost flows through time.

analysis can be reduced to a cost effectiveness analysis by merely selecting the alternative with minimum cost.

REFERENCE

Brookhaven National Laboratory, Associated Universities, Inc., Energy/Environmental Data Group (1975) Energy Model Data Base User Manual, BNL 19200.

APPENDIX TO CHAPTER 16

A SELECTED BIBLIOGRAPHY OF ENERGY ECONOMICS

COAL

Bureau of Mines (1972) Cost Analyses of Model Mines for Strip Mining Coal in the United States, Information Circular 8535. Washington: Government Printing Office.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

Interagency Synthetic Fuels Task Force (1974) Report to Project Independence Blueprint, Federal Energy Agency. Supplement 1, prepared under the direction of the Interior Department.

Katell, Sidney, and E.L. Hemingway (1974) Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines; 48-Inch Coalbed, Bureau of Mines Information Circular 8641. Washington: Government Printing Office.

Katell, Sidney, and E.L. Hemingway (1974) Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines; 72-Inch Coalbed, Bureau of Mines Information Circular 8632. Washington: Government Printing Office.

Killebrew, Clarence E. (1968) "Tractor Shovels, Tractor Dozers, Tractor Scrapers," pp. 463-477 in E.P. Pfleider (ed.) Surface Mining. New York: American Institute of Mining, Metallurgical and Petroleum Engineers.

Mutschler, P.H., R.J. Evans, and G.M. Larwood (1973) Comparative Transportation Costs of Supplying Low-Sulfur Fuels to Midwestern and Eastern Domestic Energy Markets, Bureau of Mines Information Circular 8614. Washington: Government Printing Office.

National Coal Association (1972) Bituminous Coal Facts, 1972. Washington: NCA.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee (1972) U.S. Energy Outlook: An Initial Appraisal by the Oil Shale Task Group, 1971-1985. Washington: NPC.

Office of Coal Research (1972) Development of a Process for Producing Ashless, Low-Sulfur Fuel from Coal, Vol. I--Engineering Studies, Part 3--COG Refinery Economic Evaluation--Phase II, Research and Development Report No. 53, Interior Report No. 4, prepared by Chem Systems, Inc. Washington: Government Printing Office.

Senate Committee on Interior and Insular Affairs (1973) Coal Surface Mining: An Environmental and Economic Assessment of Alternatives, by the Council on Environmental Quality. Washington: Government Printing Office.

Soo, S.L. (1972) "A Critical Review on Electrostatic Precipitators," pp. 185-193 in R.W. Coughlin, A.F. Sarofim, and N.J. Weinstein (eds.) Air Pollution and Its Control, AIChE Symposium Series, Vol. 68, No. 126. New York: American Institute of Chemical Engineers.

Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif.: Teknekron.

Weimer, W. Henry, and Wilbur A. Weimer (1973) "Surface Coal Mines," in Arthur B. Cummins and Ivan A. Given (eds.) SME Mining Engineering Handbook. New York: American Institute of Mining, Metallurgical and Petroleum Engineers, Inc.

OIL SHALE

BuMines, TOSCO, and Garrett, personal communication, passim.

Federal Energy Administration (1974) Project Independence Blueprint Final Task Force Report--Potential Future Role of Oil Shale: Prospects and Constraints. Washington: Government Printing Office.

Hittman Associates, Inc. (1975) Environmental Impacts, Efficiency and Cost of Energy Supply and End Use, Final Report: Vol. II. Columbia, Md.: Hittman Associates, Inc.

Hottel, H.C., and J.B. Howard (1971) New Energy Technology: Some Facts and Assessments. Cambridge, Mass: M.I.T. Press.

Interagency Oil Shale Task Force (1974) Potential Future Role of Shale Oil: Prospects and Constraints, for Federal Energy Administration's Project Independence Blueprint.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee, Oil Shale Task Group (1973) U.S. Energy Outlook: Oil Shale Availability. Washington: NPC.

CRUDE OIL

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, for the Office of Research and Development, Environmental Protection Agency. Columbus, Ohio: Battelle Columbus Laboratories.

Department of the Interior (1973) Draft Environmental Impact Statement: Deepwater Ports. Washington: DOI.

Hittman Associates, Inc. (1974) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I. Columbia, Md.: Hittman Associates, Inc.

Teknekron, Inc. (1973) Fuel Cycles for Electrical Power Generation, Phase I: Towards Comprehensive Standards: The Electric Power Case, report for the Office of Research and Monitoring, Environmental Protection Agency. Berkeley, Calif.: Teknekron.

NATURAL GAS

Federal Power Commission (1973) National Gas Survey, Vol. III, Transmission-Technical Advisory Task Force Report: Operations. Washington: Government Printing Office.

Federal Power Commission (1974) National Gas Survey, Vol. I, Chapter 2: The Resource and the Industry, preliminary draft issued in advance of Commission approval.

Federal Power Commission (1974) "Opinion and Order Prescribing Uniform National Rate for Sales of Natural Gas Produced from Wells Commenced On or After January 1, 1973." Opinion No. 699, Docket No. R-389-B, Issued June 21, 1974. (Also Opinion No. 699-H.)

Federal Power Commission (n.d.) Docket No. CP71-68, et al.

Hittman Associates, Inc. (1974) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I. Columbia, Md.: Hittman Associates, Inc.

IGT Highlights (1974) IGT Highlights 4 (June 24, 1974).

Khan, A.R., and W.W. Bodle (1972) "Supplementing United States Gas Supplies with Imported LNG." Journal of Petroleum Technology (May 1972).

National Petroleum Council, Committee on U.S. Energy Outlook (1972) U.S. Energy Outlook. Washington: NPC.

Phillips, J.G. (1974) "Energy Report/Congress Nears Showdown on Proposal to Decontrol Gas Prices." National Journal Reports 6 (May 25, 1974): 761-775.

TAR SANDS

Cameron, R.J. (1969) "A Comparative Study of Oil Shale, Tar Sands and Coal as Sources of Oil." Journal of Petroleum Technology 21 (March 1969): 253-259.

Camp, Frederick W. (1969) "Tar Sands," pp. 682-732 in Encyclopedia of Chemical Technology, Vol. 19 (2nd edition). New York: Interscience.

Hittman Associates, Inc. (1974) Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I. Columbia, Md.: Hittman Associates, Inc.

Hottel, H.C., and J.B. Howard (1971) New Energy Technology: Some Facts and Assessments. Cambridge, Mass.: M.I.T. Press.

National Petroleum Council, Committee on U.S. Energy Outlook (1972) U.S. Energy Outlook. Washington: NPC.

NUCLEAR ENERGY--FISSION

Atomic Energy Commission, Division of Reactor Development and Technology (1971) Reactor Fuel Cycle Costs for Nuclear Power Evaluation. Washington: Government Printing Office.

Atomic Energy Commission, Division of Reactor Research and Development (1973) Liquid Metal Fast Breeder Reactor Program Plan, compiled by LMFBR Program Office, Argonne National Laboratory. Springfield, Va.: National Technical Information Service, 10 elements.

Atomic Energy Commission (1974) Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington: Government Printing Office, 4 vols.

Atomic Industrial Forum (1974) "Comparison of Fuels Used in Power Plants." Background INFO, published under the Public Affairs and Information Program. New York: AIF.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee, Nuclear Task Group (1973) U.S. Energy Outlook: Nuclear Energy Availability. Washington: NPC.

Nuclear News Buyers Guide (Mid-February 1974).

NUCLEAR ENERGY--FUSION

No economic references.

GEOTHERMAL ENERGY

American Oil Shale Corporation and Atomic Energy Commission (1971) A Feasibility Study of a Plowshare Geothermal Power Plant. Oak Ridge, Tenn.: AEC.

Armstead, H. Christopher H. (1973) "Geothermal Economics," pp. 161-174 in H. Christopher H. Armstead (ed.) Geothermal Energy. Paris: UNESCO.

Austin, A.L., G.H. Higgens, and J.H. Howard (1973) The Total Flow Concept for Recovery of Energy From Geothermal Hot Brine Deposits. Lawrence, Calif.: Lawrence Livermore Laboratory.

Burnham, J.B. and D.H. Stewart (1970) The Economics of Geothermal Power. Richland, Wash.: Battelle Institute, Pacific Northwest Laboratories.

Facca, Giancarlo and A. Ten Dam (1964) Geothermal Power Economics. Rev. ed. Los Angeles: Worldwide Geothermal Exploration Co.

Federal Council for Science and Technology (1972) Assessment of Geothermal Energy Resources. Springfield, Va.: National Technical Information Service.

"Geothermal Energy Looms as Economic Factor." Oil Digest (January 1971)

Horvath, J.C. and R.L. Chaffen, "Geothermal Energy, The Future and Economics." Atlanta Economic Review 21 (December 1971): 16-33.

Kaufman, A. (1964) Geothermal Power: An Economic Evaluation, U.S. Bureau of Mines Information Circulat 8230. Washington: Government Printing Office.

Kaufman, A. (1970) The Economics of Geothermal Power in the United States. U.N, Symposium on Development and Utilization of Geothermal Resources, Pisa, Italy.

Kaufman, Alvin (1971) "An Economic Appraisal of Geothermal Energy." Public Utilities Fortnightly 88: 19-23.

Koenig, James B. (1973) "Worldwide Status of Geothermal Resources Development," pp. 15-58 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

Rex, Robert W. and David J. Howell (1973) "Assessment of U.S. Geothermal Resources," pp. 59-68 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

Smith, Morton, R. Potter, D. Brown, and R.L. Aamodt (1973) "Induction and Growth of Fractures in Hot Rock," pp. 251-268 in Paul Kruger and Carel Otte (eds.) Geothermal Energy: Resources, Production, Stimulation. Stanford, Calif.: Stanford University Press.

VanderTak, H.G. (1967) The Economics Choice Between Hydroelectric and Thermal Power Development, World Bank Staff Occasional Papers No. 1. Washington, D.C.

White, D.C., L.J.P. Muffler, and A.H. Truesdell (1971) "Vapor-Dominated Hydrothermal Systems Compared with Hot-Water Systems." Economic Geology 66: 75-97.

HYDROELECTRIC

Federal Power Commission (1971) 1970 National Power Survey. Washington: Government Printing Office.

National Petroleum Council, Committee on U.S. Energy Outlook (1972) U.S. Energy Outlook. Washington: NPC.

National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee, New Energy Forms Task Group (1973) U.S. Energy Outlook: New Energy Forms. Washington: NPC.

ORGANIC WASTES

Envirogenics Company (1971) Systems Evaluation of Refuse as a Low Sulfur Fuel, Vol. 1. Springfield, Va.: NTIS.

Environmental Protection Agency (1974) Second Report to Congress: Resource Recovery and Source Reduction. Washington: Government Printing Office.

Friedman, S., H.H. Gensberg, I. Wender, and P.M. Yavorsky (1972) "Continuous Processing of Urban Refuse to Oil Using Carbon Monoxide." Proceedings of the Third Mineral Waste Utilization Symposium. IIT Research Institute, Chicago, Ill., March 1972.

Hammond, A.L., W.D. Metz, and T.H. Maugh (1973) Energy and the Future. Washington: AAAS.

Kasper, William C. (1973) Solid Waste and Its Potential as a Utility Fuel, Office of Economic Research Report No. 18. Albany, N.Y.: New York State Public Service Commission.

Linaweaver, F.P. and C.W. Crooks (1974) "Pyrolysis for Baltimore, A Dramatic Breakthrough in Solid Waste Management." District Heating, January-February 1974.

Lowe, Robert A. (1973) Energy Recovery from Waste: Solid Waste as Supplementary Fuel in Power Plant Boilers, Environmental Protection Agency Solid Waste Management Series. Washington: Government Printing Office.

Mallan, G.M. and C.S. Finney (1973) "New Techniques In the Pyrolysis of Solid Wastes," pp. 56-62 in AIChE Symposium Series, Vol. 69, No. 133.

Monsanto Enviro-Chem (1973) "'LANDGARD' System for Resource Recovery and Solid Waste Disposal: Process Description for Baltimore, Maryland." St. Louis: Monsanto Enviro-Chem Systems, Inc.

Schlesinger, M.D., W.S. Sanner, and D.E. Wolfson (1972) "Pyrolysis of Waste Materials from Urban and Rural Sources," pp. 423-428 in Proceedings of the Third Mineral Waste Utilization Symposium. IIT Research Institute, Chicago, Ill., March, 1972.

SOLAR

Alich, J.A., Jr., and R.E. Inman (1974) "Effective Utilization of Solar Energy to Produce Clean Fuel," Stanford Research Institute.

Donovan, P., and W. Woodward (1972) "Solar Energy as a National Energy Resource," University of Maryland.

Glaser, P.E. (1973) "Solar Power via Satellite." Testimony before the Senate Committee on Aeronautical and Space Science, October 31, 1973.

Hughes, W.L., and others (1974) "Basic Information on the Economic Generation of Energy in Commercial Quantities from Wind." Report #EE 74-##-7, Oklahoma State University.

Rottan, V.W. (1965) The Economic Demand for Irrigated Acreage. Baltimore: Johns Hopkins Press.

ELECTRICAL POWER GENERATION

Atomic Energy Commission (1974) Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program. Washington: Government Printing Office, 4 vols.

Bartok, W., A.R. Crawford, and G.J. Piegari (1972) "Systematic Investigation of Nitrogen Oxide Emissions and Combustion Control Methods for Power Plant Boilers," pp. 66-76 in R.W. Coughlin, A.F. Sarofim, and M.J. Weinstein (eds.) Air Pollution and Its Control, AIChE Symposium Series, Vol. 68, No. 126. New York: American Institute of Chemical Engineers.

Battelle Columbus and Pacific Northwest Laboratories (1973) Environmental Considerations in Future Energy Growth, Vol. I: Fuel/Energy Systems: Technical Summaries and Associated Environmental Burdens, report for the Office of Research and Monitoring, Environmental Protection Agency, Columbus, Ohio: Battelle Columbus Laboratories.

Council on Environmental Quality (1973) Energy and the Environment: Electric Power. Washington: Government Printing Office

Davis, John C. (1973) "SO_x Control Held Feasible". Chemical Engineering 80 (October 29, 1973): 76-77.

Federal Power Commission (1971) 1970 National Power Survey. Washington: Government Printing Office, 5 parts.

Hittman Associates, Inc. (1974 and 1975) Environmental Impacts, and Cost of Energy Supply and End Use. Final Report: Vol. I, 1974: Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc.

Jimeson, R.M. and G.G. Adkins (1971) "Waste Heat Disposal in Power Plants." Chemical Engineering Progress 67 (July 1971): 64-69.

Keairns, D.L., J.R. Hamm, and D.H. Archer (1972) "Design of a Pressurized Bed Boiler Power Plant," pp. 267-275 in R.W. Coughlin, A.F. Sarofim, and M.J. Weinstein (eds.) Air Pollution and Its Control, AIChE Symposium Series, Vol. 68, No. 126. New York: American Institute of Chemical Engineers.

Olmstead, Leonard M. (1971) "17th Steam Station Cost Survey." Electrical World (November 1, 1971), as cited in Council on Environmental Quality (1973) Energy and the Environment: Electric Power. Washington: Government Printing Office.

ENERGY CONSUMPTION

Berg, Charles A. (1973) "Energy Conservation Through Effective Utilization," reprinted in Energy Conservation and S.2176, Hearings before the Committee on Interior and Insular Affairs, U.S. Senate, 93rd Cong., 1st sess., pp. 552-561.

Federal Council on Science and Technology, Committee on Energy Research, as cited in Charles A. Berg (1974) "A Technical Basis for Energy Conservation." Technology Review 76 (February 1974): 14-23.

Hirst, Eric, and Robert Herendeen (1973) Total Energy Demand for Automobiles. New York: Society of Automotive Engineers. Reprinted in Energy Conservation and S.2176, Hearings before the Committee on Interior and Insular Affairs, U.S. Senate, 93rd Cong., 1st sess., August 1973, pp. 970-976.

Hirst, Eric, and John C. Moyers (1973) "Efficiency of Energy Use in the United States." Science 179 (March 30, 1973): 1299-1304.

Hittman Associates, Inc. (1974) The Automobile--Energy and the Environment: A Technology Assessment of Advanced Automotive Propulsion Systems. Columbia, Md.: Hittman Associates, Inc.

Office of Emergency Preparedness (1972) The Potential for Energy Conservation. Washington: Government Printing Office.

Szego, G.C. (1971) The U.S. Energy Problem. Warrenton, VA.: InterTechnology Corporation.

GLOSSARY

Area mining--A surface mining technique used in flat terrain.

Air classification--A method of separation whereby air is forced up a cylindrical container at a certain velocity, causing light materials to escape from the top and heavier materials to fall to the bottom.

Aldehyde--Any of various organic compounds containing a carbonyl group (CO) and a hydrocarbon group such as CH_3. The carbonyl group is linked to the hydrocarbons at the end of the chain.

Ambient--A term referring to conditions in the vicinity of a reference point, usually related to the physical environment (e.g., the ambient temperature is the outdoor temperature).

Amine--Any of various organic compounds containing the chemical group NH_2, NH or N and a hydrocarbon group such as CH_3.

Ancillary energy--A measure of the external energy required for an energy process. It includes such things as energy for process heat, electricity for pumps, and fuel for truck, train, or barge transportation.

ANFO--An explosive which is composed of ammonium nitrate and fuel oil.

Anthracite--A high-rank coal with high fixed carbon, percentages of volatile matter and moisture; a late stage in the formation of coal (see Rank).

API gravity--A measure of the mass of a fluid relative to water; it is inversely proportional to viscosity.

Aquifer--Water-bearing permeable rock, sand or gravel.

Ash--The residue left when combustible material is thoroughly burned or otherwise oxidized.

Auger--A screw-type mechanism used in the transference or excavation of solid materials.

Backfilling--A reclamation technique which returns the spoils to mined cuts or pits. This leaves the land in a configuration similiar to the original form.

Baghouse--A fabric filter used to separate particulates from an airstream.

Basin--A geologic or land-surface feature which is lower in the center and higher at the sides. Geologic basins may be filled with sediment and not visible from the surface.

Bench--A flat excavation.

Bench test--A small scale laboratory test of a process, preceding pilot plant testing.

Beneficiation--Cleaning and minimal processing to remove major impurities or otherwise improve properties.

Binary cycle--Combination of two turbine cycles utilizing two different working fluids in electrical generation plants. The waste heat from the first turbine cycle provides the heat energy for the second turbine cycle.

Biochemical oxygen demand (BOD)--The amount of oxygen required by bacteria to convert organic material into stable compounds.

Bioconversion--The conversion of organic wastes into methane (natural gas) through the action of microorganisms.

Biomass--The amount of living matter in a unit area or volume; the living weight.

Bit--The cutting or boring element used in drilling.

Bitumen--A general name for various solid and semi-solid hydrocarbons; a native substance of dark color, comparatively hard and nonvolatile, composed principally of hydrocarbons.

Bituminous--An intermediate-rank coal with low to high fixed carbon, intermediate to high heat content, a high percentage of volatile matter, and a low percentage of moisture (see Rank).

Blanket--The area immediately surrounding the reactor core in a liquid metal fast breeder reactor. Its major function is to produce plutonium-239 from uranium-238.

Blowdown--The release or cleaning out of water with high solids content, the solids having accumulated each time water evaporates.

Blowout--An uncontrolled flow of gas, oil and other well fluids from a well into the atmosphere. A well blows out when formation pressure exceeds the counter-pressure being applied by the drilling fluid.

Blowout preventer--Equipment installed at the wellhead for the purpose of controlling pressures in the annular space between the casing and drill pipe or in an open hole during drilling and completion operations.

Boiler--A mechanism which burns fuel to create heat energy and transfer the heat to a fluid (generally water/steam).

Box cut--Initial excavation in a mine that penetrates a hill resulting in walls on three sides, with spoils dumped over the slope.

Brayton cycle engine--Turbine cycle engines using internal heat sources, usually from the burning of fossil fuels.

Breeder reactor--A nuclear reactor that produces more fissile material than it consumes. This reactor is sometimes called the fast breeder because high energy (fast) neutrons produce most of the fissions in current designs.

Brine--Water saturated with salt; a strong saline solution.

Btu (British thermal unit)--The amount of energy necessary to raise the temperature of one pound of water by one degree Fahrenheit, from 39.2 to 40.2 degrees Fahrenheit.

Bucket-wheel excavator--A continuous mining machine which uses scoops mounted in a circular rotating frame to remove overburden and deposits.

Cake--To form or harden in a cohesive mass; to form a hard or brittle layer or deposit.

Carnot efficiency--The maximum efficiency with which work can be produced from heat in ideal processes. Carnot efficiency is only dependent upon the maximum and minimum temperatures available.

Catalysis--Modification and especially an increase in the rate of a chemical reaction induced by material unchanged chemically at the end of the reaction; any reaction brought about by a separate agent.

Catalyst--A substance that induces catalysis.

Catalytic conversion--A chemical reaction induced by a catalyst.

Centrifugal separator--A device which separates two fluids, or a fluid and a solid of different density by rotating them rapidly and forcing the denser material to the outside.

Char--A mixture of ash and carbon which remains after partial combustion or heating.

Chemical oxygen demand (COD)--The amount of oxygen required to convert (oxidize) organic compounds into stable forms--usually carbon dioxide and water. COD includes all compounds requiring oxidation while BOD includes only the biodegradable fraction.

Christmas Tree--The assembly of valves, pipes, and fittings used to control the flow of oil and gas from a well.

Cladding--The long, tube-like container in which uranium or plutonium oxide fuel pellets are encased.

Clarifier--A unit operation in wastewater treatment cleaning the water of some suspended solids. Rotary scrapers in square or circular tanks are used to move the sludge in the water toward the center of the tank where it is removed by pumping.

Claus recovery plant--A Claus plant takes emission gas streams containing 10 percent or more hydrogen sulfide and oxidizes the hydrogen slufide, producing elemental sulfur of high purity.

Coal--A solid, combustible organic material.

Coke--The solid, combustible residue left after the destructive distillation of coal, crude petroleum or some other material.

Combined cycle--Combination of a steam turbine and gas turbine in an electrical generation plant (see Binary cycle).

Continuous miner--A single machine used in underground mining which accomplishes excavating, loading and initial transportation operations.

Contour mining--A mining technique used in steeply-sloped terrain where a seam outcrops on a slope.

Control rods--Devices that are inserted into the nuclear reactor core to control the chain reaction and permit a change in power level.

Core--A sample removed from a drilled hole.

Cracking--The process of breaking up large molecules in refinery feedstock to form smaller molecules with higher energy content.

Critical mass--An amount of fissile material that can sustain a chain reaction.

Cryogenic techniques--Techniques involving the use of extremely low temperatures to keep certain fuels in a liquid form (e.g., liquefied hydrogen, methane, propane).

Curie--A curie measures the radioactivity level of a substance; i.e., it is a measure of the number of unstable nuclei that are undergoing transformation in the process of radioactive decay. One curie equals the disintegration of 3.7×10^{10} nuclei per second.

Cuttings--Solid material removed from a drilled hole.

Cyclone--A cleaning device which uses a circular flow to separate the heavier particulates from stack gases.

Dedicated railroad--A system in which the right-of-way, rails and rolling stock are used exclusively to transport a single resource.

Devolatilization--The removing of volatile matter from coal; mostly used as a pretreatment step to destroy the caking property of coal.

Direct heat--Heating of a substance through immediate contact with a combustion zone.

Distillation--Heating a liquid mixture in order to drive off gases or vapors which are then separated according to boiling point and condensed into liquid products.

Dolomite--A mineral, $CaMg(CO_3)_2$, found as crystals and in extensive beds as a compact limestone.

Down-hole well-logging instruments--Instruments which measure characteristics of formations such as electrical resistivity, radioactivity, and density. The information is used to evaluate the formations for petroleum content.

Dragline--An excavating machine used for the removal of overburden in open pit mines. It has a boom from which is suspended a bucket which is filled by dragging.

Dredge--A machine for removing earth underwater, usually by buckets on an endless chain or by a suction tube.

Drilling rig--The derrick, drawworks and attendant surface equipment used to drill or service an oil well.

Drill pipe--In rotary drilling, the heavy seamless tubing used to rotate the bit and circulate the drilling fluid. Individual pipe lengths are normally 30 feet and are coupled together with tool joints (see Drill string; Rotary drilling).

Drill string--A column of pipe that connects to a bit used to bore (drill) holes for wells.

Electrolysis--Chemical changes produced by passage of an electric current through an easily ionized liquid called an electrolyte.

Emergency core cooling system (ECCS)--A safety system in a nuclear reactor whose function is to prevent the fuel in a nuclear reactor from melting if a sudden loss of coolant occurs. It consists of a reserve system of pipes, valves and water supplies designed to flood water into the core.

Energy intensiveness--In transportation, the relative amount of energy required to move one unit (one passenger or one ton of cargo) a distance of one mile. In industry, the ratio of total energy consumed for each dollar of production goods shipped out.

Enrichment--The process by which the percentage of the fissionable isotope, U-235, is increased above that contained in natural uranium.

Entrained bed--A coal combustion (or gasification) process in which pulverized coal is carried along in a gas stream.

Equity--The net worth of a firm or corporation (total assets less total debts).

Eutectic--A mixture of two metals having the lowest melting point possible of any ratio of the two.

Exothermic--Refers to a chemical reaction that gives off heat.

Fast flux test facility (FFTF)--A liquid metal fast breeder reactor presently under construction whose purpose is to test various fuels and reactor core components.

Feedstock--Raw material supplied to a processing plant.

Ferrous--Of, relating to, or containing iron.

Fischer assay--A standardized laboratory procedure which removes oil from oil shale, used as a basis for comparing oil shale processing alternatives and shale feedstocks.

Fissile material--Uranium-233, uranium-235, or plutonium-239. Fissile is a label for an atom that will fission upon absorption of a low energy neutron.

Fission--The splitting of an atomic nucleus, resulting in the release of energy.

Fixed bed--A coal combustion (or gasification) process in which the coal is combusted on a stationary platform.

Fixed carbon--The solid, non-volatile, combustible portion of coal.

Fixed charge--Expenses which have to be borne whether any business is done or not. The chief items are the company's interest on bonds or other external borrowings, some taxes levied by the government, insurance payments, and depreciation due to obsolescence.

Fixed cost--The cost of a business which exists regardless of the amount of production, for example, depreciation of a building or insurance.

Fixed investment--Outlays for land, plant, equipment, etc. occurring only in the initial time period of the life of an investment.

Flash separation--Distillation to separate liquids of different volatility, accomplished by a rapid reduction in the pressure on the liquid.

Flat plate collector--Solar energy collector characterized by non-concentration of solar radiation.

Flat-rating--Limit placed on the maximum output of a power source for economic or technical reasons.

Flue gases--Gases, usually carbon dioxide, water vapor, oxides of nitrogen and other trace gases, which result from combustion processes.

Fluidized bed--A body of finely crushed particles with a gas blown through them. The gas separates the particles so that the mixture behaves like a turbulent liquid.

Fluidized bed boiler--A new type of boiler designed to reduce combustion product pollutants and reduce boiler size (see Fluidized bed).

Fly ash--Lightweight solid particles which are carried by stack gases.

Fracturing--Splitting or cracking by explosion or other source of pressure to make rock more permeable or loose.

Front end loader--A tractor with a large bucket mounted on arms that can scoop up material and raise the load for dumping into a truck.

Froth-flotation--A separation process that uses the surface wetting behavior of chemicals to precipitate some materials and float others in an aerated pond.

Fuel cell--A device that produced electrical energy directly from the controlled electrochemical oxidation of fuel. It does not contain an intermediate heat cycle, as do most other electrical generation techniques.

Fuel fabrication--The manufacturing and assembly of reactor fuel elements containing nuclear fuel material.

Fuel pin--A long, approximately 12 to 15 foot, thin tube that is approximately one-half inch in diameter. The tube is filled with nuclear fuel pellets.

Fusion--The combining of certain light atomic nuclei to form heavier nuclei resulting in the release of energy.

Gallium arsenide--A compound used in making photovoltaic cells.

Gaseous diffusion--The process used to "enrich" nuclear fuel. The fuel in the form of a gas passes through a thin membrane. Light gas molecules move at a higher volocity than heavy molecules. These light molecules strike and pass through the membrane more often than the heavy molecules.

Gasification--Commonly refers to the conversion of coal to a gas fuel.

Generator--A mechanism which converts mechanical energy to electrical energy.

Gilsonite--Very rich tar deposits; a tar sand with a very high hydrocarbon content and low mineral content.

Graphite--Soft black carbon. A special form is used as a moderator in nuclear power plants (see Moderator).

Gravimetric survey--An exploration method which involves interpreting the probable density of minerals in the earth by measured gravity variations.

Groundwater--Water which is underground in an aquifer (see Aquifer).

Hammermill shredder--A cylindrical machine which is lined with spike-shaped projections which are utilized to tear and break up organic waste material.

"Head of hollow" method--A method of reclamation whereby solid residuals are deposited in a naturally-occurring deep canyon.

Heat exchanger--A device in which heat energy is transferred from one fluid to another due to a temperature difference between the two fluids.

Heat pump--A method of moving, concentrating or removing heat by alternately vaporizing and liquefying a fluid through the use of a compressor. A reversible refrigeration system that can provide heat.

Helical screw expander--A spiral shaped machine for driving a generator through which hot water and steam expand.

High-Btu gas--An equivalent of natural gas, predominantly methane; obtained by methanating synthesis gas; energy content is usually 950 to 1,000 Btu's per cubic foot.

High temperature gas reactor--A nuclear reactor in which helium gas is the coolant with graphite fuel elements containing coated particles of highly enriched uranium plus thorium.

Highwall--The unexcavated face of exposed overburden and coal (or other resource) in a surface mine.

Hydrate--A compound or complex ion formed by the union of water with some other substance.

Hydraulic mining--A process whereby jetted water streams are employed to fracture and excavate a mineral.

Hydrocarbon--Organic compounds containing only carbon and hydrogen, characteristically occurring in petroleum, natural gas, coal and bitumens.

Hydrogasification--The direct reaction of carbon with hydrogen to produce methane (CH_4).

Hydrogenation--Adding hydrogen to an organic compound.

Hydrostatic head--The pressure created by the weight of a height column of water.

Hydrotreating--Using a catalyst, high temperature, and high pressure to change the structure of a molecule through the addition of hydrogen. An additional benefit may be the removal of sulfur as hydrogen sulfide in the process.

Impulse turbine--A turbine driven by high velocity jets of water or steam which impinge on some kind of vane or bucket attached to a wheel. The high velocity jets are produced by forcing the water and steam through a nozzle.

In situ--In the natural or original position; applied to energy resources when they are processed in the location where they were originally deposited.

Irradiated fuel--Nuclear fuel that has been used in a nuclear reactor.

Isotope--One of two or more atoms with the same atomic number (i.e., the same chemical element) but with different atomic weights. Isotopes usually have very nearly the same chemical properties, but somewhat different physical properties.

Kerogen--A solid, largely insoluble organic material occurring in oil shale which yields oil when it is heated but not oxidized.

Ketone--Any of various organic compounds containing a carbonyl group (C) and a hydrocarbon group such as CH_3. The carbonyl group is linked to the hydrocarbon groups in the middle of the chain resulting in at least one hydrocarbon group on each side of the carbonyl group.

Kiln--An oven, furnace, or heated enclosure used for processing a substance by burning, firing or drying.

Kilocalorie--One thousand calories. A unit of energy equal to 3.968 Btu's.

Kinetic energy--The energy that an object possesses because it is moving; it is determined by the mass and the speed of the object.

Krypton-85--An inert radioactive gas which is a fission product of U-235 or Pu-239.

Leaching--The continued removal, by water, of soluble matter from rock or soil.

Lean gas--Refers to processed gas.

Light water reactor--A nuclear reactor which uses water (H_2O) to transfer heat from the fissioning of uranium to a steam turbine.

Lignite--The lowest-rank coal, with low heat content and fixed carbon, and high percentages of volatile matter and moisture; an early stage in the formation of coal.

Liquefaction of gases--Any process by which gas is converted from the gaseous to the liquid phase.

Liquefied natural gas--A clean, flammable liquid existing under very cold (see cryogenic) conditions, that is, almost pure methane.

Lock hopper--A device for introducing solids, such as coal, into a pressurized system.

Longwall Mining---Removing a mineral from an extensive exposed surface of a deposit usually underground where minerals are removed by a shearing machine, and roof support is provided by movable hydraulic jacks.

Loss of coolant accident--An accident in a nuclear reactor where the coolant is lost from the reactor core. For example, a break in a coolant pipe in the reactor cooling system would cause this accident.

Low-Btu gas--Gas obtained by partial combustion of coal with air; energy content is usually 100 to 200 Btu's per cubic foot.

Magma--Naturally occurring melted and mobile rock material occurring within the earth's crust and consisting mainly of liquid material with suspended crystals and bubbles of gas in it.

Magnetic survey--An exploration method based on distortions in the normal magnetic field of the earth's crust.

Megawatt--A megawatt is a million watts or a thousand kilowatts and is used to measure the amount of power as electricity that can be produced by a facility at any one time.

Mercaptan--Any of various organic compounds containing a sulfur and hydrogen group (SH) and a hydrocarbon group such as CH_3. The sulfur present in the compound often causes disagreeable odors.

Methanation--The catalyzed reaction of CO and H_2 to form CH_4 and H_2O.

Methane--A colorless odorless flammable gaseous hydrocarbon, CH_4, that is a product of decomposition of organic matter in marshes or mines or of the carbonization of coal. It is used as a fuel and as a raw material in chemical synthesis.

Micron--A unit of length equal to one thousandth of a millimeter.

Microsphere--A small nuclear fuel particle that is coated with layers of graphite; used in the HTGR.

Milling--A process in the uranium fuel cycle where ore which contains only .2 percent uranium oxide (U_3O_8) is converted into a compound called yellowcake which contains 80 to 83 percent U_3O_8.

Mine-mouth--The vicinity or area of a mine, usually within several miles.

Moderator--A material used in some reactors; the purpose is to reduce the energy of neutrons.

Mole--A large diameter drill mounted on a movable framework capable of tunneling holes of 5 to 30 feet in diameter.

Monazite--A yellow, red, or brown phosphate of the cerium metals and thorium found often in sand and gravel deposits.

Mrem--A unit used to measure a radiation dose.

Naphtha--Any of various volatile, often flammable liquid hydrocarbon mixtures used chiefly as solvents and dilutents.

Natural background radiation--The amount of radiation present in the environment which is not the result of man's activities.

Natural gas--A mixture of light weight hydrocarbons in geologic deposits, with its predominant compound being methane.

Noble gas--The gases helium, neon, argon, krypton, xenon, and radon which do not normally combine chemically with other elements.

Ocean thermal gradient--Difference in temperature of the ocean water at various depths.

OCS (outer continental shelf)--The submerged lands extending from the outer limit of the historic territorial sea (typically three miles) so some undefined outer limit, usually a depth of 200 meters. In the U.S., this is the portion of the shelf under federal jurisdiction.

Octane number--A measure of a gasoline's ability to burn smoothly.

Oil shale--Sedimentary rocks containing insoluble organic matter (kerogen) which can be converted into oil by heating.

Operating costs--Costs that vary with the level of output such as labor costs, raw material costs, supplies, etc.

Outcrop--A place where a mineral formation is exposed to direct observation from the land surface.

Overburden--The rock, soil, etc., covering a mineral to be mined.

Paramarginal resources--Deposits not currently produced because the recovery is not quite economically feasible or because, although recovery is economically feasible, legal or political circumstances do not allow it.

Particulates--Microscopic pieces of solids which emanate from a range of sources and are the most widespread of all substances that are usually considered air pollutants. Those between 1 and 10 microns are most numerous in the atmosphere, stemming from mechanical processes and including industrial dusts, ash, etc.

Penstock--A pipe which transports water to a turbine for the production of hydroelectric energy.

Permeability--The ability of a porous medium to conduct fluid through it.

Phenol--Any of various organic compounds containing a hydroxide group (OH) and a hydrocarbon group such as CH_3. Phenols are highly reactive compounds.

Photosynthesis--The synthesis of chemical compounds with the aid of radiant energy, especially light; the formation of carbohydrates in the chlorophyll-containing tissues of plants exposed to light.

Photovoltaic cells--A method for direct conversion of solar electrical energy. Commercially available cells are limited to an efficiency of 10 percent.

Pillar--A solid mass of coal, rock, or ore left standing to support a mine roof.

Placer deposit--A deposit of clay, silt, sand, gravel or some similar material deposited by running water which contains particles of uranium, gold, or some other valuable mineral.

Plutonium--An element that is very rare in nature, and is usually obtained by exposure of U-238 to neutrons in a reactor.

Pneumatic drill--A drill which is worked by air pressure.

Primary containment--Also referred to as a pressure vessel. The primary containment is an enclosure which surrounds the nuclear reactor core and associated equipment for the purpose of minimizing the release of radioactive material in the event of a serious malfunction in the operation of the reactor.

Profit margin--Profit as a percentage of sales.

Province--The largest unit used by the USGS to define the areal extent of coal resources.

Pyrolysis--Decomposition of materials through the application of heat with insufficient oxygen for complete oxidation.

Radiometric prospecting--Finding minerals using a geiger counter or scintillometer that measures radioactivity.

Radon gas--A radioactive gaseous element formed by disintegration of uranium.

Raffinate stream--In the solvent extraction process there are two output streams. One is the "pregnant" stream containing the recovered valuable material such as uranium and plutonium. The raffinate stream contains the unneeded material; the raffinate is transferred to a pond.

Rank--A classification of coal according to percentage of fixed carbon and heat content. High rank coal is presumed to have undergone more geological and chemical change than lower rank coal.

Rankine cycle--A cycle of processes to produce work from heat, commonly using steam as a working fluid (a steam engine).

Reactor core--The part of a nuclear power plant which contains control rods and the fuel elements where fissioning occurs.

Rem--A unit of radiation dose. Quantities of radiation dose are often quoted in millirem units (see Mrem).

Reprocessing--The used fuel elements from a nuclear reactor are subjected to a variety of chemical and mechanical processes; the purpose is to recover the created plutonium-239 and the unused uranium-235, and to remove the fission products.

Reserves--Resources which are known in location, quantity and quality and which are economically recoverable using currently available technologies.

Retort--A closed heating facility used to process oil shale.

Room and pillar--An underground mining technique in which small areas of a coal or oil shale seam are removed and columns of the deposit are left in place to support the roof.

Rotary drill--A machine which uses a revolving bit to bore out holes.

Rotary drilling--The drilling method by which a hole is drilled by a rotating bit to which a downward force is applied. The bit is fastened to and rotated by the drilling string, which also provides a passageway through which the drilling fluid is circulated. New joints of drill pipe are added as drilling progresses (see Bit, Drill string, Rotary drill).

Rotary kiln--A heated horizontal cylinder which rotates to dry coal.

Runoff--The portion of precipitation on the land that ultimately reaches streams.

Ruthenium-106--A radioactive fission fragment with a half life of 369 days. Ruthenium-106 does not occur in nature.

Scintillometer--A device that is sensitive to various types of radiation.

Scrubber--Equipment used to remove pollutants, such as sulfur dioxides or particulate matter, from stack gas emissions usually by means of a liquid sorbent.

Seam--A bed of coal or other valuable mineral of any thickness.

Secondary recovery--Methods of obtaining oil and gas by the augmentation of reservoir energy; often by the injection of air, gas, or water into a production formation (see Tertiary recovery).

Seismic survey--A geophysical exploration technique in which generated sound waves are reflected or refracted from underlying geologic strata and recorded for later analysis.

Shearing machine--An excavating machine used in longwall mining which has a rotating toothed drum which cuts parallel to the coal face.

Shift conversion--A step in the process of converting coal to methane (CH_4); during this step the ratio of H_2 to CO is altered to 3:1 through the use of a catalyst.

Shortwall mining--A variation of longwall mining in which a continuous miner rather than a shearer is used on a shorter working face; identical advance roof supporters are used (see Longwall mining).

Silt--Loose sedimentary material with rock particles usually 1/20 millimeter or less in diameter.

Siltation--The deposition or accumulation of fine particles that are suspended throughout a body of standing water or in some considerable portion of it; especially the choking, filling or covering with stream-deposited silt behind a dam or other place of retarded flow in a reservoir.

Slag--A molten or solidified ash.

Sludge--A muddy or slushy deposit or sediment.

Slug--A section of heavy or dense fluid between two lighter fluids in a pipeline or other flow passage.

Slurry--A mixture of a liquid and solid. Explosive slurries of ammonium nitrates, TNT and water are used for blasting. Slurries of oil and coal or water and coal are used in coal processing and transportation.

Solar constant--The solar radiation falling on a unit area at the outer limits of the earth's atmosphere.

Solvent--A substance capable of dissolving or dispersing one or more other substances.

Spoils--The rock, soil, etc., of the overburden after it has been broken and removed from above the coal seam.

Spot market price--The price of energy commodities sold for cash or immediate delivery.

Stack gas--Gases resulting from combustion.

Stack gas cleaning--Referring to the removal of pollutants from combustion gases before those gases are emitted to the atmosphere.

Subbituminous--A low-rank coal with low fixed carbon and high percentages of volatile matter and moisture (see Rank).

Subsidence--The sinking, descending or lowering of the land surface.

Sulfur dioxide (SO_2)--One of several forms of sulfur in the air; an air pollutant generated principally from combustion of fuels that contain sulfur. A natural source of sulfur dioxide is volcanic gases.

Super heat--A condition in which the volume of steam is a function of both pressure and temperature. It has a higher energy than steam in which the volume is only a function of temperature.

Surfactant--Surface acting agent; a chemical which reduces the surface tension between two materials, causing one to be "washed" from the surface of the other.

Syncrude--A liquid obtained by processing oil shale or coal.

Synthesis gas--Intermediate-Btu gas; almost always used as a feedstock, but it can be used as a starting point for the manufacture of high-Btu gas, methanol or other products.

Tailings--Refuse material separated as residue in the preparation of various products (as ores).

Tar--A dark brown or black bituminous liquid obtained by destructive distillation of organic material or more commonly, a viscous oil.

Tar Sands--Hydrocarbon-bearing deposits distinguished from more conventional oil and gas reservoirs by the high viscosity of the hydrocarbon, which is not recoverable in its natural state through a well by ordinary production methods.

Tertiary recovery--Use of heat and other methods other than fluid injection to augment oil recovery (presumably occurring after secondary recovery).

Thorium--A radioactive element of atomic number 90; naturally occurring thorium has one main isotope--thorium-232. The absorption of a neutron can result in the creation of uranium-233.

Throttle valve--A valve used in space cooling equipment which expands the fluid in the system to produce a cooling effect.

Trajectory--The overall combination of the technological alternatives chosen for each activity in resource development.

Tramp iron--Stray metal objects such as picks or bolts, which have become mixed with coal or ore, usually removed by magnets before they damage the ore-handling machine.

Tritium (H_3)--A radioactive isotope of hydrogen.

Trommel screen--A usually cylindrical or conical revolving screen used for screening or sizing substances such as rock, ore, or coal.

Turbine--A rotary engine activated by the reaction and/or impulse of a current of pressurized fluid (water, steam, liquid metal, etc.) and usually made with a series of curved vanes on a central rotating spindle.

Uranium--A radioactive element of atomic number 92; naturally occurring uranium consists of 99.29 percent uranium-238 and .71 percent uranium-235.

Uranium-235--An isotope of uranium of mass number 235. When bombarded with slow or fast neutrons it will undergo fission.

Uranium-238--An isotope of uranium; naturally occurring uranium consists of 99.29 percent uranium-238 and .71 percent uranium-235; uranium-uranium-238 will fission upon absorption of a fast neutron or can be converted to plutonium-239.

Uranium hexafluoride (UF_6)--A gaseous compound of uranium; used in the diffusion process of enrichment.

Uranium oxide (U_3O_8)--The most common compound of uranium that is found in typical ores.

Venturi scrub--A method for cleaning particulates from stack gases which consists of water being injected into a high-speed gas flow. The particulates are removed with the water.

Viscosity--The property of a fluid which indicates its ability to resist flow.

Volatile--Readily vaporizable at a relatively low temperature.

Well bleeding--Allowing a bore hole (usually in reference to a geothermal well) to vent to the atmosphere for the purpose either of clearing it of impurities or of testing it.

Wellbore--The hole made by the drilling bit.

Wellhead--The equipment used to maintain surface control of a well. It is formed of the casing head, tubing head, and Christmas tree. Also refers to various parameters as they exist at the wellhead: wellhead pressure, wellhead price of oil, etc.

Working fluid--Fluid in electrical generation plants that is heated by the energy source and then expands through the turbine without leaving the system.

Yellowcake--Product of the milling process in the uranium fuel cycle that contains 80 to 83 percent uranium oxide.

Xenon--An inert gas used in specialized electric lamps, present in air at about .05 parts per million.

☆ U. S. GOVERNMENT PRINTING OFFICE : 1975 O - 570-834