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Assistant Administrator for Applied Analysis
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Capital Requirements for the Transportation of Energy Materials Based on 1978 ARC Estimates

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Energy Information Administration
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Financial and Industry Studies Division
Office of Economic Analysis
Washington, D.C. 20461

October 1979

Capital Requirements for the Transportation of Energy Materials Based on 1978 ARC Estimates

Prepared by
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Asil Gezen
Project Manager
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Arlington, Virginia 22209

PREFACE

In September 1977, TERA, Inc. was retained by the Office of Mid-range Analysis of the Energy Information Administration (EIA) to develop and implement at the Department of Energy a user-interactive system for estimating investment requirements in the transportation of energy materials. Subsequent to the completion of this work, EIA's Office of Economic Analysis awarded a contract to TERA, Inc. to estimate investment requirements in the transportation sector for the energy supply and demand scenarios developed by EIA in support of the Administrator's 1977 Annual Report to Congress (ARC). This study was again revised and updated under contract for the 1978 ARC. TERA's methodology and estimates of transportation investment requirements for three EIA Scenarios are outlined in this report.

The 1977 report was the first time any attempt had been made to quantify investment requirements in the transportation industry as implied by the energy supply and demand projections developed by EIA. As such, these studies fill an important gap in the overall understanding and analysis of energy futures.

TERA's Project Manager was Dr. Asil Gezen and the Principal Investigator was Mr. Michael J. Kendrick. Dr. Robert Brooks developed the natural gas network analysis and Dr. John Rozsa

provided the extensive research into FERC filings on natural gas projects.

Dr. Suraj P. Kanhouwa of the Division of Financial and Industry Studies monitored TERA's study. Useful inputs were additionally provided by Dr. W. David Montgomery III, Director, Office of Economic Analysis and Mr. John Mitrisin, Director, Financial and Industry Studies Division, Dr. W. Charles Mylander and Mr. Richard Thrasher of EIA rendered useful assistance in accessing the MEFS model solutions.

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TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF FIGURES

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EXECUTIVE SUMMARY

Background

This report contains TERA's estimates of capital requirements to transport natural gas, crude oil, petroleum products and coal in the United States by 1990. It is a continuation of a 1978 study[1] to perform a similar analysis on 1979 scenarios. Scenarios B, C, and D from the EIA's Mid-range Energy Forecasting System (MEFS), as used in the 1978 Annual Report to Congress (ARC), were provided as a basis for the analysis and represent three alternative futures. TERA's approach varies by energy commodity to make best use of the information and analytical tools available:

- Natural Gas: Investment projections are derived from summaries of planned pipeline and LNG projects and a network analysis of the Lower 48 pipeline system to identify potential bottlenecks in the existing transmission system. Costs of expanding the gas pipeline network are computed using TERA's Gas Pipeline Investment Algorithm.
- Crude Oil: A network representation of the crude oil pipeline system is analyzed to identify needed capacity in pipelines; projected import levels are compared to deepwater port plans; and tanker requirements are projected for Alaskan oil movements. Costs for pipelines are computed using TERA's Oil Pipeline Investment Algorithm. Tanker requirements and costs make use of the Tanker Investment Algorithm developed by TERA. Barge and towboat requirements are based on average utilization rates and projected modal shares.

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[1]U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

- Petroleum Products: A general ratio method comparing growth in the pipeline system with growth in products consumption is used to estimate pipeline building. The average cost of a mile of pipeline is computed from size and mileage data using TERA's Petroleum Products Pipeline Investment Algorithm. Barge and towboat requirements are computed in similar fashion as for crude oil. Tanker requirements also make use of the utilization ratio methodology.

- Coal: Coal cars and locomotives are computed by railroad region based on originating coal traffic and general utilization ratios. A discussion on rail track and way maintenance and investment is reproduced from a recent Department of Transportation report to the Congress summarizing capital needs for railroads. These joint costs are allocated to coal based on proportion of ton miles. Barge and Collier estimates are made for a high and a low Great Lakes case. Barge estimates are made based on general utilization rates while Collier investment estimates are made for representative Great Lakes movements using TERA's Collier Investment Algorithm.

Findings

Summaries of transportation investment requirements through 1990 are given in Table 1 for Scenarios B, C, and D. Total investment requirements for the three modes and the three energy commodities are estimated to range between $36.3 and $42.7 billion by 1990 depending on the scenario.

Scenario B is a high energy demand, low oil and gas supply case and requires most capital for transportation of all energy commodities. The $1.2 to $1.8 billion extra capital for oil in Scenario B compared to C and D respectively, is made up primarily in tanker requirements for the larger Alaskan trade made necessary by lower supplies from other sources. Additional capital needs, ($1.2 to $1.6 billion) for natural gas arise primarily from increased imports of LNG requiring greater tanker and port capacity.

TABLE 1

TRANSPORTATION INVESTMENT BY MODE, MATERIAL AND SCENARIO
1990
(1978 dollars in millions)

	OIL	GAS	COAL	TOTAL
Scenario B				
Pipelines	2,614.2	13,133.0		15,747.2
Railroads			15,207.0 to 15,416.0[a]	15,207.0 to 15,416.0
Waterways	5,805.7	3,932.0	1,068.4 to 1,844.2[b]	10,806.1 to 11,581.9
TOTAL	8,419.9	17,065.0	16,275.4 to 17,260.2	41,760.3 to 42,745.1
Scenario C				
Pipelines	3,025.4	13,123.6		16,149.0
Railroads			14,073.0 to 14,282.0[a]	14,073.0 to 14,282.0
Waterways	4,168.5	2,764.0	1,427.6 to 2,203.3[b]	8,270.1 to 9,045.8
TOTAL	7,193.9	15,797.6	15,500.6 to 16,485.3	38,492.1 to 39,476.8
Scenario D				
Pipelines	2,339.3	13,127.7		15,467.0
Railroads			13,047.0 to 13,256.0[a]	13,047.0 to 13,256.0
Waterways	4,285.5	2,280.0	1,258.9 to 2,034.6[b]	7,824.4 to 8,600.1
TOTAL	6,624.8	15,407.7	14,305.9 to 15,290.6	36,338.4 to 37,323.1

[a] Range represents low and high rate of catch up on deferred maintenance of way.

[b] Range represents low and high Great Lakes coal traffic cases.

Finally the $0.8 to $2.0 billion larger required investment in coal transportation is for railroad cars and locomotives to carry a much larger production of western coal made feasible by oil and gas supply shortfalls.

Scenario D requires the least amount of investment in transportation and is the opposite in terms of supply-demand pressure represented by Scenario B. Scenario D is a high oil and gas supply low energy demand scenario which is more "relaxed" and can follow traditional distributional patterns built up during past times of relatively plentiful supplies.

Scenario C lies predictably in the middle representing a medium case for both supply and demand. Not all categories of investment, however, are in the middle. Scenario C shows the highest level of investment for oil pipelines ($0.4 to $0.7 billion) difference) from the other scenarios, due to a supply demand balance favoring petroleum consumption. Also, water mode investment in coal carriage is highest by $0.2 to $0.4 billion in Scenario C due to a larger amount of coal used domestically originating from areas where water shipment is available.

CHAPTER I. INTRODUCTION

As a part of the Department of Energy's overall Mid-Range Energy Forecasting System (MEFS) effort, impacts analyses are made on capital requirements in energy production and processing industries. This report is the second to deal with the impact of DOE energy forecasts on capital requirements in the transportation industries. The first was completed as part of the 1978 series of forecasts made by the Department for its Annual Administrator's report to Congress.[1] This year's report analyses capital requirements for transportation of energy materials in three of the scenarios run for the 1978 Annual Report to Congress (ARC).

The Mid-Range Energy Forecasting System (MEFS) is an integrating model of several models. The MEFS supply model computes production and processing levels for various energy forms based on costs and prices. The demand model computes desired levels of consumption of various energy commodities based on price elasticities and cross elasticities of demand. Both the supply and the demand models are made dependent on various exogenous factors which are constructed into a scenario for analysis. Supply scenarios allow for both optimistic and pessimistic rates of discovery for oil and gas, hence low, medium and high supply cases are studied

---

[1] U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

separately. Also, demand for energy is influenced by overall economic growth rates and conservation factors, hence, high, medium and low demand cases are studied separately.

Figure I-1 shows the five supply/demand scenarios analyzed in the integrating model. This study analyzes the investment requirements for transportation equipment implied by the production and consumption patterns found in Scenarios B, C, and D. Table I-1 gives the 1985 and 1990 consumption levels for coal, oil and natural gas as estimated by MEFS compared to 1978 domestic consumption levels.

The following report is organized in chapters by energy materials: Natural Gas, Crude Oil, Petroleum Porducts, and Coal. Each chapter is subdivided by mode of transport. The analysis is conducted for 1990 in all cases. The 1985 estimates given in the summary table in each chapter are based on an interpolation of the 1990 results from the 1978 year of reference.

Figure I-1

Mid-Range Energy Forecasting System
Scenario Structure

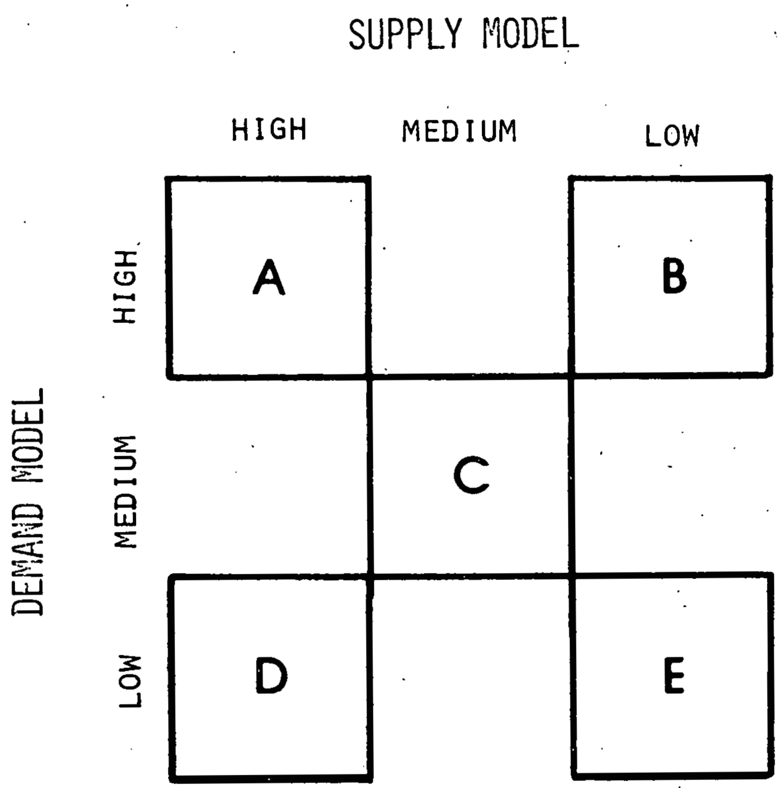

Table I-1

Annual Consumption of Energy
in the United States

Scenario		Coal (million tons)	Oil (million barrels)	Gas (billion cubic feet)
1978		640.94	6,869.94	20,571.00
1985	B	1,020.03	6,603.48	18,652.63
	C	959.64	6,982.42	19,439.28
	D	941.29	6,649.66	19,800.47
1990	B	1,476.33	6,974.56	17,416.71
	C	1,384.56	7,156.44	18,838.81
	D	1,254.20	7,403.55	18,521.60

SOURCE: Historical: U.S. Department of Energy, Energy Data Reports.

Projected: U.S. Department of Energy, Mid-Range Energy Forecasting System

CHAPTER II. NATURAL GAS

Introduction

Natural gas is transported primarily via pipeline. Gas imported from overseas sources is transported in liquid form as liquified natural gas (LNG) to receiving terminals where it is gasified and moved via pipelines to final consumption areas. Pipelines constitute a large fixed investment with limited flexibility to adjust to changes in supply and demand.

Table II-1 compares historical to projected consumption of gas. Although 1990 projected consumption of gas in the United States may be as little as 80 percent of its 1973 peak, shifting sources of supply, together with restrictions on certain uses, will result in a continuing need to build pipelines.

One growing source of supply for natural gas is through importation. Some import receiving terminals for LNG are (or are planned to be) near to the final demand areas. Other import terminals are planned near the head of major interstate pipeline systems and will supplement the decline in domestic production which historically supplied these pipelines. In both cases, some new pipeline construction is needed to connect these terminals with the existing transmission and distribution networks.

Table II-1

U.S. Supply of Natural Gas

Year		Marketed Production(s) 1/ (BCF)	LNG Imports 2/ (BCF)
1973		23,603	3
1978		20,571	84
1985	B	18,887	962
	C	19,674	570
	D	20,035	570
1990	B	17,684	1,182
	C	19,299	783
	D	18,981	611

SOURCE: Historical: DOE, Energy Data Reports; Projected; MEFS

1/ Less exports
2/ From overseas origins

A second major source of new gas supply is anticipated to be from the Arctic regions of Alaska and Canada. Significant new investment, greater than all other planned investments in gas transportation combined, will be required to get this supply to market. These new sources of supply, together with less important new gas discoveries in the Lower 48, will load the gas transmission network differently than what it was originally designed for. Consequently, some "spot" shortages or bottlenecks in capacity will occur.

The following analysis outlines major new investments for Alaskan and imported gas. The impact of shifting supply sources on existing and proposed network links are assessed under the assumption that all of the network will be used in an optimal way; that is, a way which results in the lowest overall cost of operation. For this reason the estimates given may be considered optimistic. Contractual obligations, lack of cooperation between organizations and imperfect knowledge all work against such optimality in the use of the network. At less than optimal conditions, more investment will be needed to overcome bottlenecks that develop among the many transmission systems which are characterized in this analysis as a single network. Notwithstanding this difficulty in the analysis, the results anticipate many existing plans and reinforce conventional wisdom in the industry in many cases. There are also a few surprises which suggest need for closer examination of transportation requirements in certain areas.

Importation of Natural Gas

Terminals and Pipelines

Three import locations presently bring LNG into the U.S. Two are included under the heading of El Paso I in Table II-2. In addition, five proposed projects are available to the MEFS supply model depending on the costs and alternative encountered under different scenarios. The throughputs selected by MEFS for 1990 are given in Table II-2. In the solution process used by MEFS, the proposed projects are bounded by a maximum but not by a minimum level. Consequently, they may differ from the throughput

Table II-2

LNG Importation Facilities
Modeled in MEFS

Project Name	1990 Projected Use (MMCF/D)		
	B	C	D
Existing Projects:			
Distrigas	112	112	112
El Paso I	1,000	1,000	1,000
Proposed Projects:			
El Paso II	0	0	0
Pac-Indonesia	504	0	0
Tenneco	872	291	113
Trunkline	449	449	449
Columbia 1/	0	0	0

1/ Represents an addition to the El Paso I project which includes Columbia LNG at Cove Point, Maryland and Southern LNG at Elba Island, Georgia.

volumes projected by the proponents of each project.

The El Paso II project has been proposed with a capacity of 1 billion cubic feet per day. Because it was not selected by the MEFS supply model in any scenario, its projected cost for terminal and pipelines of $741 million is not included among the capital requirements computed for this study. This also holds true for the Columbia gas LNG expansion at Cove Point, Maryland.

The Pac-Indonesia project is selected by MEFS only in the B scenario at a throughput considerably less than the 4 to 5 billion cubic feet per day for which it is planned. The MEFS supply model specified an upper bound of 1 billion cf/d. In spite of this discrepancy, the full cost in 1974 dollars of $721.9 million was used for the Point Conception facility as planned. This was done because a meaningful scaling of the project to meet projected demands is beyond the scope of this study. However, the LNG tanker portion of this proposal is amenable to a ratio estimate. Therefore, investment in tankers, to be discussed in the next section, is scaled to meet projected requirements more closely. The entire Pac-Indonesia project is still under consideration by the Federal Energy Regulatory Commission (FERC) and the Energy Regulatory Administration (ERA).[1]

The Tenneco project involves investment in both the United States and Canada. Most of the gas planned is destined for use in the United States. This project, known also as TAPCO, involves an LNG receiving facility at St. Johns, New Brunswick

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[1]FERC, Dockets CP75-83, 17 September 1974 and CP74-160, 18 April 1975.

and a total of 564 miles of pipe terminating at pipeline connections in Milford, Pennsylvania. The LNG plant was planned for a capacity of 1.3 billion cf/d at a cost of 634 million in 1981 U.S. dollars. The pipelines were projected to cost an additional $801 million. Since the MEFS supply model was last updated, approval for this project has been denied by the Energy Regulatory Administration.[2] However, since the gas supply projected by MEFS was based on this project and would have to come from some other source in any case, TAPCO costs are included in the total for all scenarios.

The "Trunkline" project is planned to feed into major interstate pipelines from a gasification plant and terminal at Lake Charles, Louisiana connected by 45.8 miles of 30" pipe. Import agreements have been made for 168 billion cubic feet per year (460 million cf/d). The MEFS supply model permits a maximum of 449 million cf/d throughput which is used in all scenarios. The cost of the terminal is projected at $164.3 million, the pipeline at $28.8 million, and a contract for channel dredging has been awarded by the U.S. Army Corps of Engineers for $4.9 million.[3] Dredging costs are continuing costs and have not been included in the capital cost summary.

<u>LNG Tankers</u>

Table II-3 presents the data used to estimate investment requirements for LNG tankers under each scenario. Two of the

---

[2]Canadian Embassy, Decision of National Energy Board of Canada, November 1977; FERC, Docket CP77-100, 27 December 1976; ERA Docket ERA77-0100LNG; ERA Decisions #3 (15 December 1978) and #4 (21 December 1978).

[3]FERC Docket CP74-139, 18 February 1977.

Table II-3

Computation of Investment
in LNG Tankers

Project Name	Scenario B	Scenario C	Scenario D
Pac-Indonesia:			
1990 use (MMCF/D)	504	0	0
Design (MMCF/D)	4,000	4,000	4,000
No. of tankers to meet design capacity	9	9	9
No. of tankers to meet projected use	1	0	0
Cost of tankers (1981 dollars) ($ million)1/	175	0	0
Tenneco:			
1990 use (MMCF/D)	872	291	113
Design (MMCF/D)	1,300	1,300	1,300
No. of tankers to meet design capacity	8	8	8
No. of tankers to meet projected use	4	3	1
Cost of tankers (1981 dollars) ($ million)2/	700	525	175
Trunkline:			
1990 use (MMCF/D)	449	449	449
Design (MMCF/D)	460	460	460
No. of tankers to meet design capacity	5	5	5
No. of tankers to meet projected use	5	5	5
Cost of tankers (1981 dollars) ($ million)3/	608	614	617

1/ Assumed to be the same as Tenneco.
2/ FERC, Docket CP77-100 (12/27/76).
3/ FERC, Docket CP74-b((18/2/77).

three proposed LNG projects chosen by MEFS are underutilized in the 1990 projections of throughput. Although the full cost of the shoreside portion of these projects are included among investment requirements, the number of tankers and, hence, investments in tankers are assumed to follow demand more closely. The tankers proposed for use in all projects are 125,000 cubic meter capacity costing between $125 and $167 million in 1978 dollars. The number of tankers needed are given in the FERC docket for each project and is dependent on the volume to be shipped and the distance to the source of the gas.

Alaskan Natural Gas

South-Alaskan Gas

The MEFS solution calls for from 59 to 289 million cf/d of gas to be shipped from southern Alaska to points on the west coast. This is planned to be accomplished through the use of LNG tankers. A liquefaction facility is planned at a capacity of 400 million cf/d and a cost of $606.4 million in 1977 dollars. A pipeline will be needed to bring gas to the liquefaction plant. Its cost is projected to be $200 million.[4] It is anticipated that the LNG would be shipped to the Pac-Indonesia plant at Point Conception in California. Data for an adequate receiving terminal, should the Pac-Indonesia project not be built, was not available. An expansion of an existing experimental Oregon LNG gasification plant and receiving terminal may be adequate to receive the

[4]Northwest Alaska Pipeline Co.

projected volumes of south-Alaskan gas. This facility may receive a maximum-sized tanker of only 25,000 cubic meters. It is not now used as a terminal for waterborne traffic but only as a storage facility. The cost of providing an alternate receiving terminal for south-Alaskan LNG could not be determined within the scope of this study and is, therefore, excluded from scenarios C and D. Scenario B provides sufficient demand for use of the Pac-Indonesia terminal which has sufficient capacity to handle both the projected Indonesian and Alaskan gas receipts.

El Paso gas had proposed an LNG shipment alternative for Alaskan gas.[5] Although the proposal was geared to the shipment of approximately 865 billion cf per year (2370 MMCF/D), more appropriate to arctic production, the tanker estimates may be scaled to the smaller volumes given in Table II-4. This proposal was denied as part of the decision to allow the building of the Alaskan Natural Gas Pipeline.

North-Alaskan Gas

The MEFS solutions assume the existence of the Alaskan Natural Gas Pipeline with capability to deliver arctic gas to pipeline connections on the west coast and in the northern tier states. The total project is designed to deliver gas from arctic regions in both Canada and Alaska to consuming centers in Canada and the United States. It consists of four separate components defined by geographical area. There is an Alaska segment, a Canadian portion and in the Lower 48 states two segments called "Northern Border" and "Western Leg."

---

[5]FERC Docket CP75-96 et. al., 1 February 1977, pp. 137-142.

Table II-4

LNG Tankers for
Delivery of South Alaskan
Natural Gas

	Scenario		
	B	C	D
Throughput (MMCF/D)	236.6	289.3	58.7
No. of tankers to meet throughput	1 1/	1 1/	1 2/
Cost of tankers ($ million) (1978 dollars)	180	180	70

1/ 165,000 cu meters.

2/ 58.7 MMCF/D translates to approximately 994,541 cu meters loaded in Alaska per year. A tanker may make 29 trips per year. Therefore, a tanker must have at least 34,294 cu meter capacity. TERA estimated the cost of a 35,000 cu meter tanker based on the cost of larger tankers.

Initial construction is anticipated to deliver approximately 1,040 million cf/d of pan-Alberta gas to markets in the United States. In this way, a "prebuilt" transmission capacity may begin amortizing costs and delivering gas before completion of the Alaskan segment of the project and development of gas fields to deliver the statutory limit of 2.4 billion cf/d to the Lower 48 States. The total project is estimated to cost $10,300 million in 1977 dollars to deliver 2.4 billion cf/d.[6] A portion of this cost provides for capacity above 2.4 billion cf/d through Canada in order to deliver Arctic gas to final demands in Canada. The Canadian share of jointly used facilities could not be determined. Therefore, the full value of the Canadian segment (about 40 percent of the total) is included in the investment summary. The Canadian gas delivered to the U.S. during the "prebuilt" phase of the project will be reimbursed to Canada either through monetary or in-kind compensation.

Network Impacts

The Network Solution

New sources of supply, together with restrictions on certain traditional, industrial, and utility demands, will cause shifts in the distribution patterns of natural gas. These shifts were analyzed using a network model of the U.S. gas transmission system.[7]

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[6] Northwest-Alaskan Pipeline Co., 1977 estimates. Current revisions of costs are being made and are not yet available.

[7] Developed by TERA and Robert Brooks & Associates based on Robert Brooks & Associates' GASNET3 system.

The complete modeling framework was designed to disaggregate MEFS regional based supply and demand projections to 173 BEA Economic Areas. Supplies are then allocated to demands in a manner which makes most efficient use of existing pipeline capacity.

Figure II-1 shows a schematic representation of the natural gas pipeline network which was used in this study. Existing pipelines and some proposed pipelines are characterized as a single system of links and nodes connecting BEA Economic Areas. The proposed pipelines in the network include all pipeline connections from proposed LNG import facilities, the Western Leg and Northern Border sections of the Alaskan pipeline project, and two proposals for the Rocky Mountain region called "Trailblazer" and "Pathfinder." Costs for LNG and Alaska related pipelines were outlined above. Trailblazer consists of three segments connecting Summit County, Utah to Gage County, Nebraska. The "Overthrust" segment is planned for 272,633 thousand cf/d from Utah to Sweetwater, Wyoming. Colorado Interstate Gas will own the section from Wyoming to Weld County, Colorado and operate the Trailblazer section from Colorado to Nebraska. The middle section is designed for a capacity of 447,317 thousand cf/d and the Trailblazer section for 350,000 thousand cf/d. The entire project is anticipated to cost $427 million in 1979 dollars.[8]

Pathfinder, proposed by Cities Service Company, consists of two major segments: reconstruction and conversion of the Arapahoe Oil Pipeline from Marino County, Wyoming to Humbolt, Kansas,[9]

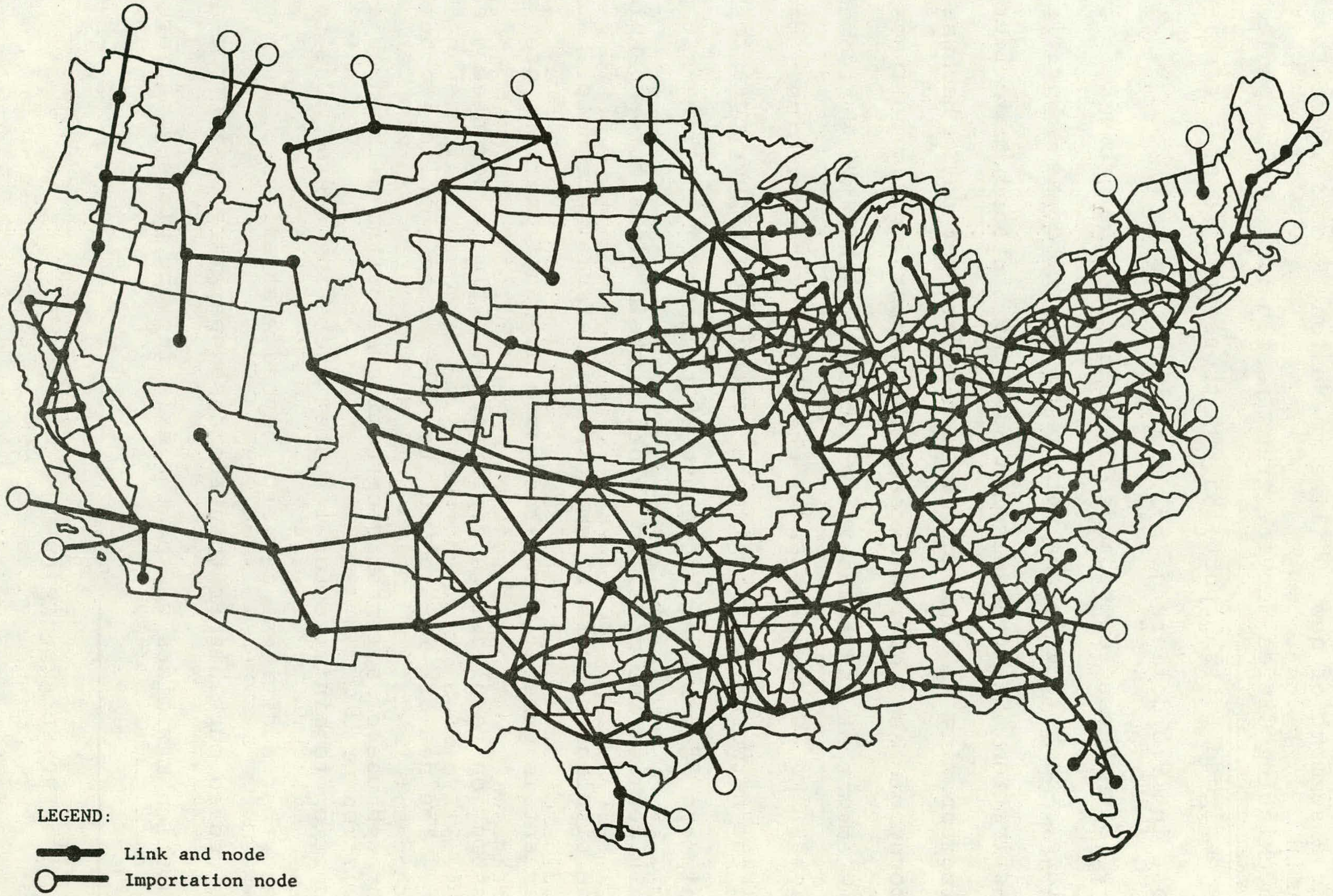
---

[8] FERC, Docket CP79-80.

[9] The Arapahoe pipeline (with a parallel Amoco pipeline) connects Region 05 to Region 09 in the crude oil pipeline network (see Chapter III) and is not required for oil shipment in any scenario.

Figure II-1

Natural Gas Pipeline Network
Representation



and a segment of new 20" line to Heston, Kansas where it connects to existing Cities Service transmission lines. The project capacity is designed to transport 185,000 thousand cf/d at a total project cost in 1976 dollars of $95.3 million.[10]

With these few proposed links added, the network is complete. Each link in the network is described as to origin and destination BEA, transmission cost per thousand cubic feet, and line capacity in thousands of cubic feet per day. Because the amount of gas tendered exceeds the amount finally delivered by the amount of gas transmission losses, each link is also characterized by the percentage of gas lost in transmission. Each link in the network is also given a second much higher cost to permit shipment of gas over and above 90 percent of the line's capacity. This permits the model to select certain links for expansion of the pipeline network if existing links are inadequate. Ninety percent is generally regarded as a high utilization rate. This assumption results in a conservative estimate for needed capacity.

The network is "solved" by allocating supplies to demands through use of a linear programming algorithm with an objective function to minimize total system operating costs. Due to the fact that additional capacity beyond what exists or is planned is priced so much higher than the base operating costs, the network solution maximizes use of the existing and planned network.

---

[10] FERC, Docket CP76-500.

Figures II-2, II-3 and II-4 show the location and direction of expanded links for scenarios B, C and D respectively. Needed new capacity in the Rocky Mountain regions exceeds already planned additions. This reflects MEFS' optimistic outlook for discovery of gas in Montana and Wyoming. The network solution calls for more than planned capacity along the Northern Border pipeline route evidently as a means of getting Montana gas to Midwest markets. The Trailblazer system from the Overthrust area, around western Colorado, is designed to allow some expansion which the MEFS projection and network solution indicates will be needed.

Gas pipeline expansion indicated within Texas may be the result of insufficient data on intrastate pipelines in Texas; therefore, these results are difficult to assess. Expansion of pipelines in Ohio and Michigan appears to be demand related. The expanded line in northern Michigan will carry Canadian imports. Other expanded links in the Appalachian region and the east coast are the result more of shifting transmission patterns than of any specific new finds or demands. On the west coast, the expanded capacity needs result from intra-BEA supply/demand imbalances which vary from scenario to scenario.

The Cost of the Network Solution

The additional capacity required on each link was costed using the Gas Pipeline Investment Algorithm developed by TERA in an earlier phase of this study.[11] The algorithm computes an optimal pipeline for a given volume of throughput, distance and

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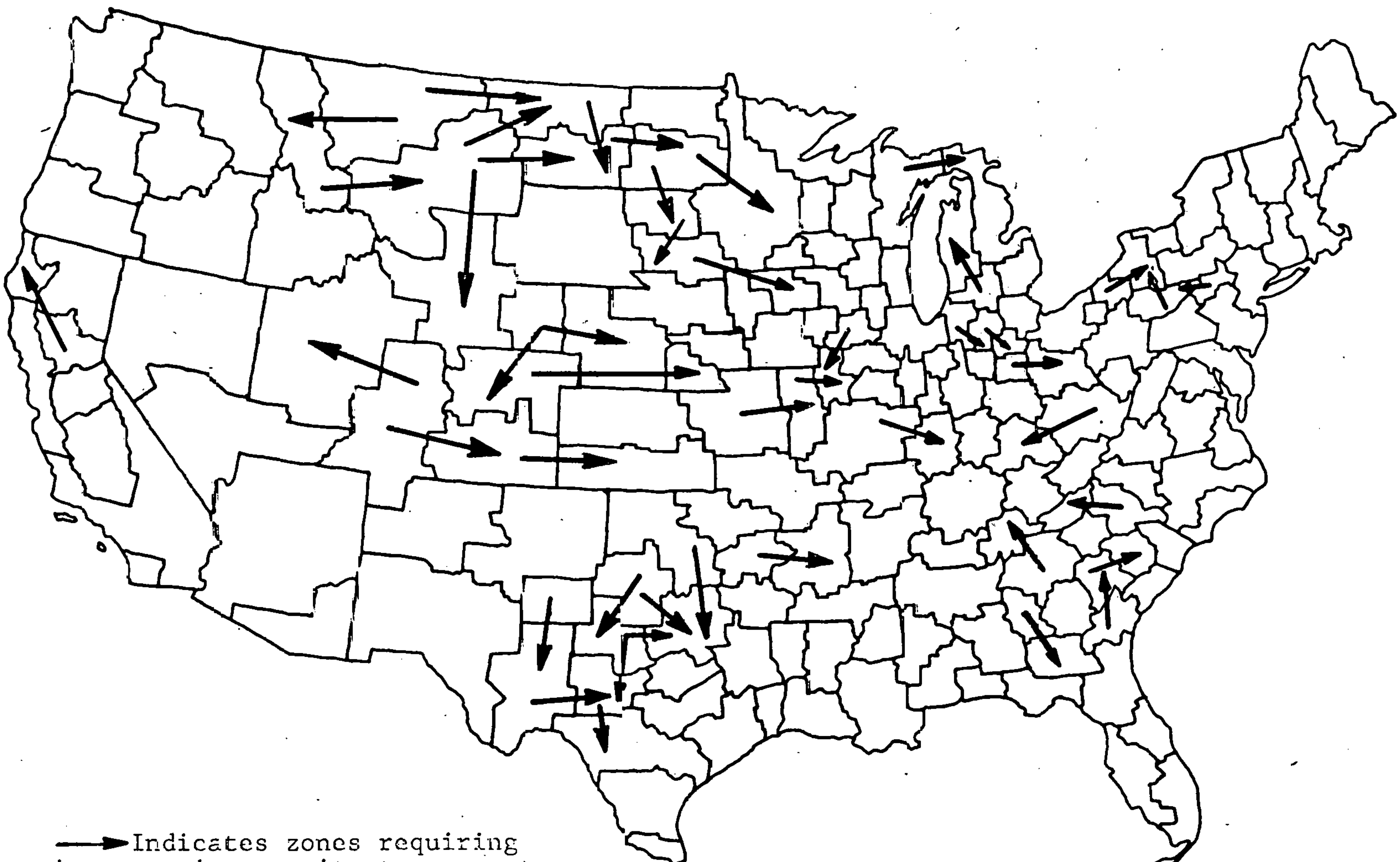
[11] U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

Figure II-2

Pipeline Links Requiring Expansion
of Capacity

1990 Scenario B



⟶ Indicates zones requiring
increase in capacity to connect.
See Figure II-1 for complete network

Figure II-3

Pipeline Links Requiring Expansion of Capacity

1990 Scenario C

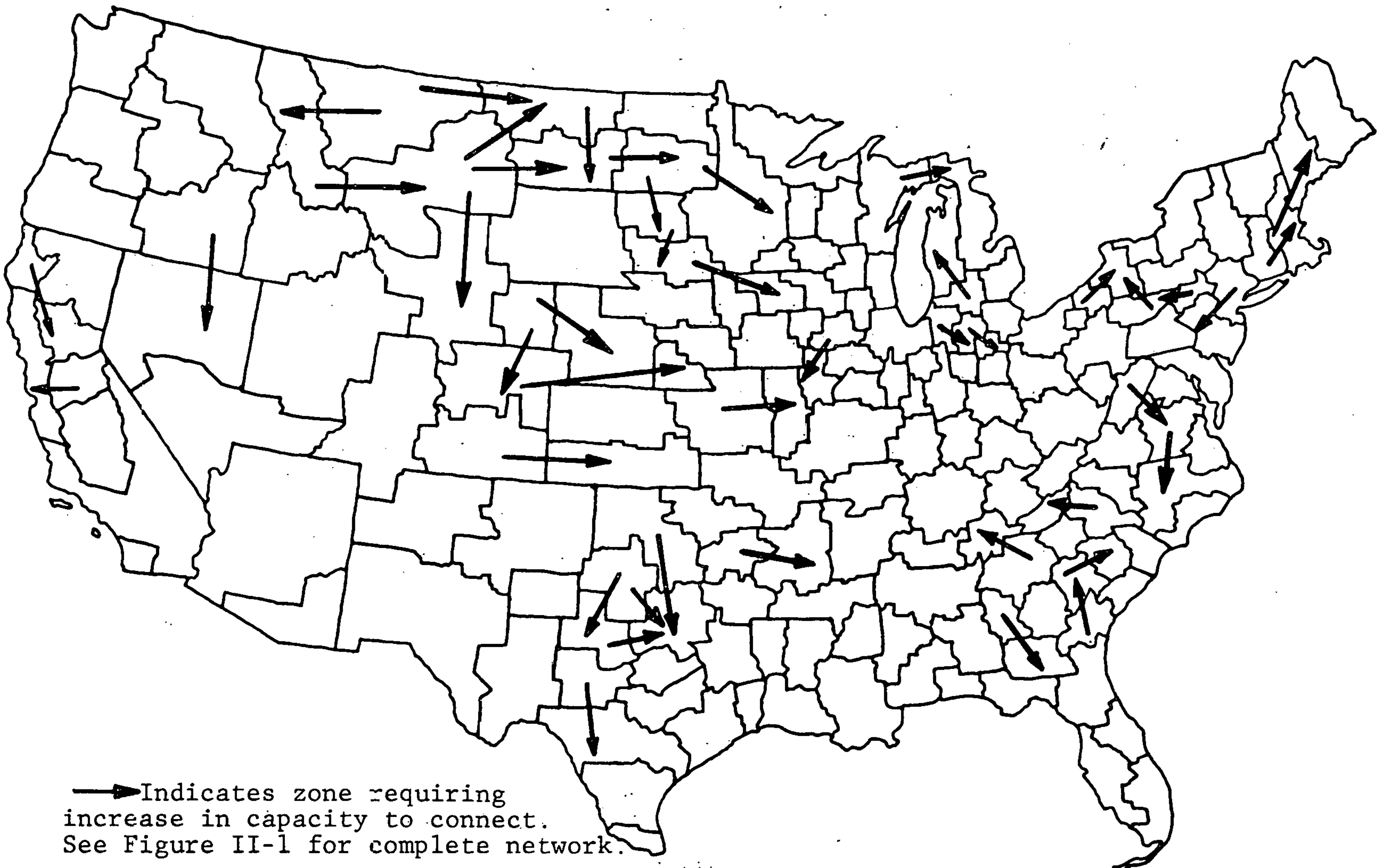
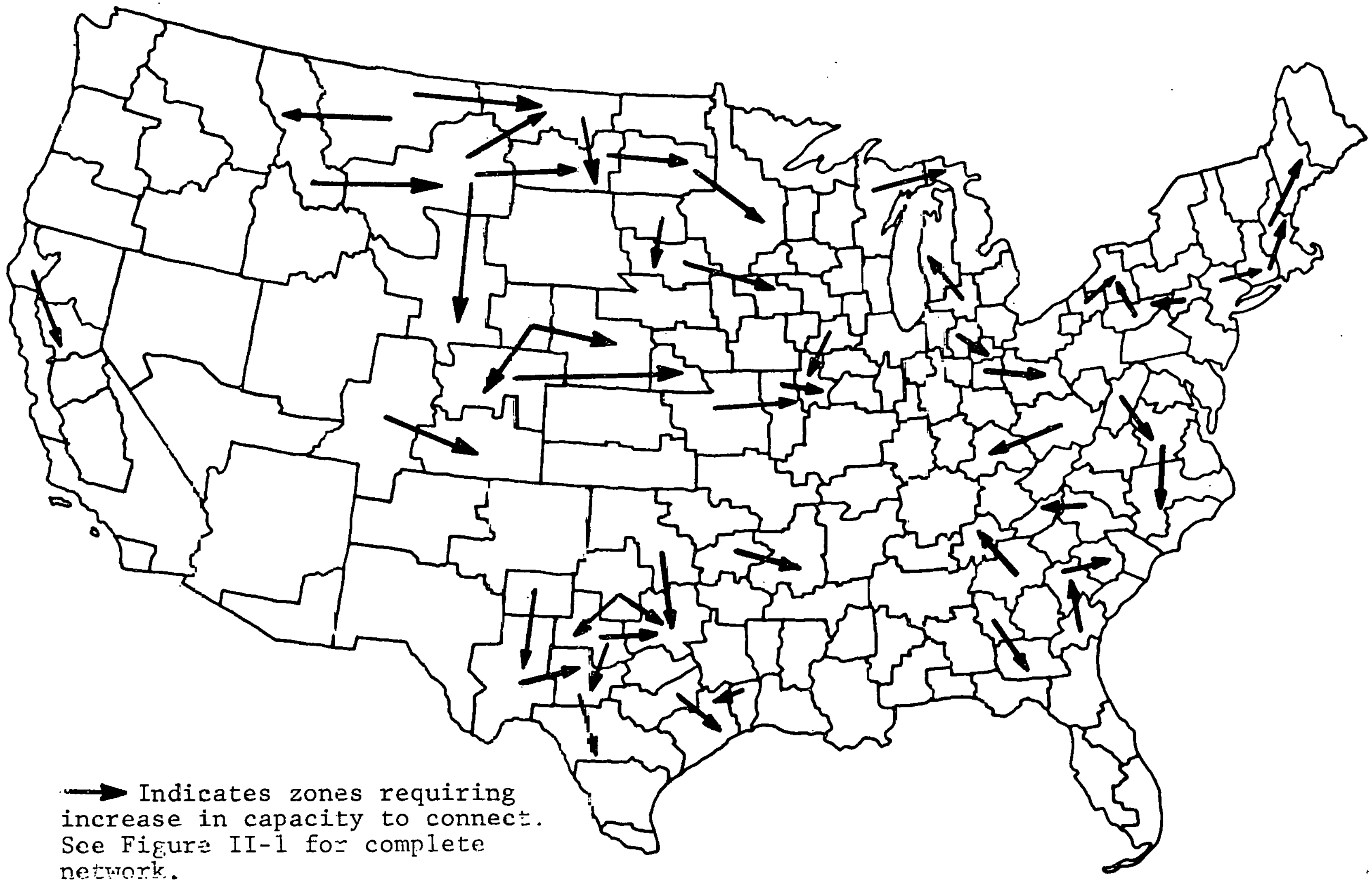


Figure II-4

Pipeline Links Requiring Expansion
of Capacity

1990 Scenario D



location (onshore or offshore) for the pipeline. A second routine varies the throughput in increments of 10 percent of the design throughput beginning with one-half the design volume and ending after 20 increments or complete looping, whichever comes first. A sample output from the algorithm is given in Figure II-5.

In some cases, an expanded link required a new pipeline. In other cases, the existing line was given greater capacity through additions to horsepower and looping. The existing capacity of the link was input to the algorithm which specified an ideal pipeline for the link which may actually be the sum of many pipelines. The variable throughput costs are examined to determine the cost of adding horsepower and looping to meet the required extra capacity. If the pipeline cannot be expanded to meet the required new throughput, the new throughput was input to the algorithm to compute the cost of building a new pipeline. Tables II-5, II-6 and II-7 outline the new construction and investment costs in 1975 dollars for each link requiring expansion of capacity as found in 1990 scenarios B, C and D respectively. A 1985 estimate was also computed through interpolation beginning with January 1979. Since gas supply declines from 1985 to 1990, no proportionality could be computed based on growth as is done for other energy materials in this report.

Figure II-5

Sample Output:

GAS PIPELINE INVESTMENT ALGORITHM

*** GAS PIPELINE PROJECT DESCRIPTION ***

THROUGHPUT (MMCF/D)	531.
DISTANCE (MILES)	65.
REGION	ONSHORE
NOMINAL DIAMETER (INCHES)	24
PIPE WALL THICKNESS (INCHES)	0.4485
HORSEPOWER PER STATION	2569.
NUMBER OF STATIONS	2
STATION SPACING (MILES)	32.50
TOTAL INVESTMENT ($ MILLION)	20.756
AVERAGE COST ($/MCF)	0.0147

* AVERAGE COST AT VARIABLE THROUGHPUT *

THROUGHPUT (MMCF/D)	LOOP PER STATION	REQUIRED HORSEPOWER	ADDITIONAL INVESTMENT	AVERAGE COST ($/MCF)
265.50	0.	330.	0.0	0.0254
318.60	0.	562.	0.0	0.0215
371.70	0.	883.	0.0	0.0188
424.80	0.	1312.	0.0	0.0170
477.90	0.	1867.	0.0	0.0156
531.00	0.	2569.	0.000	0.0147
584.10	0.	3444.	0.513	0.0143
637.20	0.	4519.	1.088	0.0142
690.30	0.	5829.	1.730	0.0143
743.40	0.	7416.	2.446	0.0146
796.50	0.	9328.	3.244	0.0151
849.60	0.	11631.	4.135	0.0157
902.70	0.	14404.	5.134	0.0166
955.80	0.	17757.	6.259	0.0177
1008.90	0.	21836.	7.537	0.0191
1062.00	0.	26851.	9.003	0.0208
1115.10	0.	33115.	10.712	0.0229
1168.20	0.	41129.	12.747	0.0257
1221.30	0.	51773.	15.257	0.0293
1274.40	0.	66832.	18.532	0.0345

SOURCE: TERA, Inc.

Table II-5

Natural Gas Pipeline Network Investment
Scenario B, 1990

Origin BEA	Destination BEA	Miles	Base Capacity (MMCFD)	Additional Volume	New P/L Size (inches)	Horsepower per Station		Looping		Investment (millions of 1975 dollars)
						new	incremental	station miles	size (inches)	
10	9	59	306	204			7194			3.69
11	9	76	689	103			2893			1.42
13	11	117	306	306			24213			13.79
26	27	151	13.7	6.58			507			.91
32	29	54	274	60.3			3472			.93
33	32	109	321	33.1			671			.65
43	41	109	57.4	37.9			7070	46	8	8.08
44	48	104	123	31.8			1654			1.13
52	53	80	85.0	85.0			10186	28	10	8.03
63	64	93	222	222			28093			10.39
74	73	54	274	162			11069			2.45
75	69	46	193	162			14848			3.27
76	75	109	1180	168			3692			2.49
79	113	98	27.4	27.4	6	490				5.48
85	72	239	912	256			5677			7.52
93	96	98	1680	175			3436			1.30
94	93	250	23.0	47.3	8	636				19.23
94	153	163	194	194			16322			14.17
95	93	152	84.0	84.0	10	1124				16.05
95	96	87	84.0	84.0	10	992				9.16
95	150	87	52.8	151	12	1378				12.55
96	97	228	1720	448			8579			9.84
97	91	109	280	184			2116			1.96
97	98	109	1680	113			2544			1.57
98	99	109	1680	116			2544			1.57
99	105	218	1680	146			3055			2.96
101	102	76	16.4	16.4			1625	19	6	2.55
101	148	54	24.0	24.0	6	383				2.89
111	112	65	1600	7.90			*			*
112	113	72	1530	10.6			*			*
114	55	52	382	43.2			1142			.31
118	117	109	306	306			21123			12.51

* Additional volume is insignificant

Table II-5 Continued

Origin BEA	Destination BEA	Miles	Base Capacity (MMCFD)	Additional Volume	New P/L Size (inches)	Horsepower per Station: new	Horsepower per Station: incremental	Looping: station miles	Looping: size (inches)	Investment (millions of 1975 dollars)
120	127	109	115	115			9653			7.49
121	125	98	96.0	96.0			10274	41	12	10.29
121	127	98	168	168			24330	12	14	11.02
123	124	120	115	115			12089			8.80
124	126	65	2160	83.8			2599			1.06
125	126	120	88.4	88.4	10	1459				13.00
125	127	109	837	105			1253			.98
126	142	61	1640	799			14928			5.45
147	110	163	14.4	14.4	6	172				7.43
148	108	445	350	350			26039			52.92
149	147	87	23.0	23.0	6	290				4.58
149	151	109	577	60.7			942			.81
153	95	196	194	114			4844			6.90
170	168	271	27.4	.974			*			*
										309.58 TOTAL

* Additional volume is insignificant

Table II-6

Natural Gas Pipeline Network Investment
Scenario C, 1990

Origin BEA	Destination BEA	Miles	Base Capacity (MMCFD)	Additional Volume	New P/L Size (inches)	Horsepower per Station: new	Horsepower per Station: incremental	Looping: station miles	Looping: size (inches)	Investment (millions of 1975 dollars)
4	2	83	22.3	.938			49			.06
5	4	59	504	260			5176			2.70
10	9	59	306	306			14947			6.53
11	9	76	689	246			7247			3.12
13	11	117	306	241			13685			8.92
14	5	93	936	40.2			823			.38
19	21	83	120	29.9			702			.56
21	23	126	193	1.96			*			*
26	27	151	13.7	7.95			749			1.24
32	29	54	274	112			5343			1.35
33	32	109	321	11.1			232			.22
43	41	109	98.7	57.4			2664			2.79
44	48	104	123	115			16718	26	12	10.51
63	64	93	222	222			28093			10.39
67	10	65	531	4.48			*			*
68	64	109	240	44.7			1208			1.20
74	73	54	274	126			7789			1.84
75	69	46	193	193			21204			4.28
76	75	109	1180	215			3692			2.49
79	113	98	27.4	27.4	6	490				5.48
85	72	239	912	257			5677			7.52
93	96	98	1680	117			2393			.90
94	93	250	23.0	72.5	10	654				25.00
94	153	163	194	194			16322			14.17
95	93	152	84.0	84.0	10	1124				16.05
95	96	87	84.0	84.0	10	992				9.16
95	150	87	52.8	189	14	1766				14.29
96	97	228	1720	397			8579			9.84
97	91	109	280	204			7986			5.98
97	98	109	1680	43.2			654			.40
98	99	109	1680	46.4			703			.43
99	105	218	1680	76.4			1389			1.35
101	102	76	16.4	16.4			1625	19	6	2.55

* Additional volume is insignificant

Table II-6 Continued

Origin BEA	Destination BEA	Miles	Base Capacity (MMCFD)	Additional Volume	New P/L Size (inches)	Horsepower per Station		Looping		Investment (millions of 1975 dollars)
						new	incremental	station miles	size (inches)	
101	148	54	24.0	24.0	6	383				2.89
111	112	65	1600	2.87			*			*
118	117	109	306	306			21123			12.51
120	127	109	115	78.6			4043			3.83
121	125	98	96.0	96.0			10274	41	12	10.29
121	127	98	168	168			24330	12	14	11.02
125	127	109	837	332			6889			4.62
126	142	61	1640	692			14928			5.45
147	110	163	14.4	14.4	6	172				7.43
148	108	445	350	350			26039			52.92
153	95	196	194	115			4844			6.90
159	160	229	114	5.29			155			.32
167	171	43	242	77.2			2513			.74
170	168	271	27.4	3.80			574			.97
										291.59 TOTAL

* Additional volume is insignificant

Table II-7

Natural Gas Pipeline Network Investment
Scenario D, 1990

Origin BEA	Destination BEA	Miles	Base Capacity (MMCFD)	Additional Volume	New P/L Size (inches)	Horsepower per Station: new	Horsepower per Station: incremental	Looping: station miles	Looping: size (inches)	Investment (millions of 1975 dollars)
4	2	83	22.3	22.3	6	258				4.33
5	4	59	504	384			11321			5.11
10	9	59	306	306			14947			6.53
11	9	76	689	189			4854			2.27
13	11	117	306	288			18104			11.07
14	5	93	936	120			2754			1.19
19	21	83	120	28.8			702			.56
21	23	126	193	4.09			*			*
26	27	151	13.7	8.00			749			1.24
32	29	54	274	114			5343			1.35
33	32	109	321	11.1			232			.22
43	41	109	98.7	56.5			2664			2.79
44	48	104	123	116			16718	26	12	10.51
52	53	80	85.0	85.0	10	953				8.45
63	64	93	222	222			28093			10.39
74	73	54	274	99.2			5343			1.35
75	69	46	193	162			14848			3.27
79	113	98	27.4	27.4	6	490				5.48
85	72	239	912	261			5677			7.52
93	96	98	1680	57.2			1170			.44
94	93	250	23.0	49.1	8	832				19.62
94	153	163	194	194			16322			14.17
95	93	152	84.0	84.0	10	1124				16.05
95	96	87	84.0	84.0	10	992				9.16
95	150	87	52.8	140	12	1130				12.23
96	97	228	1720	329			5157			6.22
97	91	109	280	179			7986			5.98
98	99	109	1680	2.68			*			*
99	105	218	1680	31.8			578			.56
101	102	76	16.4	16.4			1625	19	6	2.55
101	148	54	24.0	24.0	6	383				2.89
111	112	65	1600	4.54			*			*
112	113	72	1530	.314			*			*

* Additional volume is insignificant

Table II-7 Continued

Origin BEA	Destination BEA	Miles	Base Capacity (MMCFD)	Additional Volume	New P/L Size (inches)	Horsepower per Station: new	Horsepower per Station: incremental	Looping: station miles	Looping: size (inches)	Investment (millions of 1975 dollars)
118	117	109	306	306			21123			12.51
120	127	109	115	115			9653			7.49
121	125	98	96.0	96.0			10274	41	12	10.29
121	127	98	168	168			24330	12	14	11.02
123	124	120	115	42.6			1731			1.88
124	126	65	2160	153			1841			.75
125	126	120	88.4	88.4	10	1459				13.00
125	127	109	837	102			1253			.98
126	142	51	1640	901			19790			6.89
129	141	54	457	40.7			1310			.34
140	141	39	445	60.0			989			.61
148	108	445	350	350			26039			52.92
149	147	87	23.0	7.60			479			.51
153	95	196	194	105			3547			5.34
170	168	271	27.4	7.71			1935			2.90
										300.93 TOTAL

Summary

The cost estimates given in this chapter are stated in dollars of many different years both past and projected. Table II-8 gives factors assumed in this study for conversion to 1978 dollars. These factors are used to adjust the investment amounts given in this chapter.

Table II-9 shows the adjusted investment projections for planned LNG and pipeline projects assumed in the MEFS scenarios and in the gas network model. Table II-10 shows the adjusted investment figures for LNG tankers necessary to meet MEFS scenario projections. The values from these two tables plus the adjusted values from the network analysis (Tables II-5 through 7) are summarized in Table II-11. The higher investment total for scenario B is due primarily to the inclusion of the Pac-Indonesia LNG project not needed in the other scenarios.

Table II-8

Assumed GNP Deflators

1978 = 1.000

Year	Scenario B	Scenario C	Scenario D
1974	1,377	1.377	1.377
1975	1,192	1.192	1.192
1976	1.147	1.147	1.147
1977	1.082	1.082	1.082
1978	1.000	1.000	1.000
1979	.933	.935	.938
1980	.873	.882	.889
1981	.817	.831	.840

SOURCE: U.S. Department of Energy. Values to 1978 based on U.S. Department of Commerce Statistical series. Values beyond 1978 based on MEFS demand model projections.

Table II-9

Summary of Planned Pipeline and Marine Terminal
Assumed in MEFS Results and Gas Network Model

Project Name	Project Data			Assigned Throughput			Adjusted Cost Estimate (1978 dollars in millions)		
	$	Cost ($ million)	Capacity (MMCFD)	B	C	D	B	C	D
Alaska	1977	10300.0	2400.0	2400	2400	2400	11145	11145	11145
Pathfinder P/L	1976	95.3	185.0	N/A	N/A	N/A	109	109	109
Trailblazer P/L	1979	427.0	447.3	N/A	N/A	N/A	398	399	401
TAPCO - LNG	1981	636.0	1300.0	872	291	113	520	529	534
P/L - U.S.	1976	732.0					840	840	840
P/L - Can	1981	69.0					56	57	58
Pac Indonesia	1974	721.9	4000.0	504	-0-	-0-	994	-0-	-0-
Truckline	1977	193.2	460.0	449	449	449	209	209	209
Pac Alaska*									
Liquefaction	1977	606.4	400.0	236.6	289.3	58.7	656	656	656
P/L	1977	200.0	400.0				216	216	216

* Uses Pac Indonesia gasification plant and LNG terminal

N/A = Not Ascertainable

Table II-10

Summary of LNG Tanker Investment
to Meet 1979 MEFS Projections

Project Name	Cost of Tankers		Tanker Size (cu. meters)	No. of Tankers			Adjusted Cost Estimate (1978 dollars in millions)		
	$	Each ($ million)		B	C	D	B	C	D
Pac-Alaska	1978	180	165,000	1	1	*	180	180	70
Pac-Indonesia	1981	175	125,000	1	0	0	143	0	0
Tenneco	1981	175	125,000	4	3	1	572	436	147
Truckline:									
Sonatrack	1981	150	125,000	3	3	3	368	374	378
Truckline	1977	134	125,000	2	2	2	290	290	290
TOTAL							1,553	1,280	885

* Scenario D would require only a 35,000 cubic meter tanker, the cost of which as estimated to be $70,000,000 in 1978 dollars.

Table II-11

Summary of Natural Gas Transportation Investment Requirements
(1978 dollars in millions)

	Scenario		
	B	C	D
Planned LNG Terminals 1/	2379.0	1394.0	1395.0
LNG Tankers	1553.0	1280.0	885.0
Planned Pipelines	1619.0	1631.0	1624.0
Alaskan Pipeline Project 1/	11145.0	11145.0	11145.0
Other Pipeline Expansion	369.0	347.6	358.7
TOTAL (1990)	17065.0	15797.6	15407.7
(1985) 2/	9954.6	9215.3	8987.8

1/ Includes Canadian construction necessary to meet U.S. deliveries.

2/ 7/12 of the 1990 value.

CHAPTER III. CRUDE OIL

Introduction

Table III-1 shows historical and projected data for oil demand. Demand for crude oil is projected to increase through 1985 at a rate somewhat ahead of the demand for final products reflecting a trend toward greater sufficiency of refining capacity in the United States. After 1985, the growth rates for crude oil demand corresponds more closely with the growth in demand for refined products except in scenario D where final demands outstrip growth in domestic refining capacity. All scenarios project an increase in domestic production of crude oil resulting in a stabilization of imported crude oil. However, final demand for products is projected to stabilize through 1985 and thereafter grow with domestic productive capacity resulting in a lower overall importation of oil, both crude and refined, than experienced in 1977.

Increases in the domestic demand for crude oil, together with the stabilization of crude oil imports, is the result of increased new domestic supplies from non-traditional sources. Some investment in transportation facilities, primarily pipelines, ports, tankers and barges will be necessary to ship these new supplies to refineries. These new supplies include increased production in Alaska, new shale oil projects, production from

Table III-1
U.S. Oil Demand
(Thousands of Barrels)

Year	Crude Oil			Petroleum Products *		
	Growth (%)	Total Demand 1/	Imports	Growth (%)	Demand 2/	Imports
1973		4,537,254	1,234,157		6,317,303	1,049,336
1974	2.1	4,631,602	1,313,383	-3.8	6,078,239	917,564
1975	1.7	4,709,283	1,511,166	-2.0	5,957,515	699,169
1976	7.9	5,081,361	1,946,747	7.2	6,390,750	729,664
1977	7.6	5,468,348	2,425,566	5.3	6,727,468	788,902
1985 B	1.2	6,058,590	2,392,050	-.23	6,603,480	435,070
C	2.0	6,421,350	2,521,340	.47	6,982,420	460,090
D	1.4	6,131,450	1,740,130	-.15	6,649,600	423,180
1990 B	.9	6,331,430	2,482,300	1.1	6,974,560	482,500
C	.3	6,529,110	2,425,380	.49	7,156,440	488,660
D	1.5	6,616,490	1,463,410	2.2	7,403,550	688,940

SOURCES:

1/ Historical: <u>Energy Data Reports</u>: Gross input to refinery distillation units.

Projected: MEFS: Crude plus co-products supply/demand balance.

2/ Historical: U.S. Department of Energy, <u>Energy Data Reports</u>: All products of refineries less changes in stocks.

Projected: MEFS: Demand for all oils including liquified gasses and refinery fuel.

* Inputs to refineries plus product imports are less than demand by the amount of refinery gain plus the amount of unrefined products, principally liquid gasses, plus statistical errors. In the projected data the difference is equal to refinery gains plus calculation differences between the supply and demand models in MEFS.

the Atlantic outer continental shelf, and enhanced oil recovery in traditional areas. The enhanced oil recovery retards the decline of production in traditional producing areas which are already amply supplied with transportation capacity. New sources of supply will require new facilities to bring crude oil to refineries.

The modal characteristics in the shipment of crude oil are summarized in Table III-2. The most consistent data sources are reports from refineries indicating method or mode of receipt of crude oil. Since this is taken at one point in the process, the modal shares are additive. However, a pipeline receipt or other modal receipt at a refinery may have begun its journey on another mode. Obviously, overseas crude oil at inland refineries came first by tanker to a port and subsequently by another mode, most likely pipeline. If Canadian crude oil is subtracted from foreign pipeline receipts and the remainder added to foreign water receipts, the amount is still only 85 percent of what water carriers reported as total carriage of foreign crude oil imports. Much of the difference may be due to transshipment by other modes, changes in storage, and statistical errors between the two separate sources. Despite these difficulties, it is important, though often overlooked, to assess the degree of intermodalism when discussing modal shares in the movement of any commodity. From the data given on Table III-2 it would appear that 36 percent of crude oil employed some intermodal transportation. This figure is probably understated by the

Table III-2

1977 Crude Oil Transportation by Mode
(thousands of barrels per year)

Crude Receipts by Refineries 1/		5,344,834	Percent
Pipeline:	Total	3,096,694	58
	Foreign (101,778 Canadian)	567,752	
	Domestic	2,528,942	
Tank Cars and Trucks		94,393	2
Water:	Total	2,153,747	40
	Foreign	1,834,668	
	Domestic	319,079	
		TOTAL %	100
Total Waterborne Carriage 2/		3,276,443	61
	Foreign	2,708,172	
	Domestic	568,271	
	Barge	329,808	(6)
	Tanker	238,463	
Interstate Pipeline Originations (1976) 3/		3,434,362	64
Class I Railroad Originations 4/		3,487	0
Class I Motor Carriers Originations 5/		8,205	
All Motor Carriers 6/		601,771	11
		TOTAL %	136

SOURCES:
1/ Dept. of Energy, Energy Data Reports.
2/ Corps of Engineers, Waterborne Commerce Statistics.
3/ Interstate Commerce Commission, Transport Statistics, Part 6: Pipelines (1976 data is latest).
4/ I.C.C., Freight Commodity Statistics, Class I Railroad.
5/ I.C.C., Freight Commodity Statistics, Motor Carriers of Freight.
6/ Association of Oil Pipelines estimate based on data from Source 1/ and the American Trucking Assoc.

amount of movement by intrastate pipelines.[1]

The approach to analysis in this chapter relies on a simple network structure illustrated in Figure III-1. Intermodalism is permitted in the network, particularly for Alaskan and foreign tanker movements to port areas. An analysis of the degree of intermodalism in the network solution for scenario C also shows a 36 percent or greater intermodal interaction. Additional intermodalism is possible due to the lack of modal specification in the network for "local" shipments to refineries within the oil producing regions. These are outlined in heavy black in the figure. Local shipments may cover a very large area to refineries within each oil region. Twenty-six percent of shipments in the network solution were local shipments. This percentage contains pipelines, barges, trucks and railroads which may be combined intermodally to obtain a higher than 36 percent intermodal interaction.

In the following analysis, pipelines and tankers are considered within the context of the network only, except that some published plans for pipeline building are included within the local shipment areas. Otherwise, pipeline capacity inside of a local shipment area is assumed to be sufficient. Barge and towboat requirements are computed on the basis of 6 percent of the total volume of crude oil.[2]

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[1]The 64 percent pipeline share includes only major interstate pipeline systems.

[2]Only 1 percent is specifically accounted for in the network. The remaining 5 percent occurs in the local shipment areas of the network.

Rail tank cars have less than 1 percent of the traffic and are not considered in the study. Also, due to sketchy data and the short haul nature of truck shipments, this mode is excluded.

The Network Analysis of Pipelines and Tankers

In Figure III-1 the MEFS oil producing regions, labeled 02 through OC, are redrawn as noncontiguous regions depicting the areas of most significant oil producing activity and most intensive pipeline gathering systems.[3] These oil producing regions were drawn with the aid of maps prepared by the American Petroleum Institute (API).[4]

In addition to defining the geographical scope of the MEFS oil producing regions, the MEFS refining regions were subdivided to identify refineries within oil producing regions and those outside of the oil producing regions. The API map was referenced and updated for pipelines built since 1975 to draw the pipeline connections characterized as arrows on Figure III-1. These arrows represent one or more pipelines. The solid line arrows represent existing pipelines; the dashed lines, planned pipelines; and the remaining dotted line, a products pipeline which ships crude oil in batches. The Northern Tier pipeline is included in Figure III-1 but is not called for in the MEFS solution. Some of the dashed lines represent planned additions to pipeline capacity through looping. The assumed

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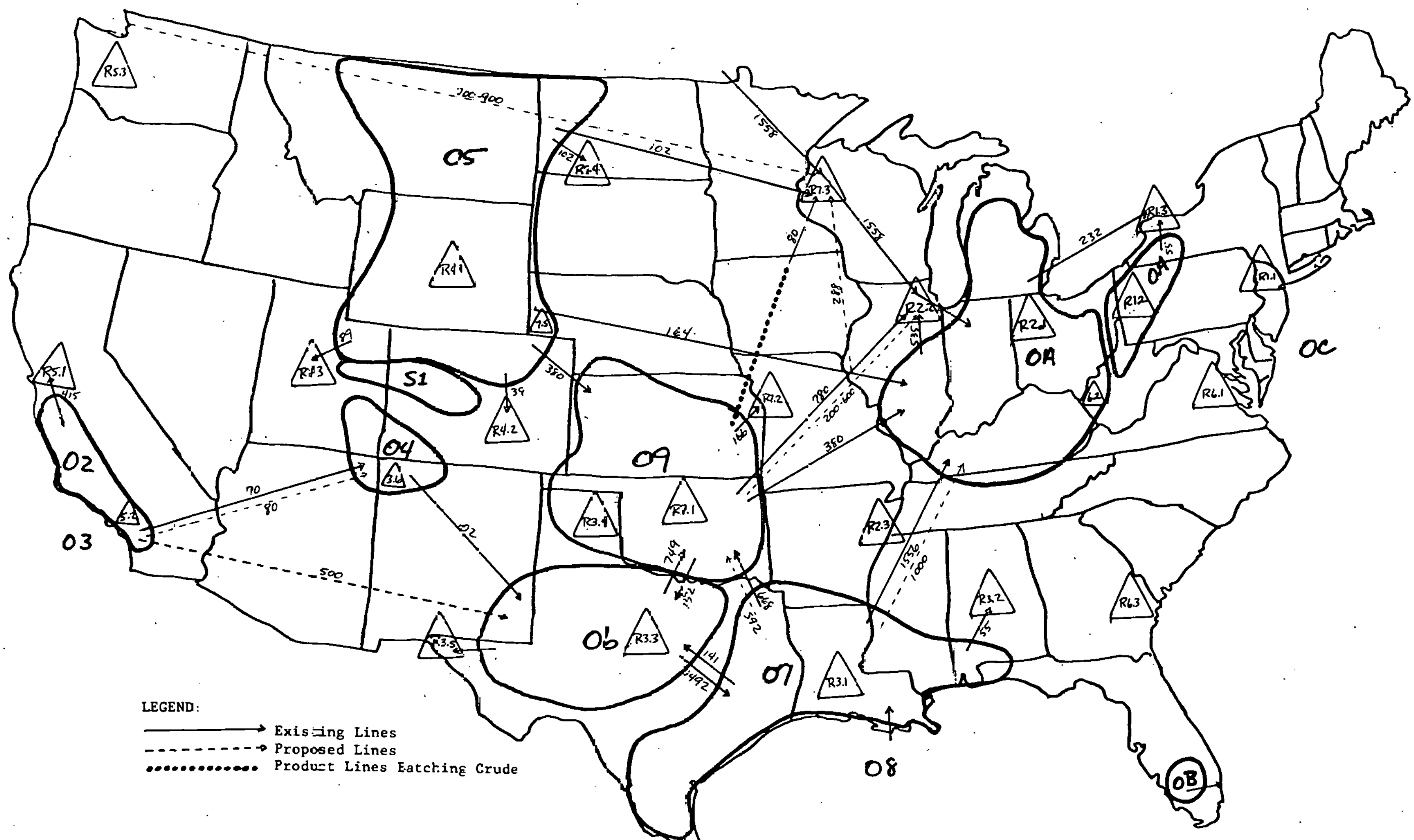
[3] Regions 01 and OD are Alaska and Alaska, North Slope respectively and are not on the figure.

[4] API, Crude Oil Pipeline Map of the United States and Southern Canada, 1975.

Figure III-1

Crude Oil Network



LEGEND:

——————→ Existing Lines

- - - - - - - → Proposed Lines

••••••••••••• Product Lines Batching Crude capacities for each pipeline link are given in the figure. These were assembled from data given in Table III-3 and industry plans.

The subdivision of MEFS refining regions into 28 refining centers was done on the basis of proportion of existing and planned capacity of refineries. Table III-4 gives the capacity data and final allocations of crude to 28 refining regions for each of the three scenarios analyzed in this study.

The MEFS solutions are computed based on a 13 by 7 interregional transportation cost of matrix. The resulting interregional flows are greatly simplified from what may reasonably be expected. While the supply-demand balance computed by MEFS is the product of a sophisticated analysis, the distributional patterns computed are not. Therefore, the allocation of crude oil supply regions to refining regions must be adjusted to make rational use of the existing pipeline network. The principal form of adjustment allows small amounts of crude to be shifted from one refining region to another to permit local shipment of crude to all refineries within the boundaries of an oil region. The second form of adjustment shifts imported crude oil from East Coast receiving points to Gulf Coast receiving points because some eastern region refineries are served via pipeline from inland not coastal sources. Tables III-5 through III-10 give the original and modified interregional flows for each of the three scenarios. The column and row totals are the same in both cases in order to be true to MEFS. The distribution is changed only as necessary to be rational with the network given in Figure III-1.

Table III-3

Assumed Crude Oil Pipeline Capacities by Size of Pipe

Pipe Size (Inches)	Capacity (MB/D)	Pipe Size (Inches)	Capacity (MB/D)
6	13	28	417
8	25	30	497
10	39	32	596
12	56	34	693
14	73	36	801
16	102	38	909
18	136	40	1,017
20	177	42	1,141
22	231	44	1,276
24	288	46	1,421
26	348	48	1,500

SOURCE: TERA, Inc. adjusted estimates from the Oil Pipeline Algorithm. The maximum throughput for which a given pipeline size is more cost effective than the next larger size is adjusted by a factor of 1.46 to represent an average increase of stated line capacity over optimum line capacity for a representative set of pipelines for which capacity data was available.

Table III-4

Allocation of Projected Refinery Receipts to Sub-Regions (000 bbls per day)

Refining Center *	Capacity in Place 1/1/78 (000) 1/	Planned New Capacity 2/	1990 Crude Receipts MEFS Scenarios B	C	D
R1	1,633.5		1475.0	1475.0	1841.0
R1.1	1,446.9		1231.1	1231.1	1536.6
R1.2	79.6		67.8	67.8	84.6
R1.3	107.0	100.0	176.1	176.1	219.8
R2	2,785.5		3121.0	3121.0	3121.1
R2.1	1,973.8		2211.5	2211.5	2211.6
R2.2	767.8		860.3	860.3	860.3
R2.3	43.9		49.2	49.2	49.2
R3	7,366.5		6416.0	6336.2	5723.7
R3.1	6,794.5	516.0	5946.7	5872.7	5305.0
R3.2	37.0		30.1	29.7	26.9
R3.3	227.8		185.3	183.0	165.3
R3.4	171.5		139.5	137.8	124.4
R3.5	93.0		75.6	74.7	67.5
R3.6	42.7	5.0	38.8	38.3	34.6
R4	579.9		502.6	498.9	489.7
R4.1	357.0	8.4	312.1	309.9	304.1
R4.2	63.4		54.2	53.8	52.8
R4.3	159.5		136.3	135.2	132.8

* Refining centers are as shown in Figure III-1 with the exception of Alaska, R5.4 and Hawaii, R5.5.

Table III-4 (Continued)

Refining Center	Capacity in Place 1/1/78 (000) 1/	Planned New Capacity 2/	1990 Crude Receipts MEFS Scenarios		
			B	C	D
R5	2,912.4		2867.0	3301.0	3301.0
R5.1	1,079.1		1040.3	1197.8	1197.8
R5.2	1,309.3	31.5	1292.6	1488.3	1488.3
R5.3	397.4	30.0	412.0	474.4	474.4
R5.4	82.6		79.6	91.7	91.7
R5.5	44.0		42.5	48.8	48.8
R6	279.0		334.0	334.0	675.6
R6.1	221.5	383.0	221.4	221.4	447.8
R6.2	19.6		7.2	7.2	14.5
R6.3	37.9	250.0	105.4	105.4	213.3
R7	1,517.6		1392.0	1392.0	1392.0
R7.1	999.0	72.4	920.6	920.6	920.6
R7.2	197.0	30.0	195.1	195.1	195.1
R7.3	257.9		221.6	221.6	221.6
R7.4	58.7		50.4	50.4	50.4
R7.5	5.0		4.3	4.3	4.3

SOURCES: 1/ National Petroleum Refiners Assn., "U.S. Refining Capacity as of Jan. 1, 1978," (based on U.S. Department of Energy Survey and independent survey), July 1978.

2/ Bureau of Mines, Projects to Expand Energy Sources in The Western States IC 8772, (as of August 1977) and Projects to Expand Fuel Sources in Eastern States IC 8765, (as of July 1977).

Table III-5

Projected Interregional Flows of Crude Oil MEFS B Scenario: 1990
(thousands of barrels per day)

Oil Region	Refining Region R1	R2	R3	R4	R5	R6	R7	Totals
01/0D			777.2		1076.1	312.7		2166.0
02			499.6		1327.0			1826.6
03					263.9			263.9
04				45.7			143.9	189.6
05				456.9				456.9
06							1008.5	1008.5
07		161.5	1268.0					1429.5
08			760.0					760.0
09		158.0					239.6	397.6
0A		248.4						248.4
0B						21.3		21.3
0C	338.5							338.5
S1			200.0					200.0
Domestic	338.5	567.9	3504.8	502.6	2667.0	334.0	1392.0	9306.8
Foreign	1136.5	2553.1	2911.2		200.0			6800.8
Total	1475.0	3121.0	6416.0	502.6	2867.0	334.0	1392.0	16107.6

Table III-6

Projected Interregional Flows of Crude Oil MEFS B Scenario: 1990 (Modified)
(thousands of barrels per day)

Oil Region	Refining Region							Totals
	R1	R2	R3	R4	R5	R6	R7	
01/0D			784.4		1076.1	305.5		2166.0
02			499.6		1327.0			1826.6
03					263.9			263.9
04			189.6					289.6
05				302.6			154.3	456.9
06			10.4				998.1	1008.5
07		161.5	1268.0					1429.5
08			760.0					760.0
09		18.5	139.5				239.6	397.6
0A	67.8	173.4				7.2		248.4
0B						21.3		21.3
0C	338.5							338.5
S1				200.0				200.0
Domestic	406.3	353.4	3651.5	502.6	2667.0	334.0	1392.0	9306.8
Foreign	1068.7	2767.6	2764.5		200.0			6800.8
Total	1475.0	3121.0	6416.0	502.6	2867.0	334.0	1392.0	16107.6

Table III-7

Projected Interregional Flows of Crude Oil MEFS C Scenario: 1990
(thousands of barrels per day)

Oil Region	Refining Region R1	R2	R3	R4	R5	R6	R7	Totals
01/0D			142.7		1505.2	286.9		1934.8
02			529.0		1311.0			1840.0
03					284.8			284.8
04				2.7			214.1	216.8
05				496.2				496.2
06		25.2					1177.9	1203.1
07		179.0	1396.9					1575.9
08			857.5					857.5
09		417.5						417.5
0A		355.0						355.0
0B						47.1		47.1
0C	484.5							484.5
S1			100.0					100.0
Domestic	484.5	976.7	3026.1	498.9	3101.0	334.0	1392.0	9813.2
Foreign	990.5	2144.3	3310.1		200.0			6644.9
Total	1475.0	3121.0	6336.2	498.9	3301.0	334.0	1392.0	16458.1

Table III-8

Projected Interregional Flows of Crude Oil MEFS C Scenario: 1990 (Modified)
(thousands of barrels per day)

Oil Region	Refining Region R1	R2	R3	R4	R5	R6	R7	Totals
01/0D			149.9		1505.2	279.7		1934.8
02			529.0		1311.0			1840.0
03					284.8			284.8
04			216.8					216.8
05				398.9			97.3	496.2
06							1203.1	1203.1
07		179.0	1396.9					1575.9
08			857.5					857.5
09		188.1	137.8				91.6	417.5
0A	67.8	280.0				7.2		355.0
0B						47.1		47.1
0C	484.5							484.5
S1				100.0				100.0
Domestic	552.3	647.1	3287.9	498.9	3101.0	334.0	1392.0	9813.2
Foreign	922.7	2473.9	3048.3		200.0			6644.9
Total	1475.0	3121.0	6336.2	498.9	3301.0	334.0	1392.0	16458.1

Table III-9

Projected Interregional Flows of Crude Oil MEFS D Scenario: 1990
(thousands of barrels per day)

Oil Region	Refining Region R1	R2	R3	R4	R5	R6	R7	Totals
01/0D					1502.3	544.0		2046.3
02			614.3		1311.0			1925.3
03					287.7			287.7
04							512.1	512.1
05		248.2		489.7				737.9
06		867.6					879.9	1747.5
07		213.9	1652.3					1866.2
08			944.1					944.1
09		1033.6						1033.6
0A		566.8						566.8
0B						131.6		131.6
0C	685.7							685.7
S1			500.0					500.0
Domestic	685.7	2930.1	3260.7	489.7	3101.0	675.6	1392.0	12534.8
Foreign	1155.3	191.0	2463.0		200.0			4009.3
Total	1841.0	3121.1	5723.7	489.7	3301.0	675.6	1392.0	16544.1

Table III-10

Projected Interregional Flows of Crude Oil MEFS D Scenario: 1990 (Modified)
(thousands of barrels per day)

Oil Region	Refining Region							Totals
	R1	R2	R3	R4	R5	R6	R7	
01/OD			14.5		1502.3	529.5		2046.3
02			614.3		1311.0			1925.3
03					287.7			287.7
04			512.1					512.1
05		141.5		439.7			156.7	737.9
06		867.6					879.9	1747.5
07		72.4	1652.3				141.5	1866.2
08			944.1					944.1
09		695.3	124.4				213.9	1033.6
0A	84.6	467.7				14.5		566.8
0B						131.6		131.6
0C	685.7							685.7
S1				50.0				50.0
Domestic	770.3	2244.5	3861.7	489.7	3101.0	675.6	1392.0	12534.8
Foreign	1070.7	876.6	1862.0		200.0			4009.3
Total	1841.0	3121.1	5723.7	489.7	3301.0	675.6	1392.0	16544.1

Interregional Pipeline Requirements

The modified distribution is input to the network and solved by hand, using a flow chart method. Figures III-2, III-3 and III-4 are the flow chart solutions to each scenario. The result of each network solution is an allocation of needed new capacity to specific pipeline links. In most cases, new capacity was added to existing links where it is already proposed to be added.

The new capacity required by the network solution is given an estimated capital cost through use of the Oil Pipeline Investment Algorithm developed in an earlier phase of this study.[5] This algorithm is similar to the Gas Pipeline Investment Algorithm described in the previous chapter. Tables III-11, III-12, and III-13 give new pipeline building called for by the network with the outputs of the Oil Pipeline Investment Algorithm. These outputs describe the pipeline to be built and give its cost in 1975 dollars. The pipelines are designed on the basis of lowest average unit cost for the desired throughput, distance and change in elevation.

Planned Pipeline Construction in Local Shipment Areas

Several pipeline and oil industry publications were reviewed to identify pipeline building proposals which would not be covered by the network analysis. Published information includes pipeline size, distance, location and company ownership.

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[5] U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

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Figure III-2

Crude Oil Pipeline Network Solution Flow Chart
Scenario B

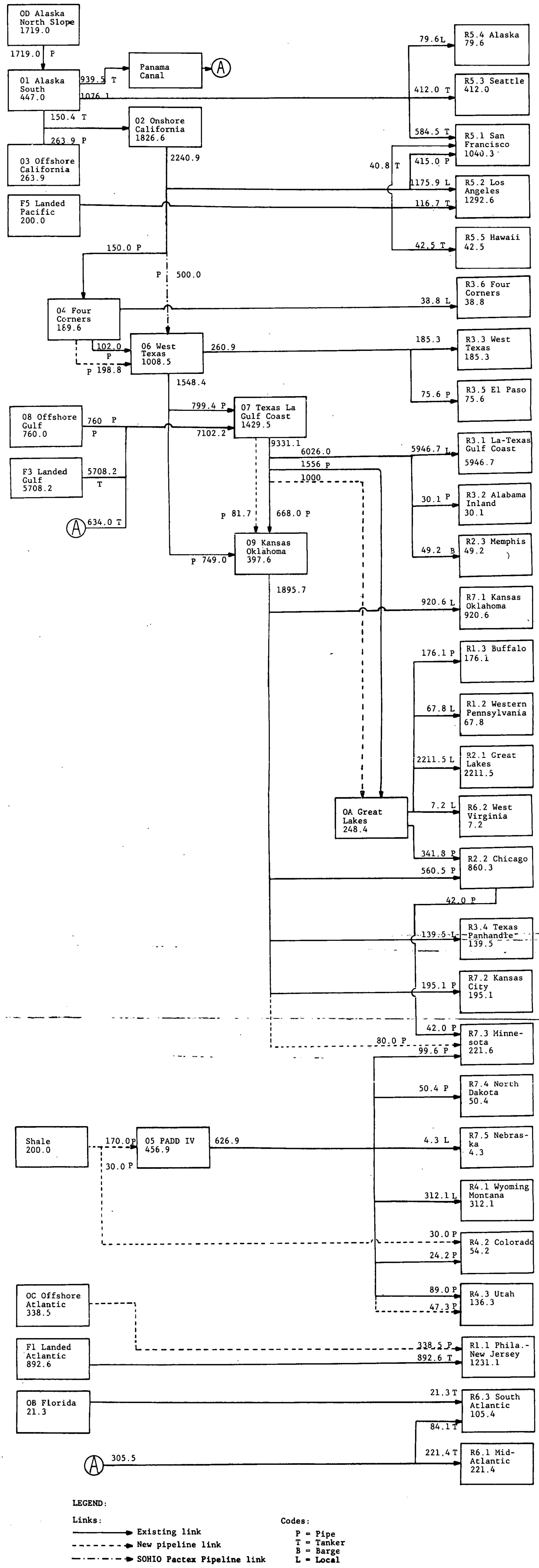

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Figure III-3

Crude Oil Pipeline Network Solution Flow Chart
Scenario C

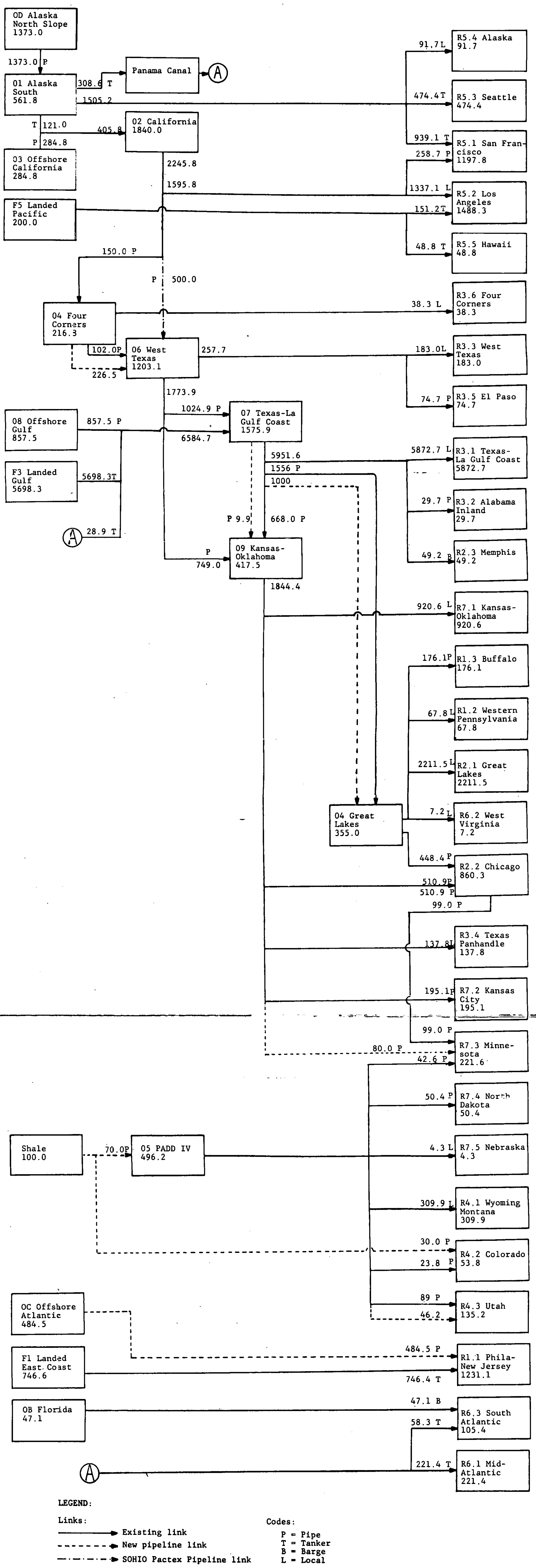

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Figure III-4

Crude Oil Pipeline Network Solution Flow Chart
Scenario D

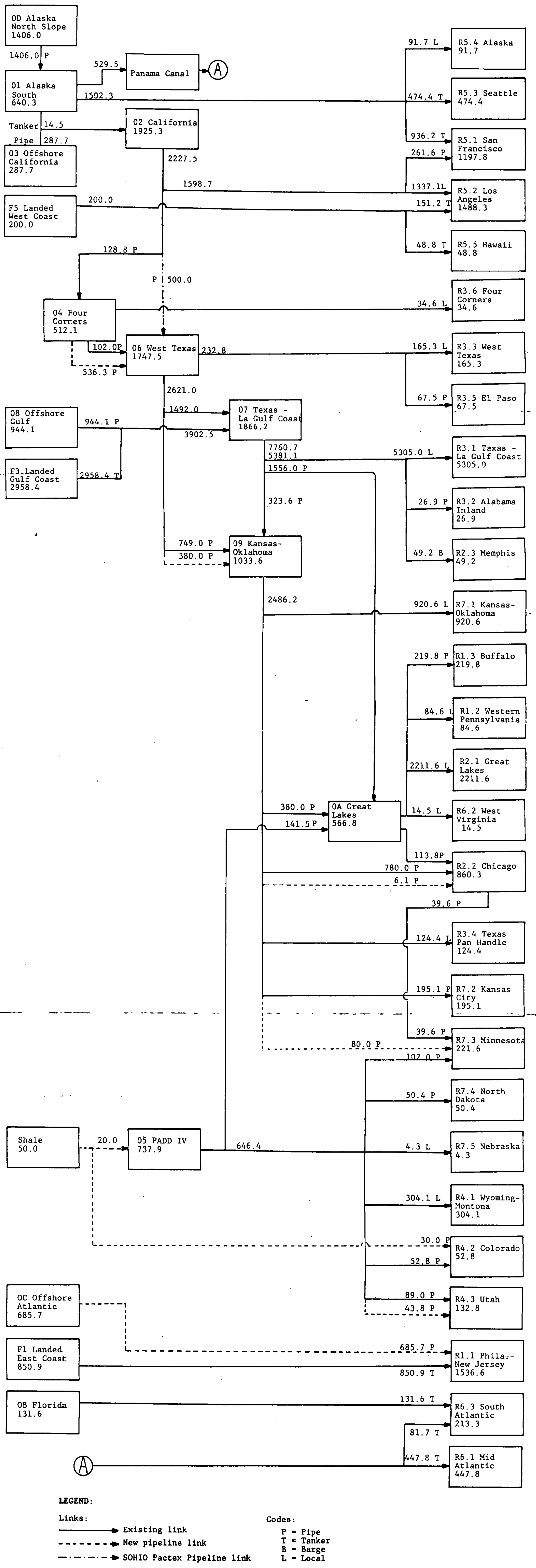

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Table III-11

Crude Oil Pipeline Investment
Scenario B, 1990

Origin-Destination	Throughput (MBD)	Distance (miles)	Elevation change (feet)	Pipe diameter & wall thickness (inches)	Pumping Station horsepower	Number of Stations	Investment millions of 1975 dollars	Comment
Long Beach - Four Corners	80.0	600	+4500	16 X .1475 loop 42 mi X 13	add 962	13	85.5	Expansion of Reversed P/L
Four Corners - Midland, TX	198.8	500	-3500	24 X .1935	1511	5	84.6	
Long Beach - Midland, TX	500.0						400.0	SOHIO Pactex Proposal
Brownsville, TX - Cushing, OK	81.1	480	+1000	30 X .234 loop 24 mi X 6	add 1033	6	37.4	Expansion of Texoma P/L
St. James, LA - Patooka, IL	1000.0	624	+ 500	48 X .3785	6003	9	300.3	Looping of Capline
Wood River, IL Minneaspolis, MN	42.0	490	+ 500	14 X .1355	462	6	45.5	Northern P/L Proposal Route
Central WY Salt Lake City	47.3	270	-5000	12 X .1241	330	3	22.6	
Baltimore Canyon - Shore line	338.5	75	+ 600	26 X .2445	3760	2	38.4	
Shore line - Philadelphia	338.5	60	50	30 X .234	2436	1	14.1	
Shale Region - Local Refinery	30.0	20	0	10 X .114	146	1	2.2	New Refinery in West Colo.
Shale Region - Wyoming P/L	170.0	50	0	22 X .1809	1297	1	8.2	
TOTAL							1038.8	

SOURCE: TERA, Inc., Crude Oil Pipeline Investment Algorithm.

Table III-12

Crude Oil Pipeline Investment
Scenario C, 1990

Origin Destination	Throughput (MBD)	Distance (miles)	Elevation change (feet)	Pipe diameter & wall thickness (inches)	Pumping Station horsepower	Number of Stations	Investment millions of 1975 dollars	Comment
Long Beach - Four Corners	80.0	600	+4500	16 X .1475 loop 42 mi X 13	add 962	13	85.5	Expansion of reversed P/L
Four Corners - Midland, TX	226.5	500	-3500	26 X .2066	1272	5	93.5	
Long Beach - Midland, TX	500.0						400.0	SOHIO Pactex Proposal
Brownsville, TX - Cushing, OK	9.9	480	+1000	*	add 479	6	.2	Expansion of Texoma
St. James, LA - Patooka, IL	1000.0	624	+ 500	48 X .3785	6003	9	300.3	Looping of Capline
Wood River, IL - Minneapolis, MN	99.0	490	+ 500	20 X .1687	823	6	66.8	Northern P/L Proposal Route
Central Wyoming - Salt Lake City	46.2	270	-5000	12 X .1241	281	3	22.6	
Baltimore Canyon - Shore Line	486.5	75	+ 600	30 X .2401	5144	2	41.2	
Shore Line - Philadelphia	484.5	60	+ 50	34 X .2631	3604	1	17.0	
Shale Region - Local Refinery	30.0	20	0	10 X .114	146	1	2.2	New Refinery in West Colo.
Shale Region - Wyoming P/L	70.0	50	0	16 X .1455	545	1	5.7	
TOTAL							1035.0	

SOURCE: TERA, Inc., Crude Oil Pipeline Investment Algorithm
* Looping not necessary

Table III-13

Crude Oil Pipeline Investment
Scenario D, 1990

Origin-Destination	Throughput (MBD)	Distance (miles)	Elevation change (feet)	Pipe diameter & wall thickness (inches)	Pumping Station horsepower	Number of Stations	Investment millions of 1975 dollars	Comment
Long Beach - Four Corners	80.0	600	+4500	16 X .1475 loop 42 mi X 13	add 962	13	85.5	Expansion of Reversed P/L
Four Corners - Midland, TX	504.3	500	-3500	36 X .2783	2021	5	148.5	
Long Beach - Midland, TX	500.0						400.0	SOHIO Pactex Proposal
Cushing, OK Wood River, IL	6.1	420	- 500	*	add 479	6	.2	Expansion of existing lines
Wood River, IL - Minneapolis, MN	39.6	490	+ 500	14 X .1449	472	5	45.3	Northern P/L Proposal Route
Central Wyoming - Salt Lake City	43.8	270	-5000	12 X .1241	184	3	22.6	
Shale Region - Local Refinery	30.0	20	0	10 X .114	146	1	2.2	
Shale Region - Wyoming P/L	20.0	50	0	8 X .1264	340	1	3.5	
Baltimore Canyon - Shore line	685.7	75	+ 600	34 X .2746	7359	2	45.8	
Shore line - Philadelphia	685.7	60	+ 50	40 X .3100	4344	1	21.5	
TOTAL							775.1	

SOURCE: TERA, Inc., Crude Oil Pipeline Investment Algorithm
* Looping not necessary

Table III-14 gives assumed total investment costs per mile for crude oil pipelines by size and region, onshore or offshore. These were developed using the Oil Pipeline Investment Algorithm. Table III-15 summarizes the pipeline projects in the local areas not analyzed by the network. Costs were estimated using data from Table III-14 for each project which total $240.4 million in 1975 dollars.

Tanker Requirements

Most foreign oil imported into the United States via tanker is shipped in foreign flag tankers. These are excluded from the U.S. investment total not because they do not represent U.S. investment but because the world tanker fleet still exceeds requirements and additions to the fleet may be made by other than U.S. firms. Domestic crude oil movements by tanker will be concentrated in the Alaskan trade. Tanker requirements expected in 1990 for the Alaskan Trade are given in Table III-16. The throughput volumes are taken from the network solutions shown in Figures III-2, III-3, and III-4. At present, approximately 1.2 MMB/D of oil is being shipped from Alaska to destinations in the lower 48 states. Tanker requirements for this trade and one other small intercoastal movement of crude oil is given in Table III-17. Assuming that the one movement from the Gulf to the East Coast remains in spite of its absence from the network solution, an estimate of incremental tanker investment to meet 1990 domestic ocean shipments of crude oil may be computed by subtracting the Alaska total on Table III-17 from the totals on Table III-16. The results of this calculation are given in Table III-18.

Table III-14

Crude Oil Pipelines

Investment Cost Per Mile
(Thousands of 1975 Dollars)

Size	Onshore	Offshore
6	46	331
8	58	346
10	75	357
12	83	370
14	92	381
16	105	394
18	121	412
20	136	432
22	157	
24	172	
26	189	
28	209	
30	229	
32	256	
34	278	
36	300	
38	327	
40	378	
42	388	
44	416	
46	448	
48	482	

SOURCE: TERA Inc., Oil Pipeline Investment Algorithm.

Table III-15

Summary of Planned Pipelines
Not Analyzed in the Network

Location	Company	Size (Inches)	Distance (Miles)
Offshore:			
Cameron Area	ARCO	10	20
Cameron Area	Gulf	16,14	24
Iberia, Vermillion & Cameron	Gulf	8,16	61
Grand Isle & South Timbalier	Gulf	6,12,16	37
Terrebonne & Lafourche	Gulf	12,20	27
Cameron Area	Gulf	12	32
Lake Borgne	Koch	6	16
Eugene Island & Ship Shoal	Placid	12	45
Ship Shoal	Placid	8	20
Mississippi Canyon	Shell	12	24
Vermillion & South Marsh Areas	Shell	6,8	36
West Delta	Shell	12	20
Santa Barbara Channel	*	12	27
Onshore:			
Williston Basin, ND	AMOCO	4,6	57
Texas City, TX	ARCO	36,42	39
Mont Belview, TX	Continental	6	111
Harbor Is. Bay, TX	Deeport Terminal	36	31
Portland, ME	New England Energy	24	35
Albany, NY	New England Petroleum	20	165
Trinity, TX	Oil Dev. Co. of Texas	24	24
Port Arthur, TX	Texaco	6,8	21
Mobil, AL	Wallace & Wallace Chem.	20	255

SOURCES: <u>Pipeline and Gas Journal</u>, Jan. 1979; <u>Pipeline</u>, Jan. 1979.

* Not given.

Table III-16

Alaskan Tanker Requirements (1990)

Route and Scenario	Volume 1/ (MB/D)	Size of 2/ Tankers (000DWT)	No of Tankers	Cost of Tankers (1975 $ million)
Scenario B:				
Alaska - Washington	412.0	120	4.4	238
Alaska - California	734.9	120	12.3	664
Alaska - Panama Canal	939.5	120	33.2	1795
Panama C. - S. Atlantic	84.1	37	3.7	112
Panama C. - M. Atlantic	221.4	37	11.7	351
Panama C. - Gulf of Mexico	634.0	37	25.9	776
TOTALS:	2086.4	7516	91.2	3936
Scenario C:				
Alaska - Washington	474.4	120	5.1	274
Alaska - California	1060.1	120	17.7	958
Alaska - Panama Canal	308.6	120	10.9	590
Panama C. - S. Atlantic	58.3	37	2.6	78
Panama C. - M. Atlantic	221.4	37	11.7	351
Panama C. - Gulf of Mexico	28.9	37	1.2	35
TOTALS:	1843.1	4620	49.2	2286
Scenario D:				
Alaska - Washington	474.4	120	5.1	274
Alaska - California	950.7	120	15.9	859
Alaska - Panama Canal	529.5	120	18.7	1012
Panama C. - S. Atlantic	81.7	37	3.6	109
Panama C. - M. Atlantic	447.8	37	23.7	710
TOTALS:	1954.6	5774	67.0	2964

SOURCE: TERA, Inc., Oil Barge and Tanker Investment Algorithm

1/ Total net of double counting through Panama Canal.
2/ Total is gross capacity for the scenario in 000DWT.

Table III-17

Alaskan and other Tanker Requirements
1978*

Route	Volume in B/D	Size of Tanker (000DWT)	No of Tankers	Cost of Tankers (1975 $ million)
Alaska - Washington	474.0	120	5.1	274
Alaska - California	474.0	120	7.9	428
Alaska - Panama Canal	252.0	120	8.9	482
Panama C. - East Coast	84.0	37	4.4	133
Panama C. - Gulf Coast	168.0	37	6.9	206
TOTALS:	1,200.0	3,046	33.2	1,523
Gulf - East Coast	26.7	37	1.3	38
TOTALS:	1,226.7	3,092	34.5	1,561

* Estimated from 11 month data given in DOE, Energy Data Reports, "Petroleum Statement, Monthly," November 1978.

Table III-18

Crude Oil
Incremental Tanker Investment
1979 through 1990

	Scenario		
	B	C	D
Gross Deadweight Tonnage (000)	4,470	1,574	2,729
Cost (1975 $ million)	2,413	763	1,441

SOURCE: TERA, Inc.

These results are reinforced by observations gained from shipping industry experts to the effect that U.S. flag tankers in domestic service are presently being used to capacity. The newer, larger vessels ply the Pacific routes while older, smaller vessels handle the trans-Panama Canal trade. In all scenarios there is a requirement for new, larger vessels for the Pacific trade. In spite of the inclusion of the SOHIO Pactex pipeline all scenarios require continuation of tanker deliveries to the East Coast through the Panama Canal. Scenarios B and D also require additional smaller tankers for this trade over and above 1978 estimated levels. Tankers are characterized by very long useful lives and are typically scrapped only during periods of slack demand. Consequently no estimate is made of tankers needed to replace existing fleet by 1990.

Deepwater Port Requirements

A significant development in the transportation of crude oil in the United States is the shift to deepwater ports. These offshore unloading facilities enable crude oil to be received in tankers too large to enter a coastal port. These tankers, often called Very Large Crude Carriers or VLCC's, are the dominant mode of long distance water transportation of oil. At present, much of the crude oil being shipped to the United States from origins in the Middle East comes to Caribbean ports in VLCC's and is trans-shipped from there to U.S. ports in smaller tankers.

By 1981 the Lousiana Offshore Oil Port (LOOP) will be receiving oil from VLCC's to be shipped to refineries in Louisiana and the midwest. The total project is estimated to cost $513 million in current dollars. Of this amount $84 million has been spent.[6] The projected capacity of the LOOP project is 1.4 million barrels per day.

Receipts of foreign crude oil at Gulf coast ports is outlined in the network to be 5.7 MMB/D in Scenarios B and C and 2.95 MMB/D in Scenario D. This foreign crude comes from unspecified sources some of which may be only as far away as Venezuela. Therefore, one deepwater port, LOOP, is assumed to be sufficient to handle VLCC traffic under conditions of Scenario D but not B or C.

When the SEADOCK proposal for a deepwater port offshore of the Texas coast was abandoned by its promoters due to too restrictive licensing conditions, the Texas Legislature authorized the creation of the Texas Deepwater Port Authority. The Authority could seek to build and operate a deepwater port if private interests would not. The Texas Deepwater Port Authority has gone forward with plans to build a 2.5 MMB/D facility at an estimated total cost of $1,124 million in current dollars. The Department of Transportation has recently given authority to begin construction.[7] Both scenarios B and C project sufficient volumes to use such a port. Although present capacity of coastal ports together with LOOP could handle projected import levels, the cost of the Texas Deepwater Port is included in the investment totals for these two scenarios.

Analysis of Barge and Towboat Requirements

Table III-19 shows data used to estimate total barge capacity in barrels for tank barges certificated to carry oil in 1977.

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[6]As of February 18, 1979 per LOOP, INc.

[7]U.S. Department of Transportation, Office of Deepwater Ports.

Table III-19

Inspected Tank Barges That
May Carry Oil

April 1978

Route	No of Barges	Average Capacity (bbls)
Ocean	241	28,227
Coastwise	105	20,716
Lakes, Bays & Sounds	2997	14,319
River	262	9,008
Great Lakes	20	29,092
Coastwise/ Great Lakes	33	21,785
Other	204	17,796
Total	3862	15,324
Gross Capacity		59,183,155
less 1978 Barges	195	15,324
1977 Gross Capacity		56,194,975

SOURCE: U.S. Coast Guard, Inspected Tank Barge File, Subchapter D and O/D Tank Barges. Average Capacity computed from a sample of barges listed in a computer printout obtained from the USCG.

Many of these barges may also carry other hazardous substances. During 1977 total domestic barge traffic amounted to approximately 593,347,000 barrels of crude oil and liquid bulk petroleum products.[8] Dividing total carried by carrying capacity yields a utilization rate of approximately 11 barrels delivered per year per barrel of barge capacity.

A profile of the fleets of 16 Major Regulated Barge Carriers shows an average of 23.8 Barges per towboat in the fleet.[9] Although these are not major carriers of oil, this average will be assumed for the lack of more comprehensive data. The barges typically used by such carriers measure 195 X 35 feet with 9 foot draft. This corresponds to a 13,000 barrel capacity tank barge. At 6.7 barrels per ton this converts to 46,000 deadweight tons (DWT) per towboat. This ratio is used to compute the number of towboats required to handle any additional barge capacity to meet 1990 traffic levels and estimate total towboats in oil carriage service in 1977 for purposes of computing towboat fleet retirements by 1990.

Table III-20 gives an age profile of the oil tank barge fleet by percent of capacity. If the same profile is assumed to prevail in 1990, then 14.6 percent of the 1979 fleet would have to have been retired. Based on 1978 Barge traffic volumes, this amounts to 668,000 DWT of capacity which would need to be replaced to maintain 1978 gross barge capacity. This amount must be added to the growth in the fleet to compute a total new investment value for 1990.

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[8] Computed by converting ton data to barrels. U.S. Army Corps of Engineers, Waterborne Commerce of the United States: Calendar Year 1977, District Engineer, Vicksburg, Miss.

[9] A.T. Kearney Inc., Domestic Waterborne Shipping Market Analysis, Inland Waterways Trade Area, Final Report, Feb. 1974, p. I-A-8.

Table III-20

Age Profile
Oil Tank Barge Fleet

Barges Built Before	Percent of Capacity
1949	8.8
1957	20.8
1963	35.7
1967	48.6
1970	62.8
1973	77.0
1979	100.0

SOURCE: Compute from a sampling of the U.S. Coast Guard, Inspected Tank Barge File, Subchapter D and O/D Barges.

Table III-21 shows an age and size profile of all inspected towboats in the United States. If a similar profile is assumed to exist in 1990, then approximately 24 percent of boats presently in use would have to be retired and hence replaced. However, boats are not often fully retired, they are sold and put into less strenuous service as their age increases. The distribution of towboats is not weighted by level of service. Therefore, a more accurate representation of retirement cannot be found. The 24 percent total retirements by 1990 represents an approximately 2 percent annual retirement rate from a stable fleet size and less than 2 percent for a growing fleet. This would correspond to an average life of fifty years or more. The average age of the fleet is about 22 years, but this is heavily influenced by the larger number of vessels built in recent years. Without data on the number of vessels built each year it is impossible to compute a true average life. Therefore, this study will assume that the age profile of vessels will remain constant until 1990 which results in a 24 percent reduction in the present fleet from service.

Assuming that the pattern of replacement and growth exists in 1990 as it has since 1975, then the distribution of towboat sizes will be the same as given in Table III-21 for boats built after January 1, 1975. Using data given in Table III-22, an average cost of $1,871,000 in 1976 dollars is computed for boats built after January 1, 1975.

Table III-21

Profile of Towboat Fleet

Built After Jan 1	Ave HP	Horsepower Distribution (%) 1/							Age Distribution (%)	No of Boats
		≤250	≤500	≤1000	≤2000	≤4000	≤8000	>8000		
1850	2/								1.9	130
1900	533	48.3	24.1	6.9	20.7				14.0	958
1940	1017	21.2	21.2	18.2	27.3	12.1			15.9	1089
1950	706	23.4	31.9	25.5	12.8	6.4			22.7	1554
1960	778		41.2	47.0	5.9	5.9			8.2	561
1965	1283	10.0	33.3	20.0	13.3	20.0	3.3		14.5	993
1970	1722	3.8	11.5	30.8	34.6	7.7	7.7	3.8	12.6	863
1975	3574		9.5	19.0	19.0	14.3	28.6	9.5	10.2	698
HP Distribution (%)		17.7	25.1	22.7	19.2	9.4	4.4	1.5	100.0	6846
Total/Ave	1250	1189	1686	1525	1289	631	295	101	6716	

SOURCE: Three percent sample of U.S. Coast Guard, Inspected Vessel File: Boats in Towing Service.

1/ Distribution adds across to 100 percent.
2/ Boats built before 1900 are not analyzed.

Table III-22

Towboat Costs by Size
($1976 thousand)

Horsepower	Cost
400 - 600	300
800 - 1200	550
1400 - 1600	1,000
2800 - 3400	1,700
4000 - 4400	2,200
5000 - 6000	2,600
6100 - 7000	3,100
7100 - 8000	3,500
8100 - 9000	3,900
10,000	4,500

SOURCE: U.S. Army, Corps of Engineers, Unpublished.

Barge sizes vary considerably depending on the area of service. Therefore, barge requirements are measured in a common unit of deadweight tons. Table III-23 presents data for computing the average cost per deadweight ton of both single skin and double skin barges. From 1970 to 1977, 33 percent of the new tank barges built were constructed with full double hulls and 20 percent with partial double hulls. The U.S. Coast Guard is presently undergoing rule-making procedures to make full double hulls mandatory on all new barges.[10] Considering this likelihood and the wide acceptance by the industry of double hulls, the value of $200 per DWT will be used in computing investment requirements. Table III-24 summarizes the foregoing analysis and presents the investment totals for 1990.

Summary

Table III-25 summarizes the foregoing estimates of investment requirements by scenario and category of investment converted to 1978 dollars using factors given in Table II-8. 1985 investment requirements were computed as a proportion of the 1990 estimate based on the growth in crude supply and demand for each scenario.

Scenario B requires more investment for transportation due to both the Texas Deepwater Port and a large demand for domestic tanker to move a larger supply of Alaskan crude oil.

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[10] Johnson, LCRD E. K., U.S. Coast Guard Implementation of Presidential Initiative for an Evaluation of Design, Construction and Equipment Standards for Tank Barges Which Carry Oil, U.S. Coast Guard, August 1, 1978.

Table III-23

Cost of Barges
($1976 thousand)

Size	Capacity 1/ (DWT)	Single Skin 2/	Double Skin 2/
195' X 35'	1300	275	310
240' X 50'	2800	435	515
290' X 50'	3800	570	710
Ave Cost per DWT		185	200

SOURCES: 1/ Capacity estimated by TERA from representative barges in USCG inspected tank barge file.

2/ Costs obtained from U.S. Army Corps of Engineers, unpublished data.

Table III-24

Barge and Towboat Investment
Crude Oil

	Scenario		
	B	C	D
1990 Barge Traffic 1/ (thousand bbl.)	379,886	391,747	396,989
1977 Barge Traffic 2/	337,222	337,222	337,222
Incremental Traffic (000bbl)	42,664	54,525	59,767
Required New Barges 3/ (000 DWT)	579	740	811
Required New Towboats 4/	12.6	16.1	17.6
Replacement Barges (000 DWT)	668	668	668
Replacement Towboats	23.8	23.8	23.8
Total Barges (000 DWT)	1,247	1,408	1,479
Total Towboats	36.4	39.9	41.4
Investment ($1976 million)			
Barges	249.4	281.6	295.8
Towboats	68.1	74.6	77.5

1/ Equal to 6 percent of U.S. crude oil demand.

2/ U.S. Army Crops of Engineers, Waterborne Commerce of the United States. Ton data converted to barrels by a factor of 6.7 bbl/T.

3/ Incremental traffic divided by 11 bbl per year and bbl of capacity divided by 6.7 bbl/T.

4/ Based on 46,000 DWT per towboat.

5/ Based on $200 per DWT average.

6/ Based on $1,871,000 per towboat average.

Table III-25

Summary of Crude Oil Transportation Investment Requirements
($1978 millions)

	Scenario		
	B	C	D
Interregional Pipelines	1238.2	1233.7	923.9
Pipeline Plans in Local Areas	286.6	286.6	286.6
Tankers	2876.3	909.5	1717.7
Deepwater Ports	1554.0	1554.0	429.0
Barges	286.1	323.0	339.3
Towboats	78.1	85.6	88.9
TOTAL (1990)	6319.3	4392.4	3785.4
(1985) 1/	4319.2	3939.5	2181.1

1/ Based on proportion of crude oil demand growth from 1978 as given in Table III-1.

The total investment requirements for Scenarios C and D are roughly equivalent. However, Scenario D requires more domestic tankers for the Alaskan trade but does not need the Texas Deepwater Port. Scenario C assumes the use of the Texas Deepwater Port, but needs less tanker capacity for the Alaskan trade. Scenario D is the lowest mainly due to the effect of lower pipeline requirements.

CHAPTER IV. PETROLEUM PRODUCTS

Introduction

Total demand for petroleum products is projected to increase very slowly by 1990 with an actual drop from 1977 demand in 1985 for two of the scenarios. Table IV-1 shows historical and projected demand for all petroleum products by product type. Also listed is a total for products capable of being shipped in pipelines.

Nearly 79 percent of all products capable of being shipped in pipelines are shipped in pipelines. Table IV-2 presents data used to calculate modal share for products pipelines. This modal share is stated in terms of share of pipeable products. As a share of all products of petroleum refineries, pipelines constitute approximately 60 percent.

Tankers and barges, on the other hand, may carry any petroleum products. Table IV-3 shows the amount of various liquid bulk products carried by barge and tanker in 1977. When compared with total production for 1977, barges and tankers show a 21.7 and a 14.5 percent modal share, respectively. Because of the way that the data was collected, these shares are additive for a total of 36.2 percent for water modes in the transportation of petroleum products.

Table IV-1

Demand for Petroleum Products
(millions of barrels per Year)

Year (Scenario)		Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquid Petroleum Gasses	Naptha	Other	Total 1/	Total 2/ Pipeable
1976		2567.2	361.4	1208.6	1025.1	696.9		349.9	6209.1	4834.1
1977		2633.5	379.3	1287.3	1120.9	740.3		375.0	6536.3	5040.4
1985	B	2424.8	446.8	1302.7	995.2	260.0	612.9	368.2	6410.7	5047.2
	C	2525.7	440.0	1400.7	1141.8	277.4	614.5	378.8	6778.8	5258.3
	D	2439.6	415.3	1328.1	1035.4	271.6	603.8	364.8	6458.4	5058.4
1990	B	2474.1	483.3	1425.8	929.9	268.8	775.0	413.5	6770.3	5427.0
	C	2521.1	459.2	1490.9	1008.6	284.3	761.5	422.0	6947.6	5516.9
	D	2462.6	421.9	1520.2	1355.5	286.4	744.4	413.8	7204.8	5435.5

1/ Still Gasses omitted.

2/ Equal to Gasoline, Jet Fuel, Distillate, LPG, and Naptha.

SOURCE: Historical: U.S. Department of Energy, Energy Data Reports, Petroleum Statement, Annual.

Projected: U.S. Department of Energy, Mid-Range Forecasting System.

Table IV-2

Pipeline Modal Share Petroleum Products
(millions of barrels per Year)

Year	Trunkline Movements 1/	Pipeable Products Demand 2/	Modal Share
1973	3633.1	4737.9	.7668
1974	3588.8	4579.4	.7837
1975	3645.5	4544.9	.8021
1976	3813.2	4834.1	.7888
TOTAL	14680.6	18696.3	.7852

SOURCES: 1/ Interstate Commerce Commission, Transport Statistics in the United States, Part 6: Pipelines

2/ U.S. Department of Energy, Energy Data Reports, Petroleum Statement, Annual; and
U.S. Bureau of Mines, Mineral Industries Surveys, Petroleum Statement, Monthly, Annual Summary

Table IV-3

Tank Barge and Tanker Totals
Petroleum Products 1977
(millions of Barrels per Year)

Product	Barge	Tanker
Gasoline	410.3	308.8
Jet Fuel	44.5	44.3
Kerosene	17.0	21.2
Distillate Fuel Oil	333.9	267.7
Residual Fuel Oil	523.9	253.3
Lube Stocks	17.5	17.8
Napthas & Solvents	26.3	18.1
Asphalt	34.5	17.5
LPG's	12.9	-
TOTAL Water Mode	1420.8	948.8
TOTAL Production	6536.3	6536.3
Modal Share (%)	21.7	14.5

SOURCE: U.S. Army, Corps of Engineers, Waterborne Commerce of the United States, Calendar Year 1977. Ton data converted to barrels.

Both trucks and railroads carry petroleum products. However, railroads have a very small share in the total volume produced and transported. Therefore, they are excluded from the analysis. Trucks are excluded because they are used almost exclusively for local distribution of products.

The following analysis is based on the assumption that present modal shares will prevail.

Investment in Products Pipelines

Table IV-4 presents an estimate of total three year investment in petroleum products pipelines from 1974 through 1976. If the total investment of $889.94 million is divided by the increase in throughput of pipelines of 180.1 million barrels per year [1] for the same period, an investment to demand ratio of $4.94 per barrel of increased annual throughput is computed. This ratio is multiplied by the projected increases in throughput of products pipelines for each scenario to estimate total investment requirements given in Table IV-5.

Investment in Tankers

According to experts in the industry, the U.S. tanker fleet in domestic trade is currently in equilibrium between supply and demand. Consequently, any additional demand on the tanker fleet will require new tankers to be built.

The present U.S. tanker fleet carrying crude oil and petroleum products in domestic trade totals 6,921,000 deadweight tons

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[1] See Table IV-2.

Table IV-4

Product Pipeline Investments by Size
Jan. 1, 1974 - Dec. 31, 1976

Pipeline Size (inches)	Mileage Added 1/ in 1974-76	Average Cost per 2/ Mile (thousands 1975 dollars)	Total 1974-76 Investment (millions 1975 dollars)
2	17	13.7	.23
3	59	26.2	1.55
4	511	38.7	19.78
6	2935	51.2	150.27
8	2977	63.4	188.74
10	2570	76.4	196.35
12	1363	88.7	120.90
14	550	97.7	53.74
16	263	112.2	29.51
18	74	127.4	9.43
20	170	143.7	24.43
22	-	161.3	-
24	23	180.1	4.14
26	-	199.3	-
28	52	219.5	11.41
30	40	242.0	9.68
32	-	267.0	-
34	-	291.0	-
36	-	316.1	-
40	185	377.2	69.78
Total Investment			889.94

SOURCES: 1/ Taken from DOE/EIA Energy Data Reports, "Crude Oil and Product Pipelines, Triennial," December 13, 1977, Tables 2 and 4.

2/ Estimated by TERA from Pipeline Investment Algorithm (See Appendix B).

Table IV-5

Products Pipelines Investment Calculation 1/
(millions of barrels)

	Scenario		
	B	C	D
(a) Total Pipeable Products	5427.0	5516.9	5435.5
(b) Pipeline Share	.7852	.7852	.7852
(c) Products having trunkline movement (a) X (b)	4261.3	4331.9	4268.0
(d) 1978 Products having trunkline movement 2/	4076.3	4076.3	4076.3
(e) 11-Year Increase in Annual Throughput (c) - (d)	185.0	255.6	191.7
(f) Investment in Pipelines per barrel of Annual Throughput (1975 dollars)	$ 4.94	$ 4.94	$ 4.94
(g) Required Investment for 1990 Throughput (millions of 1975 dollars) (e) X (f)	$913.9	$1262.7	$947.0

1/ Includes LPG Product lines.

2/ ICC, Transport Statistics in the United States, Part 6: Pipelines.

(DWT) of capacity.[2] This figure does not include the 1,068,000 DWT computed for carrying Alaskan crude oil to the Panama Canal transshipment facility. If the crude oil fleet capacity of 2,024,000 DWT[3] is subtracted from the total, an estimated 4,897,000 DWT of tanker capacity is derived for domestic transportation of petroleum products.

In 1977 a total of 948.8 million barrels of petroleum products were transported by tanker (see Table IV-3). Based on 11 month data[4] a 1978 total may be computed as 2.4 percent greater than 1977, assuming that tankers held the same modal share as in 1977. Dividing 1978 carriage by total capacity, a utilization factor of 198.40 barrels per year per DWT of capacity is computed. Using this datum, additional tanker investment requirements may be computed. Table IV-6 shows data used to compute an average cost of $773 per DWT in 1974 dollars. Table IV-7 outlines the computation of 1990 tanker investment requirements.

Investment in Barges and Towboats

In Chapter III, the barge and towboat requirements were computed using a utilization factor of 11 barrels per year per barrel of barge capacity, and a ratio of 46,000 DWT of barges

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[2]U.S. Maritime Administration, Employment of U.S. Flag Ocean-going Merchant Fleet as of March 31, 1979, preliminary unpublished figures.

[3]See Table III-17.

[4]U.S. Department of Energy, Energy Data Reports, Petroleum Statement Monthly, November 1978.

Table IV-6

Cost of Conventional Tankers

Tanker Size (000 DWT)	Cost (1974 $ million)
20	23.0
25	25.0
37	30.0
50	34.0
60	36.5

SOURCE: U.S. Army, Corps of Engineers, unpublished.

Table IV-7

Investment in Tankers
Petroleum Products
1990

	Scenario		
	B	C	D
(a) Total Product Demand in 1990 (million barrels per year)	6770.3	6947.6	7204.8
(b) Tanker Modal Share (%)	14.5	14.5	14.5
(c) Tanker Movements (a) X (b)	981.7	1007.4	1044.7
(d) Required Tanker Capacity (000 DWT) (c) ÷ 198.4	4,948	5,078	5,266
(e) 1978/9 Tanker Fleet	4,897	4,897	4,897
(f) Additional Tanker Capacity Required (000 DWT) (d) - (e)	51	181	369
(g) Cost per DWT (1974 dollars)	$773	$773	$773
(h) Investment Requirement (1974 $ million) (f) X (g)	$ 39.4	$139.9	$285.2

per towboat. For petroleum products, barrels of oil are converted to tons by a factor of 6.55. Although most products of petroleum are lighter than crude oil, the residual fuel oil is not. Together with distillate fuel oil, which is just as heavy as crude oil, these two products make up 60 percent of the product volume carried by barges.

Replacement barges and towboats are computed on the basis of 1978 fleet requirements times 14.6 percent for barge and 24 percent for towboats. The data supporting these retirement rates are given in Chapter III.

Table IV-8 presents the data and computation of investment requirements for barges and towboats in 1990.

Summary

The foregoing estimates of investment are converted to 1978 dollars using factors given in Table II-8. Summary investment requirements are presented in Table IV-9. Investment for 1985 is computed based on the growth in petroleum product demand from 1978. In two scenarios, growth is projected to be negative through 1985 and positive thereafter. The lower investment projection in Scenario B reflects the lower demand for petroleum products in that scenario.

Table IV-8

Barge and Towboat Investment
Petroleum Products

	Scenario		
	B	C	D
1990 Barge Traffic 1/ (million bbl)	1469.2	1507.6	1563.4
1978 Barge Traffic 2/ (million bbl)	1454.9	1454.9	1454.9
Incremental Traffic (million bbl)	14.3	52.7	108.5
Required new Barge 3/ Capacity (000 DWT)	198	731	1506
Required new Towboats 4/	4.3	15.9	32.7
Replacement Barge 5/ Capacity (000 DWT)	2948	2948	2948
Replacement Towboats 6/	105.3	105.3	105.3
Total Barge Capacity (000 DWT)	3146	3678	4454
Total Towboats	109.6	121.2	138.0
Investment (1976 $ million)			
Barges 7/	629.2	735.6	890.8
Towboats 8/	205.1	226.8	258.2

1/ Equal to 21.7 percent of Petroleum Product Demand (see Table IV-3)
2/ 1977 value from Table IV-3 times 1.024.
3/ Incremental traffic divided by 11 bbls per bbl of capacity divided by 6.55 bbl per ton.
4/ Based on 46,000 DWT per towboat.
5/ Based on 1978 traffic and 14.6 percent retirement to 1990.
6/ Based on 1978 traffic and 24 percent retirement to 1990./
7/ Based on $200 per DWT average (See Chapter III).
8/ Based on $1,871,000 per boat average (See Chapter III).

Table IV-9

Summary of Petroleum Products Transportation Investment Requirements ($1978 million)

	Scenario		
	B	C	D
Pipelines	1089.4	1505.1	1128.8
Tankers	54.3	192.6	392.7
Barges	721.7	843.7	1021.7
Towboats	235.2	260.1	296.2
TOTAL (1990)	2100.6	2801.5	2839.4
(1985)1/	-0-	942.8	-0-

1/ 1985 values based on growth from 1978 Total Product Demand (6693.2 estimated) using data found in Table IV-1.

CHAPTER V. COAL

Introduction

Coal production to 1990 is projected to increase greatly from current levels. Table V-1 contrasts the coal production in the MEFS regions in 1975 with 1990. A greater than two-fold increase is projected in all scenarios.

The analysis of transportation is done primarily on the basis of historical modal shares. Table V-2 summarizes data on modal activity in 1975 collected from several sources. The effects on intermodalism can be clearly seen in that the modal shares sum to greater than the production of coal. Truck movements are understated in the table by the amount transshipped from the mine to water and rail carriers. Since most coal shipments by truck are local, truck investment requirements are not estimated in this study.

The water mode in Table V-2 must be further broken down into barge traffic, domestic self-propelled vessels on the Great Lakes, in coastal trades, and in overseas trades. This is done with data given in Table V-3. No intermodalism is assumed within the water modes due to incomplete data.

The following analysis discusses each mode separately.

Table V-1

Production of Coal by Region

(Million tons per year)

Region	1975	1990 Scenario		
		B	C	D
(C1) North Appalachia	178.58	259.11	247.48	181.44
(C2) Central Appalachia	193.85	227.71	225.06	228.59
(C3) South Appalachia	24.06	10.83	12.37	19.19
(C4) Midwest	141.02	301.81	290.45	308.59
(C5) Central-west	21.10	12.59	11.92	12.82
(C6) Gulf	1/	71.76	71.76	82.21
(C7) North-East Great Plains	8.52	32.18	32.18	32.44
(C8) North-West Great Plains	46.34	595.33	503.27	361.67
(C9) Rocky Mountains	15.71	47.04	41.15	66.42
(CA) Southwest	14.76	25.56	22.85	17.38
(CB) Northwest	4.51	6.02	6.12	23.48
(CC) Alaska	2/	---	---	---
TOTAL	648.44	1589.94	1464.61	1334.23

SOURCES: Historical: U.S. Bureau of Mines, Coal - Bituminous and Lignite, Annual, 1975, Feb. 10, 1977.
Projected: U.S. Department of Energy, Mid-Range Energy Forecasting System.

1/ Included in C5.

2/ Included in CB.

Table V-2

Coal Modal Shares
1975
(thousand tons per year)

MEFS Coal District	Production	Mine Mouth & Truck 1/	Rail	Percent of Region	Water 2/	Percent of Region
C1	178,578	59,898	93,348	52	60,150	34
C2	193,852	20,384	147,552	76	107,169	55
C3	24,056	8,502	14,403	60	7,889	33
C4	141,018	26,503	99,712	71	43,561	31
C5 3/	21,103	15,852	5,251	25	176	1
C7	8,515	4,168	4,347	51		
C8	46,341	7,520	38,821	84		
C9	15,712	3,014	12,698	81	47	-
CA	14,755	11,471	3,284	22		
CB 4/	4,509	3,884	625	14		
TOTAL	648,438	161,196	420,042		218,992	

SOURCE: TERA; Estimated based on Data from the U.S. Bureau of Mines, Interstate Commerce Commission and U.S. Army, Corps of Engineers. Modal estimates sum to greater than production due to multi-modal movements.

1/ Mine Mouth Generation plus complete shipments by Truck plus other.

2/ Includes Exports plus Imports.

3/ Includes C6

4/ Includes CC

NOTE: More recent data has been made available as this report goes to press. 1978 production equals 640,944 thousand tons compared to a revised 1975 figure of 640,826.

Table V-3

Water Carriage of Coal
1977
(000 short tons)

	Barge	Self-Propelled	Total
Imports		1,722	1,722
Coastwise Exports		37,058	37,058
Lakewise Exports (Canada)		16,880	16,880
Coastwise	3,607	55	3,662
Lakewise		22,248	22,248
Internal	127,627	1	127,628
Local	2,758		2,758
TOTAL	133,992	77,964	211,956

SOURCE: U.S. Army, Corps of Engineers, Waterborne Commerce of the United States: Calendar Year 1977, Engineer Division, Vicksburg, Miss.

Investment in Railroad Cars and Locomotives

Railroads are the principal carriers of coal, hauling 65 percent of production in 1975. Railroads' share in 1990 will depend upon the modal characteristics in the coal-producting regions. Data from Tables V-1 and V-2 are used to compute coal originations on railroads for the three 1990 scenarios. These originations by MEFS coal regions are allocated to the railroad regions shown in Figure V-1, by factors given in Table V-4. The resulting originations for coal by railroad region are given in Table V-5 for each scenario. These values are divided by productivity measures for cars and locomotives to obtain total fleet requirements for 1990. The present fleet remaining in use in 1990 is then subtracted from the total requirement to estimate the need for new equipment. The new equipment is multiplied by a current price to obtain the total cost for the equipment.

Productivity of Cars and Locomotives

Table V-6 presents data obtained through a survey of major coal hauling railroads in the three railroad regions shown in Figure V-1. As can be seen from the table, the utilization characteristics for coal fleets differ between the regions. Since growth in coal production varies between the regions considerably, the use of separate utilization rates is essential to obtain reasonable estimates of future requirements.

Figure V-1

Regional Rail Association Territories

Table V-4

Allocation of MEFS Coal Regions to Railroad Regions

PIES Coal Region[1/]	Railroad Region	Percent Allocation
C1	1 Eastern	100
C2	1 Eastern	34
	2 Southern	66
C3	2 Southern	100
C4	1 Eastern	60
	2 Southern	40
C5	3 Western	100
C6	3 Western	100
C7	3 Western	100
C8	3 Western	100
C9	3 Western	100
CA	3 Western	100
CB	3 Western	100
CC	(Alaska)	-

SOURCE: TERA, Inc.

Table V-5

Coal Originations on Regional Railroads
(million tons per Year)

Railroad Region	Scenario		
	B	C	D
Eastern	332.15	310.58	284.88
Southern	206.43	202.80	213.81
Western	582.14	499.29	419.81
TOTAL	1,110.72	1,012.67	918.50

Table V-6

1974 Productivity Measures for Rail Transportation of Coal

Region	Originated Tons per Car per Year	Originated Tons per Locomotive per Year
Eastern	1,540	196,593
Southern	2,739	163,022
Western	4,631	152,670

SOURCE: Anderson and Desai, Rail Transportation Requirements for Coal Movement in 1980, prepared for the U.S. Department of Transportation by Input Output Computer Services Inc., Cambridge, MA, December 1976.

In any particular year, the utilization rates (computed by dividing total orginations by total number of cars) can be influenced by factors beyond the control of the railroads. Strikes or poor weather can idle either the roads or the mines. Table V-7 presents a historical series of utilization rates for the entire nation. Data for regionalization of such a series is not available. The year 1974 was relatively high in utilization of equipment. This historical series also shows no clear trend which might be extrapolated to 1990. In spite of the railroads' contentions to the contrary, an improvement in railroad equipment utilization by 1990 is not assured. Therefore, the 1974 regional utilization rates were used to project 1990 equipment needs based on coal originations in the railroad regions.

Current Rail Fleet in Coal Service

A survey of major coal carrying railroads taken in 1974 resulted in the fleet projections given in Table V-8. The values in Table V-8 are the sample values, not the totals. The Association of American Railroads uses an estimating factor of 80 percent of all open top hopper cars and 10 percent of all gondola cars to compute the coal carrying fleet. Virtually all of the gondolas used in coal service are privately owned and used in local service. These are not analyzed in this study. Eighty percent of the entire hopper car fleet, both railroad owned and privately owned, was standardized to cars of 100 ton equivalent and listed in Table V-9 for 11 years. The

Table V-7

Average Coal Car Utilization Rates

Year	Coal Tons Originated 1/ (000)	Hopper Fleet 2/ (100 Ton Equiv.)	Tons per Car per Year
1968	400,142	243,905	1641
1969	405,194	241,193	1680
1970	425,920	243,935	1746
1971	380,309	247,023	1540
1972	399,525	246,501	1621
1973	400,327	238,197	1681
1974	415,632	238,226	1745
1975	429,880	244,933	1755
1976	430,007	250,020	1720
1977	437,245	247,970	1763
1978	400,300	247,010	1621

SOURCES: Economics and Finance Department, Association of American Railroads.

1/ Based on ICC statistics.

2/ Based on 80 percent of total hopper fleet.

Table V-8

Existing and Projected Coal Carrying Equipment

	1974	1980
Eastern Region:		
Cars 1/	126,372	151,990
Locomotives 2/	990	1,126
Southern Region:		
Cars	40,317	54,183
Locomotives	675	801
Western Region:		
Cars	14,206	59,916
Locomotives	-	1,890
TOTAL:		
Cars	180,895	266,089
Locomotives	-	3,817
Cars per Locomotive		69.7

SOURCES: Anderson and Desai, Rail Transportation Requirements for Coal Movement in 1980, prepared for the U. S. Department of Transportation by Input Output Computer Services, Inc., Cambridge, MA, Dec. 1976. Based on a survey of major coal carrying railroads.

1/ 100 Ton equivalent.

2/ 3000 hp equivalent.

Table V-9

Open Hopper Car Turnover

Year	Coal Hopper Fleet 1/	Delivered New Cars 2/	Annual Retirements	Percent 3/
1968	243,905	11,770	-	-
1969	241,193	8,006	10,718	4.4
1970	243,935	11,945	6,203	2.3
1971	247,023	14,034	10,946	4.5
1972	246,501	6,149	6,671	2.7
1973	238,197	2,526	10,830	4.4
1974	238,226	6,321	6,292	2.6
1975	244,933	17,878	11,171	4.7
1976	250,020	14,944	9,857	4.0
1977	247,970	8,850	10,900	4.4
1978	247,010	12,164	13,124	5.3
Average				3.9

SOURCE: Computed from Data given in Association of American Railroads, "Coal and the Railroads - 1979," Background on Transportation, a 1979 update paper to be published in June 1979.

1/ 100 Ton equivalent.

2/ Assumed to be 100 Tons each.

3/ Percent of previous year's fleet retired by the year indicated.

1974 total in Table V-9 is greater than the total in Table V-8 because the data reported in Table V-8 is based on a sample of railroads.

The 1974 survey also provided information on locomotives in coal service. Although the western railroad owners said that they drew their locomotives for coal from a general pool, they did project locomotive requirements for coal service in 1980. Given these projections, an overall ratio of 69.7 cars per locomotive is computed for coal service. This is used to compute the number of locomotives in coal service for 1978 based on 247,010 cars (see Table V-9).

Not all of the cars and locomotives presently in service will continue to be used in 1990. To compute the new and rebuilt cars which will be needed for coal carriage in 1990, the remaining fleet of those cars now in use must be computed. Table V-9 shows a computation of average retirements of hopper cars as a percent of the total fleet. Twelve years times the average annual retirement equals 115,601 cars which need to be purchased just to maintain the 1978 fleet size in 1990. Similarly, data from Table V-10 permits calculation of average retirements for locomotives. The 1978 locomotive fleet in coal service is estimated, based on data from Table V-8 and V-9, to be 3,543. In order for that many locomotives to be available in 1990, a total of 1,658 locomotives must be purchased in the intervening years.

Investment in Cars and Locomotives

In addition to the cars and locomotives purchased to maintain present fleet levels, growth in coal traffic will require

Table V-10

Locomotive Fleet Turnover

Year	Locomotives in Service	Locomotives Installed	Retirements	Percent
1970	27,086	1093	-	-
1971	27,189	1287	1184	4.4
1972	27,364	1577	1402	5.2
1973	27,800	1384	948	3.5
1974	28,084	1395	1111	4.0
1975	28,210	840	714	2.5
1976	27,609	567	1168	4.1
1977	27,667	992	934	3.4
1978(p)	27,772	1322	1217	4.4
Average				3.9

SOURCE: Economics and Finance Department, Association of American Railroads, Yearbook of Railroad Facts, 1979 and unpublished table: "Diesel Locomotives Installed," Revised May 14, 1979.

additional equipment purchases. Using the data given in Tables V-5 and V-6, total regional fleet requirements were computed for three scenarios in 1990. Table V-11 summarizes the equipment needs for 1990 for each scenario. The coal cars are stated in 100 ton equivalents.

A 100 ton open hopper car in 1978 cost approximately $30,000 and a 3,000 horsepower locomotive cost $585,000. The cost for a rebuilt car or locomotive is, on the average, one-half of the new price. In the past several years, rebuilts have averaged 4.7 percent of new and rebuilt cars, and 11.9 percent of new and rebuilt locomotives delivered to operating companies. Therefore, the average unit cost for open hopper cars is $29,588 and for locomotives $550,193. These values are used to compute total investment requirements in Table V-11.

Capital Expenditures for Rail Track and Way

Expenses for railroad track and way are not commodity specific but relate to the total volume and dispersion of traffic. Much of the expenditure is mandated by law in order to maintain service availability. Yet not all such expenditures have been made as needed, resulting in a significant account for deferred maintenance and delayed capital improvement. As of June 30, 1976 deferred maintenance of way of all Class I railroads totaled

Table V-11

Investment Requirements for Coal Cars and Locomotives

	Scenario		
	B	C	D
Eastern Region			
Coal Cars 1/	209,188	201,675	184,987
Locomotives 2/	1,639	1,580	1,449
Southern Region			
Coal Cars	75,367	74,042	78,061
Locomotives	1,266	1,244	1,312
Western Region			
Coal Cars	125,705	107,815	96,652
Locomotives	3,813	3,270	2,750
Total Cars Required	410,260	383,532	359,700
Cars needed to Maintain 1978 Fleet	115,601	115,601	115,601
Cars needed for Growth	163,270	136,522	112,690
Total New & Rebuilt Cars	278,851	252,123	228,291
Cost of New Cars 3/ (million dollars)	$8,251	$7,460	$6,755
Total Locomotives	6,718	6,094	5,511
Locomotives needed to Maintain 1978 Fleet	1,658	1,658	1,658
Locomotives for Growth	3,175	2,551	1,968
Total New and Rebuilt Locomotives	4,833	4,209	3,626
Cost of New Locomotives 4/ (million dollars)	$2,659	$2,316	$1,995

1/ All Cars in 100 ton equivalents.
2/ All Locomotives in 3000 hp equivalents.
3/ Assumes 4.7 percent of new cars are rebuilt at ½ cost of new (1978 dollars).
4/ Assumes 11.9 percent of new locomotives are rebuilt at ½ cost of new (1978 dollars).

$1,345.8 million and delayed capital improvement of roadway $1,134.1 million.[1] Deferred maintenance is a deterioration of the rail plant permitted to occur either through lack of funds or a conscious decision to disinvest. The latter may anticipate a request for permission to abandon service.

Since maintenance of way resumed on a normalized schedule would eventually result in catch up on deferred maintenance, and because cycles in catch up of maintenance of track and way beget more cycles, the Secretary of Transportation has recommended that no significant bulge of expenditures be made to catch up on deferred maintenance.[2] Assuming a 25 percent catch up on deferred maintenance of way and equipment over 10 years from 1976 to 1985, the Federal Railroad Administration computes a total outlay of $2.837 million for catch up of deferred maintenance. At a 50 percent catch up rate the outlay would be $6.065 million.[3] The outlays from 1979 to 1985 are given in Table V-12 with a projection to 1990 based on growth rates used in the Federal Railroad Administration (FRA) Analysis.

In addition to maintenance of way the FRA also projected investment in road property from 1976 through 1985. Table V-13 is reproduced from the "Prospectus" study cited above. Using a similar approach as was used to project maintenance of way expenditures, capital expenditures for road property are computed to be $12,329 million in current (inflated) dollars for the period 1979 through 1990.

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[1]A Preliminary Report by the Secretary of Transportation, A Prospectus for Change in the Freight Railroad Industry, October 1978, p. 24.

[2]*Ibid.*

[3]*Ibid.*, current dollars.

Table V-12

Maintenance of Way and Catch-up on Deferred Maintenance
1979 through 1990
(Current $ million)

	Deferred Maintenance	Total Maintenance of Way
25% Catch-up Scenario		
1979 - 1985	638	9,580
1986 - 1990	907	13,617
TOTAL 1990	1,545	23,197
50% Catch-up Scenario		
1979 - 1985	1,362	10,305
1986 - 1990	1,936	14,651
TOTAL 1990	3,298	24,956

SOURCE: Computed from data given in: A Preliminary Report by the Secretary of Transportation, A Prospectus for Change in the Freight Railroad Industry, October 1978, Appendix A.

Table V-13

Projected Sources and Uses of Funds, 1976-1985[a] (Million $)

Category	Scenario 1 Constant $	Scenario 1 Current year $	Scenario 2 Constant $	Scenario 2 Current year $
Sources of funds:				
Funds from operations	12,551	10,142	10,569	6,999
Sales of equipment obligations[b]	11,237	16,755	11,237	16,755
Sale of equity and/or debt	1,664	1,664	1,664	1,664
Other sources	457	911	457	910
Total	25,909	29,472	23,927	26,328
Uses of funds:				
Investment in road property	4,333	6,819	4,333	6,819
Investment in equipment	14,362	21,491	14,362	21,491
Repayment of funded debt	1,643	1,644	1,643	1,644
Repayment of equipment debt	7,688	9,095	7,688	9,095
Increase in working capital	853	3,168	859	3,185
Other uses	0	258	0	258
Total	28,879	42,475	28,885	42,492
Additional funds required[c]	2,970	13,003	4,958	16,164
Peak additional funds required	4,557	13,140	5,364	16,164

[a]Represents annual charge to retained earnings (i.e., ex dividends), net of noncash items.

[b]Conditional sales agreements and equipment trusts.

[c]These amounts are net of annual funding surpluses.

NOTE: Current year dollar amounts reflect the effect of inflation as opposed to constant dollar amounts which do not reflect the effect of inflation and which, therefore, are equivalent in value from year to year.

SOURCE: Federal Railroad Administration study.

SOURCE: Reproduced from: A Preliminary Report by the Secretary of Transportation, A Prospectus for Change in the Freight Railroad Industry, October 1978.

Coal traffic accounts for 25 percent of the tonnage of Class I railroads and 11 percent of the revenues. The most appropriate measure of productive output for transportation, however, is ton-miles. Coal traffic constitutes 18 percent of total Class I railroad ton-miles.[4] Arbitrary as it may be, 18 percent may be used to allocate such joint costs as track and way expenditure to coal traffic. The results of this computation, plus a deflation to 1978 dollars, is given in Table V-14.

Investment in Coal Barges, Towboats and Colliers

Independent data on coal barge fleet and collier fleet are not available. Therefore, utilization ratios computed for petroleum barges are assumed to hold true for coal barges. Total barges required are computed on the basis of 11 tons per year delivered per ton of barge capacity in use. The same ratio applies to both 1978 and 1990 traffic levels to compute existing barge fleet and future barge requirements. Collier requirements for the Great Lakes and Tidewater movements are computed using representative coal flows. Table V-15 gives the total carriage of coal by modes for 1977 and 1990. Fleet requirements for 1977 will be considered adequate for 1978 due to an overall drop in coal production from 1977 to 1978, which is assumed to be reflected in a drop in water carriage as well.

[4] 1976 Carload Waybill Statistics, U.S. Department of Transportation, Washington, D.C., July 1977.

Table V-14

Investment and Maintenance
of Track and Way
1990

	Current Dollars Million	1978 Dollars 1/ Million
Deferred Maintenance	1,545 - 3,298	1,023 - 2,185
Normal Maintenance	21,652	14,347
Investment	12,829	8,500
Total Capital Expenses	36,026 - 37,779	23,870 - 25,032
18 percent Allocation 2/ to Coal	6,485 - 6,800	4,297 - 4,506

1/ Based on FRA ratio of inflated to 1976 dollars adjusted to 1978 dollars.

2/ Based on proportion of ton-miles.

Table V-15

Carriage of Coal by Water Mode

(million tons per year)

Mode	1977	1990 Scenario		
		B	C	D
Total Water Mode	211.96	310.61	302.17	289.54
Overseas Exports	37.06	89.89	55.89	55.89
Barge Traffic	133.99	170.77	190.57	180.80
Lake Traffic	39.13	49.86	55.63	52.78
Canadian Exports	16.88	25.11[a/]	25.11[a/]	25.11[a/]
Domestic	22.25	24.75	30.52	27.67
Coastwise Vessels	.06	.07	.08	.07

a/ Allocation of Exports to Canada made on the basis of historical proportion for Scenarios C and D and set equal for Scenario B.

Barge and Towboat Investment

Based on the barge traffic projections given in Table V-15, estimates for needed barge capacity are computed as shown in Table V-16. As with petroleum barge movements, a single barge is assumed to carry 11 times its capacity in a year. The standard coal barge is a 195-foot by 35-foot open hopper capable of loading 1500 tons of coal. This barge was estimated to cost approximately $160,000 in 1976.[5] The economic life of an open hopper barge is assumed to be the same as a tank barge for which data is presented in Chapter III. The remaining fleet was computed based on 1977 barge traffic and a retirement of 14.6 percent of the fleet over 12 years.

Towboats are required in proportion to the number of barges needed. A fixed ratio of 23.8 barges per towboat assumes no substantive change in barge distribution patterns from the historical base. The ratio of barges to towboats was obtained from a survey of major regulated barge carriers.[6] Retirement rates for towboats were computed for the entire fleet of towboats in all services and apply to coal service as well as oil service. It is assumed that 24 percent of the towboat fleet will be retired by 1990. The cost of towboats is based on a distribution of towboats by horsepower purchased since 1975 and costs for towboats of various horsepower provided by the Corps of Engineers.[7]

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[5] U.S. Army, Corps of Engineers, "Estimated Operating Costs of Barges on the Mississippi River System," December 1976, Unpublished table.

[6] A.T. Kearney Inc., Domestic Waterborne Shipping Market Analysis Inland Waterways Trade Area, Final Report, February 1974, p. 1-A-8.

[7] U.S. Army, Corps of Engineers, "Estimated Operating Costs of Towboats on the Mississippi Riber System," December 1976, Unpublished Table (See Table III-22).

Table V-16

Investment in Coal Barges and Towboats

	Scenario		
	B	C	D
Barges:			
Total Required	10,350	11,550	10,958
Remaining Fleet	6,935	6,935	6,935
New Barges	3,415	4,515	4,023
Cost (1976 $ million)	$546.4	$722.4	$643.7
Towboats:			
Total Required	435	485	460
Remaining Fleet	259	259	259
New Towboats	176	226	201
Cost (1976 $ million)	$329.3	$422.8	$376.1

Collier Investment

There is a considerable potential for deep-draft vessel carriage of coal. This is particularly true for the distribution of western coal, either via the lakes or through Gulf Coast or lower Mississippi transshipment to the East Coast. Basic projections for water movement of coal assume no change in current modal shares. However, a high Great Lakes case is also included by adding an extra 60 million tons per year to Great Lakes volumes. The movement of this extra volume is assumed to be from Superior, Wisconsin to Detroit, Michigan and other parts of similar distance. The amount of 60 million tons was taken from the U.S. Army, Corps of Engineers, Great Lakes, Saint Lawrence Seaway Navigation Season Extension Survey Study.[8]

Using the Coal Barge and Collier Investment Algorithm developed by TERA,[9] representative coal flows were run to compute the total capacity in deadweight tons (DWT) and cost of vessels required to sustain current and projected coal flows on the lakes. Coastwise coal movements show such a small increase that no new investment was assumed to be needed. Table V-17 gives the results of these computations under the assumption that no presently used colliers will be scrapped by 1990.

The high volume case may result in compensating reductions in the need for railroad investment. However, the method used to compute railroad investment requirements is not sensitive

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[8]Printouts of route split allocations obtained by TERA from COE show this size of western coal movement if the navigation season is extended.

[9]U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-01202/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

Table V-17

Investment in Colliers for Great Lakes Coal Traffic
(Cost in 1975 $ million)

	Scenario		
	B	C	D
Total DWT Capacity Required:			
Normal Case	494	568	532
High Case	1,616	1,690	1,654
Present Fleet Capacity 1/	403	403	403
New Capacity:			
Normal Case	91	165	129
High Case	1,213	1,287	1,251
Cost:			
Normal Case	53.7	95.6	74.8
High Case	704.5	746.4	725.6

1/ Estimated based on present coal flows. The assumption is that the present fleet is fully utilized.

enough to permit estimating the effects of shortening the average haul for western coal on the investment needs of western carriers.

Summary

Table V-18 presents a summary of the coal transport investment requirements computed in this chapter. All dollar values have been converted to 1978 dollars using the factors given in Table II-8. Investment in 1985 is estimated based on the percentage growth from 1978 coal production of 640.94 million tons[10] and anticipated coal production in 1985 (1113.66, 1032.59 and 1014.69 million tons annually for scenarios B, C and D, respectively).

[10] U.S. Department of Energy, Energy Data Reports: Bituminous Coal and Lignite, Quarterly, Year 1978.

Table V-18

Summary of Coal Transportation
Investment Requirements
(1978 dollars in millions)

	Scenario		
	B	C	D
Railroad Equipment			
Coal Cars	8,251.0	7,460.0	6,755.0
Locomotives	2,659.0	2,316.0	1,995.0
Rail Track and Way	4,297.0 - 4,506.0	4,297.0 - 4,506.0	4,297.0 - 4,506.0
Inland Waterways			
Barges	626.7	828.6	738.3
Towbaots	377.7	485.0	431.4
Great Lakes Colliers	64.0 - 839.8	114.0 - 839.7	89.2 - 864.9
TOTAL (1990)	16,275.4 - 17,260.2	15,500.5 - 16,485.3	14,305.9 - 15,290.6
(1985)	8,107.2 - 8,597.7	7,370.4 - 7,838.6	7,712.3 - 8,243.1

CHAPTER VI. CONCLUSIONS

Findings

Summaries of transportation investment requirements through 1990 are given in Table VI-1 for Scenarios B, C, and D. Total investment requirements for the three modes and the three energy commodities can accumulate to a $36.3 billion or $42.7 billion range by 1990 depending on the scenario.

Scenario B is a high demand, low supply case and requires the most investment for transportation needs for all energy commodities. The extra investment for oil is made up primarily in tanker requirements for the larger Alaskan trade made necessary by lower supplies from other sources and made possible by the high price for crude oil resulting from the low supply high demand balance. The additional capital need for natural gas transportation arises primarily from increased imports of LNG requiring greater tanker and port capacity. Finally the larger required investment in coal transportation is for railroad cars and locomotives to carry a much larger production of western coal made feasible by the relative shortages in the supplies of oil and gas.

Scenario D requires the least amount of investment in transportation and is the opposite in terms of supply - demand pressure than Scenario B. Scenario D is a high supply low demand scenario which is more "relaxed" and can follow the traditional distributional patterns built up during past relatively plentiful supplies.

Many of the individual proposed energy transportation projects included in this study are included not as a finding of the

Table VI-1

Transportation Investment by Mode, Material and Scenario
1990
(1978 dollars in millions)

	OIL	GAS	COAL	TOTAL
Scenario B				
Pipelines	2,614.2	13,133.0		15,747.2
Railroads			15,207.0 to 15,416.0[a]	15,207.0 to 15,416.0
Waterways	5,805.7	3,932.0	1,068.4 to 1,844.2[b]	10,806.1 to 11,581.9
TOTAL	8,419.9	17,065.0	16,275.4 to 17,260.2	41,760.3 to 42,745.1
Scenario C				
Pipelines	3,025.4	13,123.6		16,149.0
Railroads			14,073.0 to 14,282.0[a]	14,073.0 to 14,282.0
Waterways	4,168.5	2,764.0	1,427.6 to 2,203.3[b]	8,270.1 to 9,045.8
TOTAL	7,193.9	15,797.6	15,500.6 to 16,485.3	38,492.1 to 39,476.8
Scenario D				
Pipelines	2,339.3	13,127.7		15,467.0
Railroads			13,047.0 to 13,256.0[a]	13,047.0 to 13,256.0
Waterways	4,285.5	2,280.0	1,258.9 to 2,034.6[b]	7,824.4 to 8,600.1
TOTAL	6,624.8	15,407.7	14,305.9 to 15,290.6	36,338.4 to 37,323.1

[a] Range represents low and high rate of catch up on deferred maintenance of way.

[b] Range represents low and high Great Lakes coal traffic cases.

study, but because they are part of the assumptions underlying MEFS. This is particularly true of the Alaska natural gas pipeline and several LNG receiving terminals. The number of railroad cars, locomotives, barges, towboats, tankers and colliers vary closely with the scenario totals. Pipeline building in the lower 48 states is also sensitive to scenario volumes and sources of supply. In scenario D it was found that only one deepwater oil port in the Gulf (loop) would be sufficient. Scenarios B and C, on the other hand, project sufficient imports through the Gulf Coast to permit the operation of the Texas Deepwater Port. Finally, railroad track and way expenditures are the same for all scenarios, not because it is insensitive to the differences in scenarios but because practical means of measuring that sensitivity is not available within the scope of this study. Specifically, the development of western coal fields may require extensive investment in new branch lines and possible upgrading of trunklines in impacted areas neither of which may be measured outside of a detailed network analysis.

Comparison of 1978 ARC Estimates with 1977 ARC Estimates

The projections of energy supply and demand which formed the basis of TERA's 1977 report[1] differ from the projections used in this report as shown in Table VI-2. In the 1977 report scenarios A, C and E for 1985 were used. Scenario A is a high demand-high

[1]U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

Table VI - 2

Annual Consumption of Energy in the United States
Comparison of 1978 ARC Projections with 1977 ARC

Year	Scenario		Coal (million tons)		Oil (million barrels)		Gas (billion cubic feet)	
	1978 ARC	1977 ARC	1978 ARC	1977 ARC	1978 ARC	1977 ARC	1978 ARC	1977 ARC
1977			674.73		6727.47		20,981.00	
1978			640.94		6869.94		20,571.00	
1985	B	A	1,020.03	962,42	6,603.48	8,049.66	18,652.63	20,348.08
	C	C	959.64	960.98	6,982.42	7,960.65	19,439.28	18,547.89
	D	E	941.29	944.88	6,649.66	7,690.16	19,800.47	17,086.82
1990	B		1,476.33		6,974.56		17,416.71	
	C		1,384.56		7,156.44		18,838.81	
	D		1,254.20		7,403.55		18,521.60	

supply scenario and Scenario E is a low demand-low supply scenario.[2] This report is based on Scenarios B, C, and D for 1990. Therefore, the primary difference between the reports is that the 1977 ARC covers the years 1978 through 1985, while the 1978 ARC covers the years 1979 through 1990, with interpolated results for 1985 included in the chapter summaries. Two things happened which result in changes in the projections: (1) the base year totals differ sometimes in unexpected ways (such as the drop in coal consumption from 1977 to 1978, and the significant increase in oil consumption which supports the 1977 ARC growth rates better than the 1978 ARC oil consumption growth rates); and (2) projection of consumption to 1990 differ from the growth path indicated in the 1977 ARC projections for 1985.

Table VI-3 displays the transportation investment estimates from TERA's 1977 report reformatted to correspond to Table VI-1. The most valid comparison may be made for Scenario C. The greatest difference is in coal transportation. This is due, in most part, to the very large growth in coal production and consumption between 1985 and 1990. Also, the longer period of the investment (12 years versus 8 years) requires more expense for replacement of retired cars and locomotives. In this report, rail track and way maintenance and investment estimates benefit from a more complete analysis than the 1977 report.[3]

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[2]See Chapter I, Figure I-1 for scenario structure.

[3]This report uses data presented for all Class I railroads given in "A Prospectus for Change in the Freight Railroad Industry," op. cit., while last year's report uses survey data from major coal carriers given in Anderson and Desai, op. cit.

Table VI-3

Transportation Investment by Mode, Material, and Scenario
1977 ARC

1985
(1975 dollars million)

	OIL	GAS	COAL	TOTAL
Scenario A				
Pipelines	6,770.6	11,231.4	NA	18,002.0
Railroads	NA	NA	2,650.0 to 5,807.0	2,650.0 to 5,807.0
Waterways	5,495.2 to 5,565.9	2,578.0	887.0 to 1,604.0	8,960.2 to 9,747.9
TOTAL	12,265.8 to 12,336.5	13,809.4	3,537.0 to 7,411.0	29,612.2 to 33,556.9
Scenario C				
Pipelines	6,357.4	11,230.7	NA	17,588.1
Railroads	NA	NA	2,958.0 to 6,275.0	2,958.0 6.275.0
Waterways	5,545.2 to 5,615.9	4,593.6	848.0 to 1,616.0	10,986.8 to 11,825.5
TOTAL	11,902.6 to 11,973.3	15,824.3	3,806.0 to 7,891.0	31,532.9 to 35.688.6
Scenario E				
Pipelines	5,588.2	10,825.1	NA	16,413.3
Railroads	NA	NA	2,667.0 to 5,866.0	2,667.0 to 5,866.0
Waterways	5,416.9 to 5,487.6	5,272.6	752.0 to 1,498.0	11,441.5 to 12,258.2
TOTAL	11,005.1 to 11,075.8	16,097.7	3,419.0 to 7,364.0	30,521.8 to 34,537.5

SOURCE: U.S. Department of Energy, "Capital Requirements for the Transportation of Energy Materials Based on PIES Scenario Estimates," Analysis Memorandum, DOE/EIA-0102/47 prepared by TERA, Inc., Arlington, VA, for the Energy Information Administration, Washington, D.C., January 1979, (Available from NTIS).

NA = Not Analyzed.

Another significant difference between this report and last year's is in oil pipelines. The major reason for the difference is the much lower projection of oil consumption for 1990 than in last year's 1985 projection. Together with a large increase in consumption from 1977 to 1978, this results in a much smaller growth in pipelines, particularly products pipelines. Waterway totals are larger, however, because 1990 Alaskan oil throughput is larger requiring more tankers.

Finally, the natural gas pipeline total is affected by inflation of 1975 dollars to 1978 dollars. Also, a different, more sophisticated method was used to compute other pipeline needs. This year's MEFS output was more specific concerning which LNG facilities were to be used while last year's "PIES"[4] made no such distinction. Consequently, all pending plans for LNG facilities were included in last year's report which could remotely be required. In addition, some pipeline construction associated with planned LNG terminals is included in the water total in last year's report while it was separated to the extent possible and added in with pipelines in this year's report.

Additional differences between the reports are the result of a different base year for deflating dollars. 1978 dollars are equal to 1.192 times 1975 dollars.[5] There has also been some changes in source data and methodology giving evidence of TERA's

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[4]Project Independence Evaluation System, changed name to Mid-Range Forecasting System (MEFS).

[5]See Table II-8.

intervening growth in understanding of this entire subject. The network model of the natural gas pipeline system is a major growth in capability enhancing the output of this study.

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