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ENERGY CONSUMPTION IN THE PIPELINE INDUSTRY

Technical Report, Task 1 (Partial)

By
William F. Banks

December 31, 1977

Work Performed Under Contract No. EY-76-C-03-1171

Department of Energy
San Francisco Operations Office
Oakland, California

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DEPARTMENT OF ENERGY
SAN FRANCISCO OPERATIONS OFFICE
1333 BROADWAY
OAKLAND, CALIFORNIA 94612

31 December 1977

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Energy Consumption in the Pipeline Industry

by

William F. Banks

ABSTRACT

Estimates are developed of the energy consumption and energy intensity (EI) of five categories of U. S. pipeline industries: natural gas, crude oil, petroleum products, coal slurry, and water. For comparability with other transportation modes, it is desirable to calculate EI in Btu/Ton-Mile, and this is done, although the necessary unit conversions introduce additional uncertainties. Since water and sewer lines operate by lift and gravity, a comparable EI is not definable.

PREFACE

Subsequent to Congressional approval of the Department of Energy Organization Act of 1977 (Public Law 95-91 - Aug. 4, 1977), various federal government departments and agencies previously having some form of regulatory jurisdiction over pipelines were removed of some or all of their regulatory responsibilities. These regulatory responsibilities were transferred, mainly, to either the Federal Energy Regulatory Commission (FERC) or the Economic Regulatory Administration (ERA) within the newly formed Department of Energy (DOE).

Two of the independent agencies, the Federal Power Commission (FPC) and the Federal Energy Administration (FEA), were liquidated and all of their duties transferred to the DOE. In addition, the Interstate Commerce Commission (ICC), as related to its pipeline regulatory responsibilities, was relieved of all of its duties <u>except</u> for jurisdiction over coal slurry pipelines. The remaining federal agencies and departments described in Section 5.0 of report number HCP/M-1171-3 of this series (i.e., the Department of Transportation, the Environmental Protection Agency, the Department of the Interior and the Department of Labor) retained their regulatory responsibilities over pipelines.

FERC (an independent, five-member organization within the DOE) inherited most of the gas pipeline regulatory functions of the FPC. In addition, FERC inherited the authority of the ICC to establish rates or charges for the transportation of oil by pipeline as well as the valuation of such pipelines. Under the DOE Organization Act, the FERC was delegated the following general responsibilites:

- Issue and enforce licenses for hydroelectric power-projects.

- Establish and enforce rates and charges for the sale and transmission of electricity and for the non-emergency interconnection of facilities for the generation, transmission, and sale of electricity.

- o Establish and enforce rates and charges for the transmission and sale of natural gas.

- o Issue and enforce certificates of public convenience and necessity for construction of facilities, abandonment of services or facilities, etc for natural gas lines.

- o Establish and enforce curtailments of natural gas (other than establishment and review of curtailment priorities).

- o Regulate mergers and securities acquisitions under the Natural Gas Act and Federal Power Act.

- o Other functions as may be assigned by the Secretary.

The ERA is charged with administering many of the DOE's regulatory programs other than those of the FERC. The ERA inherited the former responsibilities of the FEA as related to oil pricing, allocation, and import programs. In addition, the ERA administers other regulatory programs, including conversion of oil- and gas-fired utility and industrial facilities to coal; natural gas import/export controls; natural gas curtailment priorities and emergency allocations; regional coordination of electric power system planning and reliability of bulk power supply, and emergency and contingency planning.

Under the DOE organization Act, the ERA was delegated the following responsibilities:

- o Assure availability and regulate pricing and allocation of crude oil, natural gas liquids, and natural gas liquids products.

- o Assure availability and regulate pricing and allocation of pretroleum products.

- Develop and implement standby and emergency regulations and programs.
- Assure compliance with the enforcement of ERA program regulations.
- Ensure market competition.
- Provide a Special Counsel for compliance and enforcement.
- Administer program for conversion of utilities and MFBI's to coal.
- Intervene before FERC and other Federal regulatory agencies (with Assistant Secretaries and General Counsel).
- Perform compliance and litigation for regulatory programs (with Assistant Secretaries and General Counsel).
- Intervene before state utility regulatory proceedings (with Assistant Secretaries and General Counsel).
- Regulate natural gas and electric power imports and exports.
- Establish natural gas curtailment priorities.
- Assure voluntary coordination of electric utilities.
- Perform long range utility planning.
- Assure establishment of emergency interconnections.
- Review interlocking directorates.
- Perform non-FERC oil pipeline regulation.

Pipeline industry data collection, previously done by the BoM, FPC, and ICC has been consolidated under the Energy Information Administration of the DOE. This organization is responsible for the collection of data required by the FERC and the ERA.

It is of particular interest to note that the FERC, as stated in the DOE Organization Act, is not subject to the supervision or direction of any other official of the DOE. However, the ERA is charged with the responsibility of organizing and managing an active intervention program on behalf of the Secretary of the DOE before the FERC and other Federal and State regulatory agencies in support of Departmental policy objectives.

It is apparent then that the FERC is now the principle pipeline regulatory agency of the Federal Government. It concerns itself with tariffs, profits and other similar matters that directly impact the day to day operation of a pipeline. The reporting requirements previously administered by the FPC and ICC are now handled by the FERC. The duties of the ERA are more broad and policy oriented than FERC. It is apparent from the list of their responsibilites that the ERA is interested in assuring that energy is distributed and allocated fairly and at reasonable prices. The ERA does not involve itself with daily operation unless it becomes necessary to influence the industry to achieve a policy objective, or change a condition such as a market place imbalance.

This study was substantially completed before the DOE was created. As a result, references to the pipeline regulatory structure do not acknowledge the events and agencies described above. The purpose of this preface is to alert the reader to this situation and to update the regulatory references of this report. In general, an accurate understanding of the regulatory structure of the Federal Government as relates to pipelines will result if the reader substitutes DOE (FERC) for all references to the FPC or ICC in the context of gas and oil pipeline regulation.

GLOSSARY OF ABBREVIATIONS, SYMBOLS AND TERMS

AGA	American Gas Association
B, Bbl	Barrel
B-Mi	Barrel Mile
B-M	Barrel Mile
B-Mile	Barrel Mile
Bbl-Mile	Barrel Mile
BS&W	Basic Sediment and Water
DOE	Department of Energy
ED	Eminent Domain
EI, I_E	Energy Intensity
ERA	Economic Regulatory Administration
ETSI	Energy Transportation Systems, Inc.
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
FPCo	Florida Power Corporation
fps	feet per second
gpm	gallons per minute
HHV	high heating value
IC	Internal Combustion
ICC	Interstate Commerce Commission
IRD	International Research and Development Co.
ISO	International Standards Organization
JFM	General Financial Model
LAC	Long run average cost, present (discounted) value of the total average unit cost over the life of the project
leverage	Ratio of the amount of capital that a firm can raise based on the amount of cash that is invested by that firm; e.g., if a firm puts up $1,000 and based on this investment is able to raise another $100,000, then the leverage is 100:1.
LHV	Lower Heating Value
loss carry forward	Refers to that portion of operating loss that is carried forward to the next year after the maximum amount allowed has been deducted from the current year's books.
MMM	Billion
MOD	United Kingdom Ministry of Defense
PEM	Pipeline Economies Model

GLOSSARY OF ABBREVIATIONS, SYMBOLS AND TERMS
(continued)

PEP	Pipeline energy program
Pipetech	Pipeline Technologists, Inc.
PSI	pounds per square inch
ROI	Return on investment
ROW	Right of way
scf	standard cubic feet
S^3	Systems, Science and Software
T-Mi	Ton-mile
T-Mile	Ton-mile
Ton-Mile	Ton-mile
$\equiv$	Is Defined As
μ	Absolute or Dynamic Viscosity

FIGURES

FIGURES
(continued)

TABLES

TABLES
(continued)

TABLES
(continued)

1.0 OBJECTIVES

1.1 Purpose of the Project

The work reported here is a part of a project which is being conducted by the team of Systems, Science and Software (S^3) of San Diego, and Pipe Line Technologists, Inc. (Pipetech) of Houston, under ERDA Contract E(04-03)-1171, "Energy Study of Pipeline Transportation Systems." The basic purpose of the project is to assess the susceptibility of the oil, gas, and other pipeline industries to energy-conservative technological innovations, and to identify the necessary research, development, and demonstrations (R, D, & D) to exploit those opportunities.

The project final report is being published as S^3 report HCP/M-1171-1, "An Energy Study of Pipeline Transportation Systems." That final report will be a summary, combining the results from the task reports listed in Table 1.1-1. As will be noted from the table, this present report is one of those task reports.

1.2 Purpose of this Report

Accomplishment of the broad objectives defined above can best be realized if the energy consumption of the pipeline industry is understood. Stated equivalently, it is desired to understand the magnitude of the energy being expended, its pattern, what measures could reduce it, and what R, D, and D program will best enable and/or enhance such reduction. The purpose of this report is to address the first two of these questions, i.e., how much energy is being expended by the industry and what general pattern it follows.

TABLE 1.1-1

Project Reports

HCP/M-1171-	Title	Associated Tasks
1	An Energy Study of Pipeline Transportation Systems - Executive Summary	All
2	Energy Consumption in the Pipeline Industry	1
3	Federal Regulation of the Pipeline Industry	2
4	Efficiency Improvements in Pipeline Transportation Systems	3
5	Prospects for Energy Conservation in the Pipeline Industry	4,5

Related Reports

SSS-R-77-	
3021	An Economic Model of Pipeline Transportation Systems (limited issue)
3023	Slurry Pipelines - Economic and Political Issues - A Review (limited issue)
3069	S^3 Financial Projection Model - Preliminary User's Manual and System Overview

A second purpose is to estimate the unit energy consumption, i.e., the energy consumed per unit of transport accomplished. This index of merit is often called energy intensiveness (EI), but for succinctness it is herein referred to as energy intensity. It is calculated from any of the formulae

$$I_E = \frac{E}{Q x D} = \frac{P}{F x D} = \frac{\frac{dE}{dt}}{\frac{dQ}{dt} x D}$$

where

$I_E \equiv$ energy intensity
$E \equiv$ energy consumed
$Q \equiv$ quantity of commodity transported
$D \equiv$ distance transported
$P \equiv$ power
$F \equiv$ commodity flow.

The second and third formulae yield an instantaneous value for I_E, while the first yields an average over whatever time period E and Q have been integrated. In this study, only annual averages are considered, so the line is considered to be in quasi-steady state operation. It is, of course, recognized that system transients do in fact adversely affect energy consumption, as is discussed in Report HCP/M-1171-4 of this series, Section 4.3.6.1.2, in connection with pipeline duty cycles.

The task of developing an accurate and precise estimate of energy intensity reduces in practice to an effort to determine the three quantities E, Q, and D, or equivalently, the numerator E and the denominator (Q x D).

As will be seen in what follows, in the case of gas pipelines the numerator E is known rather accurately but the denominator (Q x D) can only be determined accurately by research into the records of each individual pipeline company. The opposite situation obtains with the oil pipelines, where the denominator (Q x D) is reported by each company and published by the ICC, but the numerator E can only be determined accurately by research into the records of each individual pipeline company.

For purposes of drawing comparisons with other transportation modes, it is highly desirable to convert the I_E to a common set of units, which in the ancient English system is

$$\frac{\text{Btu}}{\text{Ton-Mile}}\ *$$

This conversion introduces an inaccuracy, since the standard units of measure for quantity are different in the different types of pipelines. The standard unit in the natural gas industry is the standard cubic foot (Scf). In the petroleum industry it is the Barrel (Bbl or B), which is 42 gallons. In the water industry it is the gallon. And in the slurry industry it is the ton of coal. These and other inaccuracies, and their reduction in the course of future research into the subject, are discussed in the text as they are encountered.

* Energy Intensity as used in this study refers to only the energy consumed in operating the system. No allowance for energy consumed in construction of a system or other points of energy consumption are considered.

2.0 SUMMARY

Table 2.0-1 presents a summary of the energy estimates for the six types of pipelines which were examined.

2.1 Gas Pipeline Energy Summary

The total annual energy consumption of the gas pipeline industry, as pipeline fuel, is approximately 0.7 Quad ($7x10^{14}$ Btu). The 25-year trend may be seen by reference to Table 3.3-1. The peak consumption, which occurred in 1972, was 766,156 x 10^{6} cf, or approximately 0.8 Quad. Additionally, a small amount of compression energy, estimated to be less than five percent, is taken from non-gas sources, principally as purchased electricity.

It is estimated that between 85 and 90% of the pipeline fuel is consumed in the transmission function. The production function consumes 4 or 5%, and the collection function consumes between 6 and 8%, while the storage function appears to consume a negligible amount. No reliable data have been found to indicate consumption by the distribution function, but it is believed to be of the same order of magnitude as the collection function, i.e., less than 8%. The approximate breakdown for 1974 can be seen by reference to Table 3.3-3 in Section 3.3, p. 3-29.

The energy intensity (EI) of gas pipelines varies widely, usually between about 1000 and 4000 Btu/Ton-Mile. The average appears to lie near 2000.

The pipeline companies do not calculate their energy intensity since it is not a useful parameter to them in their business, although energy consumption and conservation are matters of primary concern to all levels of their management. However, one large gas pipeline company, as an act of cooperation with the DOE, performed the necessary research to assemble the data and calculate the EI of their entire trunkline system for 1976. The result was just over 1000 Btu/Ton-Mile. In earlier years, when the system

TABLES 2.0-1
Pipeline Energy Estimates

	Natural Gas	Crude Oil	Petroleum Products	Coal-Water Slurry	Water Supply	Waste Water	Total
Energy Consumption, Quads	0.710	0.070	0.068	0.0054	0.050	0.017	0.92
Energy Intensity	2000 (1)	300 (1)	400 (1)	4800 (1)	220 (2)		

(1) Btu/Ton-Mile

(2) Kw-Min/10^5 Gal-Ft

throughput was higher, the EI was possibly as much as 50% greater.

The minimum-cost EI appears to occur near the lower end of the 1000-4000 range as may be seen from Table 3.4.2-2, p. 3-44. A further point of interest is the fact that the maximum profit and cash flow appear to occur near the top of the range. It therefore appears that the price of gas must increase by several times above the present interstate regulated value of $1.48/Mcf before the pipeline owner will be motivated to operate at the most energy-conservation condition. In making this observation, it is of course recognized that there are other practicalities that militate against operating gas pipelines in their most energy-conservative mode.

2.2 Crude Oil Pipeline Energy Summary

The 1976 energy consumption of the United States crude oil pipeline industry is estimated to be 2×10^{10} kw-hr (0.07 Quad). Within the inherent accuracy of the method which was employed to derive this figure, it would carry a high confidence level. There are, however, unknowns regarding the input data which render the estimate suspect. Further research would be required to resolve these unknowns and improve the accuracy of both the method and of the specific results.

The estimate for the energy intensity of the crude lines is 286 Btu/Ton-Mile. This estimate is much below others, e.g., those of Hirst (Ref. 1) and of Project Independence (Ref. 2). However, search of those references has not yet revealed the basis for those higher numbers, so that reconciliation has not yet been completed, although it is planned to continue the reconciliation.

To avoid leaving impressions of non-existent accuracy, it is suggested that the rounded value of 300 Btu/Ton-Mile be used.

2.3 Products Pipeline Energy Summary

The estimates for products lines are 0.068 Quad for the energy consumption and 388 Btu/Ton-Mile for the energy intensity. The general comments made earlier regarding the crude oil estimates apply here also. It is suggested that the rounded value of 400 Btu/Ton-Mile be used for the EI.

2.4 Coal-Water Slurry Pipeline Energy Summary

This industry presently consists of only one system, the Black Mesa Pipeline, Inc. The estimate for its total energy consumption, when the complete deslurrification process is taken into account, is 0.0054 Quad. The components of this figure are shown in Table 2.4-1, which is a replica of Table 6.4-1. The estimate for energy intensity is 4730 Btu/ton-mile, rounded to 4800. Several comments are in order.

First, although the figure of 341,000 Btu/Ton for the pipeline operation is known to be accurate, since it was supplied as a courtesy by Black Mesa Pipeline, it of course includes whatever inaccuracy is introduced by the postulated efficiency of the electric generation and distribution grid. Also, the 341,000 Btu/Ton for all pipeline operation may be either overstated or understated, depending upon viewpoint, if the purpose is comparison with other transportation modes. On one hand, most of the energy of slurry preparation is for grinding. Since the coal must be pulverized in any case, it is not fair to charge all of this to transportation. On the other hand, the line falls 2600 feet between its head and its critical elevation. This free gravitational energy compares with less than 8000 feet of head which is added by the pumps. Thus, when a comparison is made for equilevel terminals, taking both of these factors into account, the energy consumed in pipeline operation is slightly less, as may be seen in the first column of Table 2.4-2.

Second, if one accepts the estimate of Zandi (Ref. 4) of 544 Btu/Ton-Mile for the energy intensity of a railroad to move the coal between the same two points, one sees an apparent large advantage for the railroad. When the effects of distance, scale, and current technology are taken into

Table 2.4-1

Energy consumption - Black Mesa Pipeline

(Btu/ton of coal)

Slurry Water Supply		36,000
Pipeline Operation		
Pumping Energy	186,000	
Slurry preparation & other operations	155,000	
		341,000
Deslurrification		
Initial separation	205,000	
Moisture correction, 32 to 10.74%	710,000	
		915,000
Total		1,292,000

Source: Reference 3

TABLE 2.4-2

(TABLE 6.4-5)

		Black Mesa 273 mi 10.74% moisture $4x10^6$ tons 1967 technology		ETSI 1000 mi 26% moisture $25x10^6$ tons 1977 technology
Slurry water supply		36,000		25,000
Pipeline operation				
Pumping energy	250,000		351,000	
Other operations	31,000		47,000	
		281,000		398,000
Deslurrification				
Initial separation	205,000		65,000	
Moisture	710,000		136,000	
Correction		915,000		201,000
Total		1,232,000		624,000
Length of pipeline (mi)		273		1,000
Energy intensity (Btu/ton-mi)		4512		624

Source: Reference 3

account, an energy intensity of about 600 Btu/ton-mile is anticipated for a 1000-mile, 25 million-ton/year pipeline. The comparison between this estimate and the estimate for the Black Mesa line is presented in Table 2.4-2, which is a replica of Table 6.4-5.

Finally, a major conclusion that was reached earlier in this program regarding the future of coal-slurry pipelines is confirmed. In report HCP/M-1171-4 of this series, the conclusion emerged that the coal slurry pipeline is a cost-effective and energy-effective mode of transport, but not in the coal-water form. The coal-methanol slurry offers promise of eliminating the huge energy penalties in the deslurrification process, reducing the total pipeline water requirement by a factor of perhaps three, and at the same time making a premium engine fuel available. It is not suggested that coal can be converted to methanol as easily as coal can be separated from water, but there are many other returns that accrue from the energy invested in the conversion process and which render the coal-methanol system much to be preferred. Unhibited enthusiasm for the concept is premature under the present absence of an overall system analysis. Clearly, however, the concept merits such analysis.

2.5 Water Systems Energy Summary

The estimate for energy consumption in water supply systems is 0.05 Quad, and for waste water systems, it is 0.017 Quad. Energy intensity cannot be calculated for water systems in the same way as is done for the other pipelines and other transportation modes, because in water distribution systems, unlike petroleum pipelines, the fluid is not pumped through from source to destination. Instead, the water is pumped to a high-level storage tank from which it flows by gravity through the distribution lines to consumers. Since all the energy is input to the system as work to raise the water to the storage reservoirs, the energy intensity for water systems is defined as energy per unit of mass per unit of lift. Thus, the approach used in this study to describe the EI of water systems is not compatible with that used for the other pipeline systems.

3.0 ENERGY CONSUMPTION IN GAS PIPELINES

3.1 Gas Pipeline Industry Profile

3.1.1 Systems Description - Typical Gas Pipeline

Figure 3.1.1-1 displays a schematic of a complete natural gas grid. At the top and bottom are shown gathering and transmission systems which feed into a main loop. Gas is sold off of the loop through sales meters, shown here at several points around the loop. Gas may also be taken off the loop and placed in storage, or of course returned from storage to the loop, processes which consume energy and require compression facilities. Compression facilities, called boosters, are also shown at several points around the loop. In addition to supply from long-distance transmission (trunk) lines, gas may be fed into the loop from manufactured-gas sources, LNG sources or LPG plants. At the upper right is shown an offshoot through a sales meter into a distribution system, of which there are typically several.

The present study is concerned with energy consumption and conservation in transportation, which for a pipeline is the main line, or transmission system. On Figure 3.1.1-1, these are the sections between the treating plants and the purchase meter stations, upper left and lower left corners.

3.1.2 Statistical Characterization of Gas Pipelines

As will be further explained in the next section, the FPC collects data from the 81 Class A and Class B companies (those whose annual revenue exceeds $1 million). For studying industry trends, the FPC further defines "major" Class A and Class B companies as those which sell 50 billion cubic feet per year.

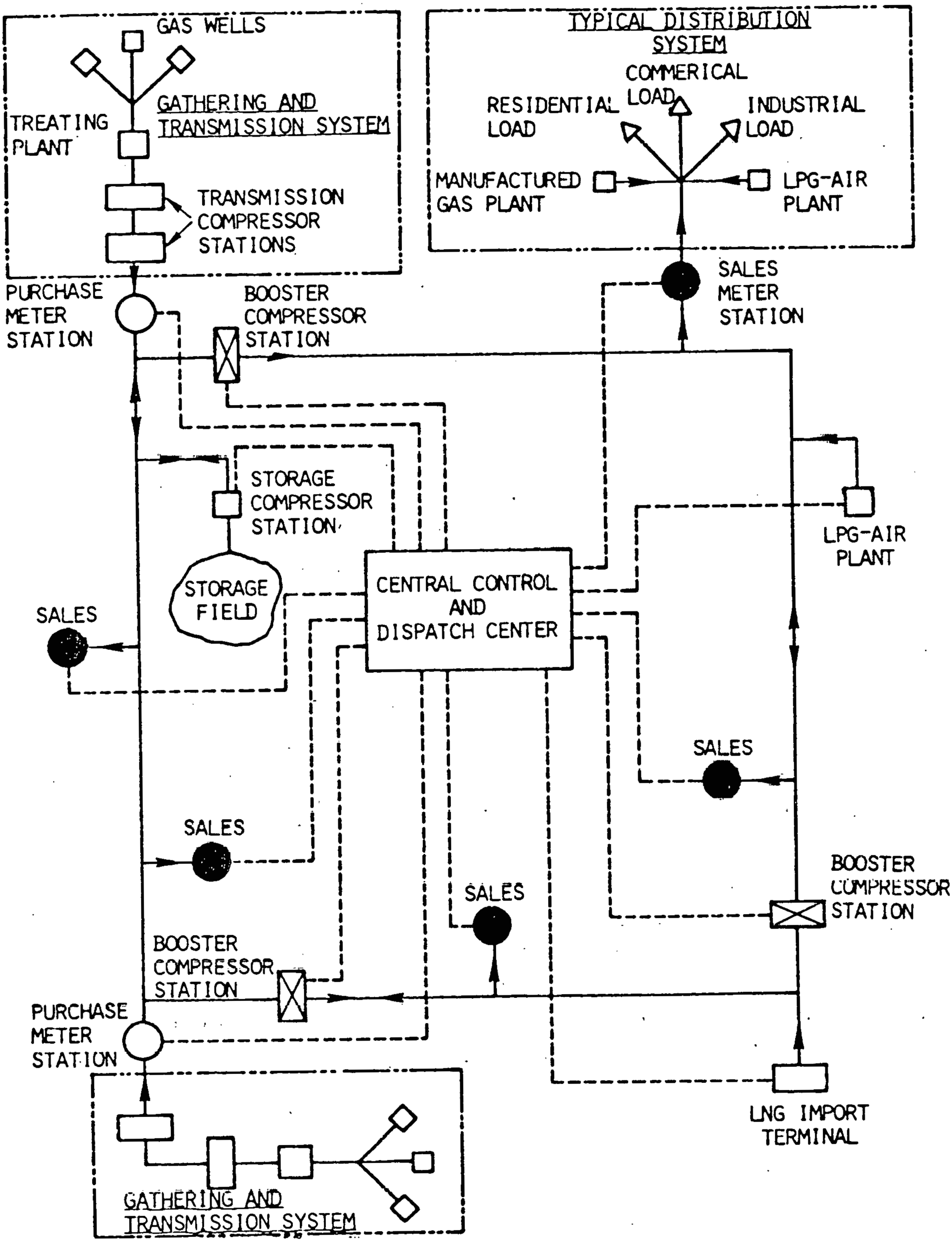


Figure 3.1.1-1. Schematic - Typical Natural Gas System

Figure 3.1.2-1 shows the growth of gas pipeline mileage by type for the years 1950-1975. In Figure 3.1.2-2, the mileage for 1973 and 1974 is disaggregated by pipe size, and Figure 3.1.2-3 shows the size trends during the decade 1964-1974 for the major companies. The Task Force which compiled the National Gas Survey in 1973 developed considerable additional information beyond that contained in the regular FPC statistics, and their breakdown is shown in Figure 3.1.2-4.

Figures 3.1.2-5 and 3.1.2-6 present statistics on total compressor horsepower. Figure 3.1.2-7 shows statistics on both pipe miles and horsepower for a selected subset of the major companies, along with peak sendouts and revenues.

The investments in plant to perform the major functions are shown in Figure 3.1.2-8 for the period 1964-1974, and more detailed breakdown compiled by the National Gas Survey Task Force is shown in Figure 3.1.2-9. Expenses to maintain and operate those plants are shown in Figure 3.1.2-10, and some load factors are shown in Figure 3.1.2-11.

Finally, consumer profiles are shown in Figures 3.1.2-12 and 3.1.2-13.

Year	Total	Field and Gathering	Transmission Pipeline[2]	Distribution Main
1950	387.5	32.8	113.1	241.6
1951	406.6	34.6	119.1	252.9
52	425.3	38.4	123.4	263.5
1953	446.4	41.5	130.4	274.5
1954	470.5	43.8	139.0	287.7
1955	496.7	45.7	145.9	305.1
1956	525.2	47.6	153.8	323.8
1957	548.8	50.0	160.1	338.7
1958	571.5	52.0	165.4	354.1
1959	599.8	54.1	174.3	371.4
1960	630.9	55.8	183.7	391.4
1961	659.0	56.7	191.9	410.4
1962	683.2	58.7	196.4	428.1
1963	709.9	60.7	200.9	448.3
1964	736.2	61.0	205.4	469.8
1965	767.5	61.7	211.3	494.5
1966	799.6	63.0	217.0	519.6
1967	828.3	63.7	225.4	539.2
1968	861.6	64.4	234.5	562.7
1969	891.6	64.9	248.1	578.6
1970*	913.3	66.3	252.2	594.8
1971*	931.4	66.2	254.8	610.4
1972*	948.1	66.9	258.1	623.1
1973*	962.9	65.9	263.1	633.8
1974*	974.1	66.4	262.2	645.6
1975	980.0	68.5	262.6	648.9
1975 Steel	879.4	68.4	260.9	550.1
Plastic[3]	35.6	0.0	0.0	35.6
Other	65.0	0.1	1.7	63.2

[1] Includes data for Hawaii subsequent to 1959 and for Alaska subsequent to 1960; excludes service pipe. Data not adjusted to common diameter equivalent. Mileage shown as of end of each year.

[2] Includes 3.6 thousand miles of underground storage pipe in 1971, 3.3 thousand miles in 1972, 3.4 thousand miles in 1973, 4.9 thousand miles in 1974, and 5.0 thousand moles in 175, some of which was formerly included in Field and Gathering pipe.

[3] Includes fiberglass.

*Revised.

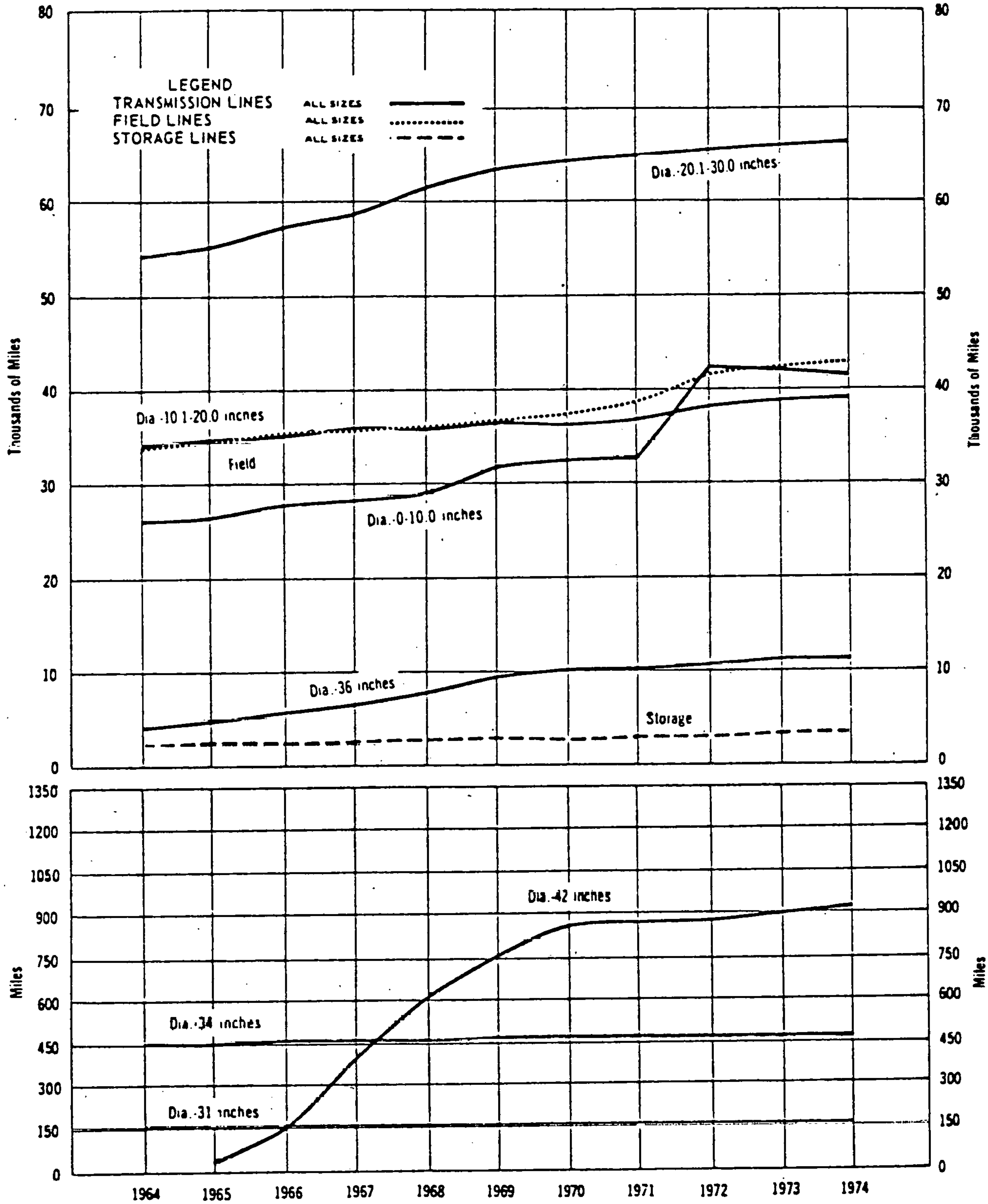
Source: Reference 5

Figure 3.1.2-1 - Gas Pipeline Mileage (in thousands)

Item	All classes A and B pipelines (amount		Major classes A and B pipelines (amount)	
	1973	1974	1973	1974
Field (all sizes combined)	54,990	55,248	42,311	42,856
Transmission				
0 - 5.0 in.	24,558	23,473	19,201	18,552
5.1 - 10.0 in.	34310	33,339	22,828	22,849
10.1 - 15.0 in.	17,820	17,833	12,917	12,930
15.1 - 20.0 in.	36,852	31,496	28,063	26,071
20.1 - 25.0 in.	23,561	23,686	22,673	22,727
26 in.	13,878	13,892	13,878	13,892
28 in.	1	1	1	1
30 in.	30,120	30,342	29,510	29,713
31 in.	154	154	154	154
32 1/2 in.	37	38	-	-
34 in.	472	471	472	471
38 in.	11,163	11,255	11,160	11,180
40 in.	6	6	6	6
42 in.	897	916	897	916
43 in.	9	9	-	-
55 in.	16	16	-	-
Total	193,855	186,927	161,760	159,462
Storage (all sizes combined)	3,960	3,634	3,234	3,347

Source: Reference 6

Figure 3.1.2-2 - Gas Pipeline Mileage by Size



Source: Reference 6

Figure 3.1.2-3 - Gas Pipeline Mileage by Function

Pipeline Size Normal O.D.		Miles of Pipelne			
		Gathering	Transmission	Storage	Total
On Shore					
Under	10"	92,657.1	99,462.5	2,908.9	195,028.5
	10"	5,787.0	13,324.8	342.1	19,453.9
	11"	161.1	867.1		1,028.2
	12"	4,301.7	20,081.2	531.9	24,914.8
	13"	120.2	905.0	25.9	1,051.1
	14"	928.8	5,176.7	11.9	6,117.4
	15"	7.3	75.8		83.1
	16"	3,305.6	16,205.4	314.8	19,825.8
	18"	516.9	5,291.4	34.3	5,842.6
	20"	1,930.7	18,186.9	322.1	20,439.7
	21"				
	22"	231.2	5,323.3	5.4	5,559.9
	23"		170.7		170.7
	24"	1,193.2	19,652.4	86.1	20.931.7
	26"	272.0	14,123.7	33.3	14,429.0
	28"	.2	1.1		1.3
	30"	627.5	34,228.2	8.7	34,864.4
	31"	.3	154.3		154.6
	32"		18.9		18.9
	34"	6.8	1,717.4		1,724.2
	36"	41.7	11,444.2	40.2	11,526.1
	40"		6.4		6.4
	42"		865.2	3.3	868.5
Off Shore					
Under	10"	954.1	204.3		1,158.4
	10"	109.8	133.3		243.1
	12"	155.1	406.9		562.0
	14"	27.8	44.2		72.0
	16"	65.2	402.1		467.3
	18"	39.7	36.1		75.8

Source: Reference 6

Figure 3.1.2-4 - Gas Pipeline Mileage in Use, 31 December 1970

YEAR	Total	Transmission
1955	5,517	4,350
1956	6,011	4,848
1957	6,633	5,412
1958	6,996	5,612
1959	7,504	6,046
1960	7,843	6,359
1961	8,169	6,696
1962	8,609	7,064
1963	8,818	7,261
1964	9,309	7,546
1965	9,708	7,736
1966	10,242	8,182
1967	10,746	8,596
1968	11,438	9,146
1969	12,742	9,375
1970	13,150	9,692
1971	14,142	10,763
1972	14,506	10,976
1973	14,358	11,272
1974[R]	15,181	11,883[a]
1975	15,413	12,069[a]

[a] Not comparable to provious years due to reclassification
[R] Revised

Source: Reference 5

Figure 3.1.2-5 - Gas Pipeline Compressor Horsepower (Thousands)

	Type of Facility							
	Gathering		Transmission		Storage		Total	
	No. Driving Units	Total HP	No. Driving Units	Total HP	No. Driving Unit	Total HP	No. Driving Units	Total HP
On Shore	7,777	3,860,751	6,215	11,459,777	749	941,944	14,741	16,262,472
Off Shore	203	166,343	4	4,400			207	170,743
Total	7,980	4,027,094	6,219	11,464,177	749	941,944	14,948	16,433,215

Source: Reference 6

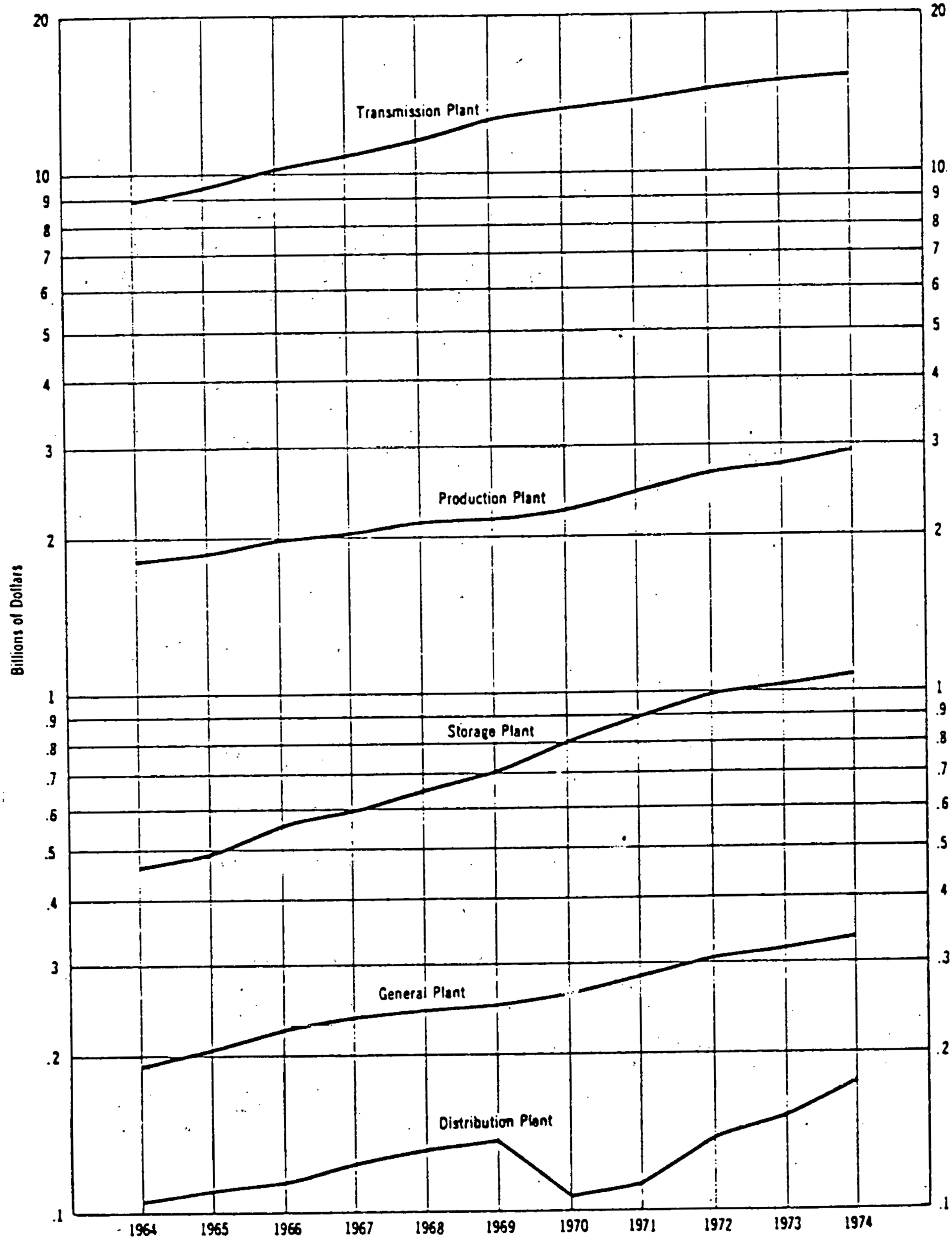
Figure 3.1.2-6 - Gas Pipeline Compressor Horsepower
31 December 1970

Name of Transmission System	Compressor Stations: No. of Transmission Stations	Compressor Stations: Installed Horse-power	Miles of Transmission Pipeline: Total	Miles of Transmission Pipeline: 10" & Under Diameter	Miles of Transmission Pipeline: 10.1" 20.0" Diameter	Miles of Transmission Pipeline: 20.1" & Over Diameter	1975: Peak Day Sendout (MMCF)	1975: Operating Revenues ($000,000)
Algonquin Gas Transmission Co.	3	30,900	909	281	138	490	704	233.4
Cities Service Gas Co.	35	225,510	5,275	1,417	2,443	1,415	1,975	244.5
Colorado Interstate Gas Co.	14	125,180	2,440	425	1,217	798	1,255	230.1
Columbia Gas Transmission Co.	85	346,577	10,325	3,774	4,986	1,655	6,652	1,008.6
Columbia Gulf Transmission Co.	18	470,516	3,576	130	368	3,078	1,477	134.9
Consolidated Gas Supply Corp.	46	119,367	3,672	538	2,454	680	4,423	598.7
East Tennessee Natural Gas Co.	10	25,170	1,012	447	383	182	308	46.9
El Paso Natural Gas Co.	53	803,068	9,488	1,801	2,690	4,997	3,624	1,009.8
Florida Gas Transmission Co.	20	144,070	4,267	1,384	893	1,990	684	101.5
Michigan Wisconsin Pipeline Co.	39	766,942	7,620	1,323	700	5,597	4,801	703.1
Midwestern Gas Transmission Co.	14	94,560	903	55	0	848	948	278.4
Mississippi River Transmission Co.	18	97,245	1,834	203	220	1,411	1,014	191.8
Natural Gas Pipeline Co. of America	50	938,105	9,775	917	979	7,879	4,773	710.9
Northern Natural Gas Co.	61	919,508	18,806	11,039	3,214	4,553	3,140	645.7
Pacific Gas Transmission Co.	12	235,620	639	0	0	639	1,282	500.8
Panhandle Eastern Pipeline Co.	57	632,574	6,695	729	1,348	4,618	2,090	427.3
South Georgia Natural Gas Co.	2	3,500	769	563	206	0	93	20.0
Southern Natural Gas Co.	36	354,726	6,690	968	3,579	2,143	2,171	442.1
Tenneco, Inc.	60	1,244,113	13,071	1,295	1,705	10,071	4,303	823.6
Texas Eastern Transmission Corp.	75	1,176,110	8,816	882	1,580	6,354	3,060	678.5
Texas Gas Transmission Corp.	19	461,710	5,559	1,191	1,439	2,929	2,498	386.9
Transcontinential Gas Pipeline Corp.	36	961,185	8,780	753	1,444	6,583	4,727	601.1
Transwestern Pipeline Co.	134	226,714	3,327	1,336	438	1,553	880	184.0
Trunkline Gas Co.	20	332,000	3,679	6	544	3,129	1,407	279.3
United Gas Pipeline Co.	30	175,505	7,309	2,364	3,044	1,901	3,633	602.5

Includes transmission systems with more than 500 miles of transmission pipeline and $5 million operating revenues.

Source: Reference 5

Figure 3.1.2-7 - Major Gas Pipeline Companies Operation Statistics, 1975



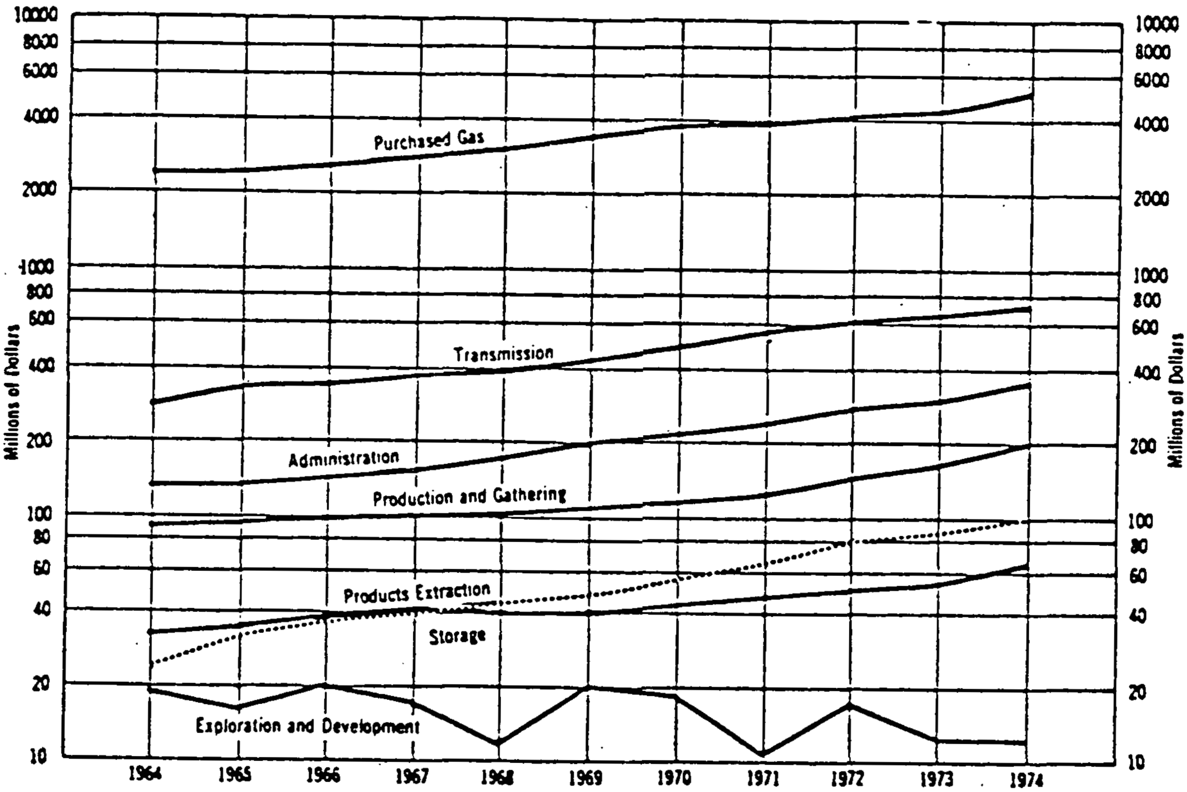
Source: Reference 6

Figure 3.1.2-8 - Major Gas Pipelines, Plant in Service

	Gross Plant By Type of Facility					Accumulated Depreciation Reserves
	Pipeline	Compressor Stations	Process and Conditioning	All Other	Total	
Production Plant						
On Shore	1,849.3	912.9	826.1	950.0	4,538.3	
Off Shore	210.7	65.2	46.4	15.1	337.4	
Total	2,060.0	978.1	872.5	965.1	4,875.7	
Transmission Plant						
On Shore	14,019.7	2,961.1	70.9	1,038.6	18,090.3	
Off Shore	505.8		.4	3.1	509.3	
Total	14,525.5	2,961.1	71.3	1,041.7	18,599.6	
Storage Plant						
On Shore	235.5	368.0	42.5	1,001.3	1,647.3	
Off Shore						
Total	235.5	368.0	42.5	1,001.3	1,647.3	
Intangible Plant						
On Shore	6.9			132.2	139.1	
Off Shore	.4			.2	.6	
Total	7.3			132.4	139.7	
General Plant						
On Shore	84.3	.4		547.1	631.8	
Off Shore				.3	.8	
Total	84.3	.4		547.4	632.1	
Other Plant						
On Shore	267.4	2.0	27.5	458.8	755.7	
Off Shore	1.5				1.5	
Total	268.9	2.0	27.5	458.8	757.2	
Total Facilities						
On Shore	16,463.1	4,244.4	967.0	4,128.0	25,802.5	
Off Shore	718.4	65.2	46.8	18.7	849.1	
Total	17,181.5	4,309.6	1,013.8	4,146.7	26,651.6	
ACCUMULATED DEPRECIATION, PLANT RESERVES (For Companies Reporting Depreciation Reserves)						
Totals	—	—	—	—	24,300.0	8,190.1

Source: Reference 6

Figure 3.1.2-9 - Gas Pipeline Plant Investment, 31 December 1970



Source: Reference 6

Figure 3.1.2.-10 - Gas Pipeline Operation and Maintenance Expenses

Range 1–6	Load Factors Included in Range	1965	1971
1	70.00–74.99	4	1
2	75.00–79.99	1	1
3	80.00–84.99	2	4
4	85.00–89.99	4	2
5	90.00–94.99	3	4
6	95.00–99.99	2	4
Total		16	16
Weighted Average		82.26	87.87
Arith. Average		84.77	88.67

(1) Source: Form 2.

Source: Reference 6

Figure 3.1.2-11 - Gas Pipeline Load Factors

Year	Total	Residential	Commercial	Industrial	Other
1950	175.4	62.5	235.9	23,188.4	7,506.0
1951	193.3	70.3	255.1	25,269.2	8,417.4
1952	203.9	72.7	263.7	26,913.2	9,749.2
1953	211.4	73.2	258.6	28,385.9	12,231.6
1954	223.1	78.9	271.6	29,549.6	10,345.7
1955	233.8	85.2	294.5	29,167.5	10,250.9
1956	245.6	90.5	306.4	30,752.8	8,996.6
1957	252.8	92.5	316.1	30,663.6	11,309.1
1958	257.0	97.7	334.5	30,375.6	10,770.1
1959	274.2	100.7	350.1	33,478.4	11,836.6
1960	281.0	104.8	374.2	33,495.0	12,577.5
1961	283.4	106.7	390.7	32,621.7	13,468.7
1962	295.1	110.9	420.7	32,713.9	13,795.1
1963	302.8	112.1	430.6	33,630.8	13,460.2
1964	317.9	115.3	469.5	37,089.1	13,234.6
1965	320.9	116.5	482.1	36,982.6	12,009.8
1966	336.4	118.8	510.0	38,259.3	12,755.1
1967	345.2	121.5	537.8	38,710.3	11,397.0
1968	362.4	124.1	567.6	40,378.0	13,129.2
1969	376.7	128.4	611.0	42,220.0	11,327.2
1970	386.8	129.2	640.9	42,386.7	12,232.3
1971	395.0	129.9	673.8	42,235.0	17,064.6
1972	397.7	130.4	697.3	41,948.8	16,428.8
1973	377.0	124.5	684.6	40,051.7	15,129.5
1974	361.1	119.6	676.1	42,066.8	12,586.1
1975	333.6	121.9	708.9	37,253.5	12,039.8

* Excludes customers purchasing for resale and sales for resale. Customer data is based on yearly averages. Excludes data for Alaska prior to 1959 and Hawaii prior to 1960.

Source: Reference 5

Figure 3.1.2-12 - National Gas Consumption (10^6 Btu/Customer)

Year	Total	Field Use	Carbon Black Plants[3]	Petroleum Refineries	Portland Cement Plants	Used as Pipeline Fuel	Electric Public Utility Power Plants[2]	Other Industrial[2]
1950	4,440,197	1,187,473	410,852	455,096	98,986	125,546	628,919	1,535,325
1951	5,163,528	1,441,870	426,423	537,774	102,508	192,496	763,898	1,698,559
1952	5,475,843	1,483,754	368,399	536,402	111,479	207,207	910,117	1,858,485
1953	5,763,185	1,471,085	300,942	558,695	115,039	230,314	1,034,072	2,052,838
1954	5,923,647	1,456,883	251,176	563,315	125,257	230,615	1,165,498	2,130,903
1955	6,317,172	1,507,671	244,794	625,243	131,400	245,246	1,153,280	2,409,538
1956	6,662,443	1,420,550	242,598	679,343	144,192	295,972	1,239,311	2,640,477
1957	7,003,590	1,479,720	233,788	678,810	146,000	299,235	1,338,079	2,827,958
1958	7,174,623	1,604,104	211,048	681,912	164,000	312,221	1,372,853	2,828,485
1959	7,931,930	1,737,402	214,612	752,239	188,000	349,348	1,627,097	3,063,232
1960	8,386,038	1,779,671	197,628	775,154	171,000	347,075	1,724,763	3,390,747
1961	8,756,287	1,881,208	161,377	772,028	180,000	377,607	1,825,341	3,558,726
1962	9,204,898	1,993,128	133,302	789,877	188,000	382,496	1,965,590	3,752,505
1963	9,783,676	2,081,339	117,378	789,951	198,000	423,783	2,142,930	4,030,295
1964	10,327,458	2,082,029	115,626[3]	820,989	202,000	433,204	2,321,889	4,351,721
1965	10,709,017	1,909,697	115,574[3]	859,899	198,507	500,524	2,318,253	4,806,563
1966	11,454,494	1,722,708	114,936[3]	903,398	203,805	535,353	2,608,768	5,315,526
1967	12,167,932	1,925,500	108,961[3]	936,085	195,717	575,752	2,743,251	5,682,666
1968	13,208,942	2,065,008	104,973[3]	973,957	202,921	590,965	3,143,858	6,127,260
1969	14,239,996	2,212,208	98,251[3]	997,886	201,295	630,962	3,486,391	6,613,003
1970	15,151,792	2,305,171	85,884[3]	1,028,794	[4]	722,166	3,894,019	7,115,758
1971	15,532,192	2,296,777	63,699	1,062,938	[4]	742,592	3,992,983	7,373,203
1972	15,596,902	2,363,556	53,939	1,070,626	[4]	766,156	3,978,673	7,363,952
1973R	15,833,909	2,412,466	49,682	1,073,742	[4]	728,177	3,640,756	7,929,086
1974	15,061,627	2,364,876	40,130	1,040,057	[4]	668,834	3,429,230	7,518,500

[1] Industrial consumption as reported by the Bureau of Mines includes sales by nonutility producers and others, and natural gas mixed with manufactured gas. Hence quantities reported in this table substantially exceed those reported in Section VII, as utility industrial sales.

[2] Consumption by "Electric Public Utility Power Plants" includes small quantities of gas other than natural, impossible to segregate. To this extent consumption by other industrials is understated.

[3] Data revised to include natural gas to enrich hydrocarbons, as of 1964.

[4] Included in "Other Industrial."

R Revised.

Source: Reference 5

Figure 3.1.2-13 - Industrial Natural Gas Consumption (10^6 Btu)[1]

	Compressor Stations		Miles of Transmission Pipeline				1975	
Name of Transmission System	No. of Transmission Stations	Installed Horse-power	Total	10" & Under Diameter	10.1" 20.0" Diameter	20.1" & Over Diameter	Peak Day Sendout (MMCF)	Operating Revenues ($000,000)
Algonquin Gas Transmission Co.	3	30,900	909	281	138	490	704	233.4
Cities Service Gas Co.	35	225,510	5,275	1,417	2,443	1,415	1,975	244.5
Colorado Interstate Gas Co.	14	125,180	2,440	425	1,217	798	1,255	230.1
Columbia Gas Transmission Co.	85	346,577	10,325	3,774	4,986	1,655	6,652	1,008.6
Columbia Gulf Transmission Co.	18	470,516	3,576	130	368	3,078	1,477	134.9
Consolidated Gas Supply Corp.	46	119,367	3,672	538	2,454	680	4,423	598.7
East Tennessee Natural Gas Co.	10	25,170	1,012	447	383	182	308	46.9
El Paso Natural Gas Co.	53	803,068	9,488	1,801	2,690	4,997	3,624	1,009.8
Florida Gas Transmission Co.	20	144,070	4,267	1,384	893	1,990	684	101.5
Michigan Wisconsin Pipeline Co.	39	766,942	7,620	1,323	700	5,597	4,801	703.1
Midwestern Gas Transmission Co.	14	94,560	903	55	0	848	948	278.4
Mississippi River Transmission Co.	18	97,245	1,834	203	220	1,411	1,014	191.8
Natural Gas Pipeline Co. of America	50	938,105	9,775	917	979	7,879	4,773	710.9
Northern Natural Gas Co.	61	919,508	18,806	11,039	3,214	4,553	3,140	645.7
Pacific Gas Transmission Co.	12	235,620	639	0	0	639	1,282	500.8
Panhandle Eastern Pipeline Co.	57	632,574	6,695	729	1,348	4,618	2,090	427.3
South Georgia Natural Gas Co.	2	3,500	769	563	206	0	93	20.0
Southern Natural Gas Co.	36	354,726	6,690	968	3,579	2,143	2,171	442.1
Tenneco, Inc.	60	1,244,113	13,071	1,295	1,705	10,071	4,303	823.6
Texas Eastern Transmission Corp.	75	1,176,110	8,816	882	1,580	6,354	3,060	678.5
Texas Gas Transmission Corp.	19	461,710	5,559	1,191	1,439	2,929	2,498	386.9
Transcontinential Gas Pipeline Corp.	36	961,185	8,780	753	1,444	6,583	4,727	601.1
Transwestern Pipeline Co.	134	226,714	3,327	1,336	438	1,553	880	184.0
Trunkline Gas Co.	20	332,000	3,679	6	544	3,129	1,407	279.3
United Gas Pipeline Co.	30	175,505	7,309	2,364	3,044	1,901	3,633	602.5

Includes transmission systems with more than 500 miles of transmission pipeline and $5 million operating revenues.

Source: Reference 5

Figure 3.1.2-7 - Major Gas Pipeline Companies Operation Statistics, 1975

3.2 Gas Pipeline Data Sources

There are two primary sources of gas pipeline data: the FPC* Form 2 and the Bureau of Mines (BOM) Form 6-1341-A.

3.2.1 FPC Data

The FPC data is submitted on FPC Form 2 by the 81 Class A and B pipeline companies. These classes, by definition, include all companies with annual gas revenues exceeding one million dollars. In addition, there are 22 Class C and D companies, i.e., those having annual revenues between $25,000 and $1,000,000. These latter, who account for less than 1 percent of all interstate sales, file an abbreviated Form 2A.

All of the Form 2 and 2A reports are available for public inspection. The FPC annually publishes a summary of statistics relating only to the 81 Class A and B companies.

For statistical summary purposes, the commission also defines a category called major companies, which includes those whose combined sales for resale and gas transported (interstate) for a fee exceed 50 MMcf per year. This category included 34 companies for 1975. Only the statistics on these companies are used by the FPC to observe developments in the interstate part of the industry. In 1975, these companies accounted for 84 percent of total gas purchases by FPC regulated pipeline companies from natural gas producers, and 85% of the natural gas production of all regulated pipeline companies. These 34 major companies also accounted for 98 percent of city gate sales to intrastate utilities not regulated by the Commission and 68 percent of the industrial sales made by pipeline companies from their main transmission lines.

Almost all of the data reported on the Form 2 consists of dollar amounts, and is, therefore, not of interest for present purposes. Figure

*The reader is referred to the Preface for a brief discussion of the current Federal pipeline regulatory structure.

3.2.1-1, Sheets 1, 2, and 3, displays the List of Schedules which comprises the Form 2 submittal. Those schedules which are of present interest are on Sheet 3 and have been overshaded to assist the reader. Examples of the information and its potential use are presented in the sections to follow.

3.2.2 BOM Data

The BOM collects data independently of the FPC. Their data are collected on their Form 6-1341-A, which is shown in Figure 3.2.2-1 Sheets 1 and 2. There are two interesting aspects to their operation. First, their coverage is more comprehensive than that of the FPC, in that the BoM tries to include all of the intrastate companies. Second, the submissions are voluntary and therefore proprietary, and cannot be disclosed without consent.

Additionally, it is worth noting that it would be remarkable indeed if full coverage were obtained by means of voluntary submissions, so it is expected that there are some omissions. This naturally leads to the thought that if it were decided to further refine the calculations which use these data, it would be desirable to verify the extent of the coverage.

3.3 Energy Consumption in Gas Piplines

The BOM data of present interest are the figures for consumption of compressor fuel. These figures are published in their annual Minerals Yearbook, and are tabulated annually in the ACA publication, Gas Facts. Table 3.3-1 presents these figures for selected years since 1950. The conversion to Quads has been done using three conversion factors - the DOE conversion factor of 0.98 trillion SCF per quadrillion Btu (Quad), taken from Reference 7, the value of 1975 Btu/Scf used by BOM, and an approximate average lower heating value of 960 Btu/Scf.

Unfortunately, it is seldom clear from the presentation of the data what heating value is assumed, or how it is calculated. The calorimeters commonly used to measure heating value introduce the gas into the combustion chamber by bubbling through water, so that the gas is saturated with water vapor. Thus, when the combustion products are cooled to the original

LIST OF SCHEDULES (Natural Gas Company)

Designate in column by the terms "none" or "not applicable" as appropriate in instances where no information or amounts have been reported in certain schedules. Pages may be omitted where the responses are "none" or "Not applicable" to the schedules on such pages.

Title of Schedule (a)	Schedule Page No. (b)	Date Revised (c)	Remarks (d)
General Corporate Information and Summary Financial Statements			
General Information	101-101A	Dec. 72	
Control Over Respondent	102	Oct. 66	
Corporations Controlled by Respondent	103		
Officers	104	Dec. 73	
Directors	105		
Security Holders and Voting Power	106-107		
Important Changes During the Year	108-109		
Comparative Balance Sheet-Statement A	110-112	Dec. 74	
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amoritization, and Depletion-Statement B	113	Dec. 73	
Statement of Income for the Year-Statement C.	114-116A	Dec. 74	
Statement of Retained Earnings for the Year-Statement D	117-117A	Dec. 74	
Statement of Changes in Financial Position-Statement E	118-119	Dec. 72	
Balance Sheet Supporting Schedules			
Nonutility Property	201	Dec. 73	
Accumulated Provision for Depreciation and Amortization of Nonutility Property	201	Dec. 69	
Investments	202	Dec. 74	
Investments in Subsidiary	203		
Notes and Accounts Receivable	204	Dec. 65	
Accumulated Provisions for Uncollectible Accounts-Cr	204		
Receivables from Associated Companies	206	Dec. 73	
Materials and Supplies	207	Dec. 73	
Gas Stored	207A	Dec. 71	
Production Fuel and Oil Stocks	209	Dec. 73	
Prepayments	210	Dec. 70	
Miscellaneous Current and Accrued Assets	210	Oct. 73	
Extraordinary Property Losses	210	Oct. 73	
Prepaid Gas Purchases Under Purchase Agreements	210A	Dec. 72	
Advances for Gas Prior to Initial Deliveries or Commission Certification	210B	Dec. 72	

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Figure 3.2.1-1 - Sheets 1-3, List of Schedules, FPC Form 2, filed by Class A and B Natural Gas Companies (Facsimile of Original Form)

LIST OF SCHEDULES (Natural Gas Company)(Continued)			
Title of Schedule (a)	Schedule Page No. (b)	Date Revised (c)	Remarks (d)
Unamortized Disc. and Exp. and Unamort. Premium on Debt	211	Dec. 73	
Preliminary Survey and Investigation Charges.	212		
Miscellaneous Deferred Debits	214	Dec. 74	
Deferred Losses from Disposition of Utility Plant	214A	Dec. 73	
Unamortized Loss and Gain on Reacquired Debt	214B		
Accumulated Deferred Income Taxes	214C-D	Dec. 75	
Capital Stock	215		
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	216		
Other Paid-In Capital	217		
Discount on Capital Stock	218		
Capital Stock Expense	218		
Long-Term Debt	219	Dec. 73	
Securities Issued or Assumed and Securities Refunded or Retired During the Year	220	Dec. 73	
Notes Payable	221	Dec. 73	
Payables to Associated Companies	221	Dec. 73	
Taxes Accrued, Prepaid and charged During Year	222-222A	Dec. 73	
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	223	Dec. 73	
Miscellaneous Current and Accrued Liabilities	224	Dec. 73	
Customer Advances for Construction	224	Dec. 73	
Deferred Gains from Disposition of Utility Plant	224A	Dec. 73	
Other Deferred Credits	225	Dec. 73	
Undelivered Gas Obligations Under Sales Agreements	225A	Jul. 65	
Operating Reserves	226	Dec. 73	
Accumulated Deferred Income Taxes	227-227E	Dec. 74	
Investment Tax Credits Generated and Utilized	228	Dec. 75	
Accumulated Deferred Investment Tax Credits	229	Dec. 75	
Income Account Supporting Schedules			
Gain or Loss on Disposition of Property	300	Dec. 73	
Income from Utility Plant Leased to Others	301	Dec. 73	
Particulars Concerning Certain Other Income Accounts	303	Dec. 73	
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	304	Dec. 73	
Expenditures for Certain Civic, Political and Related Activities	305	Dec. 73	
Extraordinary Items	306	Dec. 74	
Common Station			
Common Utility Plant and Expenses	351		
Regulatory Commission Expenses	353	Dec. 74	
Charges for Outside Professional and Other Consultative Services	354	Dec. 70	
Distribution of Salaries and Wages	355-356	Dec. 74	
Gas Plant, Sales, Operating and Statistical Data			
Gas Plant In Service	501-504	Dec. 72	
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Gas Plant Held for Future Use	506	Dec. 65	
Production Properties Held for Future Use	506A		
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Accumulated Provision for Depreciation of Gas Utility Plant	508	Dec. 74	
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Accumulated Provision for Amortization and Depletion of Gas Utility Plant-Underground Storage Land and Land Rights	510	Dec. 73	

Rev (12-75)

Sheet 2

Figure 3.2.1-1 - (Continued)

LIST OF SCHEDULES (Natural Gas Company) (Continued)			
Title of Schedule (a)	Schedule Page No. (b)	Date Revised (c)	Remarks (d)
Accumulated Provision for Amortization and Depletion of Gas Utility Plant Other Gas Plant in Service, Amortization and Depletion of Gas Plant Leased to Others, Amortization of Gas Plant Held for Future Use............	511	Dec. 73	
Accum. Prov. for Amort. & Depletion of Gas Util. Plant-Aband. of Leases................	512	Dec. 73	
Gas Plant Acquisition Adjustments and Accumulated Provision for Amortization of Gas Plant Acquisition Adjustments...........	513	Dec. 74	
Gas Operating Revenues.......................	514	Dec. 69	
Unauthorized Overrun Penalties and Waivers of Penalties..............................	515		
Sale of Natural Gas by Communities...........	516-517	Dec. 67	
Residential and Commercial Space Heating Customers................................	518	Dec. 66	
Interruptible, Off Peak, and Firm Sales to Distribution System Industrial Customers....	518	Dec. 66	
Field and Main Line Industrial Sales of Natural Gas................................	519-520	Dec. 72	
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Rent from Gas Property and Interdepartmental Rents....................................	523		
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Exchange Gas Transactions....................	537	Dec. 66	
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Gas Used in Utility Operations (Credit)......	539	Dec. 66	
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Transmission and Compression of Gas by Others....................................	541	Dec. 66	
Franchise Requirements.......................	542	Dec. 66	
Miscellaneous General Expenses (Gas).........	543	Dec. 73	
Construction Overheads--Gas..................	543		
General Description of Construction Overhead Procedure............................	544	Dec. 73	
Depreciation, Depletion, and Amortization of Gas Plant..............................	545-546a	Dec. 71	
Natural Gas Reserves and Land Acreage (Deleted, see FPC From No. 40).............	- -	- -	
Natural Gas Reserves and Land Acreage (Deleted, See FPC Form No. 40).............	- -	- -	
Changes in Estimated Hydrocarbon Reserves and Costs..................................	549A-549B		
Natural Gas Reserves Available from Purchase Agreements................................	550-551	Dec. 72	
Natural Gas Production and Gathering Statistics....................................	552-553B	Dec. 73	
Products Extraction Operations--Natural Gas..	554-555	Oct. 66	
Compressor Stations..........................	556-557	Dec. 66	
Number of Gas and Oil Wells..................	558	Dec. 69	
Field and Storage Lines......................	559	Dec. 69	
Gas Storage..................................	560-561	Dec. 72	
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Manufactured Gas Production Statistic........	563	Oct. 66	
Liquefied Petroleum Gas Operations...........	564	Oct. 66	
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Gas Account--Natural Gas.....................	568-569	Oct. 66	
Service Interruptions Occuring on the Pipeline System............................	570	Dec. 70	
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Research and Development Activities..........	572-572A	Dec. 72	
Attenuation..................................	573	Dec. 65	

Sheet 3

Figure 3.2.1-1 - (Continued)

Form 6-1341-A
Fuels (7-74)

B24

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF MINES
WASHINGTON, D.C. 20240

SUPPLY AND DISPOSITION OF NATURAL GAS

O.M.B. No. 42-R0052.
Approval expires November 30, 1977

INDIVIDUAL COMPANY DATA—CONFIDENTIAL

The data furnished in this report will be treated in confidence by the Department of the Interior, except that they may be disclosed to Federal defense agencies, or to the Congress upon official request for appropriate purposes.

Please separate forms at perforations

An extra copy is provided for your files

(Please correct if name or address has changed.)

Report all gas volumes at the pressure base of 14.73 pounds per square inch absolute at 60°F.
See instructions on reverse side.

I. STATE covered by this report: ____________

II. Supply and disposition of natural gas during the year.

Item (1)	Code	Quantity (Million cubic feet) (2)	Value (Thousands of dollars) (3)
A. Supply of raw and residue gas:			
1. Gross gas production from leases operated by your company in State designated in Item I above:			
a. From gas and condensate wells	161		$
b. From oil wells (casinghead gas)	162		$
2. Receipts of gas from State designated in Item I:			
a. From producing companies	163		
b. From pipeline companies: (Name of company)	171		
3. Receipts of gas from States other than the State designated in Item I: (Name of company) (State)			
4. Withdrawals from underground storage	181		
5. Total supply (Sum of 1, 2, 3, and 4)	199		
B. Disposition of raw and residue gas:			
1. Extraction loss	261		$
2. Used in lease operations and as plant fuel	262		$
3. Returned to formation for repressuring, pressure maintenance, and cycling	263		
4. Vented to air or burned in flares	264		
5. Used as fuel in your pipeline operations	265		$
6. Delivered to natural-gas processing plants other than your own	266		
7. Delivered to pipeline and distributing companies:			
a. Within State named above: (Name of company)	267		
b. Outside of State designated in Item I: (Name of company) (State)			
8. Delivered directly to consumers:			
a. Residental consumers	271		$
(1) Number of residential consumers at end of year	371		
b. Commercial consumers	272		$
(1) Number of commercial consumers at end of year	372		
c. Industrial consumers	273		$
d. Electric utilities	274		$
e. Other consumers	275		$
9. Stored in underground storage	281		
10. Unaccounted for	298		
11. Total disposition (Sum of 1-10; should be the same as line A5 above)	299		

Signature	Title	Date

Figure 3.2.2-1 Form 6-1341-A

INSTRUCTIONS

Please provide the information requested on the reverse side of this form and return one copy as soon as possible in the enclosed envelope. It will be appreciated if this report can be returned before the 15th of February.

Quantity—Report all volumes in MILLION CUBIC FEET at the pressure base of 14.73 pounds per square inch absolute at 60°F.

Value—Report all values in THOUSANDS OF DOLLARS.

I State—File a separate report for each State in which your company operates.

II MIXED GAS OPERATIONS: In mixed gas operations only the natural gas component should be reported. If both natural and mixed gas are distributed, report natural gas operations and the natural gas portion of your mixed gas operations on separate forms. Adjust all volumes to the pressure base of 14.73 pounds per square inch absolute at 60°F.

IIA1 When leases are not wholly owned by the reporting company, it is requested that the operator of the facility report 100 percent of the production. Exclude any production from leases, which you own that are operated by others. Your company's gross production of gas should include royalty interests and gas used in own operations. Estimate if necessary.

Value of gross production at well includes the producer's realization from all products contained in the gas delivered to natural gas processing plants. Assign no value to that portion of gross production used for repressuring. Do not include gathering charges or State taxes. Ignore tax exempt interests and tax reimbursements.

IIA2 Receipts of gas from companies within the State covered by this report.

a. Report total receipts of gas from other producers within the State.
b. Receipts of gas from within the State, from natural gas processing plants other than your own, exchange gas, and gas received for transport, should be reported by individual company and amount received from each company.

IIA3 Receipts of gas from outside of the State should be shown by individual company, the bordering State from which the gas was received, and the amount received from each company.

IIA4 Withdrawals from underground storage—Report only company-owned gas withdrawn from storage.

IIB1, 2, 5 Value of gas used in lease operations, as plant fuel, in your pipeline operations, and extraction loss, should represent the cost to your company or average wellhead price of the gas.

IIB1 Extraction loss—Total extraction loss for natural gas processing plants operated by your own company. This volume and value should agree with those reported on the Form 6-1343-A. Show disposition of residue gas from your own plants under proper use category, i.e., industrial, sales to other companies, vented, return to formation.

IIB2 Include gas used in lease operations, as plant fuel and net use for gas lift.

IIB6 Total deliveries of natural gas to natural gas processing plants operated by companies other than your own.

IIB7a Include exchange gas and gas delivered for transport as well as gas sold to other pipeline and distributing companies within State. List companies and amount of each sale individually.

IIB7b Deliveries of gas outside of the State to pipeline or distribution companies should be listed by company and amount of each sale individually.

IIB8 Delivered directly to consumers:

a. Residential—Include natural gas used in private households for heating, cooking, and other household uses.
b. Commercial—Include natural gas used by non-manufacturing organizations, such as hotels, restaurants, retail stores, laundries, and other service enterprises; also gas used in agriculture, forestry and fisheries.
c. Industrial—Gas sold directly to industrial consumers. Include gas used as fuel in chemical plants (your own and others), used to produce carbon black, and gas consumed by own company.
d. Electric utilities—Natural gas used as fuel in electric utility plants including those operated by your company.
e. Other consumers—Include deliveries to municipalities and government agencies for use in schools, institutions, street lighting, etc.

IIB9 Report only company-owned gas stored in underground storage.

Figure 3.2.2-1 (Continued)

Table 3.3-1

Energy Consumption in Gas Pipelines,
Intrastate and Interstate

		Approximate Energy Consumption, Quads		
Year	MMSCF	1020 Btu/Scf	1075 Btu/Scf	960 Btu/Scf
1950	125,546	0.128	0.135	0.117
1955	245,246	0.250	0.264	0.228
1960	347,075	0.354	0.373	0.321
1965	500,524	0.511	0.538	0.465
1970	722,166	0.736	0.776	0.672
1974	666,834	0.682	0.717	0.620

Reference 5

Source: Data collected by BOM

temperature and condensed, the latent heat of vaporization introduced by saturating the gas is also measured. The appropriate correction for this latent heat is taken as part of the standard measuring technique. However, the amount of gas originally present is less than would be the case with dry gas, by the amount of dry gas which is displaced by the water vapor, but no correction is made for this effect. Thus, the higher heating value (HHV) on the dry basis, is about 20 Btu/Scf more than on the wet basis. Contracts are usually written on the wet basis, many times for an HHV of 1000 Btu/Scf. The gas is delivered dry, or nearly so, so that the delivered HHV is generally around 1020 Btu/Scf. The lower heating value (LHV) is approximately 90 Btu less than the HHV. The HHV is used in the table.

The figures presented in the last three columns of Table 3.3-1 are a good approximation to the total energy consumption in the gas pipeline industry. In addition to the uncertainty already mentioned in Section 3.2.2 as to completeness of coverage of all the intrastate pipelines, these figures contain three additional sources of error. The first additional source is just the cumulative result of the inherent imprecision in each of the constituent numbers which are added to make the total. The standard deviation of the sum is simply the rms of the sum of the individual variances.

The second error source is the variation in heating values of the fuel. The 1020 Btu/Scf which was used in the conversion from column 2 of Table 3.3-1 to column 3 was used in Reference 7 as an approximation to the average value for pipeline-quality gas. However, the BOM uses 1075 Btu/Scf, and that value was used in column 4. A more realistic value would appear to be that based upon the lower heating value, as shown in the last column. The actual hhv varies of course but is generally in the neighborhood of the first two figures.

The third error source lies in the fact that the figures presented do not include other sources of compression energy besides gas. There is a small fraction of pipeline compressors which are electrically driven. For 1970-71, this fraction was estimated as 4.1 percent. However, the methodology employed in that reference is believed to contain a systematic error which would reduce this figure by something over 10 percent. The electric bills for electrically-driven compressor stations are reported on Schedules 556 and 557 of Form 2. Thus, if further refinement should become necessary or desirable, an estimate of this error could be made by totaling the figures from those schedules of the 81 Class A and B interstate companies. The uncertainty would then be reduced to the non-gas energy by intrastate and Class C and D interstate companies.

The first two of these error sources are compensating and would tend to average out when taken over large blocks of data. The third is in the form of omissions, and thus makes the estimate low. Also, as has been noted, there are almost certainly some omissions from the original BOM compilations. Thus, it is likely that the best estimate is near the high side of the range. It is therefore suggested that a two-figure estimate of 0.71 Quad be used. For a single-figure estimate, 0.7 Quad is probably very good, i.e., the true value is more likely to be nearer to 0.7 than to 0.6 or 0.8.

The breakdown of energy consumed in the categories of collection, transmission, storage and distribution is not reported in terms of Btu consumed in each of these functions. However, the dollar values of energy consumed by the interstate companies are reported on FPC Form 2 and are broken into the first three of these categories. The task force which prepared the National Gas Survey compiled these figures for the 10 regions defined earlier by the Future Gas Requirements Committee. These regions are shown in Figure 3.3-1. The task force compilations are shown in Table 3.3-2. It is immediately noted, though not unexpected, that there is no reported consumption for the distribution process, since the reporting companies are not engaged in distribution. Application of this same fractional breakdown to the total consumption previously quoted in Table 3.3-1, yields the approximate breakdown for 1974, which is shown in Table 3.3-3. The values for distribution were derived by simply assuming that function about equal to collection.

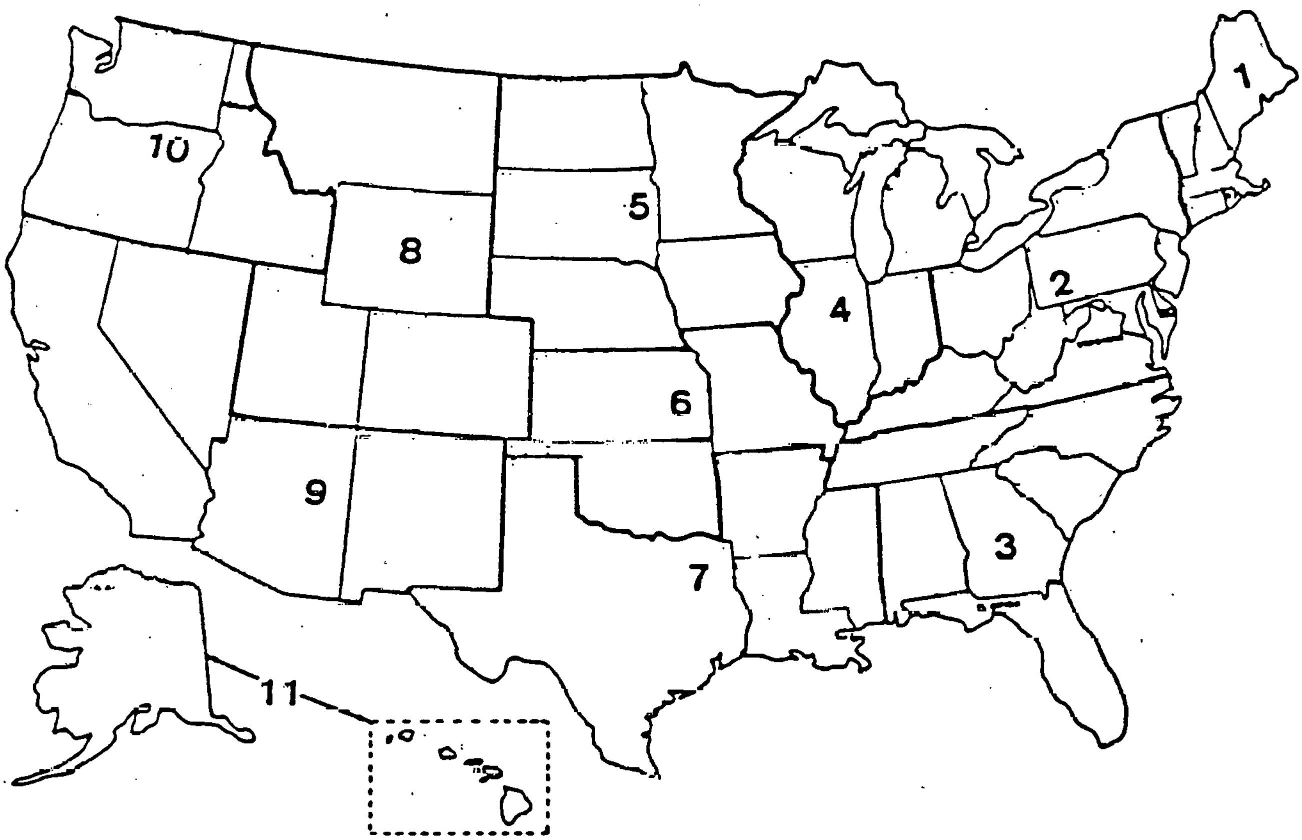
3.4 Estimate of Energy Intensity of Gas Pipelines

As was explained in Section 1.2 above, the energy intensity of a transportation mode is calculated from the formula

$$I_E = \frac{\text{energy consumed}}{\text{throughput x distance.}}$$

The throughput can be expressed in any convenient way, e.g., as a mass, volume, or energy content but for purposes of comparison with other modes, the most useful term is mass. Thus, in the English system of units, the EI is expressed usually in Btu/ton-mile, or Btu per ton per mile.

FUTURE GAS REQUIREMENTS COMMITTEE REGIONS



Source: Reference 6

Figure 3.3-1 - Regions Used in the Analysis

Table 3.3-2

Distribution of Energy Cost, 1970, ¢/Mcf
Major Companies Only

Region	Prod.	Coll'n.	Transmission	Strg.	Dist.	Total
1	0.037	0	1.311	0.015	0	1.363
2	0.026	0.019	0.931	0.064	0	1.040
3	0.016	0.008	0.776	0.007	0	0.807
4	0.003	0.025	0.814	0.026	0	0.868
5	0.026	0.031	1.089	0.012	0	1.158
6	0.007	0.073	0.542	0.021	0	0.643
7	0.021	0.027	0.028	0.007	0	0.263
8	0.045	0.089	0.167	0.001	0	0.302
9	0.068	0.108	0.523	0.000	0	0.699
10	0.098	0.156	0.476	0.000	0	0.730
	0.347	0.536	6.837	0.153	0	7.873
%	4.41	6.81	86.84	0.02	0	100

Source: Reference 6

Table 3.3-3

Approximate Breakdown of 1974 Energy Consumption in Gas Pipeline

Function	Fraction	Energy, Quads: DOE Factor (1020 Btu/cf)	Energy, Quads: BOM Factor (1075 Btu/cf)
Production	0.0441	0.0301	0.0316
Collection	0.0681	0.0464	0.0488
Transmission	0.8684	0.5922	0.6227
Storage	0.0194	0.0133	0.0139
	1.0000	0.6820	0.7170

3.4.1 Industry-average Energy Intensity of Gas Pipelines

It is obvious that the average EI for the industry cannot be calculated from summary statistics. Although total energy consumed and total throughput are known with high precision, no figure for the distance exists. The distance figure that would possibly be the most interesting would be the sum of the throughput-weighted distances for each leg. In principle, it would be possible to calculate the throughput for every leg if there were a meter reading available at every branch point. Such readings probably exist for most trunkline branch points. The collection, compilation and reduction, and analysis of that data would exceed the cost limits of the present project, so it has not been attempted. The complexity and scope of such an undertaking can be appreciated by study of the gas pipeline map published by the Federal Power Commission. Moreover, as seen below, it is unnecessary for the present purpose, which is the first order estimate of gas pipeline EI.

It is well to note at this point an important distinction between the overall, industrywide EI and that which obtains for a specific route and haul. For example, in the case of railroads, if one takes the total locomotive energy consumed and divides it by the total ton-miles of transport, the result, for the year 1972, is

$$(I_E)_{\text{Rail}} = \frac{5.446 \times 10^{14} \text{ Btu}}{7.84 \times 10^{11} \text{ Ton-Mile}} \sim 700 \frac{\text{Btu}}{\text{Ton-Mile}}$$

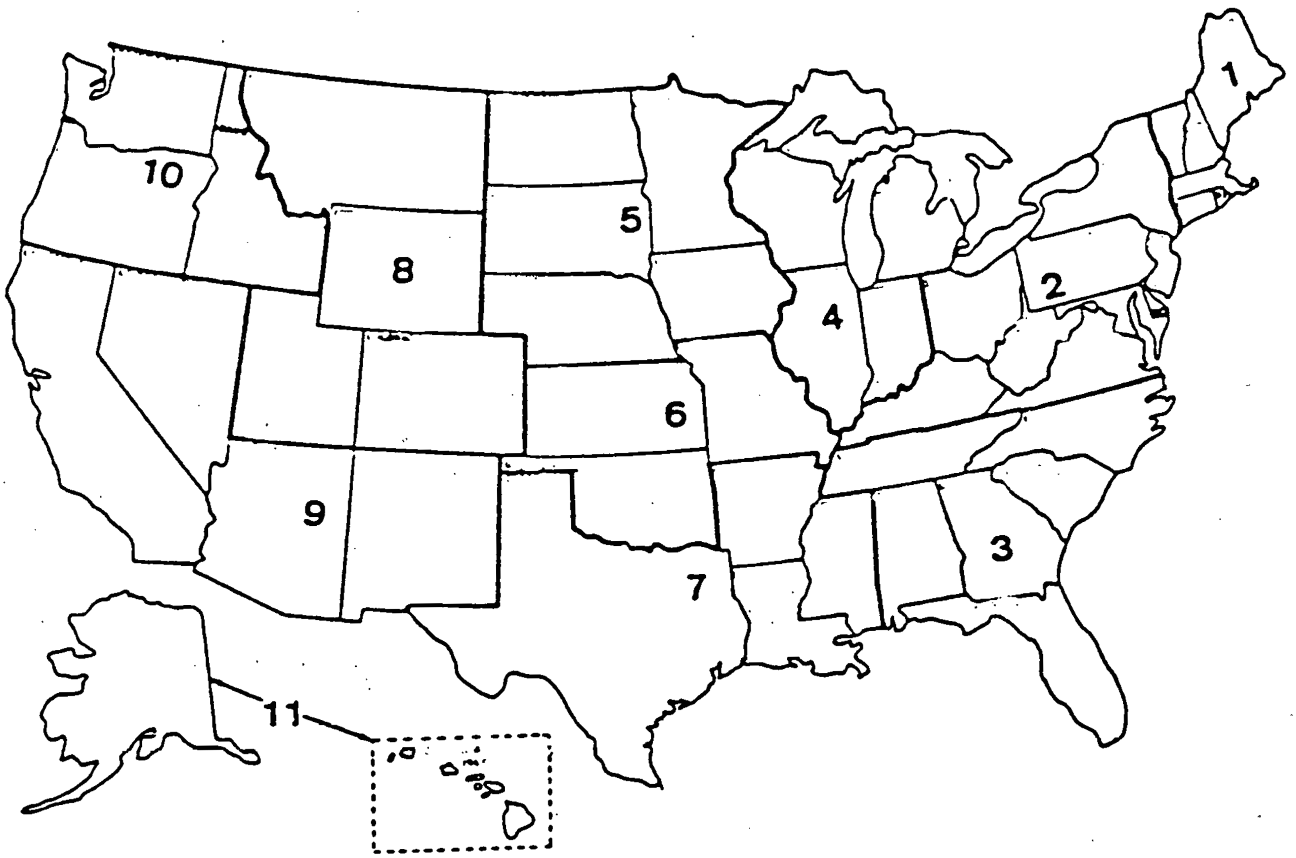
However, if one examines a particular route and haul, one almost invariably obtains a much different figure. For example, Zandi (Ref. 4) used the railway engineers' handbook formula to calculate the EI of a railroad which would duplicate the haul of the Black Mesa slurry pipeline. He obtained a figure of 450 Btu/Ton-Mile.

Returning now to the case of the gas pipelines and considering first the industry-wide EI, in the absence of throughput data, it is necessary to make an estimate of the throughput.

In preparing the FPC National Gas Survey, the Task Force for Transmission Operations prepared estimates of the cost of service in 1970 to each of the ten regions, shown again in Figure 3.4.1-1. Referring once more to the national map one again appreciates the complexity of the national gas transmission network. However, it is observed that Region 1 is supplied almost exclusively by Tennessee Gas Pipeline Company (Tenneco) from wells on the coast of Texas and Louisiana. From the map, the separation of the center of collection and center of distribution is scaled to be approximately 1700 miles. This provides a first-order estimate of the distance.

An estimate of the fuel consumed per MCF of throughput is obtained from the Task Force estimate of the cost of service for Region 1, which is presented in Table 3.4.1-1. It is seen that the cost of fuel is estimated to be 1.311 ¢/MCF. Under FPC accounting, this gas is credited to purchases (or production) at whatever purchase price (or production cost) was paid. Reference to Schedule 529, Line 1, of the Form 2 filed by Tenneco for 1970 will reveal that figure. Since the 1970 figure is not readily at hand, for present illustrative purposes the national average figure is used. Reference to Gas Facts, 1975, p. 110, repeated here for convenience of the reader as Table 3.4.1-2, reveals that figure to be 17.1 ¢/MCF. That this figure is probably very close to what Tenneco paid in 1970 can be inferred from inspection of Table 3.4.1-3, where it is seen that the Texas-Louisiana average wellhead price for 1974 was very close, i.e., within less than 2%, to the national average. If the same were true for 1970, dividing the 17.1¢ value into the 1.311 ¢/MCF average fuel cost for transmission to Region 1 yield a value of 7.667% for the ratio of gas consumed in compression to gas transported. Using 1020 Btu/Scf for the heating value and 41,000 Scf per ton then yields an EI of 3206 Btu/Ton-Mile for the energy intensity.

Repeating the process for Region 4, the average distance is scaled to be approximately 850 miles from the Texas-Oklahoma panhandles to the Chicago area, yielding a value of 2593 Btu/Ton-Mile for the EI. Further note of these estimated values will be taken at the end of the next section.



Source: Reference 6

Figure 3.4.1-1 - Regions Defined by Future Gas Requirements Committee

Table 3.4.1-1

COST OF SERVICE, 1970

Region 1

	Production ¢/MCF	Gathering ¢/MCF	Transmission ¢/MCF	Storage ¢/MCF	Distribution ¢/MCF	Total ¢/MCF
Operating	0.479	0	3.062	0.054	0	3.595
Fuel	0.037	0	1.311	0.015	0	1.363
Maintenance	0.086	0.002	1.183	0.012	0	1.283
G & A	0	0	3.212	0	0	3.212
Depreciation	0.086	0	8.992	0.066	0	9.144
Income Taxes	0.134	0	4.074	0.012	0	4.220
Other Taxes	0.148	0	3.553	0.015	0	3.716
Return	0.741	0	15.762	0.074	0	16.577
Totals	1.711	0.002	41.149	0.248	0	43.11

Region 4

	Production ¢/MCF	Gathering ¢/MCF	Transmission ¢/MCF	Storage ¢/MCF	Distribution ¢/MCF	Total ¢/MCF
Operating	0.197	0.126	1.460	0.411	0.055	2.249
Fuel	0.003	0.025	0.814	0.026	0.000	0.868
Maintenance	0.019	0.051	0.716	0.059	0.008	0.853
G & A	0.000	0.000	1.513	0.000	0.000	1.513
Depreciation	0.084	0.227	3.051	0.158	0.026	3.546
Income Taxes	0.019	0.091	1.357	0.091	0.015	1.374
Other Taxes	0.017	0.082	1.202	0.057	0.016	1.374
Return	0.061	0.380	4.968	0.243	0.052	5.704
Totals	0.400	0.982	15.081	1.045	0.172	17.68

Data extracted from FPC Forms 2, 2A, 15 15A.

Source: Reference 6

Table 3.4.1-2

Average Wellhead Price and Marketed Production of Natural Gas, 1950-1975[a]

Year	Average Wellhead Price (cents per MCF)	Marketed Production: Millions of Cubic Feet	Marketed Production: Trillions of BTU
1950	6.5	6,282,060	6,753.0
1951	7.3	7,457,359	8,016.7
1952	7.8	8,013,457	8,614.5
1953	9.2	8,396,916	9,026.7
1954	10.1	8,742,546	9,398.2
1955	10.4	9,405,351	10,110.4
1956	10.8	10,081,923	10,838.2
1957	11.3	10,680,258	11,481.0
1958	11.9	11,030,248	11,857.5
1959	12.9	12,046,115	12,949.5
1960	14.0	12,771,038	13,728.8
1961	15.1	13,254,025	14,248.1
1962	15.5	13,876,622	14,917.4
1963	15.8	14,746,663	15,852.7
1964	15.4	15,462,143	16,621.8
1965	15.6	16,039,753	17,242.7
1966	15.7	17,206,628	18,497.1
1967	16.0	18,171,325	19,534.2
1968	16.4	19,322,400	20,771.6
1969	16.7	20,698,240	22,250.6
1970	17.1	21,920,642	23,564.7
1971	18.2	22,493,012	24,180.0
1972	18.6	22,531,698	24,221.6
1973	21.6	22,647,549	24,346.1
1974	30.4	21,600,522	23,220.6
1975	44.5	20,108,661	21,616.8

[a] Marketed production as reported by the Bureau of Mines is equivalent to natural gas production usefully consumed. It includes natural gas sold by producers and other non-utilities to industrial consumers and includes natural gas mixed with manufactured gas for consumption.

Source: Reference 5

Table 3.4.1-3

Average Wellhead Price and Marketed Production of Natural Gas, By State, 1974 and 1975

Division and State	1974 Average Wellhead Price (cents per MCF)	1974 Marketed Production (MMCF)	1975 Average Wellhead Price (cents per MCF)	1975 Marketed Production (MMCF)
United States	30.4	21,600,522	44.5	20,108,661
New England	0.0	0	0.0	0
Middle Atlantic	44.6	87,627	68.0	92,304
New Jersey	0.0	0	0.0	0
New York	55.0	4,990	74.0	7,628
Pennsylvania	44.0	82,637	67.5	84,676
East North Central	49.0	162,800	66.6	188,859
Illinois	40.0	1,436	70.0	1,440
Indiana	14.0	176	39.0	346
Michigan	50.4	69,133	63.4	102,113
Ohio	48.2	92,055	70.6	84,960
Wisconsin	0.0	0	0.0	0
West North Central	16.8	920,559	17.5	871,006
Iowa	0.0	0	0.0	0
Kansas	16.6	886,782	17.2	843,635
Minnesota	0.0	0	0.0	0
Missouri	31.4	33	34.0	30
Nebraska	34.0	2,538	54.1	2,565
North Dakota	19.9	31,206	23.0	24,786
South Dakota	0.0	0	0.0	0
South Atlantic	36.5	247,672	50.4	205,683
Delaware	0.0	0	0.0	0
District of Columbia	0.0	0	0.0	0
Florida	53.6	38,137	97.3	44,383
Georgia	0.0	0	0.0	0
Maryland	24.0	133	27.0	93
North Carolina	0.0	0	0.0	0
South Carolina	0.0	0	0.0	0
Virginia	51.0	7,096	51.5	6,723
West Virginia	32.8	202,306	36.9	154,484
East South Central	44.7	178,545	59.3	172,697
Alabama	74.3	27,865	87.0	37,814
Kentucky	50.0	71,876	54.0	60,511
Mississippi	29.5	78,787	49.6	74,345
Tennessee	36.0	17	43.0	27
West South Central	30.6	17,687,346	45.6	16,298,056
Arkansas	26.0	123,975	34.7	116,237
Louisiana	30.7	7,753,631	42.3	7,090,645
Oklahoma	28.0	1,638,942	32.0	1,605,410
Texas	31.1	8,170,798	51.9	7,485,764
Mountain	29.3	1,821,684	38.2	1,801,478
Arizona	20.0	224	28.0	208
Colorado	20.0	144,629	26.0	171,629
Idaho	0.0	0	0.0	0
Montana	25.3	54,873	43.3	40,734
Nevada	0.0	0	0.0	0
New Mexico	31.4	1,244,779	40.5	1,217,430
Utah	41.2	50,522	48.0	55,354
Wyoming	24.5	326,657	33.7	316,123
Pacific	40.0	494,289	56.7	478,578
Alaska	17.0	128,938	30.2	168,578
California	44.0	365,354	70.0	318,308
Hawaii	0.0	0	0.0	0
Oregon	0.0	0	0.0	0
Washington	0.0	0	0.0	0

[a] Reflects price at first point of transfer, representing sales made by producers.

Source: Reference 5

3.4.2 Specific-haul Energy Intensity of Gas Pipelines

The EI for a specific transmission system can be calculated with high precision if all the pertinent engineering design parameters are known with high precision, because the gas dynamics are thoroughly understood and well-documented, steady flow correlations are available. Some of the more familiar correlations are:

- Weymouth - used in distribution and gathering systems. The flow calculated with this formula will result in conservative values and since the formula is not complex, it is suitable for preliminary sizing.

- Panhandle A - used extensively in the United States for large high-pressure transmission systems. The formula is suitable for use in a Reynolds number range of 5×10^6 to 11×10^6.

- Revised Panhandle - used for high-pressure transmission systems. This formula is used in the Reynolds number range of 4×10^6 to 40×10^6.

Each formula has as a variable the transmission factor on which is based the loss in pressure due to friction in the pipeline. The method for calculating this factor as well as the application of the formulas is noted in a flow computation manual published by the American Gas Association. The Petroleum Engineer Pipeline Handbook (Ref. 8) contains the data required for solving the revised Panhandle formula in metric units.

The gas dynamics model used in this study is a proprietary computer code of Pipe Line Technologists, Inc., a participating company in this project. The code is available, for a royalty, to serve the needs of qualified investigators who may wish to verify or extend the results of this study. Figure 3.4.2-1 presents, for illustrative purposes only, the printout from the model for a particular system in a particular year of its operation, and for a particular market (throughput).

Elsewhere in Task 1 of this project, reference systems have been designed for each principal type of pipeline - gas, crude, products, slurry and water. The reference gas system was introduced in another report of this series, HCP/M-1171-3, Section 7.1, where some economic simulation results were presented. Between the reference system design and economic model is the gas dynamics model already described, which takes as input the system design parameters and the prescribed throughput (market forecast) and calculates the energy consumption and cost of compression.

Table 3.4.2-1 presents selected outputs from a series of full economic simulation runs. The third column is the EI for four throughputs. As would be expected, the EI is nearly proportional to the square of the flow. Thus, there is seen to be a wide variation in EI, within a range of reasonably expectable, or at least not highly unusual, market conditions.

This now raises the question of what is the EI most likely to be seen in practice. To the extent that pipeline operators understand their business and influence their own destiny, the answer must be that the most likely EI is that at which either the return to the operator is maximum or some cost is a minimum. For any line, the total unit cost of course is infinite for zero throughput, first decreasing as throughput increases, passing through a minimum, then increasing. The magnitude of the minimum cost, and the throughput at which it occurs, are sensitive to line diameter, as is seen in the example of Figure 3.4.2-2.

To investigate this question, a search for the optimum throughput(s) was made by conducting full 16-year simulations of pipeline operation at each throughput. All capital investment was made in year zero, and throughput was held constant for each case. Zero debt was taken, in an effort to expose the true economic effect in terms of return on ownership. Some selected results are tabulated in Table 3.4.2-2.

The first observation to be made is that the minimum-cost point is below even the lowest EI (and throughput) which was examined. It may be noted that the engineers who designed the system were not surprised

```
**********************************
* PIPE LINE TECHNOLOGISTS, INC.  *
*      STEADY STATE GAS          *
*      PIPELINE FLOW MODEL       *
**********************************
```

*** THIS IS THE ERDA EXAMPLE GAS PIPELINE ***
*** YEAR 3 ***

FLOWING PROFILE SUMMARY

	SEGMENT			INLET			OUTLET			AVERAGE			
NO.	FROM MILE POST	TO MILE POST	ELEV RISE FT	PRESS PSIA	TEMP DEG.F	GAS RATE MCF/D	PRESS PSIA	TEMP DEG.F	GAS RATE MCF/D	VELOCITY FT/SEC	PRESS DROP PSI/MI	STANDARD FLOW RATE MMSCF/D	LINE PACK MSCF
1	0.00	.00	0.	450.0	70.0	7139.61	450.0	70.0	7139.67	27.73	5.69	228.73	1.
2	.00	59.22	59.	920.0	194.6	4025.33	883.3	72.3	3413.93	14.54	1.80	226.80	56448.
3	59.22	88.00	29.	883.3	72.3	3413.93	831.0	69.0	3620.93	13.64	1.82	226.80	25240.
4	88.00	121.72	-9.	831.0	69.0	3620.93	765.9	68.3	3557.53	14.68	1.93	226.80	31840.
5	121.72	152.00	-6.	990.0	107.8	3306.67	940.4	75.3	3202.50	12.64	1.64	226.25	33112.
6	152.00	185.56	21.	940.4	75.3	3202.50	883.8	69.4	3374.65	12.75	1.69	226.25	36380.
7	185.56	250.23	40.	883.8	69.4	3374.65	762.7	68.2	3965.12	14.14	1.87	226.25	63247.
8	250.23	263.00	8.	990.0	108.3	3303.18	968.7	87.4	3198.63	12.63	1.66	225.69	13944.
9	263.00	315.69	-9.	968.7	87.4	3198.63	881.5	69.3	3375.76	12.74	1.65	225.69	57257.
10	315.69	382.48	-11.	881.5	69.3	3375.76	757.8	68.3	3984.10	14.17	1.86	225.69	64813.
11	382.48	398.00	-3.	985.1	108.6	3315.09	959.6	84.7	3200.44	12.66	1.64	225.12	16870.
12	398.00	450.00	-13.	959.6	84.7	3200.44	873.6	69.3	3400.59	12.79	1.65	225.12	55543.
13	450.00	518.39	-18.	873.6	69.3	3400.59	745.5	68.2	4046.24	14.33	1.87	225.12	65679.
14	518.39	587.71	-10.	969.2	108.5	3305.37	852.9	69.1	3483.40	13.26	1.68	224.56	71734.
15	587.71	658.00	-18.	852.9	69.1	3483.40	717.4	68.2	4210.80	14.78	1.93	224.56	65284.
16	658.00	686.00	-7.	932.6	108.3	3498.84	884.4	76.0	3403.07	13.40	1.72	224.00	26593.
17	686.00	758.00	-54.	884.4	76.0	3403.07	803.2	69.4	1859.20	9.90	1.13	112.00	49754.
18	758.00	784.00	10.	803.2	69.4	1859.20	771.0	69.4	1545.44	10.61	1.24	112.00	16773.
19	784.00	822.00	-39.	771.0	69.4	1545.44	682.2	68.8	2223.42	14.36	2.34	112.00	18106.
20	822.00	837.00	-15.	682.2	68.8	2223.42	643.3	68.7	2370.48	15.90	2.59	112.00	6458.
21	837.00	891.00	-15.	643.3	68.7	2370.48	474.4	68.3	3291.17	18.97	3.13	112.00	19478.
													800954.

DELIVERY SUMMARY

	MILE POST	PRESS PSIA	TEMP DEG F	GAS RATE MMSCF/D
1	0.00	450.00	70.0	-228.73
2	686.00	884.40	76.0	112.00
3	891.00	474.37	68.3	112.00
22	891.00	474.37	68.3	-.00

Figure 3.4.2-1 - Pipetech Computer Printout, Sheet 1

COMPRESSOR SUMMARY

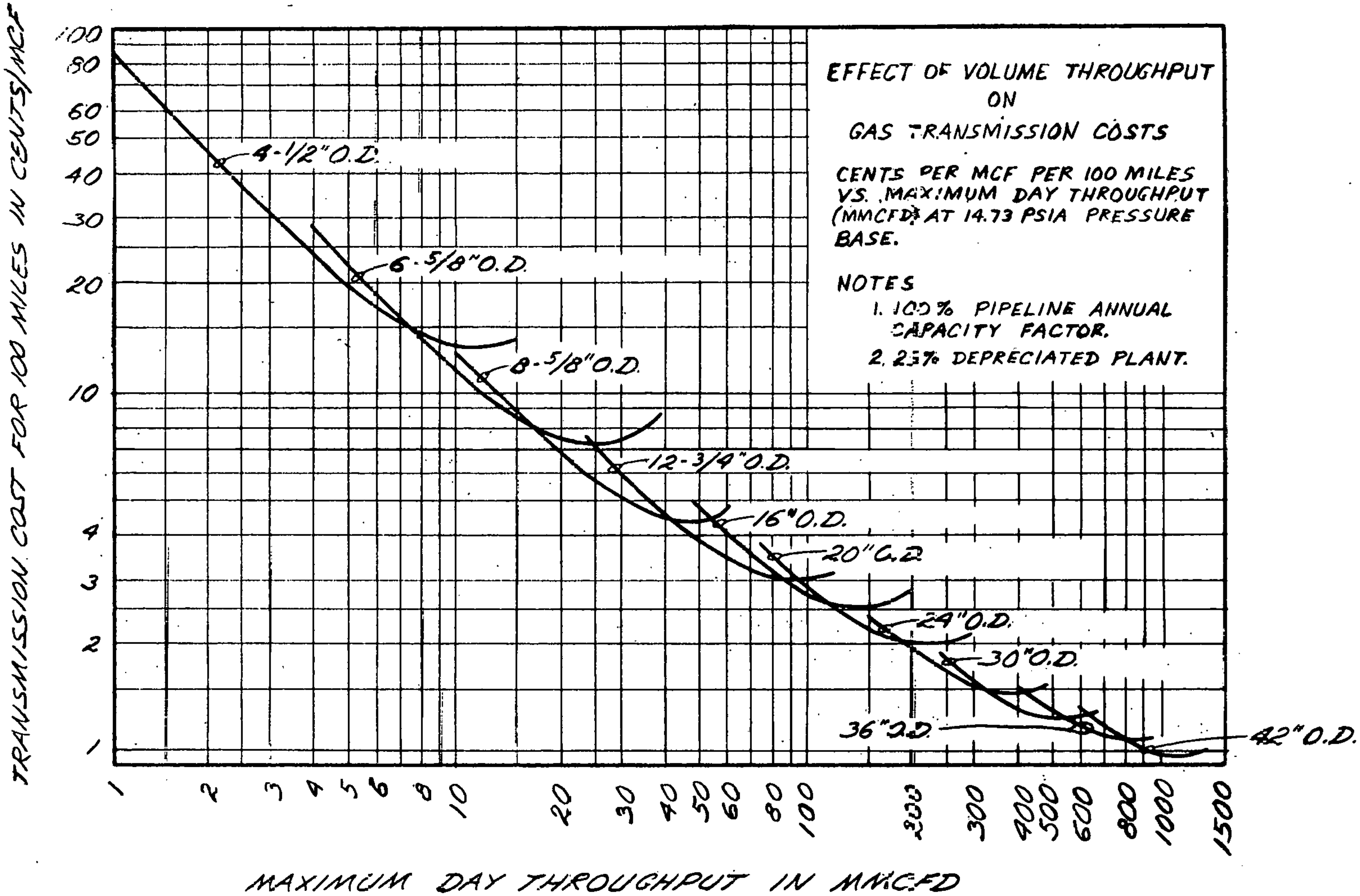
NO.	MILE POST	ELEVATION FEET ABOVE SEA LEVEL	SUCTION PRESSURE PSIA	SUCTION TEMP. DEG.F	DISCHARGE PRESSURE PSIA	DISCHARGE TEMP. DEG.F	COMPRESSOR OPERATING HORSEPOWER	FUEL REQUIRED MMSCF/D	COOLING REQUIRED TONS	STATION THROUGHPUT MMSCF/D
1	.00	80.0	550.0	70.0	990.0	194.8	10031.	1.926	0.	226.80
2	121.72	159.0	765.9	68.3	990.0	107.8	2884.	.554	0.	226.25
3	256.23	212.1	762.7	68.2	990.0	106.3	2928.	.562	0.	225.69
4	382.48	200.5	757.6	68.3	985.1	108.6	2939.	.564	0.	225.12
5	518.39	167.1	745.5	68.2	969.2	106.5	2930.	.563	0.	224.56
6	658.00	131.0	717.4	68.2	932.6	108.3	2921.	.561	0.	224.00
							24634.	4.730	0.	

Figure 3.4.2-1 - Pipetech Computer Printout, Sheet 2

Table 3.4.2-1

Energy Intensity of Reference Gas System

Throughput, 10^9 Ton-Mile/Yr	Compression Energy, 10^{12} Btu	EI Btu/Ton-Mile
1.363	1.528	1121
1.868	4.312	2308
2.3706	7.586	3125
2.5313	10.447	4127



SOURCE: TESTIMONY, DOCKET NO. AR61-2; HEARING EXHIBIT NO. 59; DATE IDENTIFIED 12-10-63; DATE ADMITTED 5-26-64 P. 2456-2462

FIGURE 3.4.2-2 - THROUGHPUT - DIAMETER RELATIONSHIPS TO UNIT COST FOR GAS PIPELINES

Table 3.4.2-2

Search for Economic Energy Intensity

EI Btu/Ton-Mile	LAC* Mills/Ton-Mile	Book Profit* 10^6 $	Cash Flow* 10^6 $
1121	5.17	107	163
2308	5.95	134	204
3125	7.36	142	234
4127	8.21	133	227

*16-year present value, discounted at 10%.

at this result. It was their feeling that the minimum throughput condition, i.e., the 1.363×10^6 Ton-Miles/Day which corresponds to the EI of 1121, is about at the minimum-cost operating point for this line.

More importantly, it may be observed that the operating point which yields maximum return to an owner-investor is at a much higher energy intensity. The price of fuel was taken to be the $1.46/MCF (1977 regulated price) recently set by the FPC, and even at this relatively high price, in terms of previous years, the maximum return operating point falls at an EI approximately three times greater than that of the minimum-cost point. To bring the two together would require a gas price of several dollars per MCF.

It may also be noted that in none of the cases studied was the FPC profit limit reached, so that the cost to the consumer is the same all cases.

This area of investigation, i.e., the relationships between energy consumption, profit, and cost to the consumer, contains many interesting questions and warrants further investigation. In particular, when a plan is being developed for implementation of the recommendations of Task 2, Regulation and Tarriff, more detailed case studies will be needed. Further work is therefore recommended.

Referring again to Figure 3.4.2-1, it is seen to be consistent with the result just derived. For a 24-inch line, which is the diameter of the reference system, the figure indicates a minimum cost at about 300×10^6 ft^3/day, as opposed to the 200×10^6 ft^3/day which corresponds to the minimum-throughput point in Table 3.3.2-3. It seems quite reasonable that the increase in fuel prices since 1963 could account for this shift to lower flow.

Finally, it is observed that the maximum-return EI of approximately 3100 BTU/Ton-Mile for the reference system is not inconsistent with the 3200 derived in the previous section for Regional 1, New England. The

Tenneco line consists of parallel pipes ranging in size from 24 to 30 inches. The lower figure of 2600 which was derived for Region 4 is also not inconsistent when it is recognized that the principal line from the Panhandle area to Chicago consists of 24 to 36 inch pipes. For the larger pipes, a lower energy intensity would be expected.

The foregoing calculations were sent to several pipeline companies for review. The responses were that the methodology and values seemed reasonable, but since they had never calculated EI, they could not comment upon the actual magnitudes. However, one large company performed the necessary research into their own records and calculated the EI for the trunkline portion of their system in 1976. The result was just over 1000 Btu/Ton-Mile. However, in earlier years, when the throughput was much higher, the EI was of course much higher, so that the EI for that system may well have been above 1500 Btu/Ton-Mile. This result, of course, leads to the suspicion that the estimates developed above are high.

Taking all of the foregoing discussion into account, it is concluded that the 1976 average EI lies between 1000 and 4000 Btu/Ton-Mile, at high confidence. Taking the geometric mean, in recognition of the skewed nature of the probability density function, yields a value of 2000 Btu/Ton-Mile. This is the estimate for energy intensity of gas pipelines.

4.0 ENERGY CONSUMPTION IN OIL PIPELINES

4.1 Oil Pipeline Industry Profile

4.1.1 Pipeline History

On October 10, 1865, the first oil pipeline in the United States was completed. It was 5 miles of 2-inch, lap-welded, wrought iron pipe, held together by threaded couplings, and ran from Pithole to Miller's Farm in Pennsylvania. It reduced the cost of transporting crude oil from $3 to $1 per barrel. In the years immediately following, pipelines of 2 to 6 inch-diameter pipe were built.

Table 4.1.1-1 is a statistical history of all oil pipeline miles in the United States from 1918 through 1964. Figure 4.1.1-1 shows the growth of various types of pipeline for the same period.

From 1900 to 1910, United States oil pipeline operators increased total trunkline length by 138%. In the decade from 1920 to 1930, the total length in operation was increased by 81%, while actual shipments in that period increased by 158%, due to the steadily increasing use of larger diameter pipe. The greatest technical gain of the 1920-30 decade for reducing operating costs was the increase in pipe diameter to 10 and 12 inches. With the exception of the Prairie Pipeline's 12-inch pipe in 1906 and Shell's 10-inch in 1916, the largest in the United States had been 8 inches.

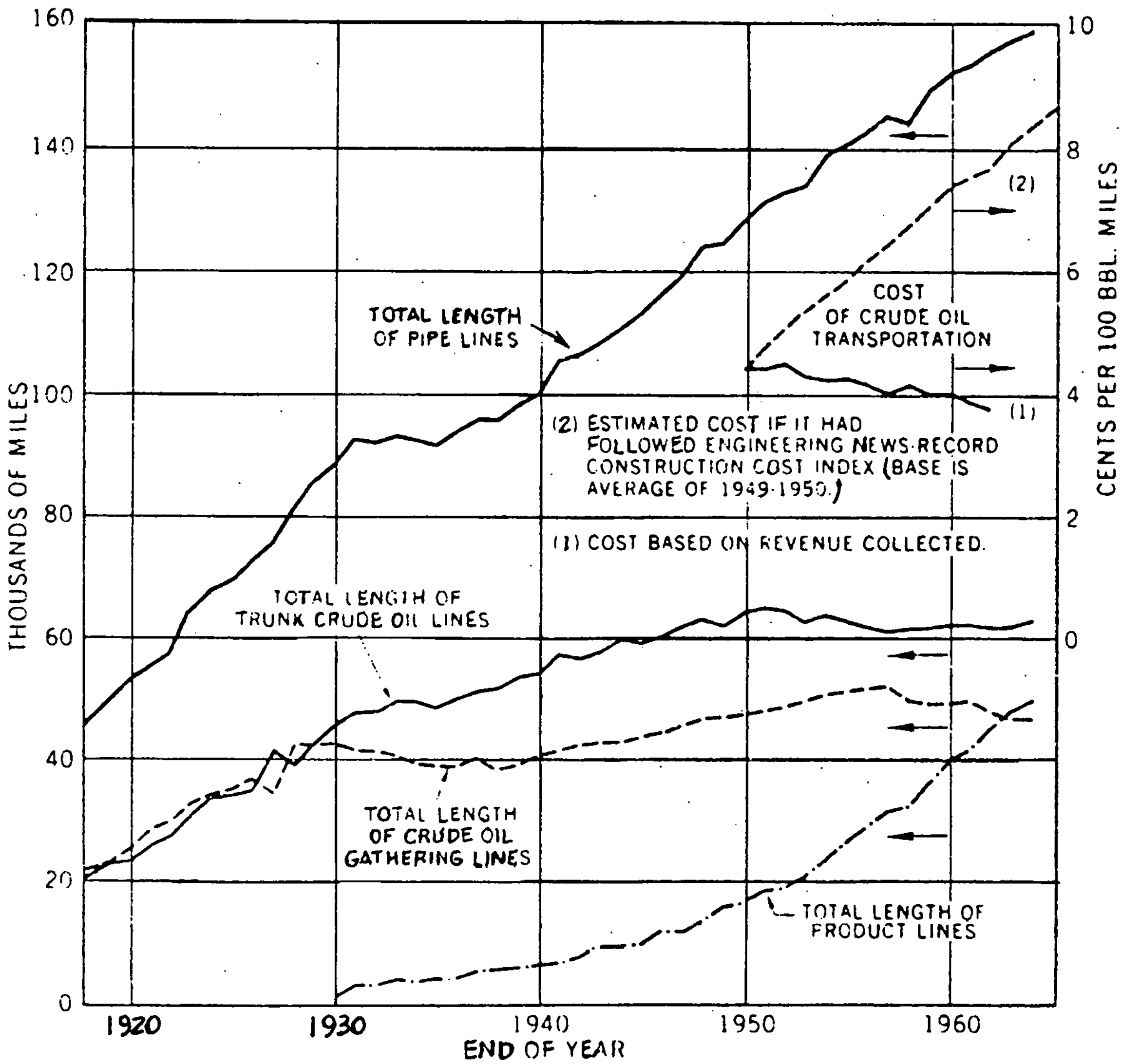
During the 1930's, pipeline industry expansion was erratic, due no doubt to the depression. However, there were some important events. The first pipeline to cross the Continental Divide was built in this period. It was a 440-mile line, with 6- and 8-inch pipe, which ran from Lance Creek, Wyoming, to the Salt Lake plant of the Utah Oil Refining Co. Also, products pipelines started their major development during the depression, a noteworthy example being the construction of the 732-mile Susquehanna-Sun Oil Line system in 1930-31. By 1937 it was transporting gasoline at one-third the unit cost of railroad shipping. Statistics for this period are given in Table 4.1.1-2.

Table 4.1.1-1

Pipeline Operations
in U. S. as Indicated
by Number of Miles of Pepeline in Operation
(Those Reporting to ICC - End of Year)

YEAR	CRUDE OIL LINES		PRODUCT LINES	
	TRUNK	GATHERING	TRUNK	TOTAL
1918	22,157	23,415	....	45,572
1919	24,435	24,867	....	49,302
1920	25,330	27,663	....	52,993
1921	26,292	28,968	....	55,260
1922	27,325	30,024	....	57,349
1923	31,322	33,438	....	64,760
1924	34,072	34,113	....	68,185
1925	34,801	35,208	....	70,009
1926	35,515	37,331	....	72,846
1927	41,610	34,460	....	76,070
1928	39,422	42,254	....	81,676
1929	43,564	42,232	....	85,796
1930	45,388	42,806	534	88,728
1931	48,014	41,803	3,273	93,090
1932	48,133	41,378	3,271	92,782
1933	49,468	40,859	3,397	93,724
1934	49,837	39,665	3,568	93,070
1935	48,641	39,380	4,016	92,037
1936	50,263	39,600	4,148	94,011
1937	51,369	40,062	5,181	96,612
1938	51,781	38,874	5,283	95,938
1939	53,641	39,373	5,467	98,681
1940	54,084	40,300	5,772	100,156
1941	57,502	41,858	6,075	105,435
1942	56,762	42,318	7,405	106,485
1943	57,586	42,471	8,726	108,783
1944	59,259	43,276	9,080	111,615
1945	59,576	43,994	9,781	113,351
1946	60,120	44,862	11,562	116,544
1947	61,561	45,909	11,828	119,298
1948	63,364	47,036	13,692	124,092
1949	62,272	47,212	15,500	124,984
1950	64,622	47,593	16,374	128,589
1951	64,922	47,629	18,836	131,387
1952	64,888	48,522	19,305	132,715
1953	63,408	50,030	20,462	133,900
1954	64,145	50,689	24,128	138,962
1955	63,347	50,645	26,832	140,374
1956	61,885	51,336	29,465	142,686
1957	61,379	52,077	31,780	145,236
1958	61,702	49,787	32,865	144,354
1959	61,860	49,567	37,732	149,159
1960	62,059	49,401	40,508	151,968
1961	62,251	49,656	41,830	153,737
1962	61,702	48,063	45,288	155,053
1963	61,832 (est)	47,125 (est)	47,855 (est)	156,812 (est)
1964	63,139 (est)	46,777 (est)	49,667 (est)	159,583 (est)

Source: Reference 10



Source: Reference 11

Figure 4.1.1-1 - Growth of U. S. Pipelines for 1918-1964

The importance of large pipe diameters is dramatic. For example, a 10-inch line will transport fluid at an average cost which is 37% lower than that for an 8-inch line. A 16-inch line can double the delivery rate and decrease the cost per barrel-mile by more than half in comparison to an 8-inch line. Of course, these savings are realized only if a certain minimum shipment level is maintained, and there are many instances in which the tradeoff of pipe costs, pumping requirements, and shipping volume favors the small-diameter pipeline.

By 1941, a 24-inch diameter pipeline was in operation. This was the Big Irish line, which extended from the Gulf Coast to the Eastern Seaboard, and whose purpose was to augment World War II tanker shipments. Table 4.1.1-3 shows the shift in oil transport methods from 1941 through 1945. Figures 4.1.1-2 and 4.1.1-3 show the 1950-1975 trends in terms of intercity freight and interstate pipeline shipments.

The Colonial system, built in 1963, was 2600 miles long, 1046 miles of which was made of 36-inch-diameter, high strength, thin wall pipe. Today the system has 4127 miles of pipe, some of which is 40 inches in diameter. Its trunkline shipping record for the year 1976 was over 591 billion barrel-miles of petroleum products, the average haul distance is approximately 1040 miles.

From the first pipeline in 1865, 5 miles of 2-inch pipe in Pennsylvania, the United States today has over 170,000 miles of crude oil and petroleum products pipelines, and growth continues as shown in Table 4.1.1-4. It is of interest that the 9391 million barrels of crude oil shipped through trunklines in 1975 was an increase over that shipped in 1945 of approximately 5 to 1.

4.1.2 Pipeline Fabrication

Early pipelines were welded, but only along the seam of the pipe during its manufacture. Lengths of pipe were joined by threaded couplings. The additional requirements of threading the pipe ends made this a costly process, particularly as pipe diameter increased. Coupling of pipes by

Table 4.1.1-2

Gasoline Production and Pipeline Shipments of Crude Oil and Petroleum Products, 1931-41 (Millions of bbl)

Year	U. S. gasoline production *	Total gasoline pipeline shipments	Shipments originated on interstate common carrier lines		
			Products	Crude	Total
1931	396.4		15.7	489.1	504.8
1932	366.3	29.9	24.9	508.1	533.0
1933	376.2	38.4	29.0	537.6	566.6
1934	388.8	45.5	35.3	577.3	612.6
1935	426.8	51.0	43.6	723.0	766.6
1936	471.0	58.9	51.5	755.1	806.6
1937	519.8	74.1	63.0	885.4	948.4
1938	516.1	85.6	65.1	793.3	858.4
1939	556.9	95.1	70.2	802.8	873.0
1940	557.8	97.1	72.0	886.4	958.4
1941	623.3	113.0	82.4	971.1	1,053.5

* Finished gasoline and naphtha, excluding natural gas liquids.

Source: Reference 12

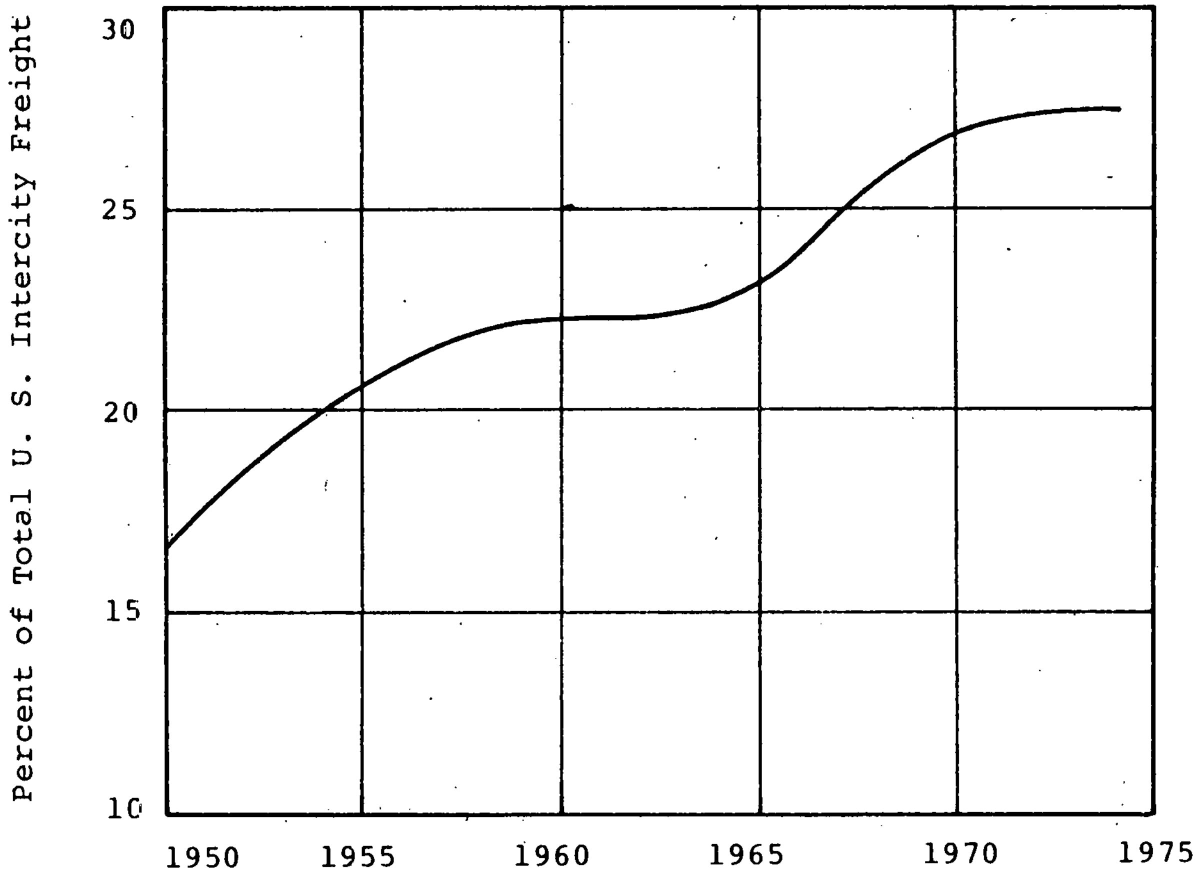
Table 4.1.1-3

Average Daily Petroleum Deliveries to the East Coast by
Mode of Transportation (1941-45)

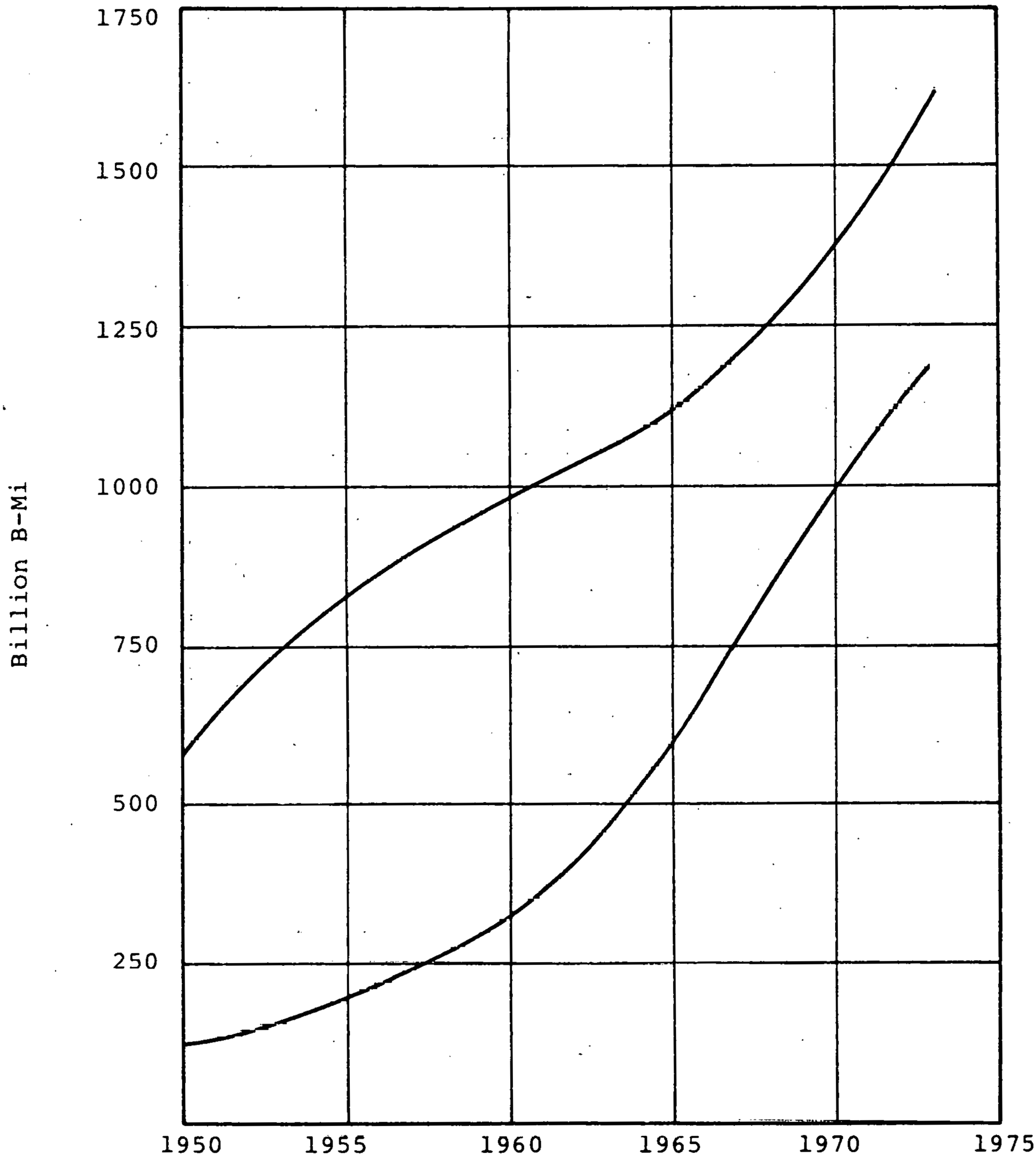
	1941		1942		1943		1944		1945 *	
Tank car	35,000	(2.3)	624,684	(51.3)	851,905	(61.3)	646,113	(37.7)	504,197	(27.7)
Pipeline	54,000	(3.5)	120,459	(9.9)	266,990	(19.2)	662,559	(38.7)	732,537	(40.3)
Barges and lake tankers	28,000	(1.8)	80,793	(6.6)	112,147	(8.1)	127,641	(7.5)	127,002	(7.0)
Total overland	117,000	(7.5)	825,936	(67.9)	1,231,042	(88.6)	1,436,353	(84.0)	1,364,336	(75.0)
Tanker	1,421,000	(92.5)	390,611	(32.1)	159,563	(11.4)	275,766	(16.0)	450,565	(25)
Total daily delivery	1,538,000		1,216,547		1,390,605		1,712,129		1,815,000	

* First six months.

Source: Reference 13



Source: Reference 14
Figure 4.1.1-2 - U. S. Intercity Pipeline Oil Shipments Compared to All Freight Shipments



Source : Reference 15

Figure 4.1.1-3 - U. S. Interstate Pipeline Trunkline Shipments

Table 4.1.1-4

U. S. Pipeline Operations, Crude Oil and Petroleum Products

	1974	1975	Increase
Miles of Pipeline	169,116	170,749	.96%
Total Deliveries (1000 B)	9,131,713	9,391,347	2.74%
Total Trunkline Traffic (1,000,000 B-Mi)	2,631,849	2,892,129	9.89%

Source: Reference 16

welding began on a large scale in the 1920's. By that time also, seamless tubing has replaced the lap-welded pipe and electric arc welding had begun to replace oxyacetylene welding. Techniques for repairing lines while they contained oil or products were also being developed.

Large pipelines need either thicker or stronger steel than do the smaller lines. Further, the use of high pressures to increase fluid flow subjected the pipe to still higher stress. These requirements were met by the development of new alloys and heat treatments to increase pipe strength to above 100,000 psi. This also increased the weldability of the material.

There was still a major problem which has forced thick-wall pipe fabrication. The corrosion of external pipe had to be accommodated by extra thickness to overcome the electrolytic metal loss. This has been circumvented by the development of special coatings and cathodic protection. In products pipelines, some of the refined products have a corrosive effect on the internal surface of the pipe. Here again, techniques for protection have been developed, namely, the use of intense coatings to prevent wall corrosion and of product additives to decrease corrosiveness of the fluid.

4.1.3 Pipeline Pumping Equipment

Pumping machinery evolved from steam engines through diesel engines to electrically driven centrifugal pumps. Electrical power for pipelines underwent its first major test in 1926 when a 30,000 barrel-per-day (B/D) main line station was successfully powered by electric pumps. In 1927, the Oklahoma Pipe Line Co. opened an all-electric 50,000 B/D station, and in 1928, Shell Oil followed with an almost completely electrically powered pipeline which was larger than the combination of the two just mentioned. This was soon superseded by Atlantics's 500-mile West Texas Line, which was exclusively powered by electricity.

In most cases today, electricity is used whenever it is available. When it is not available, or there is a capital equipment advantage in continuing to use older machinery, either diesel engines or gas turbines are used. In many cases the fuel is drawn from the pipeline. Table 4.1.3-1 shows the principal energy sources for five large companies selected for study in the Federal Energy Administration's Project Independence. It is seen that for these five companies, electricity was the principal fuel in an estimated 88% of the usage.

4.1.4 Pipeline Control and Monitoring

Control and monitoring of oil and products pipeline flow are now effected by digital computer systems which control and meter flow, follow interfaces between products, record flow operations, sense faults, actuate the alarm systems when necessary, provide delivery information, and assist in customer billing. These systems have become highly precise and have contributed enormously to both quality and efficiency.

Operational parameters such as pressure, flow, and temperature, and equipment conditions such as temperature of bearings and electrical windings, are sensed. Corrective action such as a switch to standby equipment may be handled entirely by the control system.

Modern petroleum products shipments demand highly sophisticated batch separation equipment. This equipment must first select the sequence of the products which interface in the pipeline, then the proper flow characteristics to assure nonlaminar flow and thus prevent the products from intermixing must be maintained. Next, interface cutting, probably the most delicate of the operations performed by the equipment, must be performed. Aviation gasoline, for example, must be kept absolutely uncontaminated. To achieve this, the flow into the delivery truck cannot begin until the interface between the aviation gasoline and the product preceding it in the line has passed the outlet point. Near the end of the delivery, the valve must be closed before the next interface reaches the valve. Clearly, the more reliable the equipment for this procedure, the higher the economic efficiency. It may be noted that electrical machinery is most easily controlled.

4.1.5 Economic Considerations

Pipeline barrel-mile shipment cost decreases markedly with increased

Table 4.1.3-1

Energy Intensity of

Selected Petroleum Pipeline Companies

Company		Btu per Ton-Mile[a]	Principal Fuel
1:	1970	424.8	Electricity (87%)
	1971	424.8	Electricity (87%)
	1972	414.6	Electricity (90%)
	1973	414.6	Electricity (91.3%)
2:	1971	520.9	Electricity (100%)
	1972	358.4	Electricity (100%)
3:	1972	432.5	Electricity (76.3%)
	1973	445.7	Electricity (75.8%)
4:	1970	546.9	Electricity (87.5%)
5:	1971	1018.6	Electricity (75.6%)
	1972	1067.9	Electricity (72.6%)
Estimated Weighted Average 1972 Responding Companies		432.91	88%
Estimate for All Companies		550	75-80%

[a]Adjusted to exclude fuel used on non-trunk operations since ton-miles were available only for trunkline movements. Btu's are on a production basis and represent Btu inputs to the utility plant when electricity is in the form of energy use (i.e., 11,586 Btu/kw-hr).

Source: Reference 2

quantity. These costs, however, are not affected to any large extent by shipping distance, which is quite the opposite situation from that with rail or tanker transport. As with all methods of transport, some threshold shipment size is required for economical transporatation by pipeline.

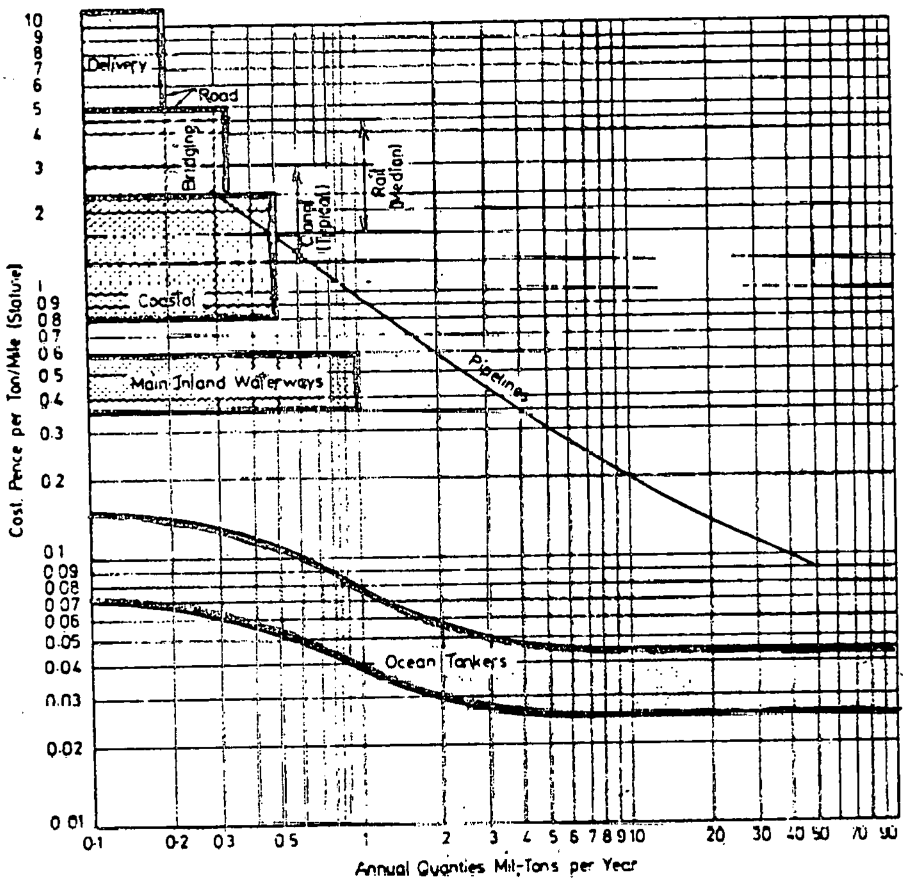
Figure 4.1.5-1 shows a comparison of cost vs. quantity for several modes of crude and products shipment to and within Europe. Figure 4.1.5-2 separates pipeline capabilities which were integrated in Figure 4.1.5-1 to show throughput as a function of pipeline size. Another interesting aspect of pipeline operation is shown in Figure 4.1.5-3 where throughput is a function of pipeline utilization. This indicated trend is consistent with that of Figure 4.1.5-1. Figure 4.1.5-3 is normalized to an ultimate minimum transportation cost. It shows unit cost of transportation for a pipeline designed to accommodate an initial throughput shown at A with a potential throughput as shown at B. Point C shows the unit cost increase caused by the addition of pumping machinery, and point D shows the advantage to both cost and throughput when the potential of the new line is fully utilized.

As noted in Section 4.1.4, the products pipeline makes much more stringent demands upon the control and monitoring system. This is particularly true in maintaining separation of the various products in the line. The intermixing of a small amount of one grade of crude oil with another is of small moment, whereas products batches must be precisely separated.

In crude oil lines, most of the personnel are concentrated at the point where the oil is gathered, gauged, and sent into the pipeline. Conversely, the products pipelines, personnel are most likely to be found at terminal points.

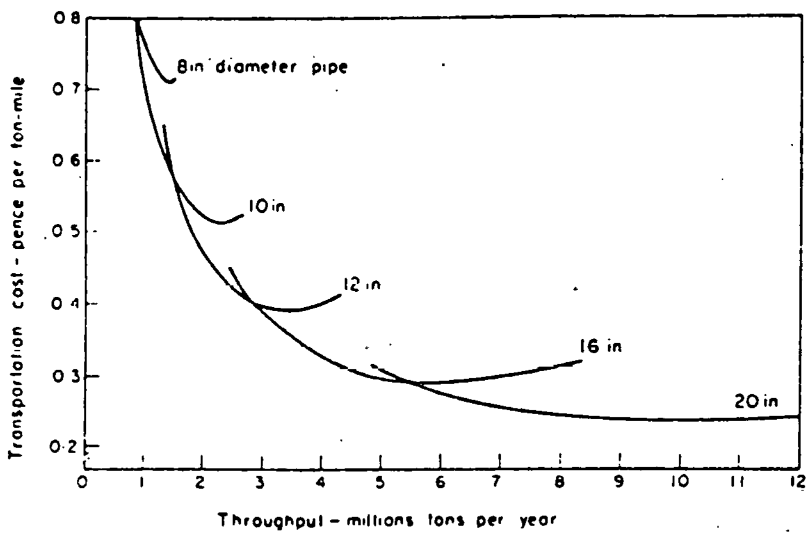
4.1.6 Pipeline Ownership

Although several large single-owned and non-shipper-owned pipelines exist, the general practice is joint ownership by a group of shippers who pool their investments and their shipments. Joint ownership in most cases has proved to be economiccally preferable. Management modes vary among jointly owned pipelines. For example, the giant Colonial Pipe Line



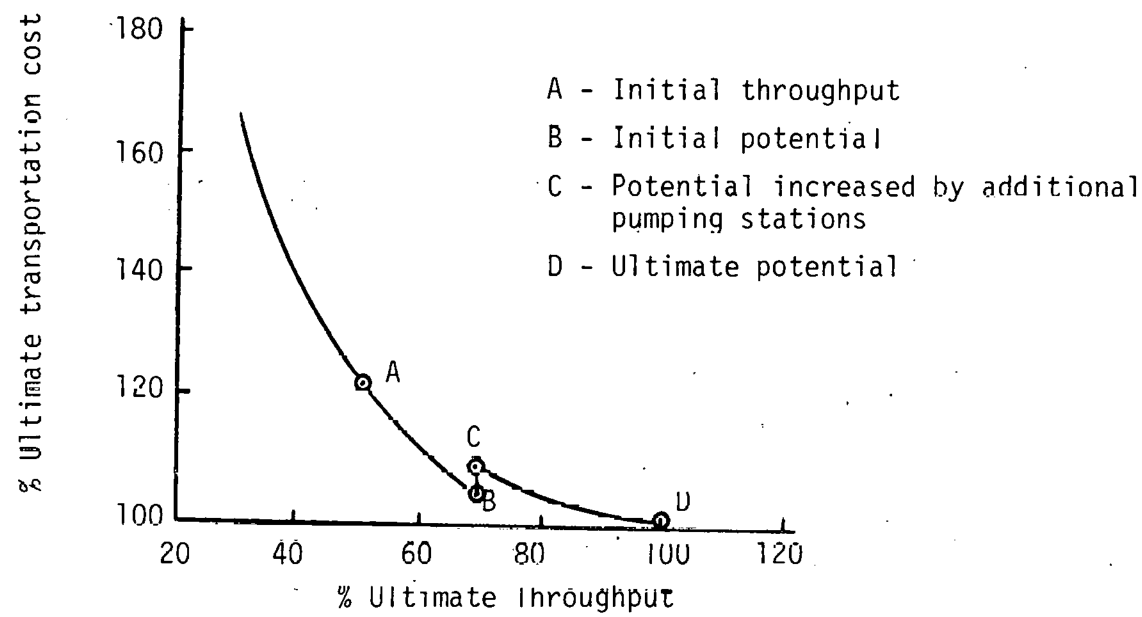
Source: Reference 17

Figure 4.1.5-1 - Cost of Transport Relative to Annual Quantities



Source: Reference 17

Figure 4.1.5-2 - Pipeline Diameter and Transportation Cost Related to Throughput



Source: Reference 17

Figure 4.1.5-3 - Transportation Cost Related to Utilization

Co. maintains a single tariff throughout the system, while in other systems each owner establishes the tarriff for his own shipments. Operations management also differs from one system to another. The two management schemes most prevalent are (1) operations management function performed by one of the pipeline owners' groups, and (2) operations management by an outside company hired by the pipeline combine.

4.1.7 Oil Pipeline Characteristics

Pipeline crude oil movements pass through two different steps or types of facilities. These are gathering systems and trunk systems. As the name implies, in a gathering system, crude oil is transported from the numerous production leases in an oil field to a pipeline trunk station or rail head. A gathering system might be compared to a series of small streams that feed into a river. It is in the gathering system that crude oil begins the first leg of its journey to market. Figures 4.1.7-1 and 4.1.7-2 show the two stages of the gathering system (Ref. 18).

In most instances, wells in the same general area produce the same grade of oil which allows all feeder lines in a gathering system to flow together into a common stream into the trunk station. If two types of crude are produced in the same area and cannot be mixed together, it is necessary to construct a dual gathering system.

The collection of lease oil in gathering systems is performed by pipeline field people known as gaugers. When lease tanks have been filled the producer notifies the pipeline gauger who samples the oil for quality and verifies the quantity before turning it into the gathering system. The oil then moves by gravity or is pumped into tanks at the nearest trunk station. In a modern oil field, a very large percentage of the production from leases is transferred automatically from producer to pipeline through Lease Automatic Custody Transfer (LACT) equipment. Such equipment automatically pumps oil from a lease surge tank when the oil reaches a certain level in the tank, continuously monitors the oil for excess sediment and water content, measures the oil through a meter as it is transferred and continuously

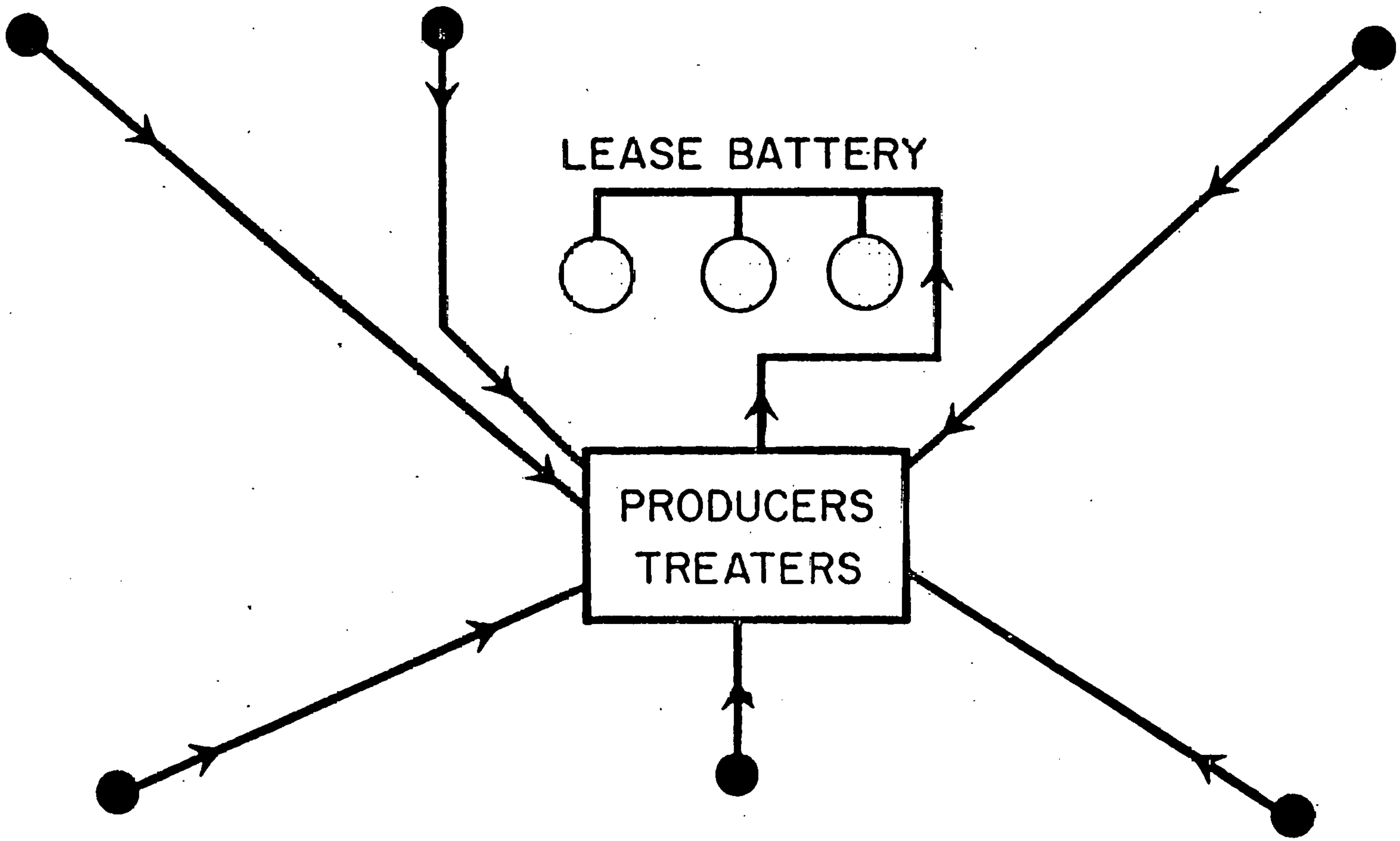


Figure 4.1.7-1 - Producing Wells and Lease Tank Battery

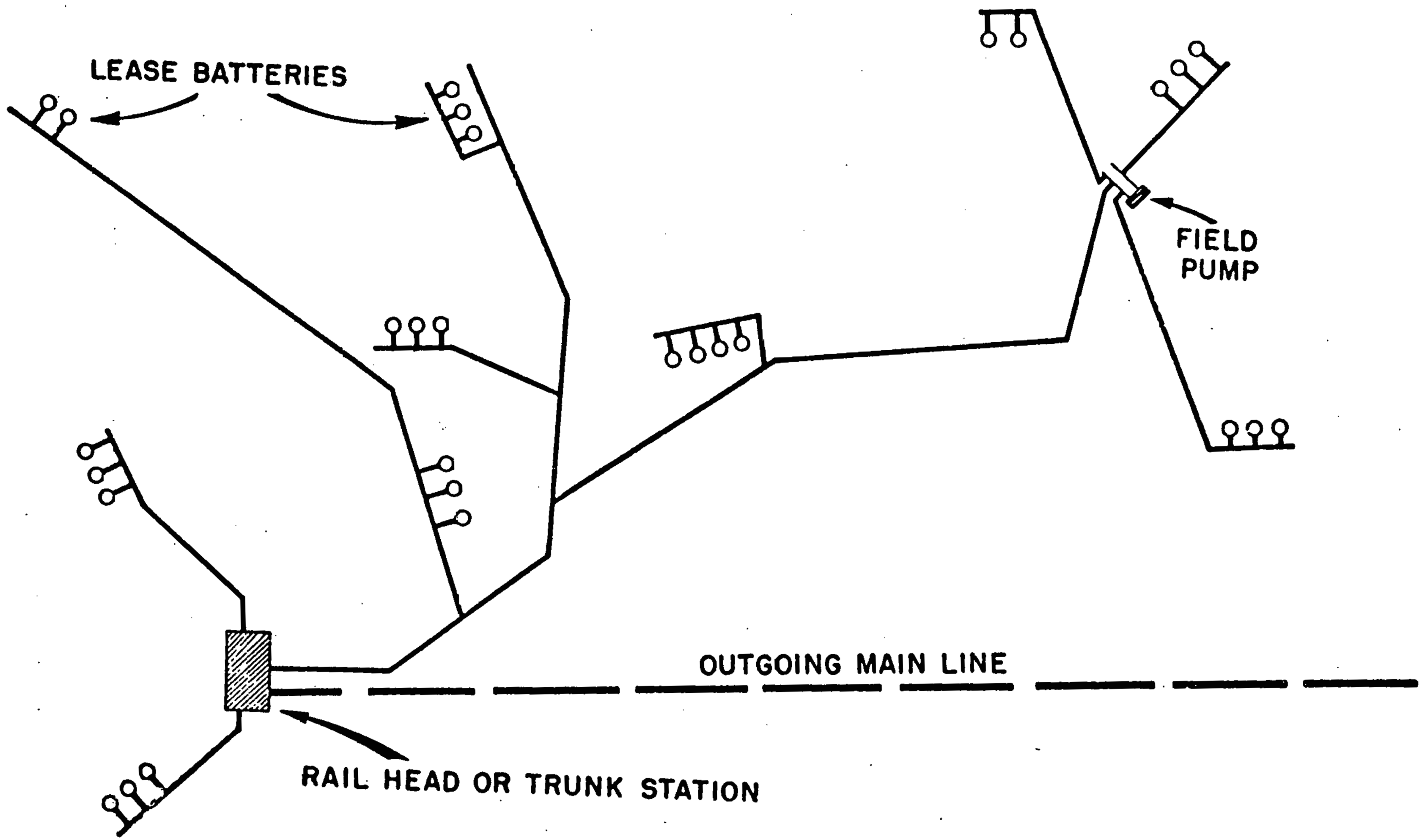


Figure 4.1.7-2 - Crude Oil Gathering System

draws off a portion of sample of the oil into a container from which the gauger can determine quality later.

The trunk line station is usually provided with several tanks having capacity to:

- o Store sufficient crude oil to maintain a constant flow to the next station.
- o Receive the variable runs from gathering systems.
- o Measure the receipts from connecting carriers.
- o Accumulate suitable quantities of different grades for desired batch sizes.

A crude trunk line station is schematically illustrated in Figure 4.1.7-3, and Figure 4.1.7-4 illustrates the trunk line system (Ref. 18).

A products trunk line is illustrated in Figure 4.1.7-5. Many similarities are obvious (Ref. 19). However, there are some important differences. Crude oil lines, because of the higher viscosity of the oil, are generally of larger diameter pipe than product lines. Products temperatures do not greatly affect their viscosity; therefore pumping rates can remain nearly constant with temperature. Also, the temperature control problem is not severe. Crude oil operations, on the other hand, are very sensitive to temperature because of the higher visocity. Thus, temperature becomes more critical in the crude lines and there are much greater demands for flexibility in the pumping machinery.

Corrosion on the internal surface is a problem chiefly confined to products pipelines. Treatment of the metal itself may help, but in most cases the products must be made less corrosive either by additives or dehydration. Crude oil lines suffer from paraffin deposits, which can build

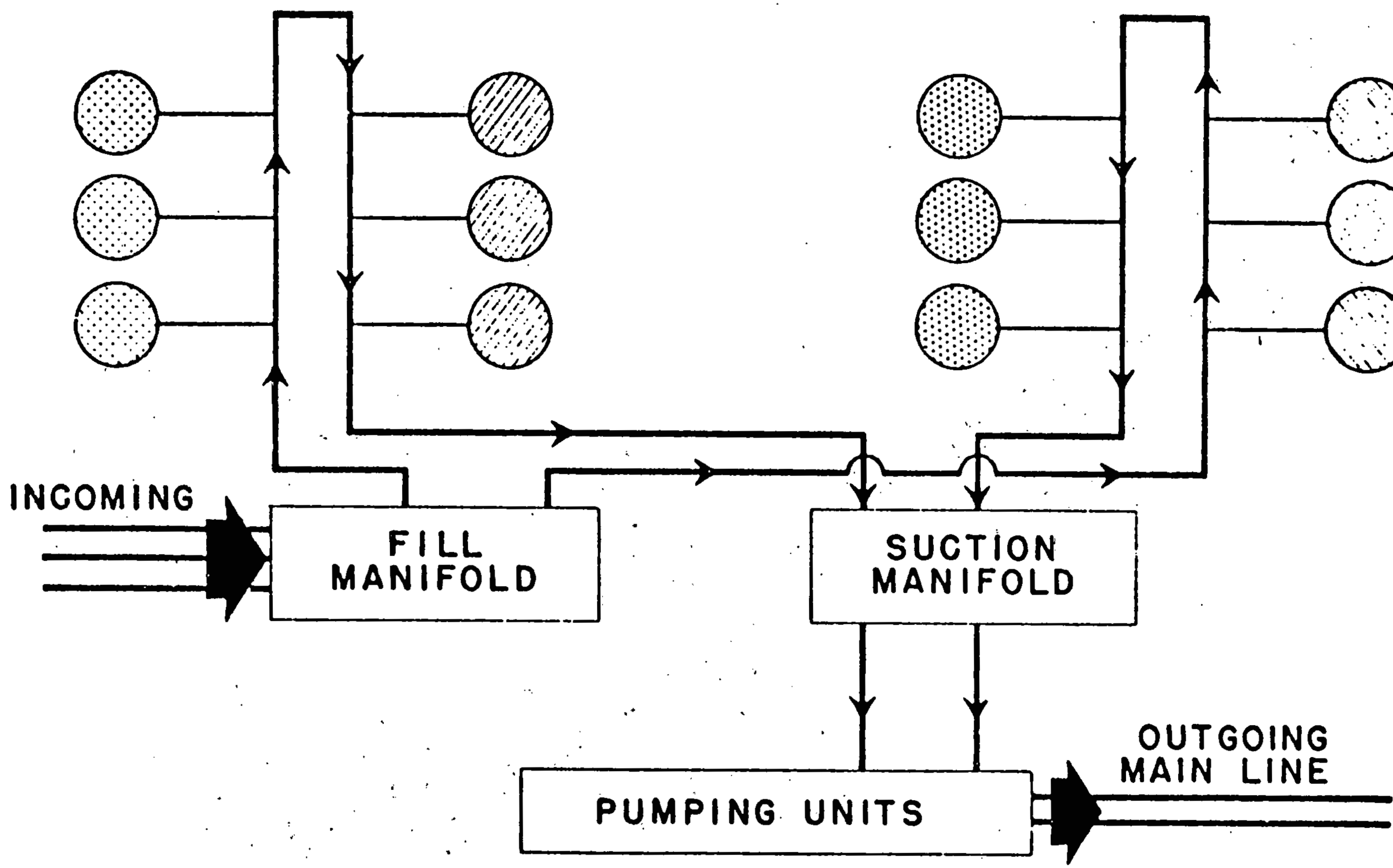


Figure 4.1.7-3 - Trunk Line Station

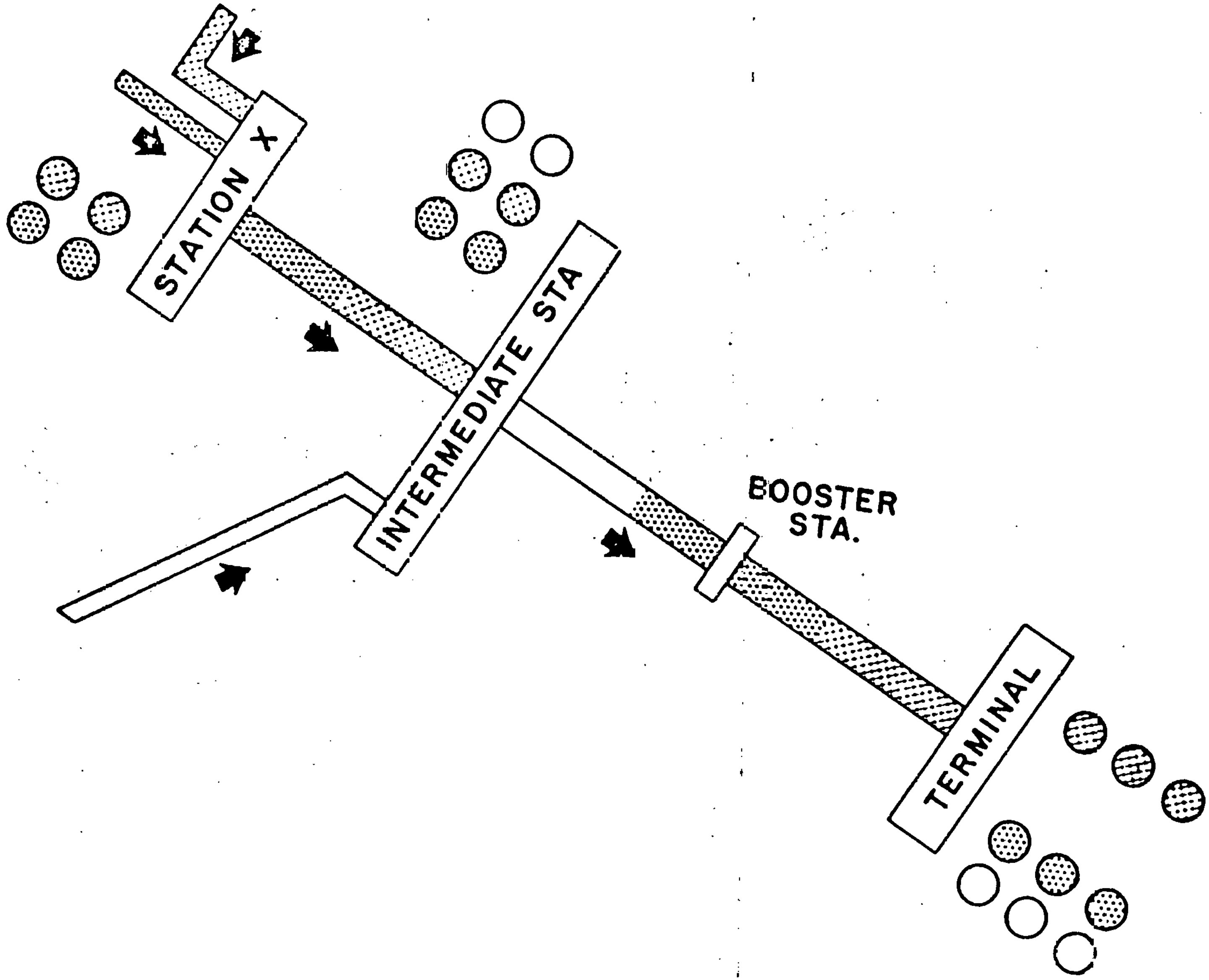


Figure 4.1.7-4 - Trunk Line System

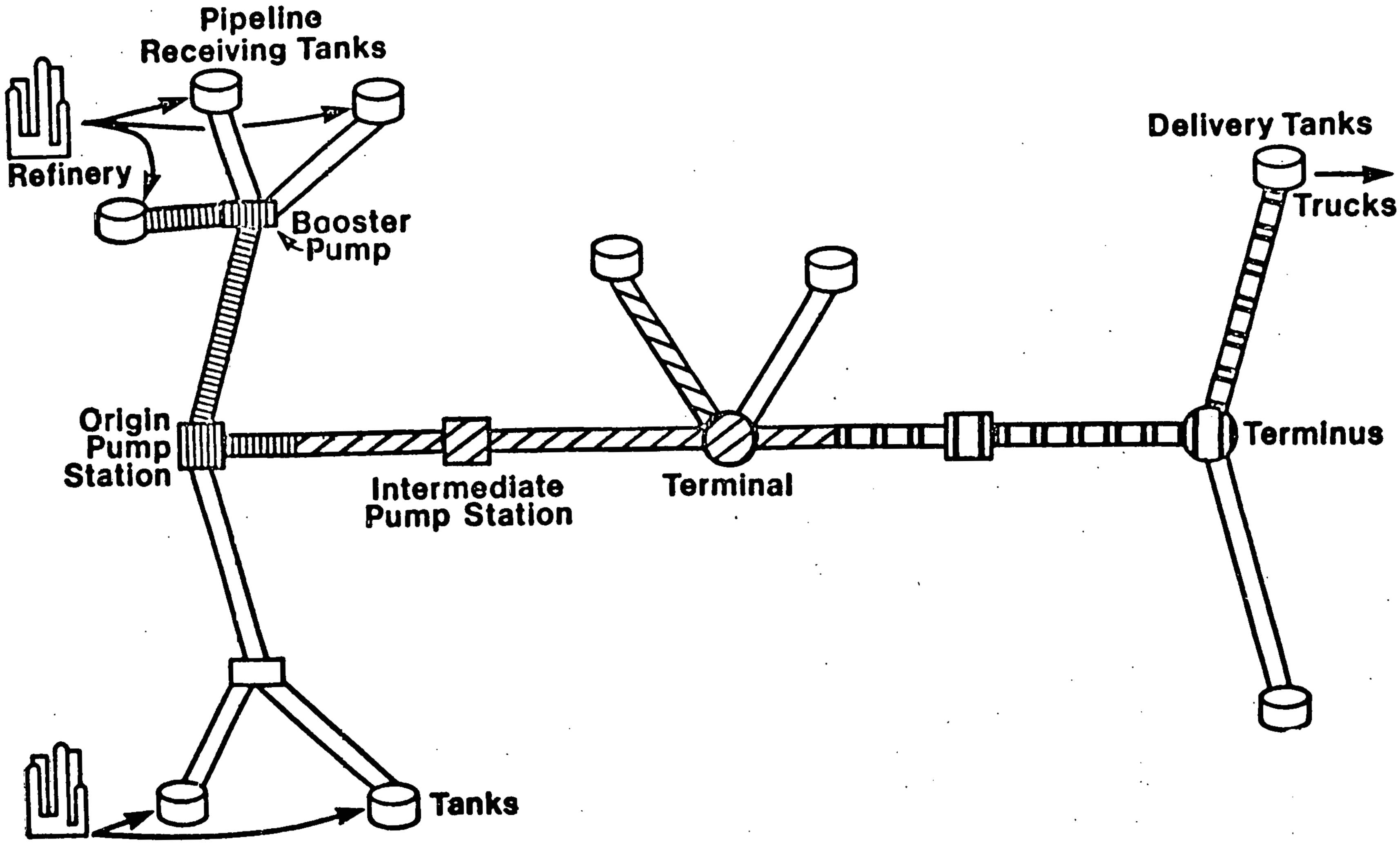


Figure 4.1.7-5 - Products Pipeline

up to considerable thickness. While this has the advantage of protecting against corrosion, the paraffin must be scraped away periodically.

4.2 Oil Pipeline Data Sources

The data used in this study was obtained from two sources:

(1) Reports to the ICC by the Companies

(2) Interviews with several individual companies

Figures 4.2-1 and 4.2-2 are copies of pages from the ICC Report P, upon which the pipeline companies report their annual operating expenses, Item Number 320, and Statistics of Operation, Item Number 400. The cost of operating fuel and power is reported on Line 4, Figure 4.2-1. The barrel-miles are reported at the bottom of Figure 4.2-2.

The acquisition of data by interview was accomplished only with great difficulty, and only a few data values were obtained. However, it will be seen that those values are useful, and are believed to be very accurate.

4.3 Estimation Methodology for Oil Pipelines

It was explained in Section 1.2 above that the accomplishment of this subtask reduces to an effort to estimate the three quantities on the right-hand side of the formula for the energy intensity,

$$I_E = \frac{E}{Q \times D}$$

where,

$I_E \equiv$ energy intensity, $\frac{\text{Btu}}{\text{Ton-Mile}}$

310. OPERATING REVENUE ACCOUNTS

State the pipeline operating revenues of the respondent for the year, classified in accordance with the Uniform System of Accounts for Pipe Lines.

Line No.	Operating revenue accounts (a)	Crude oil (b)	Products (c)	Total (d)
		$	$	$
1	(200) Gathering revenues			
2	(210) Trunk revenues			
3	(220) Delivery revenues			
4	(230) Allowance oil revenue			
5	(240) Storage and demurrage revenue			
6	(250) Rental revenue			
7	(260) Incidental revenue			
8	Total			

320. OPERATING EXPENSE ACCOUNTS

State the pipeline operating expenses of the respondent for the year

Line No.	Operating expense accounts (a)	CRUDE OIL Gathering (b)	Trunk (c)	Delivery (d)	Total (e)
	OPERATIONS	$	$	$	$
1	(300) Salaries and wages				
2	(310) Supplies and expenses				
3	(320) Outside services				
4	(330) Operating fuel and power				
5	(340) Oil losses and shortages				
6	TOTAL OPERATIONS EXPENSES				
	MAINTENANCE				
7	(400) Salaries and wages				
8	(410) Supplies and expenses				
9	(420) Outside services				
10	(430) Maintenance materials				
11	TOTAL MAINTENANCE EXPENSES				
	GENERAL				
12	(500) Salaries and wages				
13	(510) Supplies and expenses				
14	(520) Outside services				
15	(530) Rentals (p.48)				
16	(540) Depreciation and amortization				
17	(550) Pensions and benefits				
18	(560) Insurance				
19	(570) Casualty and other losses				
20	(580) Pipeline taxes (p.42)				
21	TOTAL GENERAL EXPENSES				
22	Grand Totals				
23	Operating ratio (ratio of operating expenses to operating revenues-percent). Gathering Trunk				

Figure 4.2-1 - ICC Annual Report Form P - Item 320, Operating Expense Accounts - Sheet 1 (Facsimile of original form)

320. OPERATING EXPENSE ACCOUNTS - Continued

Classifying them in accordance with the Uniform System of Accounts for

Line No.	PRODUCTS				TOTAL			
	Gathering (f)	Trunk (g)	Delivery (h)	Total (i)	Gathering (j)	Trunk (k)	Delivery (l)	Total (m)
	$	$	$	$	$	$	$	$
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								

23 Delivery__________ Total__________

Figure 4.2-1 - (Continued) Sheet 2

Carrier Initials ______ Year 19__

400. STATISTICS OF OPERATIONS

1. Give particulars by States of origin for crude oil and for each kind of product received during the year. Classify and list in column by States of origin the refined products transported in the following order: 29111 Gasoline, jet fuels and other high volatile petroleum fuels except natural gasoline; 29112 Kerosene; 29113 Distillate fuel oil; 29114 Lubricating and similar oils and derivatives; 29115 Residuel fuel oil and other low volatile petroleum fuels; 29119 Products of petroleum refining, misc.- Specify and Total - products.
2. As used herein, the term crude oil means oil in its natural state, not altered, refined or prepared for use by any process; and products means oils that have been refined, altered or processed for use, such as fuel oil and gasoline.
3. Natural gasoline or other similar products, whenever blended with crude oil in transit should be classified and reported as crude oil in this schedule.
4. In column (b) show all oils received by the respondent from connecting carriers reporting to the Interstate Commerce Commission. In column (c) show all oils originated on respondent's gathering lines and in column (d) all oils received into respondent's system from all sources, except receipts shown in columns (b) and (c). Entries in column (c) should be the sums of corresponding entries in columns (b), (c), and (d). In column (f) show all oils delivered to connecting carriers reporting to the Interstate Commerce Commission. In column (g) show all oils terminated on respondent's gathering lines, and in column (h) all oils delivered out of respondent's system, except deliveries shown under columns (f) and (g). Entries in column (i) should be the sums of corresponding entries in columns (f), (g), and (h).
5. Returns in "Note" should be estimated if not actually shown on respondent's records

Line No.	State of origin (a)	NUMBER OF BARRELS RECEIVED INTO SYSTEM: From connecting carriers (b)	ORIGINATED: On gathering lines (c)	ORIGINATED: On trunk lines (d)	Total received into system (e)	NUMBER OF BARRELS DELIVERED OUT OF SYSTEM: To connecting carriers (f)	TERMINATED: On gathering lines (g)	TERMINATED: On trunk lines (h)	Total delivered out of system (i)
	CRUDE OIL								
1									
2									
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13	TOTAL								
	PRODUCTS (State of origin and product carried).								
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25	TOTAL								
26	GRAND TOTAL								

27 NOTE.-Total number of barrel-miles (trunk lines only): Crude oil ______ : Products ______

28 Total number of barrels of oil having trunk-line movement: Crude oil ______ : Products ______

Figure 4.2-2 - Item 400, Statistics of Operation (Facsimile of Original Form)

E $\equiv$ energy consumed annually, Btu

Q $\equiv$ quantity transported annually, Barrels

D $\equiv$ distance transported annually, miles

Estimation of the numerator E constitutes an end in itself, since the total annual energy consumption is the first objective of this study. Information regarding the denominator is equally useful in the form of Q and D separately, or as the product (Q x D). It has been seen in the preceding section that oil pipelines report the data in the latter form, as barrel-miles. Unfortunately, they do not report ton-miles, nor average density. Thus, an imprecision of plus-or-minus five to ten percent is introduced by the use of any value for average density which is unsupported by considerable research.

It has also been seen in the preceding section that the direct measurements, in the form of recorded data, whose total would represent the numerator E in the formula, does not exist. The Companies are not required to record or maintain such data, and while some of them may do so, many do not. Accordingly, it becomes necessary to work with such data as does exist, which was seen to be the annual costs of energy, as reported on Line 4, Figure 4.2-1 above.

The general approach which was taken then, was to estimate the total energy by developing an estimate of the average unit cost of purchased energy and dividing that value into the total cost of power and fuel. To estimate energy intensity, the cost intensity is first calculated by dividing throughput, in barrel-miles into the total energy cost. Dividing this result by the estimate of average unit energy cost then yields the first-order estimate of energy intensity (EI) at the pumping station meter. Dividing by the efficiency of the electric generation and transmission system gives the EI at the boiler. Finally, the conversion from Btu/Barrel-

Mile to Btu/Ton-Mile is made by multiplying by a reasonable value of energy inverse density in Barrels/Ton.

Unfortunately, the totals published in the ICC statistics are not broken into sufficient detail that this method can be applied directly to those statistics, because the only figure given for fuel and power costs includes gathering and distribution energy as well as trunkline energy. To obtain that breakdown, it is necessary to consult each of the 104 reports filed by the individual companies. As will be seen, that is neither convenient nor necessary, because highly representative samples of the population of companies could be constructed. Having applied the method to those samples, the intensity value thus obtained is then extrapolated back to the entire population.

Finally, it is well to note that the same inability to obtain an accurate estimate of energy intensity had been the result of an attempt by the National Petroleum Council Task force (Ref. 20). As reported in a Rand Corporation report (Ref. 21), "The NPC Group found no valid way to correlate distance, volume, and cost, using historical information on transmission costs." The analysis presented here represents a first attack upon the problem.

4.3.1 Selection of Samples for Analysis

The first step in the execution of this method is the selection of a sample from the population of 104 companies, use of the entire population being neither necessary or desirable. Since the viscosities of the crudes are generally different from those of the products, it was desired to analyze the statistics of crude oil pipeline companies and petroleum products pipeline companies separately, so that two samples were required. Since many companies operate both products and crude lines, it was necessary to sort them into three categories, i.e., those whose operations are predominantly one type or the other, and those which are significantly both. For convenience, a "prime" company in either the products or crude category was defined as one whose trunkline shipments in one of those two categories comprise at least 80% of its total trunkline shipments. It was found that, of the 104 interstate pipeline companies in the United States in 1976, 91 met this definition. Most of the 13 which did not were comparatively small, and for some, no trunkline traffic tabulated at all was reported.

The degree of specialization of the primes into the two categories was analyzed for 1975, the figures for 1976 not being available at the time. The results are presented in Table 4.3.1-1.

Table 4.3.1-1

Prime* Pipeline Companies, 1975

Degree of Specialization in Either Crude Oil or Petroleum Products Shipments

% of Specialization	No. of Companies
100	70
95-99	10
90-94	4
85-89	4
80-84	2

*Prime Company - One whose trunkline shipments of crude or products comprise 80% of its total.

It is seen that the specialization is extremely high, indicating that the separation is virtually complete. When the 1976 figures appeared, the complete specialization analysis was not repeated; but it was verified that the specialization of the primes had not changed in any non-trival way.

After the primes in each category were identified, they were tabulated in order of trunkline barrel-miles of traffic for 1976. Then sufficient companies were taken in sequence from the top of the list to include at least 90% of the trunkline barrel-miles for all the primes in that category. This selection process yielded 21 crude and 14 products companies. Their 1976 market share is shown in Table 4.3.1-2.

Tables 4.3.1-1 and 4.3.1-2 together show that the two groups of selected companies are highly representative samples of their categories. Discussion of the analyses performed upon these samples will be presented in Section 4.4. First, however, the estimation of the cost of purchased power will be discussed.

4.3.2 Estimation of Purchased Power Cost

Early inquiries had revealed that pipeline companies do not maintain explicit records of all their power consumption, although engineering departments from time to time may collect the figures for purposes of one study or another. A number of companies (more than a dozen) were then interviewed and asked if their energy consumption and energy intensity could be obtained. It was found that they do not collect the data or perform the calculations in the ordinary course of business, although engineering studies may from time to time become involved in such questions. They were then asked to provide their actual average cost of purchased electricity in dollars per kilowatt-hour. Most of them declined; however, the information presented in Table 4.3.2-1 was obtained.

The pattern of variation which is seen in Table 4.3.2-1 is as would generally be expected. Pipelines in the Gulf Coast and Southeast generally enjoy lower power costs than elsewhere. Water companies are able to obtain the lowest cost of all by virtue of the large storage capacity in their systems, which enables them to do most of their pumping at night and take advantage of the lowest power rates. And product lines generally have to pay somewhat higher rates than crude lines, because with their more drastic duty cycles they have higher peaking charges. An example utility rate schedule is presented in Figure 4.3.2-1.

The first two values in Table 4.3.2-1 are probably below the national average because they pass through the region which enjoys the lowest power cost. The national average cost of purchased electricity for the products lines is likely to be nearer to the average of the second and fourth figures than to the second. Hence, for the analysis, that average, 0.02925 \$/kw-hr was used. Reducing this value in the proportion of the first value in the table to the second then yields 0.0280 \$/kw-hr as the estimate for the national average cost of purchased power for crude lines. There are no obvious adjustments to be made for the water lines.

No defense of these estimates is offered, except that they are reasonable. They are certainly useful as first-order estimates and as a means to exercise the methodology. The research that would be necessary to refine them is discussed later in this report.

Table 4.3.1-2

Market Share of Selected Companies, 1976

Group	Trunkline Traffic, 10^6 B-Mi Crude	Trunkline Traffic, 10^6 B-Mi Products
All Companies	1,639,479	1,279,016
Selected Sample	1,447,949 (88%)	1,017,999 (88%)

Table 4.3.2-1

Electricity Costs of Pipeline Companies

	Type of Pipeline	Geographical Region	Average Electricity Average Cost $/Kw-hr	Time Period
1.	Large Crude	South-Southwest	0.0225	1976
2.	Large Products	Southwest	0.0235	1976
3.	Small crude	West	0.0230	1976
4.	Small Products	Far West	0.0350	1976
5.	Small Products	Mid-West	0.0125	1/73-3/74
6.	Large Water	West-Central	0.0200	1976
7.	Large Sewage	Far-West	0.03666 0.3594 0.03162 0.02289	June 1977 6/1/76-6/1/77 6/1/75-6/1/76 6/1/74-6/1/75

Source: Reference 14

SAN DIEGO GAS & ELECTRIC COMPANY
SAN DIEGO, CALIFORNIA

Revised Cal. P.U.C. Sheet No. 2649-E
Cancelling Revised Cal. P.U.C. Sheet No. 2462-E
(Sheet 1 of 3)

SCHEDULE A-6

GENERAL SERVICE - LARGE

APPLICABILITY

Applicable to general service including lighting, appliances, heating, and power, or any combination thereof, except as limited by Special Conditions 1., 7. and 10.

TERRITORY

Within the entire territory served by utility.

RATES

	Per Meter Per Month
Energy Charge:	
First 100 kwhr per kw of billing demand, per kwhr.....	$ 0.04132
Next 100 kwhr per kw of billing demand, per kwhr.....	.03582
Next 100 kwhr per kw of billing demand, per kwhr.....	.02197
All excess kwhr, per kwhr..............................	.01907

Minimum Charge:
The monthly minimum charge shall be $7,000.00 but not less than $1.40 per kw of billing demand.

Energy Cost Adjustment:
An Energy Cost Adjustment, as specified in Section 9. of the Preliminary Statement, will be included in each bill for service. The Energy Cost Adjustment amount shall be the product of the total kilowatt-hours for which the bill is rendered multiplied by $0.00761 per kilowatt-hour. (The Energy Cost Adjustment amount is not subject to any adjustment for serving voltage.)

Fuel Collection Balance Adjustment:
A Fuel Collection Balance Adjustment, as specified in Section 10. of the Preliminary Statement, will be deducted from each bill for service. The Fuel Collection Balance Adjustment amount shall be the product of the total kilowatt-hours for which the bill is rendered multiplied by ______ per kilowatt-hour. (The Fuel Collection Balance Adjustment amount is not subject to any adjustment for serving voltage.)

(Continued)

(To be inserted by utility)
Advice Letter No. 413-E
Decision No. ______

ISSUED BY
JOHN H. WOY
VICE PRESIDENT RATES & VALUATION

(To be inserted by Cal. P.U.C.)
Date Filed September 7, 1976
Effective September 1, 1976

E-1599

Figure 4.3.2-1 - Example of Electric Utility Rate Schedule

SCHEDULE A-6 (Continued)

RATES (Continued)

Residual Oil Sales Adjustment:

A Residual Oil Sales Adjustment, as specified in Section 11. of the Preliminary Statement, will be deducted from each bill for service. The Residual Oil Sales Adjustment amount shall be the product of the total kilowatt-hours for which the bill is rendered multiplied by ________ per kilowatt-hour. (The Residual Oil Sales Adjustment amount is not subject to any adjustment for serving voltage.)

Franchise Fee Differential:

The franchise fee differential as indicated below will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits as follows:

City of San Diego 1.9%

Such franchise fee differential shall be so indicated and added as a separate item to bills rendered to such customers.

SPECIAL CONDITIONS

1. Voltage. This schedule is applicable where the customer receives service at a standard voltage of the utility above 2 kv.

2. Primary Voltage Discount. When delivery hereunder is made and energy is received at an available standard voltage above 2 kv, the charges before power factor adjustment will be reduced as follows:

1 per cent in the range of 10.1 kv to 25 kv
4 per cent above 25 kv

The utility retains the right to change its delivery voltage after reasonable advance notice in writing to any customer receiving a discount hereunder and affected by such change, and such customer then has the option to change his system so as to receive service at the new delivery voltage or to accept service without voltage discount after the change in delivery voltage, through transformers owned by the utility.

3. Voltage Regulators. Voltage regulators, if required by the customer, shall be furnished, installed and maintained by the customer.

4. Billing Demand. The billing demand will be based on kilowatts of maximum demand as measured each month, provided that the billing demand shall in no case be less than the highest of (a) 5,000 kw, (b) 80 per cent of the highest billing demand registered during the preceding eleven months, or (c) the diversified resistance welder load computed in accordance with the utility's Rule 2F-2b.

(Continued)

Figure 4.3.2-1 - Continued (Sheet 2)

SAN DIEGO GAS & ELECTRIC COMPANY
SAN DIEGO, CALIFORNIA

Revised Cal. P.U.C. Sheet No. 2651-E
Revised
Cancelling Revised Cal. P.U.C. Sheet No. 2329-E 2330-E

SCHEDULE A-6 (Continued) (Sheet 3 of 3)

SPECIAL CONDITIONS (Continued)

4. Billing Demand. (Continued)

For maximum demands occurring between the hours of 10 p.m. to 7 a.m. of the following day, only 60 per cent of such maximum demand shall be considered.

5. Maximum Demand. The maximum demand in any month shall be the average kilowatt input during that 15 minute interval in which the consumption of electric energy is greater than in any other 15-minute interval in the month as indicated or recorded by instruments installed, owned and maintained by the utility.

In the case of hoists, elevators, furnaces and other loads where the energy demand is intermittent or subject to violent fluctuations, the utility may base the maximum demand upon a five-minute interval instead of a 15 minute interval.

6. Power Factor Adjustment. This schedule is based on service to loads having a maximum reactive kilovolt ampere demand not greater than 75 per cent of the maximum kilowatt demand. In the event that the reactive demand exceeds 75 per cent of the kilowatt demand, the customer shall, upon receiving written notice from the utility, install and operate such compensating equipment as may be necessary to reduce the reactive demand to 75 per cent or less of the kilowatt demand. Unless such correction of reactive demand is made within ninety days, there will be added to each monthly bill following the ninety day period a charge of 15 cents per kilovar of maximum reactive demand in excess of 75 per cent of the maximum kilowatt demand (whether on peak or off peak) for the month.

7. Limitation on Multi-family Service. This schedule is not applicable to service to multi-family housing projects or other services associated therewith, except housing on the premises of educational institutions, industrial plants and military establishments when such housing is associated with the operation of the establishment.

8. Contract. A contract for an initial period of ten years, and for subsequent periods of five years each thereafter, will be required for each customer served under this schedule. This contract may be cancelled at the end of the initial period or at the end of any subsequent period, provided written notice is given two years in advance of the end of any such period.

9. Customer's Right to Terminate. In the event the net bill for electric service to the customer is increased as a result of changes in this schedule, the customer shall have the right to terminate the contract upon written notice given one year in advance of the date such service is to terminate, and given within 90 days after the effective date of such change.

10. Miscellaneous. This schedule is not applicable to standby, auxiliary service or service operated in parallel with a customer's generating plant. Submetering or resale of energy will not be permitted.

(To be inserted by utility) (To be inserted by Cal. P.U.C.)

Advice Letter No. 413-E
Decision No.

ISSUED BY
JOHN H. WOY
VICE PRESIDENT-RATES & VALUATION

Date Filed September 7, 1976
Effective September 1, 1976
Resolution No. E-1599

Figure 4.3.2-1 - Continued (Sheet 3)

4.4 Energy Estimates for Crude Oil Pipelines

The sample of 21 crude oil pipeline companies that were selected in Section 4.3.1 above are listed in Table 4.4-1, along with some of their statistics of interest. In 1976, they transported approximately 95% of all crude oil trunkline traffic by primes and 90% of that by the entire population. They were responsible for a combined shipment in 1976 of 4,054,845 thousand barrels in an average haul of 357 miles, for a total of 1,447,949 million barrel-miles shipped (columns 1, 2, and 8).

Before proceeding with the energy calculations, it is well to take note of column 4, shortages and losses. The reasons for the negative losses, which if real would represent gains, or inflows of oil into the system, are not known. It is presumed that this is an over-and-under account which is used to balance inventories. In that case, these figures have no direct significance in the present calculation, except as they may perhaps indicate something about the accuracy of the other figures in the report. The significance of these loss figures as indicators of physical leakage is further discussed in Section 9.0 of Report HCP/M-1171-4 of this series (See Table 1.1-1 above).

Column 5 is also interesting. It shows the total operations expense for each company. This total combines salaries and wages, supplies and expenses, outside services, operating fuel and power, and oil losses and shortages. By comparison with column 3, it is seen that energy is by far the largest component of operating expense, using 75% of the total. Column 9 shows the percentages of total operations expense for fuel and power costs for each company and; as in the other cases, provides the weighted average for all the companies listed.

Table 4.4-1 - Selected Crude Oil Companies

COST INTENSITY ANALYSIS

Company	Trunkline Shipments 1 MM B-Mi	2 M B	3 Fuel & Power $	4 Oil Losses &Shortages $	5 Total Operating Expense $	6 Fuel & Power $/MM, B-Mi	7 Fuel & Power $/M, B	8 Avg. Shipment Mi	9 % of Tot. Operating Expense Col.3	10 % of Tot. Operating Expense Col.4	11 Total Operating Expense $/MM, B-Mi	12 Total Operating Expense $/M B
Lakehead	293,629	391,540	18,507,533	832,231	23,206,770	63.03	47.27	750	79.8	3.6	79.03	59.27
Amoco	190,548	410,263	16,878,116	-	22,188,619	88.58	41.14	464	76.1	-	116.45	54.08
Shell	128,236	368,823	9,987,771	4,623,156	17,888,104	77.89	27.08	348	55.8	25.9	139.49	48.50
Mid-Valley	107,986	142,803	9,977,052	104,559	11,261,282	92.39	69.87	766	88.6	9.3	104.28	78.86
Texas Pipe Line Co.	94,083	335,957	5,668,842	397,358	9,143,089	70.88	19.85	280	72.9	4.3	97.18	27.22
Mobil	93,114	308,884	8,401,843	415,253	10,589,953	90.23	27.20	301	79.3	3.9	113.73	34.28
Arco	81,258	239,406	7,159,934	515,104	10,724,514	88.11	29.91	339	66.8	4.8	131.98	44.80
Marathon	63,480	256,586	5,646,913	(1,950,054)	4,974,345	88.96	22.01	247	113.5	(39.2)	78.36	19.39
Exxon	62,111	445,637	6,178,988	1,417,716	10,988,270	99.48	13.87	139	56.2	12.9	176.91	24.68
Ashland	52,542	76,148	3,594,068	665,964	5,007,641	68.40	47.20	690	71.8	13.3	95.31	65.76
West Texas Pipe Line	52,392	131,873	2,255,450	(90,901)	2,823,009	43.05	17.10	397	79.9	(3.2)	49.19	21.41
Southcap	44,234	69,378	2,393,579	-	2,649,767	54.11	34.50	638	90.3	-	59.90	38.19
Platte	35,357	51,307	1 821,852	-	2,165,823	51.53	35.51	689	84.1		61.26	42.21
Portland	23,322	140,242	3.082,864	872,086	4,173,679	132.19	21.98	166	73.9	20.9	178.96	29.76
Chicap	23,285	118,014	1.914,162	-	2,114,390	82.21	16.22	197	90.5	-	90.80	17.92
Texaco-Cities Service	22,715	109,398	1.915,815	(51,751)	2,787,382	84.34	17.51	208	68.7	(1.9)	122.71	25.48
Pure	20,939	93,228	1,825,319	12,325	2,861,435	87.17	19.58	225	63.8	4.3	136.66	30.69
Texas-NMex.	16,567	155,154	1,183,487	(30,687)	1,601,305	71.44	7.63	107	73.9	(1.9)	96.66	10.32
Owensboro-Ashland	16,033	54,348	538,092	(365.191)	373,886	33.56	9.90	295	143.9	(97.6)	23.32	6.88
Minnesota	13,330	51,304	2,553,828	(126.291)	2,706,174	191.58	49.78	260	94.4	(4.7)	203.01	52.75
Cities Service	12,788	104,546	1,115,491	(38.946)	1,629,096	87.23	10.67	122	68.5	(2.4)	127.39	15.58
Total/Avg.	1,447,949	4,054,845	113,600,990	7,206,931	151,858,533	78.46	28.01	357	74.8	4.7	104.87	37.45

Source: Reference 22

Finally, columns 11 and 12 show individual company total operations expenses per million barrel-miles and per thousand barrels shipped, respectively. Weighted averages are again provided.

4.4.1 Energy Consumption in Crude Oil Pipelines

The energy consumption of the sample may now be estimated. The point of departure is the total trunkline power and fuel cost, column 3, of \$113,600,990. Dividing this cost by the value derived in the preceding section for unit power cost, 0.0280 \$/kw-hr, yields 4.057×10^9 kw-hr. This is the indicated consumption of energy at the pumping station meter.

To obtain the energy consumption at the electric generating station, it is necessary to divide this result by the appropriately - averaged efficiency of the generation and distribution network. This efficiency has been variously estimated between 20 and 25%, and for present purposes a value of 22% will be used. The result is 1.8442×10^{10} kw-hr, equal to 6.293×10^{13} Btu (0.063 Quad). This is the estimate for the energy consumption of the sample.

Similarly, an estimate for the energy consumption by the total national crude pipeline population may be derived, beginning with the 1976 fuel and power cost for all the companies of \$126,645,547.

$$\frac{126,645,547}{0.28 \times 0.22} = 2.056 \times 10^{10} \text{ kw-hr}$$

$$= 0.070 \text{ Quad}$$

The foregoing calculation disregards the fact that some of the power is not purchased electricity. In Figure 4.1.3-1 above, it was seen that in five particular cases the average amount of non-electric power was 12%. Now, if the reason that most of the power is electric is that electricity is generally cheaper, then a somewhat higher unit power cost estimate than 0.0280 should be used for the non-electric fraction. However, there is an offsetting influence in that other prime movers tend to be more efficient energy converters than the electric generation and distribution systems. Since these two factors are both unknown and offsetting, there is no readily evident basis to modify the result to account for the non-electric prime movers.

4.4.2 Energy Intensity of Crude Oil Pipelines

Referring again to Table 4.4-1, the trunkline energy cost intensity for the sample is seen at the bottom of column 6 to be $78.46 per million Barrel-Miles. Taking a reasonable average specific gravity of 0.87 (6.58 barrels per ton) converts this cost intensity to $516.27 per million Ton-Miles. So in the total energy calculation above, dividing by 0.028 $/kw-hr yields 0.018438 kw-hr/Ton-Mile at the station meter. Dividing again by 0.22 yields 0.0838 kw-hr/Ton-Mile or 286 Btu/Ton-Mile at the generating station.

It is of further value to specialize to a specific pipeline system. It was explained in Section 4.2.2 above that some actual power cost experience information was obtained through interviews with individual companies. Taking this information and repeating the process yielded a value of 490 Btu/Ton-Mile, much more than obtained above for the national average. The calculation is not presented here to preserve the anonymity of the source.

The reasons for this large difference were not explored in depth, but the parameters of density, viscosity, speed, lengths and diameters for the system were reviewed and compared with those of other lines, and the difference was found to be not unreasonable. The sensitivity of the result to some of these parameters can be appreciated from Table 4.4.2-1.

This higher value for the specific case does of course lead to the suspicion that the estimate derived above may be low, but without further data and analysis there appears to be no basis to raise the estimate except by rounding. It is, therefore, concluded that the best single-figure estimate is 300, and the best two-figure estimate is 290. In view of the imprecision of the method, it is suggested that 300 Btu/Ton-Mile be used for both.

4.5 Energy Estimates for Products Pipelines

The sample of 14 products pipeline companies that were selected in Section 4.3.1 above are listed in Table 4.5-1, along with some of their statistics of interest. In 1976, they transported approximately 94% of trunkline products traffic by the primes and 78% of that by the entire population. This table is the analog of Table 4.4-1, and the earlier general comments again apply.

4.5.1 Energy Consumption in Products Pipelines

The estimation of energy consumption for the product lines is the parallel of that given earlier for the crude lines. The results are 1.5508×10^{10} kw-hr (0.053 Quad) and 1.9780×10^{10} kw-hr (0.068 Quad) respectively, for the sample and the national total. The 1976 total power and fuel cost as reported by the ICC, of $127,284,960, and the average power cost from Section 4.2.3 were used in these calculations.

Table 4.4.2-1

Pipeline Energy Intensiveness

(Btu/ton-mile)

Pipeline diameter (in)	Kinematic Viscosity 0.000010 ft²/sec[a] Velocity (ft/sec)			Kinematic Viscosity 0.000075 ft²/sec[b] Velocity (ft/sec)			Kinematic Viscosity 0.00050 ft²/sec[c] Velocity (ft/sec)		
	3	5	9	3	6	9	3	6	9
8	180	590	1330	290	960	1850	460	1500	2870
20	60	220	450	90	310	660	140	490	980
32	30	130	260	50	170	360	80	270	540

[a]Kerosene at 80°F

[b]California crude oil at 80°F

[c]Light engine oil at 80°F

Source: Reference 1

COST INTENSITY ANALYSIS

Company	Trunkline Shipments: 1 MM B-Mi	2 M B	3 Fuel & Power $	4 Oil Losses &Shortages $	5 Total Operating Expense $	6 Fuel & Power $/MM, B-Mi	7 Fuel & Power $/M, B	8 Avg. Shipment Mi	9 % of Tot. Operating Expense Col.3	10 % of Tot. Operating Expense Col.4	11 Total Operating Expense $/MM, B-Mi	12 Total Operating Expense $/M B
Colonial	591,688	569,396	56,503,564	127,388	64,383,213	95.50	99.23	1039	87.8	0.2	108.81	113.07
Plantation	105,640	186,089	9,059,872	372,462	13,682,728	85.76	48.69	568	66.2	2.7	129.52	73.52
Texas Eastern	65,570	115,518	5,090,446	657,295	9,182,267	77.63	44.07	568	55.4	7.2	140.03	79.49
Williams	62,463	177,781	7,756,856	-	14,029,105	124.18	43.63	351	55.3	0	224.60	78.91
Mid-America	42,577	103,648	3,971,866	(478,014)	6,249,930	93.29	38.32	411	63.6	(7.6)	146.79	60.30
Explorer	33,805	59,029	1,730,074	623,459	3,312,077	51.18	29.31	573	52.2	18.8	97.98	56.11
Southern Pacific	26,080	206,846	4,648,535	67,154	8,566,931	178.24	22.47	126	54.3	0.8	328.49	41.02
Dixie	18,797	29,078	2,155,141	445,103	3,453,575	114.65	74.12	646	62.4	12.9	183.73	118.77
Hydrocarbon	18,474	27,364	3,670,318	-	5,262,716	198.67	134.13	675	69.7	0	284.87	192.32
Wolverine	13,009	83,276	2,615,420	193,035	3,855,490	201.05	31.41	156	67.8	5.0	296.37	46.30
Olympic	12,838	68.424	985,814	-	1,724,286	76.79	14.41	188	57.2	0	134.31	25.20
Santa Fe	9,683	20,044	265,876	-	7,954,109	27.46	13.26	483	3.34	0	821.45	396.83
Yellowstone	8,918	20,784	754,969	(26,027)	1,219,048	84.66	36.32	429	61.9	(2.1)	136.70	58.65
Laurel	8,457	42,706	582,661	699,672	2,146,303	68.90	13.64	198	27.1	32.6	253.79	50.26
Total/Avg.	1,017,999	1,705,983	99,791,412	2,681,527	145,021,778	98.03	58.49	597	68.8	1.8	142.46	84.81

Source: Reference 22

Table 4.5.1 - Major Petroleum Pipeline Companies
U. S. Trunklines, 1976

4.5.2 Energy Intensity of Products Pipelines

Continuing as before, and taking 0.80 (7.15 barrels per ton) as a reasonable average specific gravity, the average cost intensity of 98.03 $\$/10^6$ B-Mi from Table 4.5-1, column 6 becomes 700.62 $\$/10^6$ T-Mile, and the estimate for average energy intensity of the sample is 388 Btu/Ton-Mile at the generating station. This is also the best estimate for the population.

Again specializing to companies which were interviewed, energy intensities of 323, and 405 and 887 Btu/T-Mi were calculated. As before, the reasons for the variability were not researched in depth, but the parameters were reviewed and found to be reasonable. The very high number is not typical, but is due to particular operating circumstances, one of which is the kind of extreme duty cycle variation that is discussed in depth in Report HCP/M-1171-4 of this series. In fact, the only reason that the data were collected was that the power costs had risen so high that management had ordered a special engineering study of the situation. The results were used in an intensive internal education program for operating personnel and firstline supervision.

As before, rounding the value derived above leads to 390 and 400 as the best two-figure and single-figure estimates. In view of the imprecision of the method, the difference is not significant, and it is suggested that 400 Btu/T-Mi be used.

5.0 ENERGY CONSUMPTION IN WATER PIPELINES

Water systems may be placed into two classes - supply and waste. Generally, the supply system provides potable fresh water and the waste system is a sewage system. Their character is very different from that of other pipelines. Notably, a characteristic of large water systems is the fact that they are not pipelines at all over much of their span. For example, the largest such system, the California (Feather River) project, contains more canals than pipelines. Waste systems are likewise characterized by the fact that most of the flow is by gravity in hydraulically open channels under gravity, as opposed to full-pipe flow under imposed head. The energy input in both types of systems is almost exclusively by electrically-driven pumps at intermittent lift stations.

It was explained in the opening section of this report that the primary objective of this program is to assess the susceptibility of the pipeline industry to energy-conservative innovations, and to identify the opportunities for energy conservation. Report HCP/M-1171-4 of this series identifies those opportunities and recommends the R, D, and D programs to exploit them. That report identified few such opportunities for improvements in pipelines whose prime movers are electric motors. Moreover, the notable exception, i.e., use of fuel cells with DC motors, derives part of its attraction from two factors which are absent in water systems. These are extreme duty cycles and the possibility of transporting the fuel through the pipeline itself. Thus, no attractive energy-conservative opportunities have been identified for water pipelines.

5.1 Water Pipeline Industry Profile

Table 5.1-1 presents some interesting water industry statistics, to which reference will again be made later, in developing an estimate of industry energy consumption.

The best sourcebook for general information about the water industry is the Water Encyclopedia (Ref. 23) (Todd 70). Unfortunately, it is becoming somewhat out-of-date, and there are apparently no plans to republish. Most of the tables to follow are found there.

Table 5.1-2 presents the total water in use in the U. S. in 1965. It is noted that about 81% of withdrawal (254,000 mgd of 314,470) is surface water and 19% is ground water. The nationwide per capita use, bottom of second column, was 1600 gpd, a very high figure because it includes all agriculture and industrial use. A better correlation is perhaps seen in the per capita withdrawals through supply systems, shown in Table 5.1-3. Table 5.1-4 presents the withdrawals and use for 1965, and Table 5.1-5 presents projections of those statistics to 1980. These projections were made in 1968. Table 5.1-6, which presents costs of municipally supplied water in the 1950's is interesting in that cost does not appear too particularly well correlated with abundance.

Table 5.1-7 shows the drilling activity in 1964, and Table 5.1-8 shows depths of the 1966 wells. The average depth may be calculated from these figures as approximately 153 feet, a figure that will be useful later in estimating energy consumption. Also useful will be the information in Tables 5.1-9 and 5.1-10.

Table 5.1-1

Water Industry Statistics

August, 1974

Public Water Supply Systems	Total United States
Number of Public Water Supply Systems	40,000
Municipal Systems, % of Total	70%
Private Systems, % of Total	30%
Miles of Pipe for Water Distribution	12 million
Population Served	180 million
Replacement Value	$125 billion
Capital Expenditures	$1.4 billion
Metered Usage as Per Cent of Total Delivery Water Delivered	
Municipal Systems	83%
Private Systems	73%
Number of Employees	180,000
Average Per Capita Usage	150 gpd - 0.10417 gpm
Average Per Capita Residential Usage	60 gpd
Total Water Supplies	
Daily Withdrawal of Water From All Sources	370 bgd
Fresh Surface	67%
Fresh Ground	18%
Saline Surface	14%
Saline Ground	1%

Source: Reference 24

Table 5.1-2 - Water Used for Public Supplies in the United States, 1965

State	Population 1,000's	Per capita use (gpd)	Water withdrawn — Including irrigation conveyance losses — Ground water — Fresh	Saline	Fresh and saline	Surface water — Fresh	Saline	Fresh and saline	Sewage	All sources — Fresh	Saline	Fresh and saline	Excluding conveyance losses	Water consumed
Alabama	3,486	1,900	200	0	200	6,300	0	6,300	0	6,500	0	6,500	6,500	250
Alaska	267	640	26	0	26	120	1.0	120	0	140	1.0	140	140	11
Arizona	1,575	4,000	4,200	0	4,200	2,100	0	2,100	56	6,300	0	6,300	5,100	3,100
Arkansas	1,941	1,100	1,200	0	1,200	850	0	850	0	2,100	0	2,100	2,000	1,100
California	18,403	2,300	14,000	140	14,000	17,000	11,000	28,000	400	31,000	11,000	42,000	37,000	17,000
Colorado	1,986	6,000	1,600	6.3	1,600	10,000	8.0	10,000	0	12,000	14	12,000	11,000	5,800
Connecticut	2,832	790	110	0	110	700	1,400	2,100	0	810	1,400	2,200	2,200	160
Delaware	503	2,300	59	0	59	55	1,100	1,100	0	110	1,100	1,200	1,200	17
Florida	5,796	2,300	2,700	80	2,800	4,100	6,100	10,000	0	6,800	6,200	13,000	13,000	1,600
Georgia	4,391	730	560	0	560	2,000	620	2,700	0	2,600	620	3,200	3,200	220
Hawaii	710	2,800	780	37	820	670	500	1,200	0	1,500	540	2,000	1,800	570
Idaho	693	23,000	3,000	0	3,000	13,000	0	13,000	0	16,000	0	16,000	12,000	5,500
Illinois	10,641	1,600	670	34	700	16,000	0	16,000	0	16,000	34	17,000	17,000	370
Indiana	4,893	2,000	600	5.9	610	9,000	0	9,000	0	9,600	5.9	9,600	9,600	330
Iowa	2,758	770	500	0	500	1,600	0	1,600	0	2,100	0	2,100	2,100	290
Kansas	2,248	1,600	2,300	.4	2,300	550	0	550	0	2,800	0	2,800	2,500	2,200
Kentucky	3,173	1,000	150	.6	150	3,200	.3	3,200	.2	3,300	.9	3,300	3,300	160
Louisiana	3,560	1,900	1,200	51	1,300	5,100	340	5,400	0	6,300	400	6,700	6,400	1,600
Maine	986	800	44	0	44	520	220	740	0	570	220	780	780	57
Maryland	3,534	1,200	120	0	120	1,300	2,500	3,800	130	1,500	2,500	4,100	4,100	200
Massachusetts	5,365	620	280	0	280	1,300	1,700	3,100	1.1	1,600	1,700	3,300	3,300	110
Michigan	8,317	1,100	430	14	460	8,400	0	8,400	0	8,800	14	8,800	8,800	310
Minnesota	3,562	860	510	0	510	2,500	0	2,500	0	3,100	0	3,100	3,100	280
Mississippi	2,309	550	600	0	600	370	300	670	0	970	300	1,300	1,200	330
Missouri	4,492	590	370	5.8	380	2,300	0	2,300	0	2,700	5.8	2,700	2,700	320
Montana	703	9,500	81	0	81	6,600	0	6,600	0	6,700	0	6,700	5,400	4,500
Nebraska	1,459	3,100	1,900	0	1,900	2,700	0	2,700	0	4,600	0	4,600	3,900	2,700
Nevada	470	4,800	560	2.7	560	1,600	0	1,600	1.2	2,200	2.7	2,200	1,700	1,300
New Hampshire	673	720	42	0	42	300	140	440	0	340	140	490	490	20
New Jersey	6,781	950	590	9.0	600	2,000	3,700	5,700	0	2,600	3,700	6,300	6,300	470
New Mexico	1,014	3,000	1,400	0	1,400	1,600	0	1,600	22	3,000	0	3,000	2,600	1,700
New York	18,106	890	830	15	840	8,200	7,100	15,000	0	9,000	7,100	16,000	16,000	620
North Carolina	4,935	800	420	0	420	3,500	32	3,500	0	3,900	32	4,000	3,900	360
North Dakota	652	500	48	6.7	54	270	0	270	0	320	6.7	330	280	170
Ohio	10,203	1,500	800	0	800	14,000	0	14,000	0	15,000	0	15,000	15,000	400
Oklahoma	2,448	480	380	46	430	850	17	870	0	1,200	63	1,300	1,300	460
Oregon	1,938	3,400	710	0	710	5,900	0	5,900	2.9	6,600	0	6,600	5,100	2,400
Pennsylvania	11,583	1,300	590	0	590	15,000	50	15,000	0	15,000	50	15,000	15,000	390
Puerto Rico	2,633	630	150	1.7	150	430	1,100	1,500	0	580	1,100	1,700	1,600	270
Rhode Island	891	500	45	0	45	110	300	400	0	150	300	450	450	27
South Carolina	2,550	690	130	0	130	1,500	150	1,600	0	1,600	150	1,800	1,800	150
South Dakota	686	630	160	1.9	160	270	1.0	270	0	430	2.9	430	340	250
Tennessee	3,850	1,200	350	0	350	4,300	0	4,300	0	4,600	0	4,600	4,600	350
Texas	10,591	2,300	13,000	2.2	13,000	6,600	4,600	11,000	7.4	20,000	4,600	25,000	22,000	12,000
Utah	994	4,100	620	3.5	620	3,400	5.1	3,400	62	4,100	8.6	4,100	3,400	2,400
Vermont	404	320	24	0	24	110	0	110	0	130	0	130	130	15
Virginia	4,420	1,200	200	0	200	3,900	1,300	5,200	0	4,100	1,300	5,400	5,400	130
Washington	2,973	2,100	720	0	720	5,500	30	5,600	0	6,200	31	6,300	5,100	2,400
West Virginia	1,815	2,700	160	.4	160	4,800	.0	4,800	.1	4,900	.4	4,900	4,900	190
Wisconsin	4,086	1,200	460	0	460	4,300	0	4,300	0	4,800	0	4,800	4,800	160
Wyoming	330	15,000	100	.9	100	4,800	.1	4,800	0	4,900	1.0	4,900	3,600	2,100
District of Columbia	802	440	1	0	1	350	0	350	0	350	0	350	350	15
United States[1]	196,411	1,600	61,000	470	61,000	210,000	44,000	250,000	670	270,000	45,000	310,000	290,000	78,000

[1] Including Puerto Rico.

Source: Reference 23

Table 5.1-3 - Water Withdrawals Per Capita for Public and Individual Water Supply Systems in the United States

(Gallons per capita per day)

Year	Public Systems					Individual
	Domestic	Public	Commercial	Industrial	Total	Systems
1965	73	20	28	36	157	51
1980	77	18	28	40	163	58
2000	81	16	28	43	168	71
2020	83	14	28	45	170	83

Source: Reference 23

Table 5.1-4 - Withdrawals and Consumptive Use of Water in the United States, 1965

A. Withdrawals

Region	Rural domestic	Municipal	Self-supplied industrial	Steam-electric power		Agriculture		Total	From ground-water sources	From saline sources
				Fresh	Saline	Irrigation	Livestock			
North Atlantic	390	5,446	9,499	10,500	11,400	151	81	37,476	2,562	15,380
South Atlantic-Gulf	504	1.980	3,360	7,600	3,700	3,270	146	20,560	4,221	4,132
Great Lakes	274	3,622	9,069	12,000	--	75	79	25,119	963	25
Ohio	300	1,791	8,606	17,400	--	24	134	28,255	1,760	27
Tennessee	64	253	1,076	4,329	--	3	37	5,767	202	--
Upper Mississippi	203	1,103	1,664	4,800	--	95	314	8,179	1,707	18
Lower Mississippi	58	470	1,884	1,600	200	1,320	39	5,571	1,671	240
Souris-Red-Rainy	14	36	98	200	--	24	19	391	55	--
Missouri	106	969	462	1,400	--	16,039	368	19,344	4,005	--
Arkansas-White-Red	103	687	910	600	--	6,960	150	9,410	5,598	75
Texas-Gulf	40	1,055	5,465	2,100	200	7,450	100	16,410	8,390	3,300
Rio Grande	10	254	215	70	--	6,571	69	7,289	3,130	133
Upper Colorado	6	60	40	20	--	3,880	11	4,017	36	--
Lower Colorado	6	342	140	10	--	6,400	15	6,913	4,147	--
Great Basin	15	274	225	10	--	4,575	16	5,115	935	--
Columbia-North Pacific	148	1,105	1,911	8	--	26,400	59	29,631	4,289	31
California	90	4,010	1,250	70	5,600	26,200	80	37,300	13,610	6,140
Alaska	8	32	102	20	--	—	--	162	25	--
Hawaii	7	115	112	--	300	1,060	3	1,597	706	316
Puerto Rico	5	141	317	1	400	250	6	1,120	157	535
Total......................	2,351	23,745	46,405	62,738	21,800	110,852	1,726	269,617	58,169	30,352

Source: Reference 23

Table 5.1-4 (cont.)

B. Consumptive Use

Region	Rural domestic	Municipal	Self-supplied industrial	Steam-electric power		Agriculture		Total
				Fresh	Saline	Irrigation	Livestock	
North Atlantic	186	905	555	75	83	150	69	2,023
South Atlantic-Gulf	472	363	260	42	19	1,400	139	2,695
Great Lakes	100	502	362	95	--	68	72	1,199
Ohio	200	230	410	138	--	24	132	1,134
Tennessee	61	46	174	6	--	8	36	331
Upper Mississippi	101	162	58	61	--	83	305	770
Lower Mississippi	52	175	296	16	3	890	38	1,470
Souris-Red-Rainy	14	11	7	2	--	24	19	77
Missouri	85	221	71	24	--	9,798	355	10,554
Arkansas-White-Red	94	241	322	41	--	5,030	146	5,874
Texas-Gulf	40	400	880	57	2	5,810	100	7,289
Rio Grande	7	108	46	9	--	4,165	68	4,403
Upper Colorado	3	14	8	13	--	1,934	10	1,982
Lower Colorado	5	203	50	8	--	3,170	12	3,448
Great Basin	9	94	37	2	--	2,100	11	2,253
Columbia-North Pacific	134	182	100	--	--	10,050	55	10,521
California	60	1,320	110	70	44	19,290	50	20,944
Alaska	1	7	4	--	--	--	--	12
Hawaii	7	39	4	--	3	477	3	533
Puerto Rico	5	21	10	--	3	225	6	270
Total	1,636	5,244	3,764	659	157	64,696	1,626	77,782

Source: Reference 23

Table 5.1-5 - Projections of Withdrawals and Consumptive Use of Water in the United States, 1980

A. Withdrawals

Region	Rural domestic	Municipal	Self-supplied industrial	Steam-electric power		Agriculture		Total
				Fresh	Saline	Irrigation	Livestock	
North Atlantic	400	7,100	14,100	10,900	22,100	230	90	54,920
South Atlantic-Gulf	380	3,300	4,900	28,500	12,000	3,900	200	53,180
Great Lakes	257	5,030	16,700	25,700	--	110	96	47,893
Ohio	350	2,330	11,600	27,300	--	40	129	41,749
Tennessee	128	358	1,600	10,100	--	18	48	12,252
Upper Mississippi	143	1,770	2,800	9,500	--	110	477	14,800
Lower Mississippi	80	647	2,500	5,900	600	3,030	59	12,816
Souris-Red-Rainy	16	49	150	500	--	200	21	936
Missouri	134	1,225	584	1,500	--	19,300	521	23,264
Arkansas-White-Red.............	213	1,418	1,880	4,100	40	9,400	228	17,279
Texas-Gulf	70	1,890	9,340	5,500	2,700	9,400	180	29,080
Rio Grande	10	430	910	70	--	6,840	70	8,330
Upper Colorado	10	120	200	30	--	5,300	15	5,675
Lower Colorado	7	520	210	40	--	7,700	20	8,497
Great Basin	15	450	340	30	--	6,200	20	7,055
Columbia-North Pacific.........	148	1,304	4,478	4,000	--	31,400	77	41,407
California	90	5,090	1,660	90	18,300	30,950	110	56,290
Alaska	11	120	200	200	--	4	--	535
Hawaii	5	195	134	--	900	1,420	4	2,658
Puerto Rico	7	250	740	3	2,700	300	10	4,010
Total	2,474	33,596	75,026	133,963	59,340	135,852	2,375	442,626

Source: Reference 23

Table 5.1-5 (cont.)

B. Consumptive Use

Region	Rural domestic	Municipal	Self-supplied industrial	Steam-electric power		Agriculture		Total
				Fresh	Saline	Irrigation	Livestock	
North Atlantic	200	1,210	850	120	180	230	80	2,870
South Atlantic-Gulf	355	600	380	190	80	1,600	190	3,395
Great Lakes......................	85	702	728	184	--	95	87	1,881
Ohio	250	300	550	350	--	40	129	1,619
Tennessee	122	64	258	65	--	16	47	572
Upper Mississippi	94	258	98	166	--	95	392	1,103
Lower Mississippi	72	238	400	60	4	2,180	58	3,012
Souris-Red-Rainy	16	16	8	4	--	150	21	215
Missouri	108	280	90	80	--	12,100	502	13,160
Arkansas-White-Red	194	496	674	95	--	6,800	223	8,482
Texas-Gulf	65	740	1,160	180	20	7,100	170	9,435
Rio Grande	7	220	90	20	--	4,270	69	4,676
Upper Colorado	4	30	35	17	--	2,600	14	2,700
Lower Colorado	5	310	80	35	--	3,630	15	4,075
Great Basin......................	9	154	56	25	--	3,040	15	3,299
Columbia-North Pacific	134	219	244	13	--	12,900	71	13,581
California	60	4,620	380	80	185	23,800	80	29,205
Alaska	2	24	20	1	--	3	--	50
Hawaii	5	65	5	--	9	640	4	728
Puerto Rico	5	35	20	--	20	270	10	360
Total	1,792	10,581	6,126	1,685	498	81,559	2,177	104,418

Source: Reference 23

Table 5.1-6 - Cost of Water from Municipal Systems in the United States

[Costs include operation, maintenance, and amortization]

	Dollars per million gallons		Dollars per million gallons
Alabama	$227	Nebraska	$145
Arizona	157	Nevada	137
Arkansas	302	New Hampshire	209
California	208	New Jersey	196
Colorado	229	New Mexico	245
Connecticut	214	New York	190
Delaware	128	North Carolina	229
District of Columbia	168	North Dakota	302
Florida	244	Ohio	181
Georgia	174	Oklahoma	247
Idaho	232	Oregon	207
Illinois	136	Pennsylvania	180
Indiana	184	Rhode Island	195
Iowa	236	South Carolina	169
Kansas	264	South Dakota	281
Kentucky	144	Tennessee	233
Louisiana	188	Texas	244
Maine	103	Utah	184
Maryland	136	Vermont	382
Massachusetts	193	Virginia	187
Michigan	151	Washington	173
Minnesota	175	West Virginia	212
Mississippi	219	Wisconsin	153
Missouri	180	Wyoming	224
Montana	185		

Source: Reference 23

Table 5.1-7 - Number of Water Wells Drilled in the United States in 1964

State	Estimated number of wells drilled 1964	State	Estimated number of wells drilled 1964
Alabama	4,500	Montana	2,000
Alaska	1,001	Nebraska	6,005
Arizona	1,520	Nevada	825
Arkansas	5,000	New Hampshire	4,400
California	10,000	New Jersey	3,440
Colorado	5,911	New Mexico	3,150
Connecticut	6,500	New York	25,000
Delaware	3,440	North Carolina	25,000
District of Columbia	12	North Dakota	3,760
Florida	55,000	Ohio	18,622
Georgia	10,000	Oklahoma	5,000
Hawaii	21	Oregon	4,500
Idaho	1,400	Pennsylvania	16,220
Illinois	19,500	Rhode Island	250
Indiana	15,000	South Carolina	5,400
Iowa	15,000	South Dakota	5,426
Kansas	5,500	Tennessee	8,000
Kentucky	9,620	Texas	25,000
Louisiana	2,620	Utah	650
Maine	1,700	Vermont	1,460
Maryland	6,902	Virginia	10,000
Massachusetts	9,000	Washington	1,700
Michigan	25,000	West Virginia	5,900
Minnesota	9,000	Wisconsin	12,000
Mississippi	5,900	Wyoming	1,000
Missouri	9,990	TOTAL	433,700

Source: Reference 23

Table 5.1-8 - Depths of Water Wells Drilled in the United States in 1966

Well Depth, feet	Percent of Drilled Wells
< 50	4.1
51-100	26.9
101-150	27.8
151-200	20.6
201-300	11.5
301-400	4.4
401-500	2.6
> 500	2.1
	100.0

Table 5.1-9 - Average Power to Pump Water

Wire-to-Water Efficiency, Percent	Power Required Kilowatt-Hours per 100 ft, per 100 gpm
78	40
63	50
52	60
45	70

Source: Reference 23

Table 5.1-10 - Useful Factors in Preliminary Planning of Small Pumping Plants

Pump or pipe size, in.	Gallons per minute	Acre-inches per 24 hours	Pipe velocity, feet per second	Velocity head, $\frac{V^2}{2g}$ feet	Friction in feet per 100 feet of pipe	Horsepower required for 10 feet total head. Pump and transmission efficiency = 70 percent
6	400	21.2	4.54	0.32	2.21	1.4
6	600	31.8	6.72	0.70	4.7	2.2
6	800	42.4	9.08	1.28	8.0	2.9
6	1,000	53.0	11.32	1.99	12.0	3.6
8	900	47.7	5.75	0.52	2.46	3.2
8	1,100	58.3	7.03	0.77	3.51	4.0
8	1,300	68.9	8.32	1.07	4.72	4.7
8	1,500	79.5	9.60	1.43	6.27	5.4
10	1,200	63.6	4.91	0.38	1.46	4.3
10	1,600	84.8	6.56	0.67	2.35	5.8
10	2,000	106.1	8.10	1.02	3.65	7.2
10	2,400	127.3	9.73	1.47	5.04	8.7
12	2,000	106.1	5.60	0.48	1.43	7.2
12	2,500	132.6	7.00	0.77	2.28	9.0
12	3,000	159.1	8.40	1.10	3.15	10.8
12	3,500	185.6	9.80	1.49	4.10	12.6
14	2,000	106.1	4.20	0.27	0.66	7.2
14	3,000	159.1	6.30	0.61	1.47	10.8
14	4,000	212.1	8.40	1.09	2.47	14.4
14	5,000	265.2	10.50	1.71	3.92	18.0
16	3,600	190.9	5.74	0.51	1.10	13.0
16	4,400	233.3	7.01	0.76	1.58	15.9
16	5,200	275.8	8.29	1.06	2.16	18.8
16	6,000	318.2	9.56	1.42	2.60	21.6
18	4,500	238.6	5.70	0.50	0.93	16.2
18	5,500	291.7	6.96	0.75	1.32	19.8
18	6,500	344.7	8.22	1.05	1.82	23.4
18	8,000	424.2	10.02	1.56	2.65	28.9
20	5,000	265.2	5.13	0.41	0.68	18.0
20	6,500	344.7	6.66	0.69	1.06	23.4
20	8,000	424.2	8.17	1.03	1.63	28.9
20	10,000	530.3	10.40	1.68	2.53	36.1
24	8,000	424.2	5.68	0.50	0.66	28.9
24	10,000	530.3	7.07	0.78	0.98	36.1
24	12,000	636.4	8.50	1.12	1.40	43.3
24	14,000	742.4	9.95	1.54	1.87	50.5
30	12,000	636.4	5.44	0.46	0.47	43.3
30	16,000	848.5	7.36	0.84	0.83	57.7
30	20,000	1061.0	9.09	1.29	1.22	72.2
30	24,000	1273.0	10.90	1.86	1.71	86.6

Source: Reference 23

5.2 An Example Water System

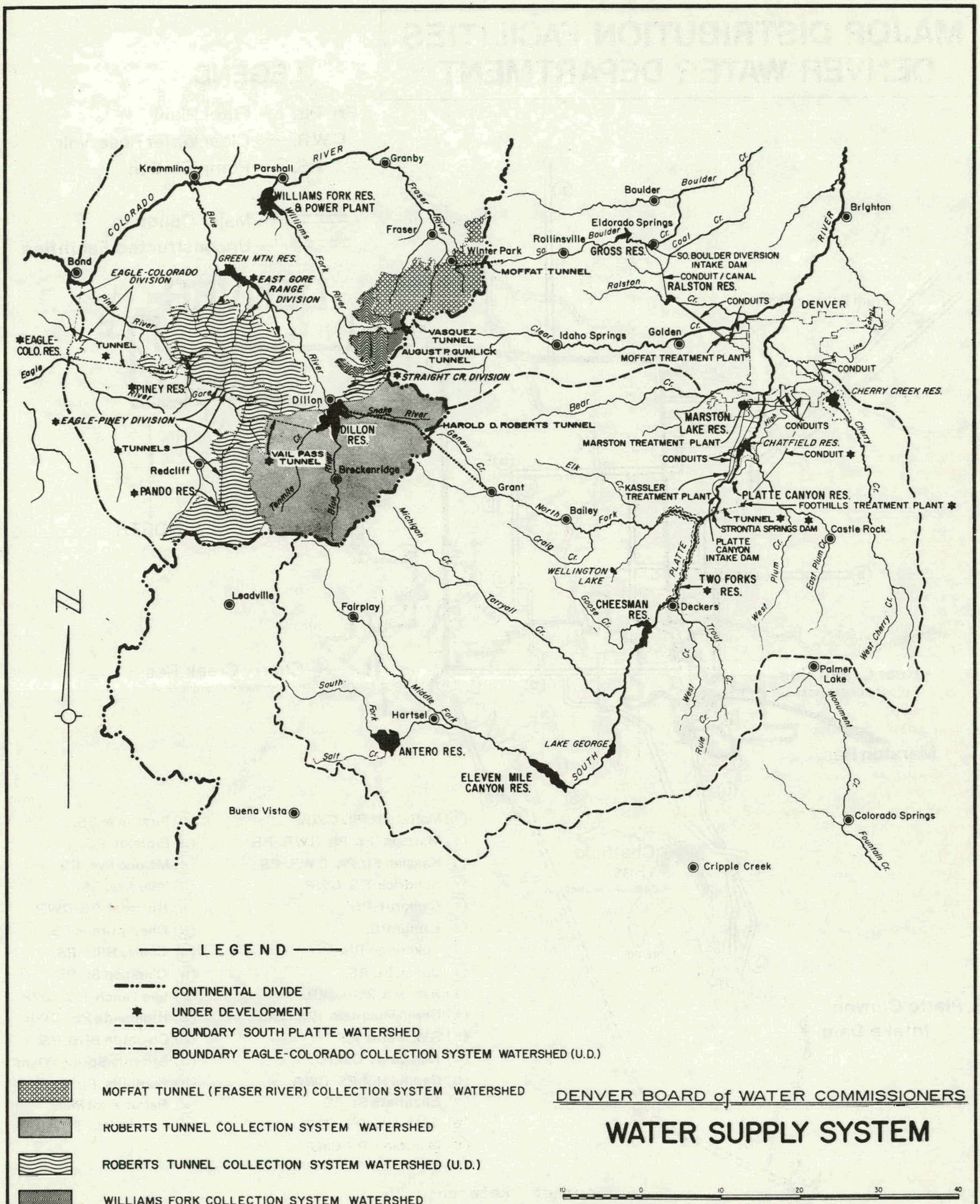
The 1976 Annual Report of the Denver Board of Water Commissioners for the city and county of Denver, Colorado, reflects a very well engineered and capably managed water system (Ref. 25). Figure 5.2-1 shows their supply system, and Figure 5.2-2 shows the major distribution facilities. Table 5.2-1 lists the pumping station capacities. Table 5.2-2 is their 1976 water report, Table 5.2-3 is the 1976 power report and Table 5.2-4 is the summary of water and power costs. Figure 5.2-3 shows the 1976 pump energy rate in kw-days through the year. Figure 5.2-4 shows power cost history for the two water systems under their jurisdiction.

Although operation of what is called their Master System (36,511 million gallons per year) and the Outside Contract System (13,770 million gallons per year) is under the same management group, fiscal jurisdiction is, in some aspects, separate.

The daily operating pumps for both systems are all electrical. There are some gas engine pumps for standby operation only. It is interesting that they have tunneled under the Continental Divide for some of their water lines, the total length of which is 1800 miles. They have a 4-stage lift with some purification done at each plateau. The highest lift for any given line is 400 feet, while the average lift for the total system is 160 feet.

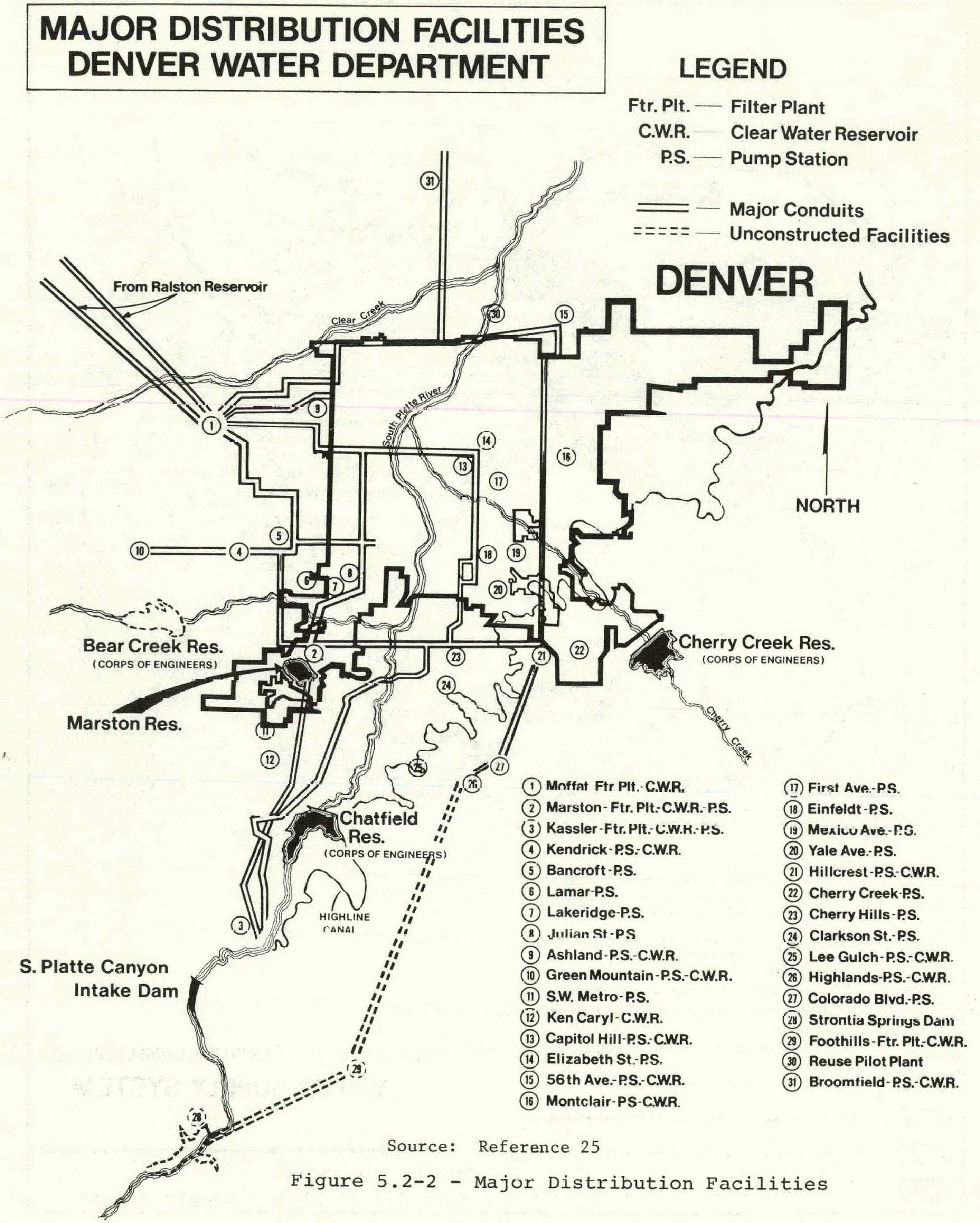
5.3 Water Pipeline Data Sources

The data sources used in the estimation of water system energy consumption were those presented in the preceding sections. The national total and unit energy consumption will be estimated from the data in Section 5.1 above.



Source: Reference 25

Figure 5.2.1 - Water Supply System



Source: Reference 25

Figure 5.2-2 - Major Distribution Facilities

Pump Station	Pump Number	Make of Pump	Make of Motor	Horse Power	Head In Feet	Capacity In M.G.D.			
ASHLAND (5406)	3	DeLaval	General Electric	250	140	8.0	M		
5260 W. 29th Ave.	5	Cameron	General Electric	550	175	15.0	M		
	6	Cameron	Westinghouse	150	175	3.5	M		
	7	Cameron	Westinghouse	200	175	5.0	M		
	8	Fairbanks Morse	Fairbanks Morse	300	265	5.0	M		
	9	Fairbanks Morse	Fairbanks Morse	300	265	5.0	M		
		Total		1,750		41.5			
BANCROFT (5495)	1	Fairbanks Morse	Fairbanks Morse	200	254	3.6	M		
1500 S. Pierce St.	2	Aurora	Lincoln	60	115	2.2	M		
		Total		260		5.8			
BROADWAY (5525)	1	Peerless	Elliot Electric	25	80	1.4	M	A	
6549 S. Broadway	2	Peerless	Newman	100	112	4.4	M	A	
		Total		125		5.8			
BROOMFIELD (5326)	1	Patterson	Ideal Electric	450	350	5.0	M		
9265 Washington St.	2	Patterson	Ideal Electric	450	350	5.0	M		
	3	Patterson	Ideal Electric	450	350	5.0	M		
		Total		1,350		15.0			
CAPITOL HILL (5401)	3	Wheeler Economy	General Electric	800	175	20.0	M		
1000 Elizabeth St.	4	Byron Jackson	General Electric	400	175	12.0	M		
	5	Cameron	General Electric	700	164	20.0	M		
	6	Byron Jackson	Westinghouse	600	175	17.0	M		
	7	Byron Jackson	Westinghouse	800	175	23.0	M		
		Total		3,300		92.0			
• CHERRY CREEK VILLAGE (5550)	1	Aurora	Marathon Electric	40	173	0.8	M	A	
4298 S. Tamarac Dr.	2	Aurora	Marathon Electric	20	173	0.3	M	A	
	3	Allis Chalmers	Allis Chalmers	50	160	1.3	M	A	
		Total		110		2.4			
CHERRY HILLS (5380)	1	Worthington	General Electric	1,000	220	20.0	M		R
1590 Radcliff Ave.	2	Worthington	General Electric	1,000	220	20.0	M		R
	3	Worthington	General Electric	1,000	220	20.0	M		R
	4	Worthington	General Electric	1,000	220	20.0	M		R
	5	Worthington	General Electric	1,000	220	20.0	M		R
	6	Worthington	General Electric	1,000	220	20.0	M		R
		Total		6,000		120.0			
• CLARKSON STREET (5482)	1	Fairbanks Morse	Fairbanks Morse	150	234	2.1	M	A	R
5300 S. Clarkson St.	2	Fairbanks Morse	Fairbanks Morse	150	234	2.1	M	A	R
	3	Fairbanks Morse	Fairbanks Morse	150	234	2.1	M	A	R
	4	Fairbanks Morse	Fairbanks Morse	150	234	2.1	M	A	R
	5	Fairbanks Morse	Fairbanks Morse	150	234	2.1	M	A	R
	6	Fairbanks Morse	Fairbanks Morse	150	234	2.1	M	A	R
		Total		900		12.6			
• COLORADO BOULEVARD (5620)	1	Allis Chalmers	Allis Chalmers	50	160	1.3	M	A	
7595 S. Colorado Blvd	2	Fairbanks Morse	Fairbanks Morse	75	200	1.4	M	A	
	3	Fairbanks Morse	Fairbanks Morse	75	200	1.4	M	A	
	4	Fairbanks Morse	Fairbanks Morse	75	160	1.4	M	A	
		Total		275		5.5			
• DATURA (5430)	1	Fairbanks Morse	United States	125	165	3.0	M	A	R
5695 S. Datura St.	2	Fairbanks Morse	United States	125	165	3.0	M	A	R
		Total		250		6.0			
EINFELDT (5360)	2	Wheeler Economy	General Electric	800	175	20.0	M		R
1900 S. University Blvd.	3	Byron Jackson	General Electric	600	175	17.0	M		R
	4	Byron Jackson	General Electric	400	175	12.0	M		R
	5	Byron Jackson	Westinghouse	200	175	5.3	M		R
	6	Worthington	Electric Machinery	800	175	20.0	M		R
	7	Wheeler Economy	General Electric	800	175	20.0	M		R
		Total		3,600		94.3			

Source: Reference 25

Table 5.2-1 - Denver Water System - Pumping Station Capacities

	Pump Number	Make of Pump	Make of Motor	Horse Power	Head In Feet	Capacity In M.G.D.	Method of Operation		
	1	Ingersoll-Rand	Reliance	125	53	10.0	M		R
	2	Ingersoll-Rand	Reliance	125	53	10.0	M		R
	3	Ingersoll-Rand	Reliance	125	53	10.0	M		R
	4	Ingersoll-Rand	Reliance	125	53	10.0	M		R
	5	Ingersoll-Rand	Reliance	125	53	10.0	M		R
		Total		625		50.0			
FIFTY-SIXTH AVENUE (5203) 7355 56th Ave.	1	Allis Chalmers	Ideal Electric	1,750	450	15.0	M		R
	2	Allis Chalmers	Ideal Electric	1,750	450	15.0	M		R
	3	Allis Chalmers	Ideal Electric	1,750	450	15.0	M		R
	4	Allis Chalmers	Ideal Electric	1,750	450	15.0	M		R
	5	Allis Chalmers	Ideal Electric	1,750	450	15.0	M		R
		Total		8,750		75.0			
FIRST AVENUE (5338) 1555 1st Ave.	1	Fairbanks Morse	Fairbanks Morse	50	70	2.9	M	A	R
	2	Peerless	Marathon Electric	30	70	1.8	M	A	R
	3	Peerless	Marathon Electric	30	70	1.8	M	A	R
	4	Peerless	Marathon Electric	30	70	1.8	M	A	R
	5	Peerless	Marathon Electric	60	70	2.9	M	A	R
		Total		200		11.2			
GREEN MOUNTAIN (5837) 12400 W. Jewell Ave.	1	Patterson	General Electric	700	260	10.0	M		R
	2	Patterson	General Electric	350	260	5.0	M		R
	3	Patterson	General Electric	350	260	5.0	M		R
	4	Patterson	General Electric	700	260	10.0	M		R
		Total		2,100		30.0			
HIGHLANDS (5722) 8100 S. University Blvd.	1	Fairbanks Morse	United States	125	165	3.0	M	A	R
	2	Fairbanks Morse	United States	125	165	3.0	M	A	R
	3	Fairbanks Morse	United States	125	165	3.0	M	A	R
	4	Fairbanks Morse	United States	125	165	3.0	M	A	R
	5	DeLaval	Ideal Electric	350	165	10.0	M	A	R
	6	DeLaval	Ideal Electric	350	165	10.0	M	A	R
	7	DeLaval	Ideal Electric	350	165	10.0	M	A	R
		Total		1,550		42.0			
HILLCREST (5602) (Low Pressure) 4200 S. Happy Canyon Rd.	1	Allis Chalmers	Allis Chalmers	50	169	1.0	M	A	R
	2	Allis Chalmers	Allis Chalmers	100	167	2.0	M	A	R
	3	DeLaval	Electric Machinery	200	163	5.0	M		R
	4	DeLaval	Electric Machinery	400	163	11.0	M		R
	5	DeLaval	Electric Machinery	400	163	11.0	M		R
	6	Worthington	Fairbanks Morse	400	163	11.0	M		R
	7	Worthington	Fairbanks Morse	400	163	11.0	M		R
		Total		1,950		52.0			
HILLCREST (5602) (High Pressure) 4200 S. Happy Canyon Rd.	8	American Marsh	Westinghouse	75	320	0.8	M	A	R
	9	DeLaval	Electric Machinery	200	318	2.5	M	A	R
	10	DeLaval	Electric Machinery	350	313	4.8	M		R
	11	DeLaval	Electric Machinery	800	315	10.5	M		R
	12	DeLaval	Electric Machinery	800	315	10.5	M		R
	13	Patterson	Ideal Electric	900	320	10.0	M		R
		Total		3,125		39.1			
JULIAN STREET (5452) 2570 S. Julian St.	1	Fairbanks Morse	Fairbanks Morse	75	120	2.9	M	A	R
	2	Allis Chalmers	Allis Chalmers	50	118	2.0	M	A	R
	3	Wheeler Economy	Ideal Electric	50	120	1.7	M	A	R
	4	Fairbanks Morse	Fairbanks Morse	75	120	2.9	M	A	R
		Total		250		9.5			
KASSLER (5496) At Waterton	1	Gould	Electric Machinery	1,250	325	15.0	M	A	R
	2	Worthington	Fairbanks Morse	800	325	10.0	M	A	R
	3	Gould	Electric Machinery	1,250	325	15.0	M	A	R
	4	Worthington	Fairbanks Morse	800	325	10.0	M	A	R
	5	Gould	Electric Machinery	1,250	325	15.0	M	A	R
		Total		5,350		65.0			

Source: Reference 25

Table 5.2-1 - Continued (Sheet 2)

Pump Station	Pump Number	Make of Pump	Make of Motor	Horse Power	Head In Feet	Capacity In M.G.D.	Method of Operation
KENDRICK (5615)	1	Patterson	Ideal Electric	300	120	10.0	M R
(Low Pressure)	2	DeLaval	General Electric	300	117	10.0	M A R
9380 W. Jewell Ave.	3	Worthington	General Electric	75	119	2.9	M A R
	4	Worthington	General Electric	75	119	2.9	M A R
	5	Worthington	General Electric	75	119	2.9	M A R
		Total		825		28.7	
KENDRICK (5615)	7	Worthington	Electric Machinery	800	260	10.0	M A R
(High Pressure)	8	Worthington	Electric Machinery	800	260	10.0	M A R
9380 W. Jewell Ave.	9	Patterson	Ideal Electric	700	260	5.0	M R
	10	DeLaval	Ideal Electric	400	260	5.0	M A
	11	Patterson	Ideal Electric	700	260	10.0	M R
		Total		3,400		40.0	
LAKERIDGE (5520)	1	American	United States	50	120	1.7	M A R
2700 S. Raleigh St.	2	Pacific	Ideal Electric	75	120	2.9	M A R
	3	Pacific	Ideal Electric	75	120	2.9	M A R
	4	Allis Chalmers	Allis Chalmers	50	120	2.0	M A R
		Total		250		9.5	
• LAMAR (5443)	1	Worthington	Marathon Electric	100	120	2.9	M A R
6301 W. Yale Ave.	2	Worthington	Marathon Electric	100	120	2.9	M A R
		Total		200		5.8	
LEE GULCH (5510)	1	Peerless	Marathon Electric	75	125	2.3	M A
7615 S. Broadway	2	Peerless	Marathon Electric	75	125	2.3	M A
		Total		150		4.6	
MARSTON (5485)	1	Worthington	General Electric	700	166	20.0	M R
(Low Pressure)	2	Worthington	General Electric	700	166	20.0	M R
5700 W. Quincy Ave.	3	Worthington	General Electric	700	166	20.0	M R
	4	Worthington	General Electric	700	166	20.0	M R
	5	Worthington	General Electric	700	166	20.0	M R
		Total		3,500		100.0	
MARSTON (5485)	7	Fairbanks Morse	Fairbanks Morse	200	320	2.9	M R
(High Pressure)	8	Patterson	Ideal Electric	400	260	6.5	M R
5700 W. Quincy Ave.	9	Patterson	Ideal Electric	900	260	10.0	M R
	10	Patterson	Ideal Electric	900	260	10.0	M R
	11	Patterson	Ideal Electric	900	260	10.0	M R
		Total		3,300		39.4	
MEXICO AVENUE (5428)	1	Peerless	Marathon Electric	50	95	1.7	M A R
4740 Mexico Ave.	2	Peerless	Marathon Electric	50	95	1.7	M A R
	3	Peerless	Marathon Electric	50	95	1.7	M A R
	4	Wheeler Economy	Marathon Electric	75	95	2.9	M A R
	5	Wheeler Economy	Marathon Electric	75	95	2.9	M A R
		Total		300		10.9	
• MONACO (5546)	2	Peerless	United States	50	120	2.1	M A
3490 S. Monaco St.							
MONTCLAIR (5376)	1	Fairbanks Morse	General Electric	400	165	10.0	M R
1105 Quebec St.	2	Byron Jackson	General Electric	200	160	5.0	M R
	3	Warner Goulds	Electric Machinery	600	165	15.0	M R
	4	Worthington	Electric Machinery	600	175	15.0	M R
		Total		1,800		45.0	
SOUTHWEST METRO NO. 2(5594)	1	Hightrust	Vertical	150	250	2.6	M A R
8775 W. Coal Mine Rd.	2	Fairbanks Morse	Fairbanks Morse	100	250	2.1	M A R
		Total		250		4.7	

Source: Reference 25

Table 5.2-1 - Continued (Sheet 3)

Pump Number	Make of Pump	Make of Motor	Horse Power	Head In Feet	Capacity In M.G.D.	Method of Operation
2	Fairbanks Morse	Fairbanks Morse	10	76	0.4	M A
3	Fairbanks Morse	Fairbanks Morse	10	76	0.4	M A
	Total		20		0.8	
1	Worthington	Century	30	120	1.3	M A R
3	American	United States	50	120	1.7	M A R
4	Fairbanks Morse	Fairbanks Morse	100	130	2.9	M A R
	Total		180		5.9	
1	Worthington	Westinghouse	25	68	1.4	M A R
2	Worthington	Westinghouse	25	68	1.4	M A R
3	Pacific	Delco Electric	60	93	2.9	M A R
4	Fairbanks Morse	Fairbanks Morse	60	93	2.9	M A R
	Total		170		8.6	
2	Allis Chalmers	General Electric	30	170	0.7	M A R
3	Fairbanks Morse	Fairbanks Morse	125	170	3.4	M A R
4	Fairbanks Morse	Fairbanks Morse	60	170	1.4	M A R
5	Fairbanks Morse	Fairbanks Morse	60	170	1.4	M A R
6	Worthington	Howell Electric	125	170	2.9	M A R
7	Fairbanks Morse	Robbins	125	170	2.9	M A R
	Total		525		12.7	
	Totals		56,740		1,093.4	

Total Clear Water Pumped, 1976:

50,713,670,000 Gallons

Total Consumption, 1976:

68,430,620,000 Gallons

Pumpage by Lifts, 1976:

First Lift	37,310,340,000 Gallons
Second Lift	8,835,680,000 Gallons
Third Lift	4,453,350,000 Gallons
Fourth Lift	114,300,000 Gallons

Source: Reference 25

Table 5.2-1 - Continued (Sheet 4)

Annual Water Report

					Percent Filtered
Moffat M. G. Filtered	16,328.53	M. G. Daily	44.74		23.81
Marston M. G. Filtered	44,405.49	M. G. Daily	121.65		64.77
Kassler M. G. Filtered	7,833.65	M. G. Daily	21.46		11.42
Total Filtered	68,567.67	Total Daily	187.85	Total %	100.00

Master Contract Total Pumpage 36,511.48 M. G.
Outside Contract Total Pumpage 13,769.78 M.G.
Grant Total, Both Pumpage Contracts for the Year 50,281.26 M. G.

Percent of First Lift Pumped	53.94%	M. G. Pumped	36,982.98
Percent of Second Lift Pumped	12.92%	M. G. Pumped	8,861.49
Percent of Third Lift Pumped	06.38%	M. G. Pumped	4,376.29
Percent of Fourth Lift Pumped	00.08%	M. G. Pumped	60.50
		Total M. G. Pumped	50,281.26

Average M. G. Pumped Per Day During 1975 128.64
Average M. G. Pumped Per Day During 1976 137.76

Source: Reference 25

Table 5.2-2 - 1976 Water Report, Denver Water System

Annual Power Report

Master Contract Annual Charge 602,611.72 Cost Per KWH 0.0180217 Total KWH Used 33,438,104.
Outside Contract Annual Charge 400,795.04 Cost Per KWH 0.0234905 Total KWH Used 17,061,941
Cost of electric & Gas (Small Bills) of Vaults & Stations 45,591.38 Total
Peak Occurred Majority of peaks occurred between 15th & 30th of each month.
Total Annual Expeditures Allocated for Power, Electric and Gas $1,048,998.14
PDP-8 Logger in Operation ______ Days; Off ______ Days
PDP-11/45 In Operation 360 Days; off 5 Days

Source: Reference 25

Table 5.2-3 - 1976 Power Report, Denver Water System

SUMMARY OF WATER AND POWER COSTS - 1976

Total Consumption - - - 68,430.62 M.G.

Total Water Produced - - 68,567.67 M.G.

FILTER PLANT PRODUCTION

	M.G.	DAILY AVERAGE	% OF TOTAL
Moffat	16.328.53	44.74	23.81%
Marston	44,405.49	121.65	64.77%
Kassler	7,833.65	21.46	11.42%
Totals:	68,567.67	187.85	100.00%

Total water pumped: 50,281.26

Master contract total pumpage ------ 36,511.48
Outside contract total pumpage ----- 13,769.78
Percent pumped to total consumption -- 73.47%

Pumpage by lift:	M.G.	% PUMPED OF TOTAL PRODUCED	COST PER LIFT
First	36,982.98	53.93%	$ 560,935.61
Second	8,861.49	12.92%	218,111.51
Third	4,376.29	6.38%	99,765.18
Fourth	60.50	0.08%	2,374.19
Metro Sewer			15,342.58
* Power Consumed other Sources			106,877.69
Small Bills, Elect. & Gas			45,591.38
Total:			$ 1,048,998.14

* Power Consumed Other Sources (Master Contract):

a. 1200 Shoshone
b. 1600 W. 12th (Meters)
c. Kassler Filters
d. Marston Lake (Filter)
e. Waterton Pump
f. Moffat

POWER

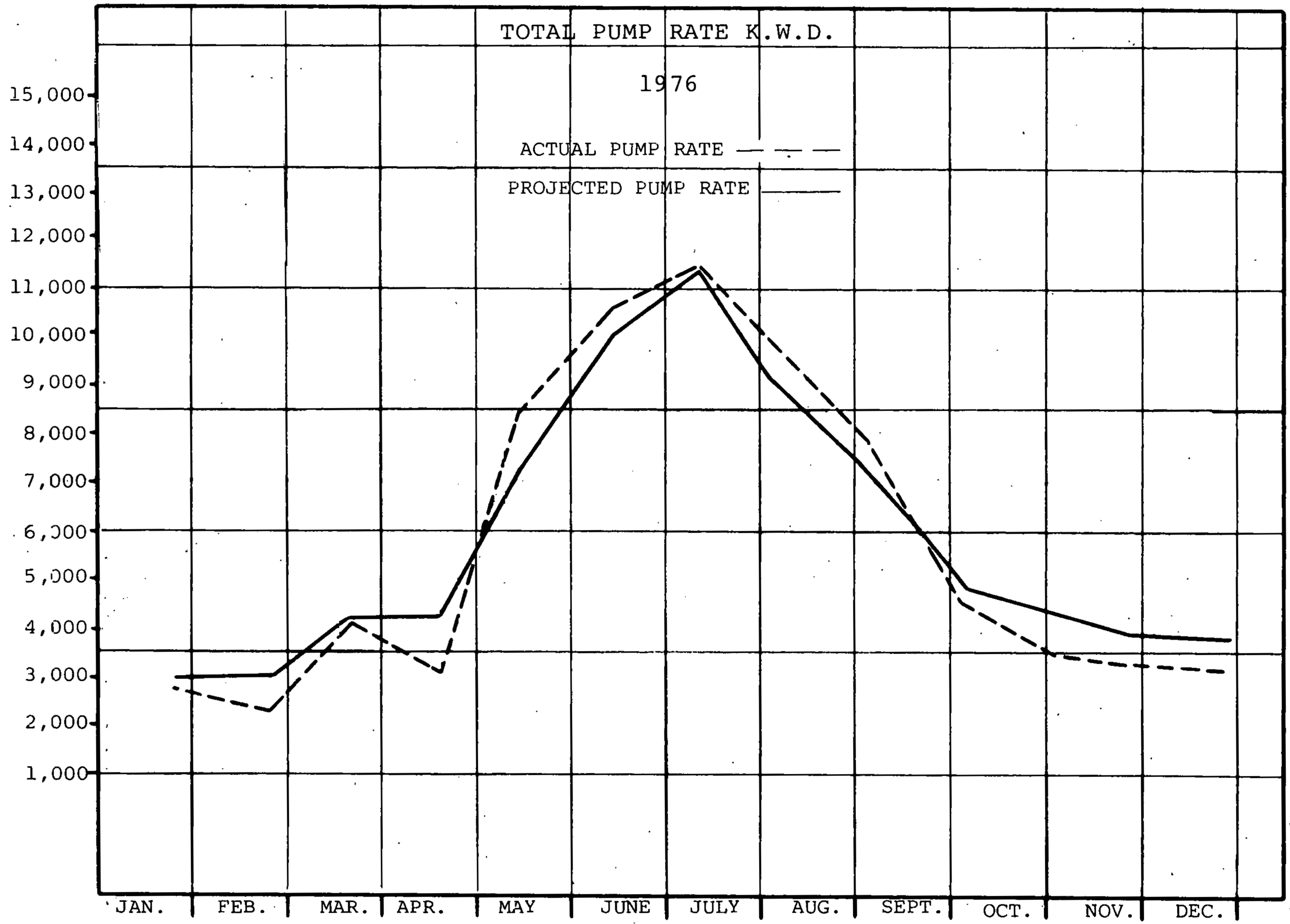
Master Contract KWH Consumed		33,438,104
Outside Contract KWH Consumed		17,061,941
Total Consumed:		50,500,045 K.W.H.
Master Contract Total Cost	$	602,611.72
Outside Contract Total Cost	$	400,795.04

Cost of electricity and gas (small bills for vaults and stations) amounted to: $ 45,591.38

Total cost all bills, 1976 $ 1,048,998.14

Source: Reference 25

Table 5.2-4 - Power Cost History



Source: Reference 25

Figure 5.2-3 - Denver Water System - 1976 Power Consumption Kilowatt-days

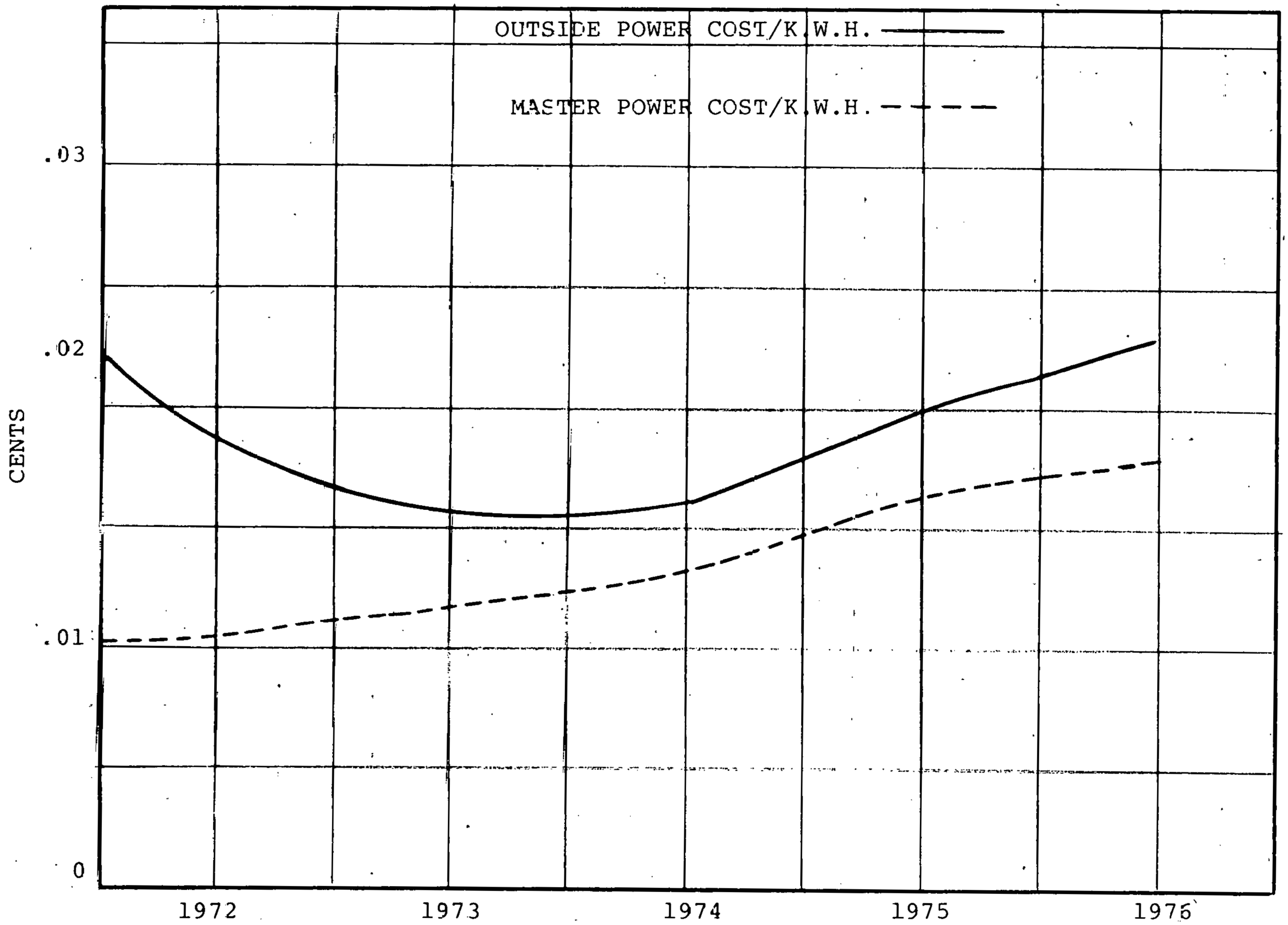


Figure 5.2-4 - Denver Water System - Power Cost History

5.4 Energy Estimates for Water Supply Systems

In this study, an energy intensity in kilowatt-hours per gallon per foot of head will be estimated. From this, an estimate of total energy consumption in kilowatt-hours can be derived. This approach is necessitated by the fact that in water distribution systems, unlike petroleum pipelines, the fluid is not pumped through from source to destination. Instead, the water is pumped up to a high-level storage tank, from which it flows by gravity through the distribution lines to consumers. Since all the energy is input to the system as work to raise the water to the storage reservoirs, the energy intensity for water systems is defined as energy per unit of mass per unit of lift. When calculating the EI, head which is dissipated in the lift pipe and the unrecovered dynamic head must of course be included.

5.4.1 Energy Intensity of Water Supply Systems

For water distribution systems, the energy intensity (I_E) just defined is calculated by the formula

$$I_E \equiv \frac{\text{Power (Kw)}}{\text{Flow (1000 gpm) x Head (100 ft)}}$$

$$\doteq 10^{-5} \ \frac{\text{KW-Min}}{\text{Gal-Ft}}$$

For 1000 gallons per minute of water at 8.328 lb/gal pumped against a total of 100 ft, the power into the water is

$$P_w = 1000 \ \frac{\text{Gal}}{\text{Min}} \times 8.328 \ \frac{\#}{\text{Gal}} \times 100 \text{ ft.} \times \frac{1}{778} \ \frac{\text{Btu}}{\text{Ft\#}}$$

$$\times \ \frac{1}{3412.14} \ \frac{\text{Kw-Hr}}{\text{Btu}} \times 60 \ \frac{\text{Min}}{\text{Hr}} = 18.823 \text{ Kw}$$

$$= 25.23 \text{ Hp}$$

At a wire-to-water efficiency of 67%, the power into the motor is

$$P_m = 28.09 \text{ Kw} = 36.66 \text{ Hp}$$

And at a 22% efficiency for the generating and transmission system, the power into the boiler at the generating station is

$$P_b = 127.70 \text{ Kw} = 171.18 \text{ Hp}$$

Thus, the energy intensity at the boiler, for the elevation head alone, is

$$I_E \text{ (Lift)} = 127.7 \frac{\text{Kw-Min}}{10^5 \text{Gal-Ft}}$$

Referring again to Table 5.1-9 a total power requirement of about 46 Kw is indicated at the pump efficiency of 67% which was used above. This would indicate that in general the velocity head and friction head together are about equal to the elevation head. Inspection of Table 5.1-10 shows that velocity head is generally small, less than two feet for typical velocities. The friction head is several feet per hundred feet, so that it is easy to see why the values in Table 5.1-9 should be reasonable. The total intensity then is

$$I_E = \frac{46}{0.22} = 209.09 \frac{\text{Kw-Min}}{10^5 \text{Gal-Ft}}$$

It is interesting to compare this with the Denver experience. That system was seen in Table 5.2-3 above to consume 50,500,045 (33,438,104 plus 17,061,941) kw-hr to move a throughput of (Table 5.2-2) 50,281.26 million gallons. The energy intensity is

$$\frac{50{,}500{,}045 \text{ Kw-hr}}{50{,}281.26 \times 10^6 \text{Gal} \times 160 \text{ ft}} \times 60 \frac{\text{Min}}{\text{Hr}} = 37.663 \frac{\text{Kw-Min}}{10^5 \text{Gal-Ft}}$$

at the motor, or

$$\frac{37.66}{0.22} = 171 \frac{\text{Kw-Min}}{10^5 \text{ Gal-Ft}}$$

at the boiler.

5.4.2 Energy Consumption in Water Supply Systems

Referring again to Table 5.1-1 above, it is seen that in 1974 the industry served approximately 180 million people, consuming 150 gpd per capita, or 27 x 10^9 gpd. Also in that table, and in Table 5.1-2, it was seen that about 20% of the supplies are taken from ground water, i.e., wells. Also, from Table 5.1-8, an average well depth of 153 feet was calculated. There is no data available on average lift from the surface, but if the 160 feet average at Denver is typical, then the energy consumption, at the generating station boiler is

$$E = 27 \times 10^9 \frac{\text{Gal}}{\text{Day}} \times \frac{1}{1440} \frac{\text{Day}}{\text{Min}} \times \frac{209.1}{10^5} \frac{\text{Kw-Min}}{\text{Gal-Ft}}$$

$$\times (0.2 \times 153 + 160) \text{ ft} \times 8760 \frac{\text{Hr}}{\text{Yr}}$$

$$= 6.54 \times 10^{10} \frac{\text{Kw-hr}}{\text{yr}} = 0.233 \text{ Quad}$$

If the Denver experience ($I_E = 171$) is typical, then

$$E = 6.54 \times 10^{10} \times \frac{171}{209} = 5.35 \times 10^{10} \frac{\text{Kw-hr}}{\text{Yr}} = 0.183 \text{ Quad}$$

The average would appear to be near 0.2 Quad.

Two comments are in order.

First, if the 0.2 Quad is at all accurate, it is somewhat surprising, in that it is several times larger than the estimates for the other liquid pipelines. It therefore merits further scrutiny.

Second, the principal uncertainty in the methodology is clearly in the estimate of average lift. In the above examples, the principal questions involve the representativeness of the Illinois Water Survey, Table 5.1-9, which is the basis of the EI of 209.9, and of the Denver lift of 160 feet. While it might be expected that the per-capita consumption might not vary widely, perhaps by a factor of two or three across the population of systems, it is easy to see how the average lift could vary by a factor of ten. Clearly, refinement of the estimate merits further research regarding these two factors, the average lift being particularly important.

5.4.3 <u>First-order Refinement of the Estimate</u>

Stimulated by the considerations just discussed, J. S. Moore (Ref. 26) of Mueller Associates obtained information about the Baltimore, Washington, D. C. and New York City systems, and found the per-capita consumption for those systems to be approximately 140, 150, and 200 gpd respectively. The geometric mean of these values is 143 gpd, quite close to the value of 150 in Table 5.1-1.

Moore also found, somewhat surprisingly, that only 43, 73, and 10 percent respectively of those systems water supplies were pumped. That is, New York apparently obtains 90% of its water by gravity. Thus, it appears unlikely that the average lift for any of these three systems even approaches the 160 feet of the Denver system. Since more specific information is not available for these systems, if they are to be useful in developing national estimates, another approach must be taken.

The per-capita energy consumptions for the Baltimore and Washington systems were found by Moore to be 18.89 and 7.64 Kw-Hr in 1976. By contrast, the 1976 per-capita energy consumption of the Denver system is approximately 48 Kw-Hr. Extrapolating from the 180 million population estimated to be served in 1974 (Table 5.1-1) to 1976 at the same growth rate as that seen in the standard metropolitan areas over the preceding two years (Statistical Abstract of the U. S., 1976, Table 18), yields 183.3 million for the 1976 population served. Taking the geometric mean of the three per-capita energy figures above and multiplying by the population served yields 1.193×10^{13} Kw-Hr consumed at the pump-motor junction boxes. As before, dividing by 0.22 for the efficiency of the electrical generation and transmission system yields 5.42×10^{13} as the estimate for the total energy consumption. The rounded, single-figure estimate of 0.05 Quad is suggested.

5.5 Energy Consumption in Waste-water Systems

Some recent energy experience of the San Diego sewage system is summarized in Table 5.5-1. This is the pump station through which all the metropolitan sewage is pumped to the treatment plant, from which it is discharged several thousand feet out into the ocean bottom. There are some 70 other pump stations in the San Diego system, many of them very tiny. The power consumption and cost data for all these plants exists, but has not been reduced or analyzed. The power for all other stations combined is believed to be not more than two-thirds that for station 2.

Table 5.5-2 shows a tabulation of the sewage plants in 1962. Taking the 1962 population served of 118,371,919 from that table, ratioing up in proportion to general population growth to 1976, and applying the San Diego per-capita energy consumption yields an estimate for the energy consumption of 0.017 Quad.

No defense of a single-point estimate such at this is offered. It is simply the first step in what could be, if they were needed, a series of successive refinements. If in the future, such refinements are desired, the methodology for the necessary research is now clear. However, due to the small portion of U. S. and pipeline sector energy consumption represented by this value no further refinement was attempted in this study.

Table 5.5-1

City of San Diego Sewage Pump Station No. 2

	FY75	FY76	FY77
Throughput, mgpd	111.457	112.155	119.931
Energy, Kw-hr x 10^3	29,557	30,504	31,176
Energy Cost, $	676,468	964,597	1,120,611
Unit Energy Cost, $/Kw-hr	0.02289	0.03162	0.03594

FY is July through June

STATES	Total		Separate		Combined		Both		Not stated	
	Number	Population served	Number	Population served	Number	Population served	Number	Population served	Number	Population served
Alabama	216	1,495,043	214	1,493,218	....	....	....	....	2	1,825
Alaska	21	61,620	8	3,260	....	....	13	58,360	....	....
Arizona	74	710,649	72	689,734	1	20,000	....	....	1	915
Arkansas	161	792,675	141	705,285	2	64,300	....	....	18	23,090
California	506	11,458,492	477	9,359,536	17	2,057,910	....	....	12	41,046
Colorado	176	1,421,106	170	1,309,431	3	107,000	....	....	3	4,675
Connecticut	91	1,491,656	66	574,837	15	490,919	9	421,900	1	4,000
Delaware	16	267,241	9	25,158	1	2,700	5	238,520	1	863
District of Columbia	1	1,323,470	....	....	....	....	1	1,323,470	....	....
Florida	346	2,170,514	333	2,111,239	2	21,500	....	....	11	37,775
Georgia	276	2,268,492	262	1,083,157	6	914,515	4	268,920	4	1,900
Hawaii	27	362,166	27	362,166	....	....	....	....	....	....
Idaho	91	302,999	79	244,894	10	48,905	2	9,200	....	....
Illinois	472	7,908,321	329	1,227,256	107	4,833,140	26	1,835,280	10	12,645
Indiana	321	2,867,845	103	364,915	206	2,445,065	3	36,040	9	21,825
Iowa	438	1,576,800	400	983,090	18	184,760	10	402,350	10	6,600
Kansas	335	1,468,250	325	1,180,005	2	107,000	3	176,400	5	4,845
Kentucky	161	1,263,145	134	563,080	20	658,620	7	41,445	....	....
Louisiana	161	2,100,673	158	2,095,553	....	....	....	....	3	5,120
Maine	109	479,453	37	68,720	39	198,650	32	210,608	1	1,475
Maryland	72	1,352,909	54	1,327,134	7	16,800	3	2,500	8	6,475
Massachusetts	144	4,389,580	81	619,165	40	931,760	10	2,828,605	13	10,050
Michigan	236	6,170,560	110	570,100	66	4,252,685	58	1,292,275	2	55,500
Minnesota	404	2,062,595	373	857,145	27	1,185,710	3	19,690	1	50
Mississippi	168	779,456	164	755,056	....	....	1	18,600	3	5,800
Missouri	466	2,643,725	411	1,065,225	6	44,945	24	1,411,960	25	121,595
Montana	114	385,220	103	299,680	4	19,600	7	65,940	....	....
Nebraska	300	802,230	275	517,470	13	26,790	6	245,150	6	12,820
Nevada	37	314,030	33	233,430	4	80,600	....	....	....	....
New Hampshire	78	283,460	19	45,660	29	91,350	27	144,200	3	2,250
New Jersey	210	4,504,015	169	2,314,640	9	366,375	5	1,311,185	27	511,815
New Mexico	76	599,821	76	599,821	....	....	....	....	....	....
New York	548	13,443,148	389	2,709,148	53	519,525	87	10,192,945	19	21,530
North Carolina	359	1,751,365	355	1,742,940	1	1,020	....	....	3	7,405
North Dakota	185	321,175	127	118,930	48	196,855	....	....	10	5,390
Ohio	441	6,776,295	241	1,856,930	117	1,735,680	59	3,110,420	24	73,265
Oklahoma	284	1,452,524	279	1,438,724	....	....	....	....	5	13,800
Oregon	165	927,080	116	270,110	37	610,280	6	46,100	....	3,590
Pennsylvania	682	9,559,417	439	2,687,262	137	707,915	95	6,144,115	11	20,125
Puerto Rico	69	121,634	69	121,634	....	....	....	....	....	....
Rhode Island	22	561,975	18	174,385	....	....	3	386,470	1	1,120
South Carolina	221	927,114	221	927,114	....	....	....	....	....	....
South Dakota	181	378,257	154	343,162	20	15,925	7	19,170	....	....
Tennessee	135	1,478,443	126	1,122,268	5	195,125	2	142,100	2	18,950
Texas	832	6,602,147	826	6,486,007	1	55,000	3	58,100	2	3,040
Utah	75	695,635	75	695,635	....	....	....	....	....	....
Vermont	52	186,157	8	8,390	7	8,555	36	165,812	1	3,400
Virginia	231	1,866,241	202	1,481,817	1	180,000	5	181,050	23	23,374
Washington	230	1,628,330	133	373,650	46	825,505	15	302,030	36	127,145
West Virginia	176	726,181	98	168,460	48	425,471	19	87,970	11	44,280
Wisconsin	392	2,668,315	306	712,268	34	1,315,600	51	640,147	1	300
Wyoming	71	222,275	68	221,155	....	....	....	....	3	1,120
Total	11,655	118,371,919	9,462	57,309,049	1,209	25,964,056	647	33,836,027	337	1,262,788

Source: Reference 23

Table 5.5-2 - Municipal Sewage Treatment Plants in the United States

Treated		Untreated		Minor		Primary		Intermediate		Secondary	
Number	Population served	Number	Population served	Number	Population served	Number	Population served	Number	Population served	Number	Population served
144	1,231,420	72	263,623	....	....	69	711,560	....	....	75	519,860
1	10,000	20	51,620	....	....	1	10,000	....	....	....	....
69	684,699	5	25,950	....	....	17	35,274	....	....	52	649,425
137	618,475	24	174,200	....	....	73	173,155	....	....	64	445,320
484	11,399,057	22	59,435	1	4,000	102	7,769,699	4	384,880	377	3,240,478
149	1,397,736	27	23,370	....	....	33	52,205	1	550,000	115	795,531
82	1,438,816	9	52,840	2	8,000	47	1,091,093	2	113,400	31	226,323
13	262,978	3	4,263	....	....	11	259,022	....	....	2	3,956
1	1,323,470	....	....	....	....	....	....	....	....	1	1,323,470
328	2,106,749	18	63,765	3	68,000	81	836,155	2	39,760	242	1,162,834
199	1,722,370	77	546,122	....	....	112	346,015	1	584,155	86	792,200
17	60,091	10	302,075	....	....	8	26,320	....	....	9	33,771
64	261,039	27	41,960	1	450	37	143,040	....	....	26	117,549
444	7,672,861	28	235,460	....	....	72	475,850	2	26,060	370	7,170,951
190	2,598,375	131	269,470	....	....	40	452,870	1	5,800	149	2,139,705
372	1,302,430	66	274,370	....	....	32	221,406	1	4,000	339	1,077,025
322	1,312,440	13	155,810	....	....	38	143,300	....	....	284	1,169,140
112	1,159,600	49	103,545	....	....	30	630,970	3	151,265	79	377,365
127	827,068	34	1,273,616	....	....	11	212,895	....	....	116	614,163
17	43,995	92	435,458	....	....	14	28,795	....	....	3	15,200
53	1,317,744	19	35,165	2	4,650	30	114,359	....	....	21	1,198,735
85	3,544,635	59	844,945	10	1,752,215	22	1,249,235	1	430	52	542,755
213	6,109,385	23	61,175	2	6,030	109	4,835,900	3	87,200	99	1,180,255
344	1,997,715	60	64,880	....	....	84	273,685	1	1,041,700	259	682,330
118	353,976	50	425,480	....	....	35	40,450	....	....	83	313,526
366	912,990	100	1,730,735	....	....	24	98,170	....	....	342	814,820
106	361,920	8	23,300	....	....	32	241,400	2	11,800	72	108,720
225	477,675	75	324,555	....	....	43	96,065	1	1,100	181	381,510
33	307,390	4	6,640	....	....	7	8,990	....	....	26	298,400
19	59,610	59	223,850	....	....	9	48,050	....	....	10	11,560
203	4,450,220	7	53,795	....	....	60	2,602,610	6	479,000	137	1,368,610
75	598,721	1	1,100	....	....	5	5,196	....	....	70	593,525
407	11,420,209	141	2,022,939	6	298,680	247	3,158,624	6	92,610	148	7,870,295
255	1,299,980	104	451,385	....	....	120	165,246	....	....	127	1,134,735
170	270,756	15	50,420	....	....	33	64,740	....	....	137	216,015
351	6,416,805	90	359,490	....	....	102	895,110	27	1,148,015	222	4,373,680
276	1,443,474	8	9,050	....	....	36	204,685	1	1,200	239	1,237,589
146	866,480	19	60,600	....	....	51	596,050	....	....	96	270,430
384	8,389,337	298	1,170,080	1	4,920	114	957,890	6	2,419,465	263	5,007,062
59	94,954	10	26,680	....	....	34	74,880	1	235	24	19,839
15	557,890	7	4,085	....	....	7	187,790	....	....	8	370,100
175	616,442	46	310,672	5	10,040	105	192,825	1	170	64	413,407
159	332,202	22	46,055	....	....	36	27,245	....	....	123	304,957
112	899,447	23	578,996	....	....	42	312,085	....	....	70	587,362
825	6,565,152	7	36,995	....	....	116	189,851	....	....	709	6,375,301
55	465,045	20	230,590	....	....	19	20,170	....	....	36	444,875
14	74,902	38	111,255	....	....	13	66,402	....	....	1	8,500
178	1,783,249	53	82,992	2	185,980	69	978,016	....	....	107	619,253
193	1,094,465	37	633,875	1	7,000	86	687,825	2	10,600	104	389,030
46	294,195	130	431,986	....	....	32	201,935	....	....	14	92,260
386	2,661,425	6	6,890	1	880	107	483,615	8	239,705	270	1,937,225
60	212,940	11	9,335	....	....	7	46,115	2	16,400	51	150,425
9,378	103,684,978	2,277	14,686,941	37	2,350,845	2,672	32,733,831	85	7,408,950	6,584	61,191,352

Source: Reference 23

Table 5.5-2 - Continued (Sheet 2)

6.0 ENERGY CONSUMPTION IN SLURRY PIPELINES

Report HCP/M-1171-4 of this series (See Table 1.1-1 above) contains a technical discussion of slurry pipelines, and a description of the only operating U.S. line for long-distance transport, the Black Mesa line. Reference 5 discusses the economics and politics of slurry pipelines in depth. Therefore, no profile is presented here.

In analyzing energy consumption in the Black Mesa pipeline, it is necessary to consider the three distinct operations:

(1) The extraction of the water from the ground and delivery to the pipeline head. These operations are conducted by the Peabody Coal Company.

(2) Slurrification and transportation of the coal. These operations are conducted by the Black Mesa Pipeline, Incorporated.

(3) Deslurrification and consumption of the coal. These operations are conducted by the Southern California Edison Company.

6.1 Energy in Slurry Water

The water for the Black Mesa pipeline is taken from wells near the head of the line. The depth of the lift varies between 2000 and 2200 feet. Taking 2100 feet as an average, and allowing another 200 feet for friction and velocity brings the total head to about 2300 feet.

The proportion of (bone-dry) coal to water is 48 to 52 (Ref. 3). The moisture content of the coal is specified by contract at 10.74%, and the content of the as-mined coal averages very close to this figure. Thus, a ton of contract coal contains

$$2000 \times (1-0.1074) = 1785$$

lb of dry coal. The slurry proportions vary slightly from day to day, but average about 48% dry coal to 52% water. Thus, a ton of contract coal entering the slurrifier emerges as

$$\frac{1785}{0.48} = 3719$$

lb of slurry, of which 2000 lb is the original contract coal and 1719 lb is water which must be added to form the slurry.

Taking as before 64% for motor-pump efficiency and 22% for the electric grid, the energy investment in the water per ton of coal is

$$\frac{1719 \times 2300}{778 \times 0.64 \times 0.22} = 36{,}093 \text{ Btu/ton}$$

at the power plant boiler.

6.2 Energy in Pipeline Operation

The Black Mesa pipeline operation requires 22 Kw-hr per ton of coal at the station meter (Ref. 3). Again (Sec. 4.4-1) allowing 22% efficiency for the electric grid yields

$$\frac{22 \times 3412}{0.22} = 341{,}200 \text{ Btu/ton}$$

of coal transported, at the power plant boiler.

6.3 Energy in Deslurrification

Deslurrification energy must be very carefully calculated. There are many operations involved, as can be seen from Table 6.3-1. Some of these operations would be required with dry coal, though to a different degree.

Table 6.3-1

ENERGY CONSUMED IN/CHARGEABLE TO DESLURRIFICATION

Active storage

- Booster pumps to active storage
- Agitators
- Slurry transfer pumps
- Water pump to primary treatment
- Water pump to evaporation pond

Boiler fuel preparation

- Centrifuges
- Pulverizer mills
- Steam cycle efficiency loss, 32% moisture vs 10.74%
- Clariflocculator agitators
- Underflow pump
- Underflow injection pump

Reslurry from inactive storage

- Conveyor motors
- Vibrator motors
- Reslurry pump, primary
- Reslurry pump, final

Source: Reference 27

The Southern California Edison engineers have calculated that the energy consumed in deslurrification is about 63,000 Btu/ton of coal. This energy is electrical power to the motors which drive the equipment. The energy which must be input to the boiler to supply this power is, for a station heat rate of 11,100 Btu/Kw hr (Ref. 27),

$$63{,}000 \times \frac{11{,}100}{3412} = 204{,}953 \text{ Btu/ton.}$$

Additionally, the steam cycle efficiency suffers under the requirement to reduce the moisture from the 32% to which it is reduced in the initial separation to the 10.74% contract value (Ref. 27) [Dina, 1976].

Now, it was seen above that a ton of contract coal (10.74% moisture) contains 1785.2 pounds of dry coal. This amount of dry coal entering the boiler constitutes

$$\frac{1785.2}{1-0.32} = 2625.3$$

pound of wet coal (32% moisture), from which 2625.3 - 2000 = 625.3 pounds of water must be removed to yeild a ton of contract coal. Taking

$$1173.8 - 34.08 = 1135.7 \text{ Btu/lb}$$

of water as the sensible and latent enthalpy to heat and evaporate the moisture between the approximate conditions of 70°F entering and 280°F stack gas exit,

$$1135.7 \times 625.3 = 710{,}153 \text{ Btu/Ton}$$

is the energy required to dry the coal, after it enters the boiler, back to the boiler, back to the contract value.

6.4 Slurry Pipeline Energy Intensity

The energy components described above are summed on Table 6.4-1. In 1976, the line transported 4,174,694 tons of coal. Thus the energy consumption was approximately

$$4{,}174{,}694 \times 1{,}292{,}000 = 5.394\text{x}10^{12} \text{ Btu}$$
$$= 0.0054 \text{ Quad.}$$

The energy intensity is obtained by dividing the energy per ton by the 273.16-mile length of the pipeline.

$$\frac{1{,}292{,}000}{273.16} = 4730 \quad 4800 \text{ Btu/ton-mile.}$$

Two of the energy components in Table 6.4-1 require explanation. First, the pumping energy is that required to add approximately 7500 ft of head to the slurry as it moves through the pipe. However, it must be noted that the line falls 2600 ft from its head to its critical elevation 12 mi from its terminal. Thus, if the purpose were an equal elevation comparison with other transport modes, it would be necessary to use

$$186{,}000 \times \frac{7500 + 2600}{7500} = 250{,}480 \text{ Btu/ton}$$

for the pumping energy.

Second, an estimated 80% of the energy for slurry preparation and other operations is used in grinding the coal, which would be necessary if the coal were transported in any other way, and therefore cannot fairly be charged to transportation. If allowance is made for that fact, only about

$$155{,}000 \times 0.2 = 31{,}000 \text{ Btu/ton}$$

would be charged to transportation. When these adjustments are made, the adjusted energy consumption given in Table 6.4-2 is obtained.

Table 6.4-1

Energy consumption - Black Mesa Pipeline
(Btu/ton of coal)

Slurry Water Supply		36,000
Pipeline Operation		
Pumping energy	186,000	
Slurry preparation & other operations	155,000	
		341,000
Deslurrification		
Initial separation	205,000	
Moisture correction, 32 to 10.74%	710,000	
		915,000
Total		1,292,000

Sources: References 3 and 27

Table 6.4-2

Adjusted energy consumption - Black Mesa Pipeline
(Btu/ton of Coal)

Slurry water Supply		36,000
Pipeline Operation		
Pumping energy	250,000	
& other operations	31,000	
		281,000
Deslurrification		
Initial separation	205,000	
Moisture correction,	710,000	
		915,000
Total		1,232,000

Several comments are in order. First, it must be recognized that all of the energy chargeable to the slurry pipeline mode of transport is still not in the calculation. For example, about a million dollars worth of chemicals per year are required in the deslurrification process. Some energy is required to manufacture those chemicals, but the amount has not been determined, and thus is not included in the calculation. It is believed to be insignificant.

Second, it is interesting to compare magnitudes. The reader will recall from Sections 4.4.1 and 4.5.1 above that the energy consumption of the crude and products pipeline networks was estimated at 0.070 and 0.068 Quad respectively. Thus it has just been concluded that when all the energy that must be consumed has been taken into account, this single pipeline consumes a tenth as much energy as either the entire crude oil pipeline network or the products network.

Third, it may be observed that the energy consumed in pumping the slurry is small compared to the deslurrification energy.

Fourth, the conclusion reached earlier in this program regarding the future of coal-slurry pipelines is supported. In report HCP/M-1171-4 of this series (see Table 1.1-1 above), the conclusion was reached that the coal slurry pipeline is a cost-effective and energy-effective mode of transport, but not in the coal-water form. The coal-methanol form offers promise of eliminating the energy penalties in the deslurrification process, and at the same time reducing the water requirement by a factor of three or four. Clearly, as was recommended in that report, the concept merits further study.

Finally, if one accepts the estimate of Zandi (Ref. 4) of 544 Btu/ton-mile for the energy intensity of a railroad to move the coal between the same two points, one sees an apparent large energy advantage for the railroad. However, this should not be extrapolated to future pipelines. As an example, Table 6.4-3 presents the energy consumption estimate of Energy Transportation Systems, Inc. (ETSI) for a 25 million ton/year, 1000-mi water slurry pipeline using advanced technology.

When these figures are adjusted on the same basis as used in Table 6.4-2, except that a gravity boost of 3000 ft was taken, the estimate shown in Table 6.4-4 is obtained. In Table 6.4-5, these results are rearranged to provide a direct comparison with the Black Mesa figures from Table 6.4-2. A dramatic sixfold reduction in EI is seen to result from the combined effects of greater distance (factor of four), greater scale (factor of six), later technology (10 years), and much less moisture to be removed (factor of 2.5).

Table 6.4-3

ETSI energy estimate
(25 million tons coal/yr, 1000 mi)

	Energy 10^6 Kw-hr/yr	Energy 10^{12} Btu/yr
Electric energy		
Slurrification	301	
Pumping	502	
Dewatering	146	
Water supply	40	
Subtotal	989	
Less grinding credit	-226	
Net electric energy	763 =	2.60
Steam energy		1.50
Total energy		4.1

Source: Reference 28

Table 6.4-4

Adjusted energy estimate - ETSI pipeline
(25 million tons coal/yr, 1000 mi)

	Energy	
	10^6 kwhre/yr	Btu/ton
Electric energy from grid (n = 0.22)		
Slurrification, net	340	47,000
Pumping	2,575	351,000
Water supply	182	25,000
Electric energy from customer power plant lines, initial separation (station heat rate = 11,100 Btu/kwhre)	475	65,000
Moisture correction, 32 to 26%		136,000
		624,000

Source: Reference 28

Table 6.4-5

Comparison of adjusted energy consumption
(Btu/ton of Coal)

		Black Mesa 273 mi 10.74% moisture $4x10^6$ tons 1967 technology		ETSI 1000 mi 26% moisture $25x10^6$ tons 1976 technology
Slurry water supply		36,000		25,000
Pipeline operation				
Pumping energy	250,000		351,000	
Other operations	31,000		47,000	
		281,000		398,000
Deslurrification			65,000	
Initial separation	205,000			
Moisture	710,000		136,000	
correction		915,000		201,000
Total		1,232,000		624,000
Length of pipeline (mi)		273		1,000
Energy intensity (Btu/ton-mi)		4512		624

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