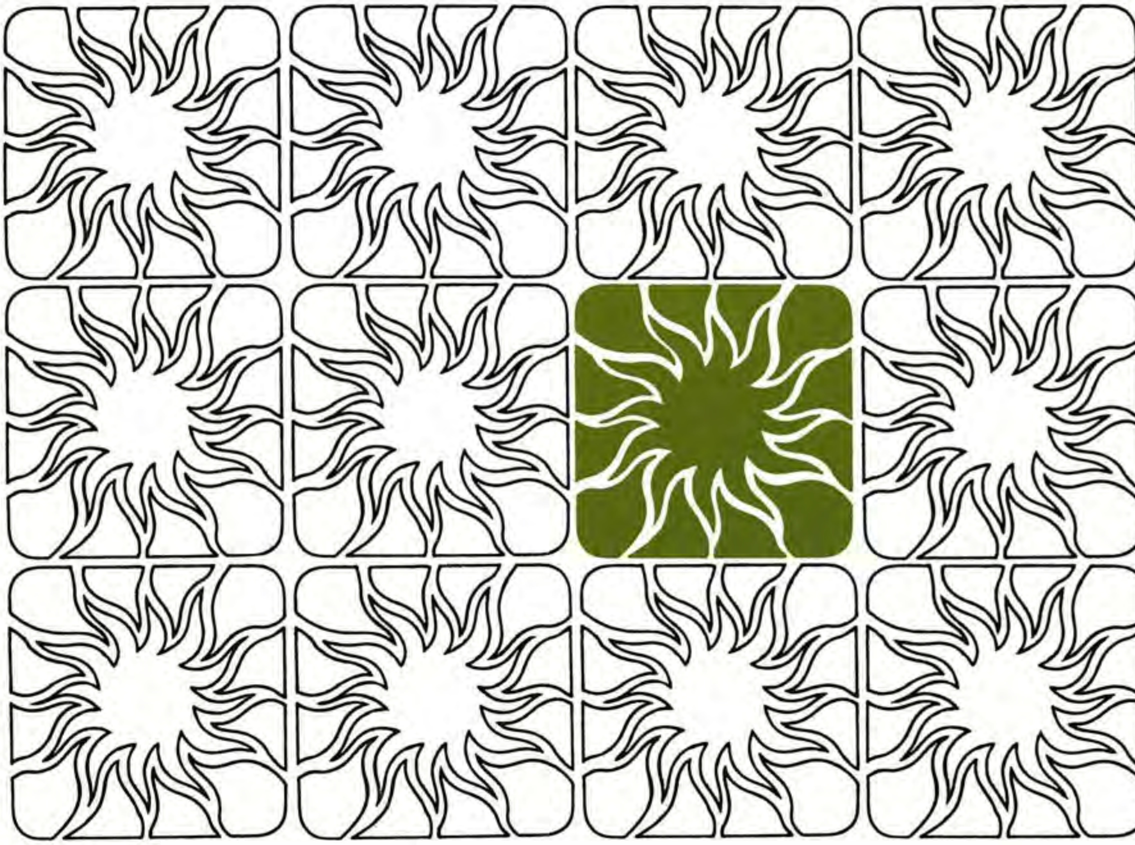
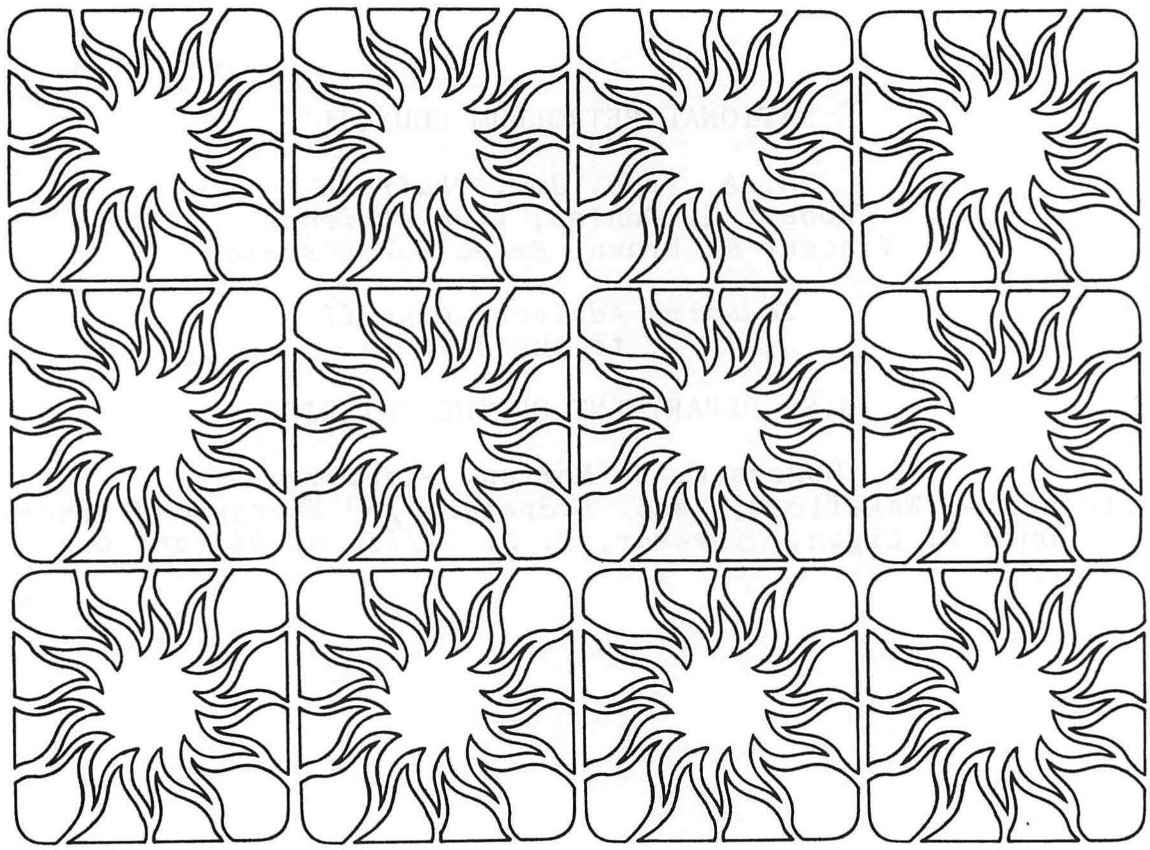


U.S. Energy Outlook

Gas Transportation

National Petroleum Council



U.S. Energy Outlook

Gas Transportation

**A Report by the
Gas Transportation Task Group
of the Gas Subcommittee of the
National Petroleum Council's Committee
on U.S. Energy Outlook**

**Chairman - George W. White
Tennessee Gas Pipeline Company**

National Petroleum Council

NATIONAL PETROLEUM COUNCIL

Industry Advisory Council
to the

U.S. DEPARTMENT OF THE INTERIOR

Library of Congress Catalog Card Number: 72-172997

Printed in the United States of America

PREFACE

On January 20, 1970, the National Petroleum Council, an officially established industry advisory board to the Secretary of the Interior, was asked to undertake a comprehensive study of the Nation's energy outlook. This request came from the Assistant Secretary-Mineral Resources, Department of the Interior, who asked the Council to project the energy outlook in the Western Hemisphere into the future as near to the end of the century as feasible, with particular reference to the evaluation of future trends and their implications for the United States.

In response to this request, the National Petroleum Council's Committee on U.S. Energy Outlook was established, with a coordinating subcommittee, four supporting subcommittees for oil, gas, other energy forms and government policy, and 14 task groups. An organization chart appears as Appendix B. In July 1971, the Council issued an interim report entitled *U.S. Energy Outlook: An Initial Appraisal 1971-1985* which, along with associated task group reports, provided the groundwork for subsequent investigation of the U.S. energy situation.

Continuing investigation by the Committee and component subcommittees and task groups resulted in the publication in December 1972 of the NPC's summary report, *U.S. Energy Outlook*, as well as an expanded full report of the Committee. Individual task group reports have been prepared to include methodology, data, illustrations and computer program descriptions for the particular area studied by the task group. This report is one of ten such detailed studies. Other fuel task group reports are available as listed on the order form included at the back of this volume.

The findings and recommendations of this report represent the best judgment of the experts from the energy industries. However, it should be noted that the political, economic, social and technological factors bearing upon the long-term U.S. energy outlook are subject to substantial change with the passage of time. Thus future developments will undoubtedly provide additional insights and amend the conclusions to some degree.

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SUMMARY

This Task Group report analyzes the capital costs of transporting, processing, and storing gas for the years 1971 to 1985. Four general types of gas are analyzed: natural gas, liquefied natural gas (LNG), substitute natural gas (SNG), and liquefied petroleum gas (LPG). Natural gas is gas that is found in the ground. Gas sold as natural gas today is primarily methane with small amounts of ethane mixed in. LNG is simply natural gas which has been liquefied at a temperature of -258°F for ease of storage and transportation. SNG is gas made synthetically from petroleum liquids (such as naphtha and methanol) or coal and consists mostly of methane with small amounts of ethane and carbon dioxide. LPG, for the purposes of this report, is either ethane, propane, butane or a mixture of these gases. It is obtained primarily by extraction from natural gas or as a by-product of the refining process. The total capital requirements for the transporting, processing and storing of all these gases, as projected for the various cases analyzed in this study, are as follows:

Total Capital Requirements
(Millions of 1970 Dollars)

Period	Case I	Case II	Case III	Case IV
1971-75	6,800	6,600	4,700	3,700
1976-80	21,300	18,700	15,900	10,200
1981-85	28,500	21,700	19,200	15,600
Total	56,600	47,000	39,800	29,500

These capital requirements include not only the cost of new facilities but also replacements of existing facilities of a capital nature. Elements of the capital requirements include:

- Cross-country natural gas pipelines
- Natural gas pipelines from Alaska and the Canadian Arctic
- Gas processing plants on pipelines from Alaska and Canada
- Gathering lines to connect new wells to pipeline systems
- Underground storage facilities
- Pipelines to connect regasified LNG, SNG plants and nuclear stimulation projects to existing pipeline networks

- LNG facilities including liquefaction plants on foreign soil; LNG tankers and domestic port facilities for receiving, storing and regasification

- LPG pipelines

- Ships and barges for importation of foreign supplies of LPG as well as for local transportation

- Railroad tank cars and trucks for local transportation of both LPG and LNG.

A breakdown of the above total capital requirements for the various sources of supply and modes of transportation is shown in Table 1 (p.3). The bases on which these capital requirements were derived are as follows:

- The location of new natural gas discoveries in the lower 48 states will result in the construction of new gathering and feeder line facilities even though total supplies from this source may remain constant or decrease. Even cross-country networks are affected. For instance, in Case II, while total marketed production is projected to increase by only 1.3 trillion cubic feet (TCF) per year between 1971 and 1985 in the lower 48 states, the marketed production from Region 6-A is projected to increase by 3.5 TCF per year during the same period.

- Unit costs of pipeline facilities generally will increase because of--

  (1) More difficult terrain
  (2) Deeper water offshore
  (3) New and greater environmental restrictions
  (4) Pipeline safety and other government regulations.

- The total costs of pipeline capacity required to transport gas from Alaska's North Slope to the lower 48 states are included.

- Costs of pipeline capacity from Canadian Arctic areas to the U.S. border are included to transport the projected increases in Canadian imports. This assumes that capital required will have to be generated in the United States for the construction of transportation facilities from these frontier areas to carry the gas available for export after allowing for Canadian needs.

- Processing costs include the stripping plants at or near the U.S./Canadian border and are included on the assumption that the pipelines from Arctic areas will be designed to carry as much of such liquids as temperature conditions will permit.

TABLE 1

REQUIRED CAPITAL EXPENDITURES FOR GAS TRANSPORTATION
(Millions of Constant 1970 Dollars)

	Gas Pipelines					LNG			LPG				
	1	2	3	4	5	6	7	8	9	10	11	12	13
Period	Storage & Trans-mission Lower 48	Trans-mission Alaska	Trans-mission Canada	Attachments-New Production Coal Gas, LNG & Syngas	Extrac-tion Plants	Plants	Ships	Terminals & Storage	Pipelines	Ships & Barges	Railroad Cars	Trucks	Total
Case I													
1971-1975	4,888.4	0	0	1,258.1	0	131.0	150.0	49.0	195.0	50.0	0	92.3	6,813.8
1976-1980	6,027.8	5,576.0	1,711.0	2,527.9	164.4	2,035.0	2,179.0	701.0	123.0	77.0	44.7	144.9	21,311.7
1981-1985	8,854.8	6,919.0	3,569.0	3,425.9	254.8	1,833.0	2,570.0	672.0	123.0	73.0	55.9	180.9	28,531.3
Total	**19,771.0**	**12,495.0**	**5,280.0**	**7,211.9**	**419.2**	**3,999.0**	**4,899.0**	**1,422.0**	**441.0**	**200.0**	**100.6**	**418.1**	**56,656.8**
% of Total	**34.9**	**22.1**	**9.3**	**12.7**	**0.7**	**7.1**	**8.6**	**2.5**	**0.8**	**0.4**	**0.2**	**0.7**	**100.0**
Case II													
1971-1975	4,676.0	0	0	1,218.9	0	131.0	150.0	49.0	180.0	50.0	0	92.3	6,547.2
1976-1980	4,552.0	5,049.0	1,743.0	1,906.7	156.2	2,035.0	2,179.0	701.0	108.0	77.0	38.8	138.7	18,684.4
1981-1985	5,768.7	4,548.0	3,499.0	2,185.3	213.7	1,833.0	2,570.0	672.0	104.0	73.0	45.9	168.3	21,680.9
Total	**14,996.7**	**9,597.0**	**5,242.0**	**5,310.9**	**369.9**	**3,999.0**	**4,899.0**	**1,422.0**	**392.0**	**200.0**	**84.7**	**399.3**	**46,912.5**
% of Total	**32.0**	**20.5**	**11.2**	**11.3**	**0.8**	**8.5**	**10.4**	**3.0**	**0.8**	**0.4**	**0.2**	**0.9**	**100.0**
Case III													
1971-1975	3,153.4	0	0	881.9	0	131.0	150.0	49.0	170.0	50.0	0	87.6	4,672.9
1976-1980	2,977.7	4,506.0	1,743.0	1,335.7	139.7	2,035.0	2,179.0	701.0	67.0	77.0	22.0	127.7	15,910.8
1981-1985	4,510.0	3,896.0	3,499.0	1,681.6	189.1	1,833.0	2,570.0	672.0	69.0	73.0	35.4	151.0	19,179.1
Total	**10,641.1**	**8,402.0**	**5,242.0**	**3,899.2**	**328.8**	**3,999.0**	**4,899.0**	**1,422.0**	**306.0**	**200.0**	**57.4**	**366.3**	**39,762.8**
% of Total	**26.8**	**21.1**	**13.2**	**9.8**	**0.8**	**10.1**	**12.3**	**3.6**	**0.8**	**0.5**	**0.1**	**0.9**	**100.0**
Case IV													
1971-1975	2,298.1	0	0	803.6	0	131.0	150.0	49.0	170.0	50.0	0	85.1	3,736.8
1976-1980	1,858.4	0	2,283.0	884.4	49.3	2,035.0	2,179.0	701.0	37.0	77.0	5.4	119.1	10,228.6
1981-1985	1,968.8	4,370.0	3,135.0	588.3	205.5	1,833.0	2,570.0	672.0	46.0	73.0	26.5	134.6	15,622.7
Total	**6,125.3**	**4,370.0**	**5,418.0**	**2,276.3**	**254.8**	**3,999.0**	**4,899.0**	**1,422.0**	**253.0**	**200.0**	**31.9**	**338.8**	**29,588.1**
% of Total	**20.7**	**14.8**	**18.3**	**7.7**	**0.9**	**13.5**	**16.5**	**4.8**	**0.9**	**0.7**	**0.1**	**1.1**	**100.0**

- LNG costs include all necessary facilities from the inlet side of the liquefaction plant to the outlet side of the regasification plant. This is based on the assumption that U.S. capital will be required even though the plants are on foreign soil and partial foreign ownership and control will be involved.

- Location, by states, of projected coal SNG plants was furnished by the Coal Task Group. Costs of pipelines from these plants to the nearest major pipeline network are included, as are pipelines from liquid SNG plants to existing networks. An average length of 50 miles for each such connection was assumed in this case since many proposed plants are not definitely located at this time.

- An average length of 100 miles was assumed for pipeline connections from LNG regasification facilities to existing pipeline networks.

Transportation to U.S. and Canadian markets of the gas volumes projected to be available in Case II from Alaska and from Canadian Frontier areas will require the construction of the equivalent of some 10,000 miles of 48-inch pipeline by 1984. The facilities and costs developed were allocated to the United States and Canada on a volumetric bases. Approximately 75 percent of this capacity will be required for projected U.S. markets. At least 10 million tons of steel pipe and fittings will be required in sizes for which there are no presently existing manufacturing facilities in the United States or Canada. Since actual construction cannot be reasonably expected to start before 1976, all of this capacity will have to be constructed in less than 10 years. The accomplishment of such a program will be extremely difficult. Moreover, capital requirements for this transportation are estimated at approximately $15 billion, 80 to 85 percent of which will be invested in Canada.

Details of the capital requirements were developed in three separate groups as indicated in Table 1. These are--

- Pipelines and underground storage

- LNG facilities

- LPG pipelines and facilities.

Chapter One

PIPELINES AND UNDERGROUND STORAGE

Before any capital costs for transportation facilities could be calculated, the volume of gas to be transported for each year through 1985 had to be projected. Furthermore, the origin, destination and mode of transportation had to be estimated. Figures on future gas supply and future gas requirements were provided by the Gas Supply and Gas Demand Task Groups. These figures always indicated *marketed* volumes of gas, excluding field use, as this is the only gas which needs to be transported. Table 2 (pp.6-8) is a summary of the gas supply and requirements volumes, calculated to be transported, which were used to estimate the transportation facilities required.

Expenditures for gas pipelines were developed by three steps:

(1) Determination of a gas demand/supply relationship for each designated district of the Petroleum Administration for Defense (PAD) and for the total United States. (Table 2 shows this relationship for the total U.S.) These demand/supply relationships were used to allocate total gas supplies, proportionately, among PAD districts. These allocations were then used to determine the amounts of new facilities required to transport available supplies, both within and between PAD districts.

(2) Development of historical unit costs in dollars per annual billion cubic feet (BCF).

(3) Application of unit costs to volumes determined under (1).

Historical unit costs were developed from the Federal Power Commission (FPC) Form-2 reports of 35 major pipeline companies for the 1966-1970 period, updated to 1970 by the use of historical escalation factors. These historical cost factors were developed on a regional basis and directly correlated to PAD districts. The cost factors account for all capital requirements for the pipelines, including testing and replacement costs for compliance with new federal regulations and normal construction and replacement costs, as well as costs of expansion facilities.

Underground storage costs were calculated by applying a storage cost factor to estimated increases in storage use. The storage cost factor was developed by dividing historic increases in storage costs by corresponding increases in storage use, giving a cost in dollars per million cubic feet (MMCF).

Projected increases in storage use, total gas injected annually, were calculated using a linear projection based on historical patterns from 1955 to 1970.

A computer model was set up which applied historical unit cost per unit of volume to volumes calculated to be transported between PAD districts and within PAD districts. This model also applied similar unit costs to volumes of new gas to be connected to existing pipeline networks in the form of gathering facilities and to underground storage volumes. Separate computations were made for the cost of connecting new gas supplies from Alaska, Canada, LNG regasification plants and from nuclear stimulation projects. Other separate computations were made for the cost of connecting projected syngas and coal gasification facilities.

Appendix D is the report of the Task Group showing details of calculations and methodology.

TABLE 2

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY–CASE I*

	1971		1975		1980		1985	
	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}
Gas Supply								
Conventional Domestic	19.97	20.61	21.74	22.44	22.34	23.05	24.17	24.94
Alaska North Slope	0	0	0	0	1.30	1.34	3.00	3.10
Canadian Imports	0.90	0.93	1.00	1.03	1.60	1.65	2.70	2.79
Mexican Imports	0.05	0.05	0.05	0.05	0	0	0	0
Total Natural	**20.92**	**21.59**	**22.79**	**23.52**	**25.24**	**26.04**	**29.87**	**30.83**
LNG Imports †	0	0	0.24	0.26	2.28	2.51	4.11	4.52
Coal Gasification	0	0	0	0	0.56	0.52	2.48	2.29
Liquid Gasification	0	0	0.64	0.64	1.32	1.32	1.32	1.32
Total Syngas	**0**	**0**	**0.64**	**0.64**	**1.88**	**1.84**	**3.80**	**3.61**
Nuclear Stimulation	0	0	0.01	0.01	0.19	0.20	1.20	1.24
Grand Total–Gas Supply	**20.92**	**21.59**	**23.68**	**24.43**	**29.59**	**30.59**	**38.98**	**40.20**
Requirements ‡		20.27		25.56		30.89		36.99
(Shortage) or Surplus		1.32		(1.13)		(0.30)		3.21

* Conversion factors:

All Natural Gas	1,032 BTU/cu.ft.
LNG Imports	1,100 BTU/cu.ft.
Coal Syngas	925 BTU/cu.ft.
Liquid Syngas	1,000 BTU/cu.ft.

These figures do not include gas consumed in production and distribution as this report is primarily concerned with logistics. Consequently, these figures will not coincide in all respects with those in Chapter Four of *U.S. Energy Outlook:*

† These figures include gas from South Alaska.

‡ From Gas Demand Task Group.

TABLE 2 (Cont'd.)

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY—CASE II*

	1971		1975		1980		1985	
	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}
Gas Supply								
Conventional Domestic	19.97	20.61	21.55	22.24	20.99	21.66	21.16	21.84
Alaska North Slope	0	0	0	0	1.20	1.24	2.40	2.48
Canadian Imports	0.90	0.93	1.00	1.03	1.60	1.65	2.70	2.79
Mexican Imports	0.05	0.05	0.05	0.05	0	0	0	0
Total Natural	**20.92**	**21.59**	**22.60**	**23.32**	**23.79**	**24.55**	**26.26**	**27.11**
LNG Imports†	0	0	0.24	0.26	2.28	2.51	4.11	4.52
Coal Gasification	0	0	0	0	0.36	0.33	1.31	1.21
Liquid Gasification	0	0	0.64	0.64	1.32	1.32	1.32	1.32
Total Syngas	**0**	**0**	**0.64**	**0.64**	**1.68**	**1.65**	**2.63**	**2.53**
Nuclear Stimulation	0	0	0	0	0.09	0.09	0.73	0.75
Grand Total—Gas Supply	**20.92**	**21.59**	**23.48**	**24.22**	**27.84**	**28.80**	**33.73**	**34.91**
Requirements‡		20.27		25.56		30.89		36.99
(Shortage) or Surplus		1.32		(1.34)		(2.09)		(2.08)

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY—CASE III*

	1971		1975		1980		1985	
	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}
Gas Supply								
Conventional Domestic	19.97	20.61	20.17	20.82	17.60	18.16	16.11	16.63
Alaska North Slope	0	0	0	0	1.00	1.03	2.00	2.06
Canadian Imports	0.90	0.93	1.00	1.03	1.60	1.65	2.70	2.79
Mexican Imports	0.05	0.05	0.05	0.05	0	0	0	0
Total Natural	**20.92**	**21.59**	**21.22**	**21.90**	**20.20**	**20.84**	**20.81**	**21.48**
LNG Imports†	0	0	0.24	0.26	2.28	2.51	4.11	4.52
Coal Gasification	0	0	0	0	0.36	0.33	1.31	1.21
Liquid Gasification	0	0	0.64	0.64	1.32	1.32	1.32	1.32
Total Syngas	**0**	**0**	**0.64**	**0.64**	**1.68**	**1.65**	**2.63**	**2.53**
Nuclear Stimulation	0	0	0	0	0.09	0.09	0.73	0.75
Grand Total—Gas Supply	**20.92**	**21.59**	**22.10**	**22.80**	**24.25**	**25.09**	**28.28**	**29.28**
Requirements‡		20.27		25.56		30.89		36.99
(Shortage) or Surplus		1.32		(2.76)		(5.80)		(7.71)

* Conversion factors:

All Natural Gas	1,032 BTU/cu.ft.
LNG Imports	1,100 BTU/cu.ft.
Coal Syngas	925 BTU/cu.ft.
Liquid Syngas	1,000 BTU/cu.ft.

† These figures include gas from South Alaska.

‡ From Gas Demand Task Group.

These figures do not include gas consumed in production and distribution as this report is primarily concerned with logistics. Consequently, these figures will not coincide in all respects with those in Chapter Four of *U.S. Energy Outlook:*

TABLE 2 (Cont'd.)

TOTAL U.S. NATURAL AND SYNTHETIC GAS REQUIREMENTS VERSUS GAS SUPPLY—CASE IV*

	1971		1975		1980		1985	
	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}	TCF	BTU x 10^{15}
Gas Supply								
Conventional Domestic	19.97	20.61	19.86	20.50	15.81	16.32	12.13	12.52
Alaska North Slope	0	0	0	0	0	0	1.20	1.24
Canadian Imports	0.90	0.93	1.00	1.03	1.60	1.65	2.70	2.79
Mexican Imports	0.05	0.05	0.05	0.05	0	0	0	0
Total Natural	**20.92**	**21.59**	**20.91**	**21.58**	**17.41**	**17.97**	**16.03**	**16.55**
LNG Imports†	0	0	0.24	0.26	2.28	2.51	4.11	4.52
Coal Gasification	0	0	0	0	0.18	0.17	0.54	0.50
Liquid Gasification	0	0	0.64	0.64	1.32	1.32	1.32	1.32
Total Syngas	**0**	**0**	**0.64**	**0.64**	**1.50**	**1.49**	**1.86**	**1.82**
Nuclear Stimulation	0	0	0	0	0	0	0	0
Grand Total—Gas Supply	**20.92**	**21.59**	**21.79**	**22.48**	**21.19**	**21.97**	**22.00**	**22.89**
Requirements‡		20.27		25.56		30.89		36.99
(Shortage) or Surplus		1.32		(3.08)		(8.92)		(14.10)

* Conversion factors:

All Natural Gas	1,032 BTU/cu.ft.
LNG Imports	1,100 BTU/cu.ft.
Coal Syngas	925 BTU/cu.ft.
Liquid Syngas	1,000 BTU/cu.ft.

† These figures include gas from South Alaska.

‡ From Gas Demand Task Group.

These figures do not include gas consumed in production and distribution as this report is primarily concerned with logistics. Consequently, these figures will not coincide in all respects with those in Chapter Four of ***U.S. Energy Outlook:***

Chapter Two

LIQUEFIED NATURAL GAS FACILITIES

While liquefaction plant technology is fairly well established and costs are reasonably well known, neither the technology of ship construction nor the costs are really established at this time. At least four different containment systems are presently under construction or contemplated, and the maximum economic size is more dependent on port restrictions, delivered annual volumes and shipping distance than on technology.

Costs have skyrocketed since the construction of such ships as the *Methane Progress* and the *Methane Princess*, and even since the construction of the *Arctic Tokyo* and *Polar Alaska*. For these reasons the costs of both ships and port facilities are highly speculative, even without considering the effects of probable inflation. With these things in mind, the costs of LNG facilities as shown in Table 3 were developed as follows:

- Ship Costs

  (1) Using British Petroleum's Sailing Distance Manual, the round trip nautical mileage for each of the cases concerned was obtained. Ships sailing speed was assumed to average 20 knots. Three days for loading and unloading plus one day weather delay were allowed for each voyage.

  (2) Ships were sized to provide for loading sufficient liquid to meet the required delivery plus the necessary boil-off and return voyage cool-down liquid of 0.25 percent per day. The maximum sized vessel was limited to 160,000 cubic meters or approximately 1 million barrels. Maximum loaded capacity was 98 percent of total volume per U.S. Coast Guard requirements.

  (3) Vessel availability was 345 days per year, based upon 20 days annual docking and survey time.

  (4) Ship costs are based upon published data, from actual costs of vessels in service and from tentative bids for proposed projects.

  (5) To the extent reasonably possible, it was assumed that advantage would be taken of maximum sized ships, but ships are to be dedicated to a specific project.

- Liquefaction Plant Costs

  Liquefaction plant costs are based upon the modular concept, with 150 million cubic feet per day used as the most efficient sized module. Costs were developed for four different capacity plants and a cost curve obtained. Plant costs for each were taken from this curve based on liquefaction to meet deliveries plus boil-off and cool-down requirements for the LNG tankers.

- Unloading Terminals and Regasification Plants

TABLE 3

LNG CAPITAL REQUIREMENTS FOR LIQUEFACTION, TRANSPORTATION AND REGASIFICATION—ALL CASES
(Millions of Constant 1970 Dollars)

Period	Voyage Route: Source	– Delivery Point	Quantity BCF/Day	Round Trip Nautical Miles	Ships Required	Capital Requirements Millions Dollars: Ships*	Liquefaction Plant	Unloading Terminal	Total Capital
Last Half 1975	Algeria	– Cove Point	.350	7,300	3	150	131	49	230
	Total by End of 1975		**.350**		**3**	**150**	**131**	**49**	**230**
Additional 1976 – 1980	Algeria	– Cove Point	.300	7,300	2	117	120	54	291
		– Savannah	.500	7,900	4	220	175	56	451
		– Delaware River	.900	7,200	6	349	291	66	706
		– New York	.300	6,900	2	114	120	53	287
	Nigeria	– Delaware River	.650	9,800	6	337	222	60	619
		– New York	.200	9,700	2	106	91	46	243
		– Chesapeake Bay	.350	9,800	3	176	131	56	363
		– Boston	.300	9,500	3	158	120	50	328
	Venezuela	– Delaware River	.500	3,900	2	118	175	59	352
		– Lake Charles	.500	3,800	2	116	175	59	350
	Trinidad	– Lake Charles	.300	3,800	2	85	120	43	248
	Alaska	– Portland	.300	2,800	2	106	120	40	266
	Ecuador	– Los Angeles	.500	6,500	3	117	175	59	411
	Total Additional 1976-1980		**5.600**		**39**	**2,179**	**2,035**	**701**	**4,915**
Additional 1981— 1985	Algeria	– New York	.500	6,900	3	183	175	61	419
		– Delaware River	.250	7,200	2	104	104	48	256
		– Chesapeake Bay	.500	7,300	4	211	175	55	441
		– Boston	.250	6,600	2	100	104	46	250
		– Savannah	.250	7,900	2	110	104	50	264
	Nigeria	– New York	.500	9,700	4	245	175	61	481
		– Delaware River	.500	9,800	4	248	175	61	484
		– Chesapeake Bay	.250	9,800	2	124	104	55	283
		– Boston	.250	9,500	2	121	104	54	279
		– Savannah	.250	9,900	2	124	104	55	283
	Pacific	– San Francisco	.500	13,200	6	341	180	58	579
		– Los Angeles	1.000	13,000	11	659	329	68	1,056
	Total Additional 1981-1985		**5.000**		**44**	**2,570**	**1,833**	**672**	**5,075**

* Based on foreign yard costs. U.S. costs approximately 40 percent higher.

(1) The cost of these plants vary even for the same delivered quantities to various ports due to the difference in storage capacity calculated for each case.

(2) Storage required was assumed to be equivalent to the capacity of two ship loads. Under this system, the storage under all cases varies from 900 thousand barrels to 2 million barrels, using an assumed cost of $15 per barrel.

Table 3 summarizes the basic data and calculations used to obtain the capital requirements shown in Columns 6, 7 and 8 of Table 1 for LNG facilities.

Appendix F shows the reasoning and detailed calculations back of the figures in Table 3 .

Chapter Three

LIQUEFIED PETROLEUM GAS FACILITIES

Liquefied Petroleum Gas supplies from conventional sources in the lower 48 states are projected to increase slightly through 1975 and decrease thereafter. However, substantial increases are projected from--

- LPG in pipeline suspension with natural gas from Alaska's North Slope and in Canadian gas imports
- LPG pipeline imports from Canada

TABLE 4

TOTAL U.S. LPG REQUIREMENTS VERSUS LPG SUPPLY—CASE I*

	1971		1975		1980		1985	
	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}
LPG Supplies								
Conventional Domestic								
From Non-Associated and Associated-Dissolved Gas	389.90	1,555.70	331.70	1,323.48	341.80	1,363.78	359.50	1,434.41
From Refineries	122.64	489.33	147.83	589.84	178.49	712.18	206.96	825.77
Total Conventional	**512.54**	**2,045.03**	**479.53**	**1,913.32**	**520.29**	**2,075.96**	**566.46**	**2,260.18**
Imports								
Liquid Pipelines	20.00	79.80	27.25	108.73	34.75	138.65	44.00	175.56
Suspension in Gas Pipelines	0	0	0	0	51.00	203.49	100.80	402.19
Ships and Barges	0.90	3.59	12.50	49.88	71.00	283.29	110.00	438.90
Total Imports	**20.90**	**83.39**	**39.75**	**158.61**	**156.75**	**625.43**	**254.80**	**1,016.65**
Total LPG Supplies	**533.44**	**2,128.42**	**519.28**	**2,071.93**	**677.04**	**2,701.39**	**821.26**	**3,276.83**
Requirements†								
For Syngas Plants	0	0	40.95	163.39	61.43	245.11	61.43	245.11
For Chemical Plants	155.39	620.01	201.25	802.99	256.39	1,023.00	299.75	1,196.00
For Other Uses	268.17	1,070.00	300.00	1,197.00	336.09	1,341.00	371.68	1,483.00
Total Requirements	**423.56**	**1,690.01**	**542.20**	**2,163.38**	**653.91**	**2,609.11**	**732.86**	**2,924.11**
(Shortage) or Oversupply	109.88	438.41	(22.92)	(91.45)	23.13	92.28	88.40	352.72

* Conversion factors: 95,000 BTU/gal.
3,990,000 BTU/bbl.

† From Gas Demand Task Group. These figures do not include LPG for motor gasoline at refineries and at chemical plants.

TABLE 4 (Cont'd.)

TOTAL U.S. LPG REQUIREMENTS VERSUS LPG SUPPLY—CASE II*

	1971		1975		1980		1985	
	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}
LPG Supplies								
Conventional Domestic								
From Non-Associated and Associated-Dissolved Gas	389.90	1,555.70	329.20	1,313.51	323.60	1,291.16	317.60	1,267.22
From Refineries	122.64	489.33	147.83	589.84	178.49	712.18	206.96	825.77
Total Conventional	**512.54**	**2,045.03**	**477.03**	**1,903.35**	**502.09**	**2,003.34**	**524.56**	**2,092.99**
Imports								
Liquid Pipelines	20.00	79.80	27.25	108.73	34.75	138.65	44.00	175.56
Suspension in Gas Pipelines	0	0	0	0	51.00	203.49	93.60	373.46
Ships and Barges	0.90	3.59	12.50	49.88	71.00	283.29	110.00	438.90
Total Imports	**20.90**	**83.39**	**39.75**	**158.61**	**156.75**	**625.43**	**247.60**	**987.92**
Total LPG Supplies	**533.44**	**2,128.42**	**516.78**	**2,061.96**	**658.84**	**2,628.77**	**772.16**	**3,080.91**
Requirements†								
For Syngas Plants	0	0	40.95	163.39	61.43	245.11	61.43	245.11
For Chemical Plants	155.39	620.00	201.25	803.00	256.39	1,023.00	299.75	1,196.00
For Other Uses	268.17	1,070.00	300.00	1,197.00	336.09	1,341.00	371.68	1,483.00
Total Requirements	**423.56**	**1,690.00**	**542.20**	**2,163.39**	**653.91**	**2,609.11**	**732.86**	**2,924.11**
(Shortage) or Oversupply	109.88	438.42	(25.42)	(101.43)	4.93	19.66	39.30	156.80

* Conversion factors: 95,000 BTU/gal.
3,990,000 BTU/bbl.

† From Gas Demand Task Group. These figures do not include LPG for motor gasoline at refineries and at chemical plants.

- LPG tanker imports from South America and elsewhere.

Table 4 (pp. 13-16) details the sources and amount of these supplies as projected by the Gas Supply, Oil Supply and Oil Logistics Task Groups, and the requirements projected by the Gas Demand Task Group. Note that requirements projected by the Gas Demand Task Group do not include LPG used for motor gasoline at refineries and chemicals.

Historical figures were used to determine volumes of LPG transported and the distances for each mode of transportation--pipelines, rail tank cars and tank trucks.

Historical unit costs of LPG pipelines, tank cars and tank trucks were then applied to these volumes. The cost of replacement

TABLE 4 (Cont'd.)

TOTAL U.S. LPG REQUIREMENTS VERSUS LPG SUPPLY—CASE III*

	1971		1975		1980		1985	
	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}	MMB	BTU x 10^{12}
LPG Supplies								
Conventional Domestic								
From Non-Associated and Associated-Dissolved Gas	389.90	1,555.70	311.80	1,244.08	276.60	1,103.63	245.60	979.94
From Refineries	122.64	489.33	147.83	589.84	178.49	712.18	206.96	825.77
Total Conventional	**512.54**	**2,045.03**	**459.63**	**1,833.92**	**455.09**	**1,815.81**	**452.56**	**1,805.71**
Imports								
Liquid Pipelines	20.00	79.80	27.25	108.73	34.75	138.65	44.00	175.56
Suspension in Gas Pipelines	0	0	0	0	46.20	184.34	81.60	325.58
Ships and Barges	0.90	3.59	12.50	49.88	71.00	283.29	110.00	438.90
Total Imports	**20.90**	**83.39**	**39.75**	**158.61**	**151.95**	**606.28**	**235.60**	**940.04**
Total LPG Supplies	**533.44**	**2,128.42**	**499.38**	**1,992.53**	**607.04**	**2,422.09**	**688.16**	**2,745.75**
Requirements†								
For Syngas Plants	0	0	40.95	163.39	61.43	245.11	61.43	245.11
For Chemical Plants	155.39	620.00	201.25	803.00	256.39	1,023.00	299.75	1,196.00
For Other Uses	268.17	1,070.00	300.00	1,197.00	336.09	1,341.00	371.68	1,483.00
Total Requirements	**423.56**	**1,690.00**	**542.20**	**2,163.39**	**653.91**	**2,609.11**	**732.86**	**2,924.11**
(Shortage) or Oversupply	109.88	438.42	(42.82)	(170.86)	(46.87)	(187.02)	(44.70)	(178.36)

* Conversion factors: 95,000 BTU/gal.
3,990,000 BTU/bbl.

† From Gas Demand Task Group. These figures do not include LPG for motor gasoline at refineries and at chemical plants.

units projected to be necessary as indicated by past experience was added. Also included in this section are the projected costs of tank trucks for the local transportation of LNG. All of these costs are shown in Columns 9 through 12 of Table 1.

Appendix G shows details of data and calculations used to derive the LPG costs shown in Table 1 and is divided into three sections:

- Pipeline, tanker and barge facilities
- Tank truck facilities
- Rail tank car facilities.

TABLE 4 (Cont'd.)

TOTAL U.S. LPG REQUIREMENTS VERSUS LPG SUPPLY–CASE IV*

	1971		1975		1980		1985	
	MMB	**BTU x 10^{12}**	**MMB**	**BTU x 10^{12}**	**MMB**	**BTU x 10^{12}**	**MMB**	**BTU x 10^{12}**
LPG Supplies								
Conventional Domestic								
From Non-Associated and Associated-Dissolved Gas	389.90	1,555.70	307.70	1,227.72	252.20	1,006.28	191.60	764.48
From Refineries	122.64	489.33	147.83	589.84	178.49	712.18	206.96	825.77
Total Conventional	**512.54**	**2,045.03**	**455.53**	**1,817.56**	**430.69**	**1,718.46**	**398.56**	**1,590.25**
Imports								
Liquid Pipelines	20.00	79.80	27.25	108.73	34.75	138.65	44.00	175.56
Suspension in Gas Pipelines	0	0	0	0	19.80	79.00	57.60	229.82
Ships and Barges	0.90	3.59	12.50	49.88	71.00	283.29	110.00	438.90
Total Imports	**20.90**	**83.39**	**39.75**	**158.61**	**125.55**	**500.94**	**211.60**	**844.28**
Total LPG Supplies	**533.44**	**2,128.42**	**495 28**	**1,976.17**	**556.24**	**2,219.40**	**610.16**	**2,434.53**
Requirements†								
For Syngas Plants	0	0	40.95	163.39	61.43	245.11	61.43	245.11
For Chemical Plants	155.39	620.00	201.25	803.00	256.39	1,023.00	299.75	1,196.00
For Other Uses	268.17	1,070.00	300.00	1,197.00	336.09	1,341.00	371.68	1,483.00
Total Requirements	**423.56**	**1,690.00**	**542.20**	**2,163.39**	**653.91**	**2,609.11**	**732.86**	**2,924.11**
(Shortage) or Oversupply	109.88	438.42	(46.92)	(187.22)	(97.67)	(389.71)	(122.70)	(489.58)

* Conversion factors: 95,000 BTU/gal.
3,990,000 BTU/bbl.

† From Gas Demand Task Group. These figures do not include LPG for motor gasoline at refineries and at chemical plants.

Appendices

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* Replaced Robert P. Kraujalis - April 1972

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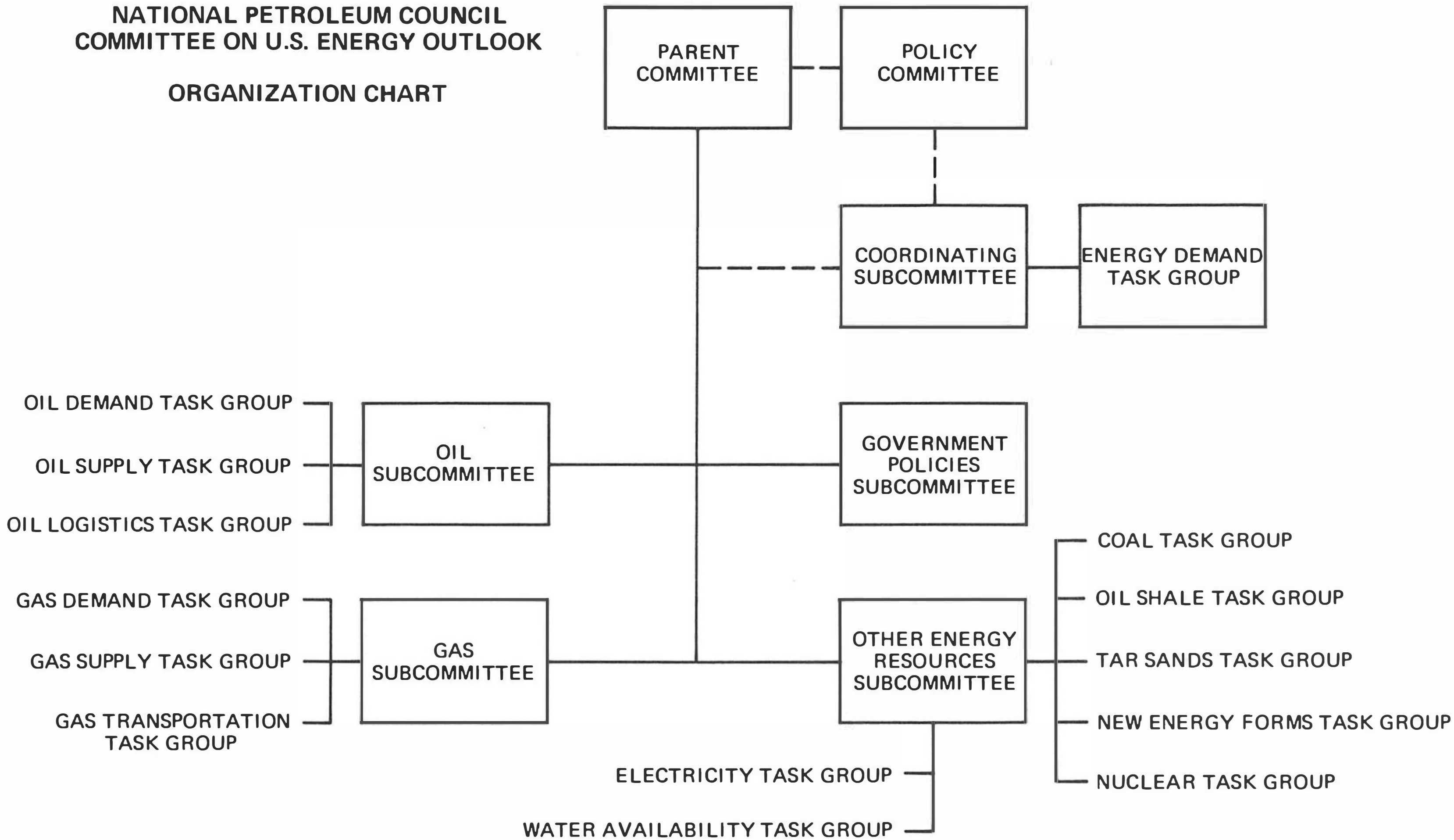

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PROJECTION OF CAPITAL REQUIREMENTS FOR GAS TRANSMISSION FACILITIES

SUMMARY

The capital requirements for gas transmission facilities for the 1971-1985 period were projected using the following broad basic assumptions:

- Any expansion of interstate pipeline systems would follow historical patterns as far as markets served and location of facilities.

- Regardless of any interstate expansion, new facilities would be required to attach new production, to enlarge and modify gathering systems for intrastate facilities and for storage growth.

- Facilities would also be required for nontraditional sources--to bring gas from the Arctic Frontier areas of Alaska and Canada, to connect SNG plants (liquid reforming) and LNG vaporization plants to existing transmission and distribution networks and to connect coal gasification plants to existing transmission networks.

Using these broad guidelines, a simple computer model was developed to receive input from the Gas Demand and Gas Supply Task Groups, to balance supply and demand using a "fair share" ratio and to compute transmission facility capital costs to handle the supply volumes available for each of the years 1971 through 1985. In addition, facilities and capital costs were developed to transport that portion of the Alaskan/Canadian Arctic Frontier gas destined for consumption in the United States.

The supply and demand volumes for Cases I, II, III and IV were analyzed using the computer model. The projected capital requirements are shown in Table 5.

Capital costs were developed by analyzing the historical costs of transporting gas between PAD districts and then updating these costs to a 1970 base. A historical cost analysis was also used for production attachments and for gathering and storage facilities. Costs based on estimated facility requirements were developed for LNG, SNG and coal gas attachments, Arctic pipeline facilities and nuclear stimulation attachments. By applying the capital cost factors to the incremental volumes, annual capital costs were computed and then summed for the 5-year periods considered for presentation.

TABLE 5

SUMMARY
PROJECTION OF
CAPITAL REQUIREMENTS FOR
GAS TRANSMISSION FACILITIES

(Millions of Dollars*)

Period	Case I	Case II	Case III	Case IV
1971-75	$ 6,146.5	$ 5,894.9	$ 4,035.3	$ 3,101.7
1976-80	16,007.1	13,406.9	10,702.1	5,075.1
1981-85	23,023.5	16,214.7	13,775.7	10,267.6
Total	$45,177.1	$35,516.5	$28,513.1	$18,444.4

*All figures are in 1970 constant dollars.

The capital cost projections appear reasonable when compared to historical patterns, considering the variations in volume projections. It is not unreasonable to expect the gas flow patterns for *interstate* and *intrastate* gas movements to continue in the same historical pattern. New facilities and patterns can be expected for SNG, LNG, coal gasification and, to some extent, nuclear stimulation gas.

The costs to transport the Alaskan/Canadian Arctic gas to existing pipeline networks in the lower 48 states are included in the study. Only the costs of facilities required to transport gas for consumption in the United States are included. Considerably more gas is estimated to be produced in the Canadian Arctic than is imported to the United States. It was assumed that the financing for the facilities to transport gas to the United States would also be accomplished in this country.

The U.S. portion of the Alaskan/Canadian facilities ranges from two equivalent 48-inch diameter, 2,500-mile long pipelines in Case IV to four equivalent 48-inch diameter, 2,500-mile pipelines in Case I. Additional gas has been scheduled from the Canadian Arctic for consumption in Canada, but *no* facilities or costs have been provided to transport these volumes. All Alaskan/Canadian facilities are scheduled to be constructed in the 10-year period from 1975 through 1985. The costs of the Arctic facilities range from a high of $17.8 billion for Case I to a low of $9.8 billion for Case IV. The ability of the United States and Canada to finance and construct the Arctic facilities may be strained when considering the following:

- The facilities must be constructed in some of the most difficult environment in the world.

- The regulatory and ecological requirements will be more strict than for any other area.

- In addition to the gas lines, oil pipelines must also be constructed from the Arctic during the same time period.

- Gas transmission facilities ranging in cost from $9 to $27 billion must be constructed in the United States during this same time.

- As a comparison, the total costs for all transmission, storage and production facilities for the prior 15-year period (1956-1970) were between $15 and $16 billion.

Other than the concern expressed for the Arctic facility requirements, the costs projected appear reasonable.

All costs presented are in 1970 constant dollars. Assuming an inflation rate of 3 percent per year and the pattern of expenditures as shown in Table 5, the total current dollars would be 30 to 40 percent larger.

DISCUSSION

The one basic assumption inherent in all cases analyzed is that the gas supply will be available as projected by the Supply Group and that the demand, as projected by the Demand Group, will be greater than or equal to the supply. The basis for all cost estimates is historical costs escalated to 1970 constant dollars.

To project future capital costs for gas transmission facilities, one basic method was developed that could be applied to all cases. The methodology used is described in a later section (see p.36). As mentioned, a simple computer model was programmed using the methodology as the specification. The program made all of the calculations except for the Arctic facilities.

The gas supply for each year from 1970 through 1985 and new domestic production for each year are required as input to the model. The gas demand was projected by the Demand Group for the years 1970, 1975, 1980 and 1985. The model needs the demand for each year. Therefore, the demand for each of the intermediate years was obtained by a linear interpolation. Cost factors were computed for each individual component and put into the program. The program computes a gas balance for each PAD district for each year. The costs required to transport the expansion gas are computed using the capital cost factors. The costs for each PAD district are summed to obtain a national total for each year. The yearly totals are summed by 5-year increments to obtain total expenditures for the periods 1975, 1980 and 1985.

The only cost computations not done by the computer were those for the Alaskan/Canadian Arctic facilities. These were done separately as shown in Exhibit I, page 73, and only the total annual costs were used in the computer.

The costs developed by the model were reviewed on an annual and on a 5-year period basis, and all appear reasonable in relation to the gas supply. The individual PAD district gas balances and costs are not presented in this report. The national totals represent a better projection, and many of the factors used in the program are based on national totals and only put in on a PAD district basis for procedural reasons. The gas balances and cost projections for Cases I, II, III and IV are shown in the following Tables 6 through 14.

METHODOLOGY

In order to analyze future gas movement in the United States, a methodology was developed which takes into account historical gas flow patterns, provides for future changes and provides a means for handling large quantities of nontraditional gas supplies. The methodology developed represents a logical procedure to account for all gas movements within the United States.

The methodology was used as the specification for the computer model which projected future costs for all cases. A description of the computer program in included in Exhibit II, page 105.

Input Requirements

Gas Demand

The gas demand figures obtained from the Demand Task Group are shown in Table 15. These figures are calculated on a BTU basis and include "field use." The field use requirements, as indicated by the Demand Task Group, were deducted from the totals. These revised figures are shown in Table 16. Annual demand figures for the years 1971 through 1985 were linearly interpolated using 1970, 1975, 1980 and 1985 as base years. Based on the Supply Task Group's standard conversion of 1,032 BTU's per cubic foot, all of the demand figures were converted to an "as metered" basis as shown in Table 17.

It was necessary to eliminate field use from the demand figures since the resultant demand numbers were to be used in developing a "fair share" ratio for each PAD district. Field use gas is not transported out of the area where it is produced and should not be included in any transmission calculation.

TABLE 6

CASE I
GAS BALANCE

National Totals	1970	1975	1980	1985
		(Tcf/Year)		
Domestic Production				
Region 2	.5698	.4200	.3350	.2920
3	.6133	.7109	.5769	.5399
4	.3820	.4839	.5299	.7069
5	2.8734	2.7020	2.8720	3.1470
6	11.1925	8.9940	8.3130	7.8110
7	3.5344	3.4710	2.8590	2.6460
8 & 9	.0999	.0190	.0240	.0380
10	.3501	.4300	.5200	.6260
11	0	.0020	.0110	.0400
2A	0	.0450	.1480	.2650
6A	(incl.in 6)	4.4600	6.1310	7.6410
11A	0	0	.0210	.3900
Sub-Total	19.6154	21.7378	22.3408	24.1698
Pipeline Imports				
Alaska Region 1N	0	0	1.3000	3.0000
Canadian Frontier	0	0	.6000	1.8000
Existing Canadian	.7790	1.0000	1.0000	.9000
Mexican	.0500	.0500	0	0
Sub-Total	.8290	1.0500	2.9000	5.7000
LNG	0	.2380	2.2820	4.1070
SNG	0	.6360	1.3150	1.3150
Coal Gas	0	0	.5600	2.4800
Nuclear Stimulation	0	.0050	.1870	1.1970
Total Supply	20.4444	23.6668	29.5848	38.9688
Adjusted Demand	20.4444	23.6668	29.5848	38.9688
Supply Balance	0	0	0	0

TABLE 6 (Cont'd.)

CASE I
GAS BALANCE

	1970	1975	1980	1985
		(Tcf/Year)		
Supply Attachment Volumes				
New Production				
Onshore	0	.8519	.8279	.5699
Offshore	0	.5580	.6330	.4500
LNG	0	.2380	.3660	.1820
SNG	0	.3240	0	0
Coal Gas	0	0	.1600	.4800
Nuclear Stimulation	0	.0050	.0840	.2390
Total	0	1.9769	2.0709	1.9209
Transmission Expansion Volumes				
Intra PAD	0	.7717	1.4269	1.4309
Inter PAD	0	.4190	.3554	.3460
Storage Expansion Volumes				
Intra PAD	0	.0932	.1863	.2008
Inter PAD	0	.0506	.0464	.0485
Total	0	.1438	.2327	.2493

TABLE 7

CASE II
GAS BALANCE

National Totals	1970	1975	1980	1985
		(Tcf/Year)		
Domestic Production				
Region 2	.5698	.4190	.3230	.2600
3	.6133	.7089	.5579	.4879
4	.3820	.4809	.4959	.5979
5	2.8734	2.6750	2.6830	2.7560
6	11.1925	8.9340	7.9380	7.0220
7	3.5344	3.4520	2.7310	2.3250
8 & 9	.0999	.0190	.0220	.0290
10	.3501	.4250	.4820	.5290
11	0	.0020	.0100	.0310
2A	0	.0440	.1320	.2200
6A	(incl. in 6)	4.3880	5.6070	6.6060
11A	0	0	.0180	.2970
Sub-Total	19.6154	21.5478	20.9998	21.1608
Pipeline Imports				
Alaska Region 1N	0	0	1.2000	2.4000
Canadian Frontier	0	0	.6000	1.8000
Existing Canadian	.7790	1.0000	1.0000	.9000
Mexican	.0500	.0500	0	0
Sub-Total	.8290	1.0500	1.8000	5.1000
LNG	0	.2380	2.2820	4.1070
SNG	0	.6360	1.3150	1.3150
Coal Gas	0	0	.3600	1.3100
Nuclear Stimulation	0	.0030	.0940	.7250
Total Supply	20.4444	23.4748	27.8508	33.7178
Adjusted Demand	20.4444	23.4748	27.8508	33.7178
Supply Balance	0	0	0	0

TABLE 7 (Cont'd.)

CASE II
GAS BALANCE

	1970	1975	1980	1985
		(Tcf/Year)		
Supply Attachment Volumes				
New Production				
Onshore	0	.7459	.6359	.3859
Offshore	0	.5340	.5150	.3470
LNG	0	.2380	.3660	.1820
SNG	0	.3240	0	0
Coal Gas	0	0	.1200	.2300
Nuclear Stimulation	0	.0030	.0460	.1510
Total	0	1.8449	1.6829	1.3229
Transmission Expansion Volumes				
Intra PAD	0	.6769	.9420	.9178
Inter PAD	0	.3767	.2593	.1648
Storage Expansion Volumes				
Intra PAD	0	.0818	.1230	.1288
Inter PAD	0	.0455	.0338	.0231
Total	0	.1273	.1568	.1519

TABLE 8

CASE III
GAS BALANCE

National Totals	1970	1975	1980	1985
		(Tcf/Year)		
Domestic Production				
Region 2	.5698	.4230	.3380	.2970
3	.6133	.7229	.6259	.6429
4	.3820	.4739	.4719	.5749
5	2.8734	2.4990	2.3210	2.2760
6	11.1925	8.3570	6.5360	5.0070
7	3.5344	3.3230	2.4100	1.7850
8 & 9	.0999	.0190	.0210	.0240
10	.3501	.4130	.4510	.4820
11	0	.0020	.0080	.0240
2A	0	.0420	.1050	.1700
6A	(incl. in 6)	3.8960	4.2990	4.6240
11A	0	0	.0130	.2030
Sub-Total	19.6154	20.1708	17.5998	16.1098
Pipeline Imports				
Alaska Region 1N	0	0	1.0000	2.0000
Canadian Frontier	0	0	.6000	1.8000
Existing Canadian	.7790	1.0000	1.0000	.9000
Mexican	.0500	.0500	0	0
Sub-Total	.8290	1.0500	2.6000	4.7000
LNG	0	.2380	2.2820	4.1070
SNG	0	.6360	1.3150	1.3150
Coal Gas	0	0	.3600	1.3100
Nuclear Stimulation	0	.0030	.0940	.7250
Total Supply	20.4444	22.0978	24.2508	28.2668
Adjusted Demand	20.4444	22.0978	24.2508	28.2668
Supply Balance	0	0	0	0

TABLE 8 (Cont'd.)

CASE III
GAS BALANCE

	1970	1975	1980	1985
		(Tcf/Year)		
Supply Attachment Volumes				
New Production				
Onshore	0	.5269	.4109	.2419
Offshore	0	.3490	.3050	.2390
LNG	0	.2380	.3660	.1820
SNG	0	.3240	0	0
Coal Gas	0	0	.1200	.2300
Nuclear Stimulation	0	.0030	.0460	.1510
Total	0	1.4409	1.2479	1.0439
Transmission Expansion Volumes				
Intra PAD	0	.3668	.6285	.7543
Inter PAD	0	.1000	.1704	.1383
Storage Expansion Volumes				
Intra PAD	0	.0443	.0820	.1058
Inter PAD	0	.0120	.0222	.0194
Total	0	.0563	.1042	.1252

TABLE 9

CASE IV
GAS BALANCE

National Totals	1970	1975	1980	1985
		(Tcf/Year)		
Domestic Production				
Region 2	.5698	.4190	.3090	.2170
3	.6133	.7149	.5499	.4629
4	.3820	.4659	.4089	.3789
5	2.8734	2.4550	2.0270	1.6110
6	11.1925	8.2770	6.1590	4.3230
7	3.5344	3.2930	2.2560	1.4750
8 & 9	.0999	.0180	.0170	.0150
10	.3501	.4030	.3850	.3240
11	0	.0020	.0060	.0120
2A	0	.0390	.0750	.0970
6A	(incl. in 6)	3.7760	3.6100	3.1220
11A	0	0	.0090	.0940
Sub-Total	19.6154	19.8628	15.8119	12.1319
Pipeline Imports				
Alaska Region 1N	0	0	0	1.2000
Canadian Frontier	0	0	.6000	1.8000
Existing Canadian	.7790	1.0000	1.0000	.9000
Mexican	.0500	.0500	0	0
Sub-Total	.8290	1.0500	1.6000	3.9000
LNG	0	.2380	2.2820	4.1070
SNG	0	.6360	1.3150	1.3150
Coal Gas	0	0	.1800	.5400
Nuclear Stimulation	0	0	0	0
Total Supply	20.4444	21.7868	21.1889	21.9939
Adjusted Demand	20.4444	21.7868	21.1889	21.9939
Supply Balance	0	0	0	0

TABLE 9 (Cont'd.)

CASE IV
GAS BALANCE

	1970	1975	1980	1985
		(Tcf/Year)		
Supply Attachment Volumes				
New Production				
Onshore	0	.4269	.1609	.0143
Offshore	0	.2830	.1420	.0320
LNG	0	.2380	.3660	.1820
SNG	0	.3240	0	0
Coal Gas	0	0	.1800	.3600
Nuclear Stimulation	0	0	0	0
Total	0	1.2719	.8489	.5883
Transmission Expansion Volumes				
Intra PAD	0	.3500	.4550	.2700
Inter PAD	0	.1507	.0004	0
Storage Expansion Volumes				
Intra PAD	0	.0423	.0594	.0378
Inter PAD	0	.0182	0	0
Total	0	.0605	.0594	.0378

TABLE 10

CASE I
CAPITAL COSTS

National Totals	1971 to 1975	1976 to 1980	1981 to 1985	Total
		(Millions of Dollars*)		
Transmission Domestic				
Intra PAD	1,403.5	2,502.1	4,188.0	8,093.6
Inter PAD	2,765.3	2,457.6	2,879.9	8,102.8
Sub-Total	4,168.8	4,959.7	7,067.9	16,196.4
Transmission Imports				
Alaska	0	5,576.0	6,919.0	12,495.0
Canadian Frontier	0	1,711.0	3,569.0	5,280.0
Sub-Total	0	7,287.0	10,488.0	17,775.0
Supply Attachments				
New Production				
Onshore	321.4	423.8	360.2	1,105.4
Offshore	887.4	1,363.0	1,295.6	3,546.0
LNG	20.2	172.3	155.1	347.6
SNG	28.6	30.6	0	59.2
Coal Gas	0	520.0	1,514.0	2,034.0
Nuclear Stimulation	.5	18.2	101.0	119.7
Sub-Total	1,258.1	2,527.9	3,425.9	7,211.9
New Storage Facilities	719.6	1,068.1	1,786.9	3,574.6
Total Transmission Facilities	6,146.5	15,842.7	22,768.7	44,757.9
Extraction Plants	0	164.4	254.8	419.2
Total Facilities	6,146.5	16,007.1	23,023.5	45,177.1

*All figures in 1970 constant dollars.

TABLE 11

CASE II
CAPITAL COSTS

National Totals	1971 to 1975	1976 to 1980	1981 to 1985	Total
		(Millions of Dollars*)		
Transmission Domestic				
Intra PAD	1,342.1	1,861.8	2,798.2	6,002.1
Inter PAD	2,648.9	1,904.5	1,820.8	6,374.2
Sub-Total	3,991.0	3,766.3	4,619.0	12,376.3
Transmission Imports				
Alaska	0	5,049.0	4,548.0	9,597.0
Canadian Frontier	0	1,743.0	3,499.0	5,242.0
Sub-Total	0	6,792.0	8,047.0	14,839.0
Supply Attachments				
New Production				
Onshore	308.9	351.3	249.7	909.9
Offshore	860.9	1,179.4	1,026.9	3,067.2
LNG	20.2	172.3	155.1	347.6
SNG	28.6	30.6	0	59.2
Coal Gas	0	164.0	690.5	854.5
Nuclear Stimulation	.3	9.1	63.1	72.5
Sub-Total	1,218.9	1,906.7	2,185.3	5,310.9
New Storage Facilities	685.0	785.7	1,149.7	2,620.4
Total Transmission Facilities	5,894.9	13,250.7	16,001.0	35,146.6
Extraction Plants	0	156.2	213.7	369.9
Total Facilities	5,894.9	13,406.9	16,214.7	35,516.5

*All figures in 1970 constant dollars.

TABLE 12

CASE III
CAPITAL COSTS

National Totals	1971 to 1975	1976 to 1980	1981 to 1985	Total
		(Millions of Dollars*)		
Transmission Domestic				
Intra PAD	1,398.2	1,359.4	2,246.6	5,004.2
Inter PAD	1,259.5	1,074.6	1,326.4	3,660.5
Sub-Total	2,657.7	2,434.0	3,573.0	8,664.7
Transmission Imports				
Alaska	0	4,506.0	3,896.0	8,402.0
Canadian Frontier	0	1,743.0	3,499.0	5,242.0
Sub-Total	0	6,249.0	7,395.0	13,644.0
Supply Attachments				
New Production				
Onshore	214.9	226.3	157.3	598.5
Offshore	617.9	733.5	615.6	1,967.0
LNG	20.2	172.3	155.1	347.6
SNG	28.6	30.5	0	59.1
Coal Gas	0	164.0	690.5	854.5
Nuclear Stimulation	.3	9.1	63.1	72.5
Sub-Total	881.9	1,335.7	1,681.6	3,899.2
New Storage Facilities	495.7	543.7	937.0	1,976.4
Total Transmission Facilities	4,035.3	10,562.4	13,586.6	28,184.3
Extraction Plants	0	139.7	189.1	328.8
Total Facilities	4,035.3	10,702.1	13,775.7	28,513.1

*All figures in 1970 constant dollars.

TABLE 13

CASE IV
CAPITAL COSTS

National Totals	1971 to 1975	1976 to 1980	1981 to 1985	Total
		(Millions of Dollars*)		
Transmission Domestic				
Intra PAD	699.4	980.8	1,443.2	3,123.4
Inter PAD	1,278.0	501.0	43.1	1,822.1
Sub-Total	1,977.4	1,481.8	1,486.3	4,945.5
Transmission Imports				
Alaska	0	0	4,370.0	4,370.0
Canadian Frontier	0	2,283.0	3,135.0	5,418.0
Sub-Total	0	2,283.0	7,505.0	9,788.0
Supply Attachments				
New Production				
Onshore	195.0	132.7	28.6	356.3
Offshore	559.8	446.4	156.2	1,162.4
LNG	20.2	172.3	155.1	347.6
SNG	28.6	30.5	0	59.1
Coal Gas	0	102.5	248.5	351.0
Nuclear Stimulation	0	0	0	0
Sub-Total	803.6	884.4	588.4	2,276.4
New Storage Facilities	320.7	376.6	482.4	1,179.7
Total Transmission Facilities	3,101.7	5,025.8	10,062.1	18,189.6
Extraction Plants	0	49.3	205.5	254.8
Total Facilities	3,101.7	5,075.1	10,267.6	18,444.4

*All figures in 1970 constant dollars.

TABLE 14

EXTRACTION PLANT COSTS

Estimated Volumes	Case I Tcf 1980	Case I Tcf 1985	Case II Tcf 1980	Case II Tcf 1985	Case III Tcf 1980	Case III Tcf 1985	Case IV Tcf 1980	Case IV Tcf 1985
Alaskan Production (1N)	1.4	3.3	1.3	2.7	1.1	2.2	0	1.3
Canadian Frontier Imports	0.6	1.8	0.6	1.8	0.6	1.8	0.6	1.8
Total Gas to be Stripped	2.0	5.1	1.9	4.5	1.7	4.0	0.6	3.1

Cost of Stripping Estimated at $30/Mcf/D
Based on Historical Costs
($30/Mcf/D = $82.2 Millions/Tcf/Year

	Case I 1980	Case I 1985	Case II 1980	Case II 1985	Case III 1980	Case III 1985	Case IV 1980	Case IV 1985
	(Millions of Dollars*)							
Estimated Cost	$164.4	$254.8	$156.2	$213.7	$139.7	$189.1	$ 49.3	$205.5
Total	$419.2		$369.9		$328.8		$254.8	

*All figures in 1970 constant dollars.

TABLE 15

ACTUAL AND PROJECTED ANNUAL GAS REQUIREMENTS BY USE CATEGORY AND PAD DISTRICT FOR SELECTED YEARS 1965 THRU 1985
(Trillions of BTU's)

		PAD I				PAD II						
Year	Use Category	New England	Middle Atlantic	South Atlantic	Total	East North Central	All Other	Total	PAD III	PAD IV	PAD V	Total U. S.
1965	Residential/Commercial	130	868	379	1,377	1,597	916	2,513	526	208	773	5,397
	Industrial	30	452	428	910	1,030	717	1,747	2,595	177	657	6,086
	Electric Utilities	14	102	120	236	69	456	525	1,040	36	586	2,423
	Transportation	3	26	17	46	104	78	182	198	8	44	478
	Raw Material and Other	8	70	53	131	111	78	189	451	22	159	963
	Total Incl. Fld. Use	185	1,518	997	2,700	2,911	2,245	5,156	4,810	462	2,219	15,347
1970	Residential/Commercial	177	1,106	517	1,800	2,138	1,059	3,197	734	260	910	6,901
	Industrial	52	578	654	1,284	1,494	984	2,478	4,140	238	897	9,037
	Electric Utilities	9	172	324	505	272	699	971	1,617	63	759	3,915
	Transportation	5	33	27	65	144	108	252	305	10	57	689
	Raw Material and Other	8	91	110	209	265	445	710	1,831	104	262	3,116
	Total Incl. Fld. Use	251	1,980	1,632	3,863	4,313	3,295	7,608	8,627	675	2,885	23,658
1975	Residential/Commercial	231	1,347	682	2,260	2,664	1,232	3,896	848	310	1,125	8,439
	Industrial	77	862	1,132	2,071	2,377	1,322	3,699	5,284	298	1,289	12,641
	Electric Utilities	17	210	339	566	578	870	1,448	2,298	83	1,068	5,463
	Transportation	6	43	39	88	205	137	342	393	12	74	909
	Raw Material and Other	6	106	139	251	346	522	868	2,079	115	220	3,533
	Total Incl. Fld. Use	337	2,568	2,331	5,236	6,170	4,083	10,253	10,902	818	3,776	30,985
1980	Residential/Commercial	287	1,576	860	2,723	3,173	1,424	4,597	1,011	349	1,327	10,007
	Industrial	97	1,063	1,506	2,666	3,085	1,588	4,673	6,038	327	1,457	15,161
	Electric Utilities	16	183	393	592	597	1,058	1,655	2,965	95	885	6,192
	Transportation	7	50	50	107	250	161	411	465	14	80	1,077
	Raw Material and Other	9	116	159	284	266	553	819	1,990	122	242	3,457
	Total Incl. Fld. Use	416	2,988	2,968	6,372	7,371	4,784	12,155	12,469	907	3,991	35,894
1985	Residential/Commercial	352	1,830	1,060	3,242	3,778	1,625	5,403	1,182	394	1,548	11,769
	Industrial	124	1,276	1,940	3,340	3,802	1,804	5,606	6,872	361	1,626	17,805
	Electric Utilities	14	185	483	682	672	1,121	1,793	3,852	116	829	7,272
	Transportation	8	59	63	130	300	180	480	551	16	87	1,264
	Raw Material and Other	9	130	181	320	217	565	782	1,774	119	241	3,236
	Total Incl. Fld. Use	507	3,480	3,727	7,714	8,769	5,295	14,064	14,231	1,006	4,331	41,346

Source: NPC - Gas Demand Task Group Report

TABLE 16

ESTIMATED DEMAND LESS FIELD USE

Year	PAD Districts Estimated Demand I	II	III	IV	V	Total
	(Btu x 10^{12})					
1970	3,815	6,856	5,119	515	2,643	18,948
1971						
1972						
1973						
1974						
1975	5,214	9,326	6,818	632	3,568	25,558
1976						
1977						
1978						
1979						
1980	6,348	11,278	8,742	719	3,807	30,894
1981						
1982						
1983						
1984						
1985	7,692	13,300	10,994	830	4,173	36,989

Source: NPC - Gas Demand Task Group Report

TABLE 17

ESTIMATED DEMAND LESS FIELD USE

Year	PAD Districts Estimated Demand in Tcf I	II	III	IV	V	Total
	(Metered Volumes - Tcf)					
1970	3,697	6,643	4,960	499	2,561	18,360
1971	3,968	7,122	5,289	522	2,740	19,641
1972	4,239	7,601	5,619	544	2,919	20,922
1973	4,510	8,079	5,948	567	3,099	22,203
1974	4,781	8,558	6,278	589	3,278	23,484
1975	5,052	9,037	6,607	612	3,457	24,765
1976	5,272	9,415	6,980	629	3,503	25,799
1977	5,492	9,793	7,353	646	3,550	26,833
1978	5,711	10,172	7,725	663	3,596	27,868
1979	5,931	10,550	8,098	680	3,643	28,902
1980	6,151	10,928	8,471	697	3,689	29,936
1981	6,411	11,320	8,907	718	3,760	31,117
1982	6,672	11,712	9,344	740	3,831	32,298
1983	6,932	12,104	9,780	761	3,902	33,480
1984	7,193	12,496	10,217	783	3,973	34,661
1985	7,453	12,888	10,653	804	4,044	35,842

Note: Table 16 figures for 1970, 1980, and 1985 were converted to as metered volumes using 1,032 BTU/CF. All other years estimated by linear interpolation.

Gas Supply

The gas supply information needed was obtained primarily from the Gas Supply Task Group and consisted of the following for each case studied:

- Total domestic production (non-associated, and associated and dissolved) for each NPC Petroleum Province (Region) by year for 1971 through 1985

- New production annually (non-associated, and associated and dissolved) by Region for each year from 1971 through 1985

- Gas production from Alaska Regions 1-N and 1-S annually (Only Region 1-N was included in this study. Region 1-S was assumed to be liquefied and included in the LNG schedule)

- A projected LNG import schedule, showing period of first delivery, quantities imported and port of entry

- Projected SNG liquid reforming projects, including approximate plant location, volume reformed, feedstock and first year on stream

- Coal gas quantities available by year, plant locations by state and number of plants required

- Pipeline imports from Canada and Mexico, showing volumes per year and approximate source

- A schedule of discoveries and production of Canadian Frontier gas (Mackenzie River Delta, Arctic Islands, Atlantic offshore) by year

- The 1970 gas supplies from each of the above sources were obtained from published documents and used as a base year in all supply and transportation analyses.

Existing Transmission Facilities

The basic gas transmission assumption is that the volumes of gas transported to market in 1970 represent the capacity of the existing facilities. No attempt was made to determine the dollar value of the existing facilities as of December 31, 1970. All transmission volumes less or equal to those transported in 1970 have been assumed to be delivered through existing facilities. If the transmission volume exceeds the 1970 base year, it is assumed that new transmission facilities will be constructed.

Volume Apportionment

In any real world situation, total demand will adjust to meet total supply. This will be accomplished either by market forces or by regulation, or a combination of both.

The first step in the volume apportionment used was to match demand and supply. The total supply includes domestic production, Alaskan production, LNG, SNG, coal gas, nuclear stimulation and pipeline imports. The total demand as developed independently by the Demand Task Force was adjusted to equal the total supply when supply is less than demand.

After the total demand was adjusted to match the total supply, the total supply was allocated to each PAD district. The PAD district allocation was done by developing a PAD district demand percentage. The demand percentage is the individual unadjusted PAD district demand less field use, divided by the total unadjusted demand less field use. This is each PAD district's fair share percentage. This percentage is multiplied by the total supply. The resulting number is the adjusted demand for the particular PAD district. The sum of the PAD adjusted demands must equal the total U.S. supply.

The next step in the volume apportionment was to assign the regional supplies as developed by the Gas Supply Task Group to an appropriate PAD district. The domestic and Alaskan production assignments are as follows:

PAD District	NPC Regions
I	10, 11 and 11a
II	7, 8, 9 and 9.59% of 4*
III	5, 6, 6a and 76.25% of 3*
IV	90.41% of 4* and 23.75% of 3*
V	2 and 2a
II, V	1 North and Canadian Arctic gas allocated 50% to each of PAD Districts II and V

* The exact allocation of Regions 3 and 4 was based on gas reserves by state as of December 31, 1970.

The LNG imports were assigned to PAD districts based on port of entry. SNG production was assigned to PAD districts based on plant locations. Coal gasification volumes were assigned to the appropriate PAD district based on plant and coal reserve locations. Canadian pipeline imports were assigned to the appropriate PAD districts based on logical points of entry.

This completes the volume apportionment. Each PAD district now has an *adjusted PAD demand* and *assigned gas supplies*. (See Figures 1 and 2 for NPC Regions and PAD Districts.)

PAD District Gas Balance

A gas balance is computed for each PAD district and for the U.S. total for each year of the projection. A sample of the format is shown in Table 18. Total supply is the sum of domestic production, pipeline imports, LNG, SNG, coal gas and nuclear stimulation gas for each PAD district.

The adjusted demand previously developed is subtracted from the total supply. The difference is the supply balance, either an excess or a deficit.

The supply attachment volumes include new domestic gas production per year split into offshore and onshore, LNG, SNG, coal gas and nuclear stimulation.

The LNG, SNG and coal gas volumes are used to develop attachment facility costs required to connect the particular plant to the nearest major transmission network. It was assumed that production attachment facilities would be required for new production each year. Gathering facilities are necessary to bring new production into existing networks. The supply attachment volumes are the incremental new production each year per source.

In the Initial Appraisal, it was assumed that the LNG attachments would require short transmission legs to connect the vaporization facilities to the nearest transmission network.* In this final report, an average distance of 100 miles was assumed between port of entry and existing transmission systems. The coal gas attachments in the Initial Appraisal were assumed to be major transmission lines from the coal gas plant locations to the nearest major market area. A more appropriate assumption is to develop transmission attachment facilities for both SNG and coal gas, which would connect the plants to the nearest major transmission system. This is more realistic than the assumption made in the Initial Appraisal. As an example, assume a coal gas plant in Wyoming. Under the Initial Appraisal assumption, a new pipeline was constructed and costs included for the pipeline from Wyoming to Chicago, the nearest major metropolitan area. Under the new assumption, an attachment pipeline would be assumed from Wyoming to the nearest major transmission system , i.e., El Paso, Transwestern, Northern Natural, Natural Gas Pipeline, or Colorado Interstate. Once the supply has been attached, expansion of the existing systems is determined by the inter and intra PAD transmission facilities.

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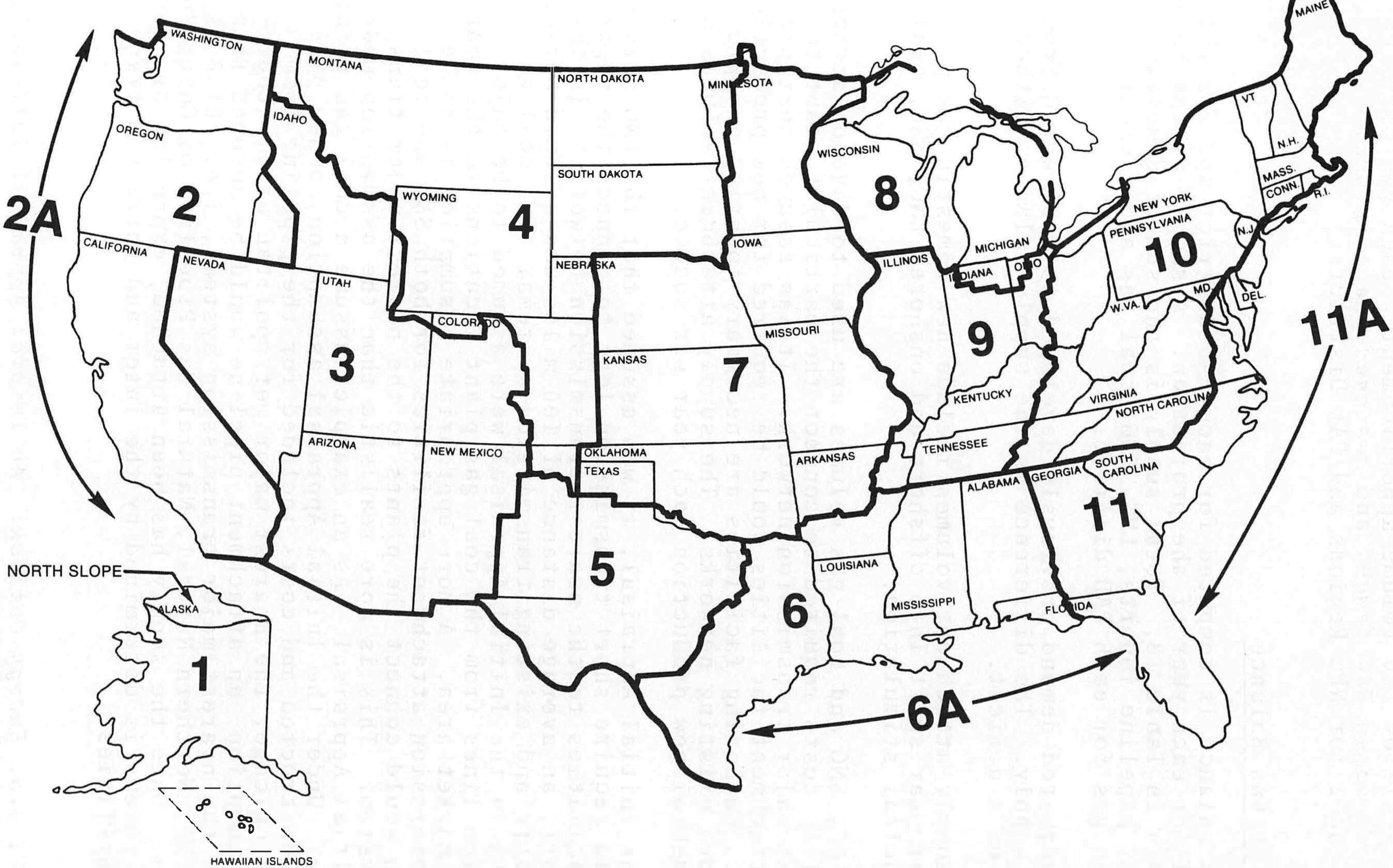
* NPC, *U.S. Energy Outlook: An Initial Appraisal 1971-1985*, Volume II, (November 1971).



Regional Boundaries: Region 1—Alaska and Hawaii, except North Slope; Region 2—Pacific Coast States; Region 2A—Pacific Ocean, except Alaska; Region 3—Western Rocky Mountains; Region 4—Eastern Rocky Mountains; Region 5—West Texas and Eastern New Mexico; Region 6—Western Gulf Basin; Region 6A—Gulf of Mexico; Region 7—Midcontinent; Region 8—Michigan Basin; Region 9—Eastern Interior; Region 10—Appalachians; Region 11—Atlantic Coast; Region 11A—Atlantic Ocean.

Source: NPC *Future Petroleum Provinces of the United States* (July 1970)—with slight modification.

Figure 1. NPC Petroleum Provinces of the United States--Supply Regions.

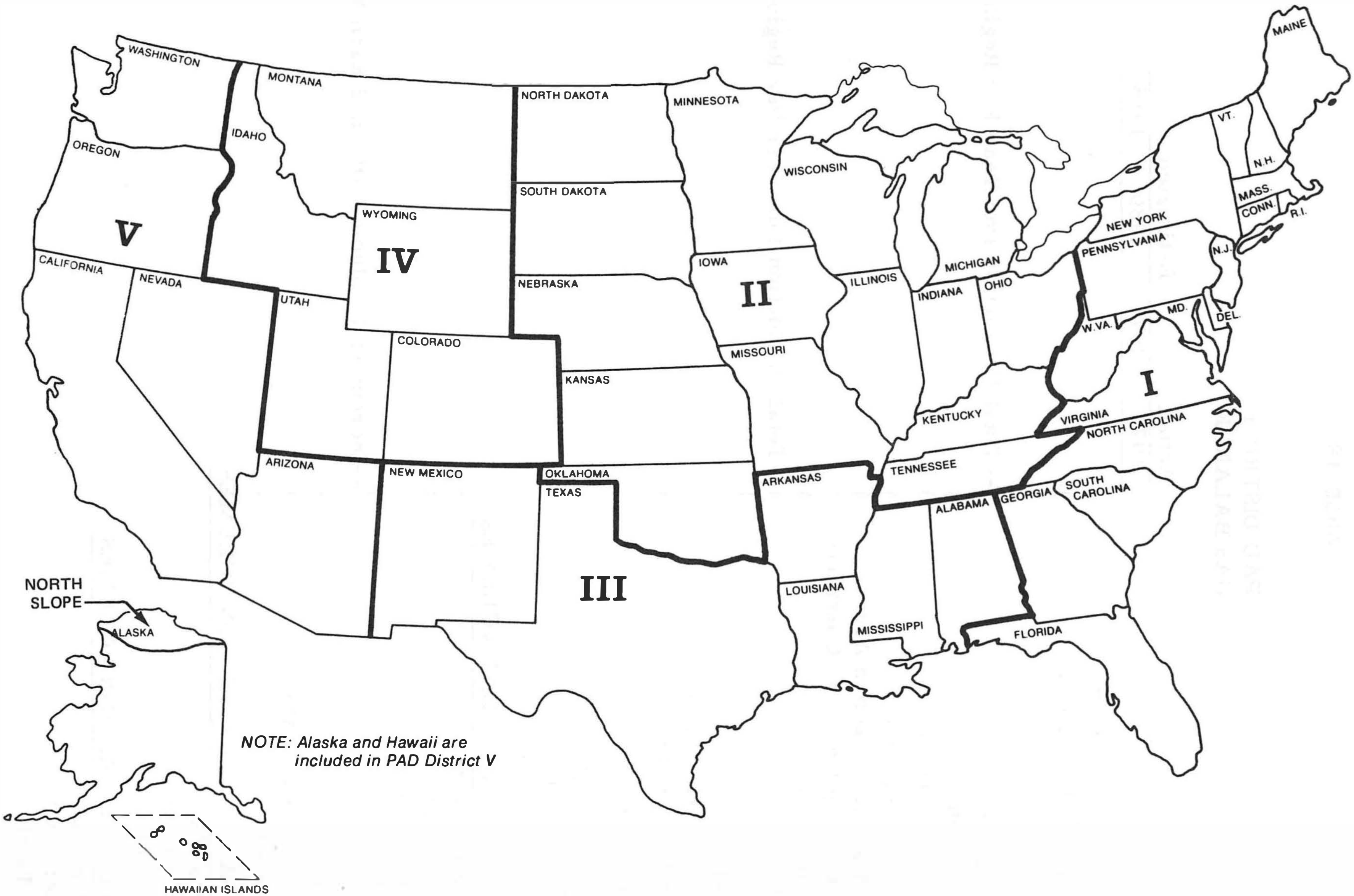


Figure 2. Petroleum Administration for Defense (PAD) Districts--Demand Regions.

TABLE 18

PAD DISTRICT
GAS BALANCE

DESCRIPTION		Actual 1970	Estimated 1975	1980	1985
PAD ________ SUPPLY					
Domestic Production	)				
Region	)				
Region	)				
Region	)--Total Production Per Year Per Region				
Region	)				
Sub-Total	)				
Pipeline Imports	)				
Alaskan/Canadian Arctic	)				
Existing Canadian Contracts	)				
Mexican	)				
LNG	)--Total Production Per Year Per Region				
SNG	)				
Coal Gas	)				
Nuclear Stimulation	)				
Total Supply (+)	)				
Adjusted Demand (-)					
SUPPLY BALANCE					
Excess (+)					
Deficiency (-)					
SUPPLY ATTACHMENT VOLUMES					
New Production	)				
Offshore	)				
Onshore	)				
LNG	)				
SNG	)--Incremental Volumes Attached Each Year				
Coal Gas	)				
Nuclear Stimulation	)				
Total	)				
TRANSMISSION EXPANSION VOLUMES					
Intra PAD					
Inter PAD					
Total					
STORAGE EXPANSION VOLUMES					
Intra PAD					
Inter PAD					
Total					

SNG plants were assumed to be constructed close to major markets and existing systems. An average distance of 50 miles was used for all plant connection facilities. The connection facilities for coal gas plants were developed on a state-by-state basis assuming connection to the nearest major transmission system. Nuclear stimulation sources were treated the same as new production attachments and assumed to be gathered and connected to existing systems in Wyoming and Colorado.

The transmission expansion volumes are computed in two parts --inter PAD volumes and intra PAD volumes. The inter PAD transmission volume is the amount of gas which must flow into a PAD district in order to satisfy the demand. The volume is developed for each PAD district by subtracting the adjusted demand from the total supply for each year. A *negative balance* is the inter PAD transmission volume. This is the volume which must flow into the PAD district to balance supply with demand. If supply exceeds demand, a positive balance occurs. A positive balance is zeroed and not used in the computation. If any year's inter PAD transmission volume exceeds the 1970 base year, or any prior year, whichever is larger, *the difference is* the *inter PAD expansion volume* and requires new facilities. The new facilities are accounted for by the receiving PAD district.

The intra PAD transmission volume is the total supply for the year. The intra PAD expansion volume is the difference between the current year's total supply and the 1970 base period supply, or any prior period supply which is larger than 1970.

The storage expansion volumes represent the incremental increase in storage use. The storage expansion volume is developed by multiplying the storage use factor times both the intra and inter PAD transmission expansion volume. This is the increase in total storage use for the particular year. The storage use factor was developed by correlating storage use with total sales of gas. The linear correlation was included in the model and develops a storage withdrawal factor for each year. This permits storage growth whether sales increase or decrease.

Facility Computational Procedure

The procedure used to develop capital costs was similar to that used in the Initial Appraisal. The volumes for each of the major facility cost areas, transmission expansion volumes, supply attachments and storage volumes are developed from the gas balance (Table 18) and used with the capital cost factors to develop total facility costs. Total capital costs are developed on an individual PAD district basis in the format shown in Table 19. Table 20 shows the capital cost factors used in the study. The development of these factors is discussed in the section on cost factors.

TABLE 19

PAD DISTRICT
CAPITAL COSTS

CAPITAL COSTS FOR ADDITIONAL TRANSMISSION FACILITIES	1971 to 1975	1976 to 1980	1981 to 1985
1. TRANSMISSION - DOMESTIC			
Intra PAD			
Inter PAD			
Sub-Total			
2. TRANSMISSION - IMPORTS			
Alaskan/Canadian Arctic			
3. SUPPLY ATTACHMENTS			
New Production			
Onshore			
Offshore			
LNG			
SNG			
Coal Gas			
Nuclear Stimulation			
Sub-Total			
4. NEW STORAGE FACILITIES			
TOTAL NEW FACILITIES			

TABLE 20

PAD DISTRICT
CAPITAL COST FACTORS
All Figures in $/MMcf of Annual Volume

PAD District	Inter PAD Transmission	Intra PAD Transmission	Onshore Gathering	Offshore Gathering	LNG Attachment	SNG Attachment	Coal Gas Attachment	Storage Use(1)
I	2,050	410	100	450	85	45	-	1,150
II	1,600	640	100	-	-	45	1,000	1,150
III	1,200	360	100	450	80	45	225	1,150
IV(2)	1,050	315	100	-	-	-	750	1,150
V	1,050	525	100	450	85	-	-	1,150

Notes:
(1) Storage use cost factor is based on U.S. Average 1970 Costs. The storage volume factor is a linear projection based on historical regression analysis.

(2) Nuclear stimulation gathering attachment cost applies only to PAD IV and is estimated at $150/MMcf.

In general, the cost factors for inter PAD transmission, onshore and offshore gathering and storage withdrawal were developed from historical cost patterns escalated to 1970 costs. The LNG attachment cost factors were estimated based on the assumption that the gas would have to be transported an average of 100 miles to enter an existing transmission or distribution network. The SNG attachment costs were estimated assuming the construction of a connecting pipeline averaging 50 miles from the plant to existing facilities. The coal gas attachment costs were estimated by designing pipelines to connect the plants to existing transmission systems. The Coal Task Group designated the plant locations by coal reserves and by state. The intra PAD transmission costs were estimated by determining an average distance that gas would move within the PAD district and then scaling down the inter PAD costs to reflect the shorter distance.

The PAD district capital costs were developed annually by multiplying the capital cost factors in Table 20 by the appropriate volume from the gas balance in Table 18. The resultant costs are summed to obtain U.S. totals and 5-year totals for 1975, 1980 and 1985.

All of the cost factors and methods used were revalidated for the final report. Based on the methodology, a computer model was developed to perform the necessary mechanical steps outlined.

BASIC ASSUMPTIONS

Gas Demand

- The basic demand figures are on a 1,000-BTU per cubic foot basis and were converted to an as metered volume using a 1,032-BTU per cubic foot conversion.

- Gas demand figures were obtained from the Gas Demand Task Group for the years 1970, 1975, 1980 and 1985. Each individual year in between was interpolated using a linear approximation.

- For the situation where total demand exceeds total supply, the "fair share" ratio is the total supply divided by total demand less field use. This fair share ratio was used to adjust each PAD district's demand.

Gas Supply

- The gas supply figures used were those supplied by the Gas Supply Task Group.

- The domestic supply figures represent marketed production, which excludes field use.

- *No* costs were provided for vaporization of LNG, production of SNG or coal gas, or for nuclear stimulation. Only attachment facilities were provided.

- The base year for gas supply comparisons was 1970.

- All figures supplied were as metered on common standard conditions.

- The figures for coal gasification, number of plants required, and locations of reserves by state were supplied by the Coal Task Group.

- Domestic supply was projected using NPC petroleum provinces. The individual province production was allocated to the respective PAD districts based on reserves in place as of December 31, 1970.

- Half of the Alaskan and Canadian Arctic gas was assumed to enter the Continental United States through PAD II and half through PAD V. For Alaska, only Region 1-N was included since it was assumed that all of Region 1-S would be liquefied and included in the LNG projections.

Facilities and Costs

- All costs are based on 1970 constant dollars.

- Historical cost factors for inter PAD transmission, onshore and offshore attachments and storage were based on an average of the costs of the last 5 years escalated to 1970.

- The data for the cost factors came from *Statistics of Interstate Natural Gas Pipeline Companies*, published annually by the Federal Power Commission. These were correlated with data from American Gas Association (AGA) (published annually).

- The storage use factor is a linear regression of actual data from AGA *Gas Facts* (published annually) for 1956 through 1970. Storage use was projected to grow linearly from 1971 through 1985.

- Intra PAD transmission costs were estimated as a percentage of the inter PAD costs based on an estimated mileage ratio.

- Costs of facilities to transport Canadian Frontier gas to a market area were included only for those facilities required to transport the gas imported to the United States. This is based on the assumption that part of the Frontier gas will flow to the United States and that at least part of the financing, materials and construction manpower will be supplied by the United States.

- Facilities would be required annually to connect new production. Even though some existing facilities may be used, it was assumed for this study that any new production required new facilities.

- Gas treating plants would be required on the Alaskan/Canadian Arctic pipelines just after they enter the United States. This is consistent with the gas supply assumption that the Arctic lines carry high hydrocarbon dewpoint gas.

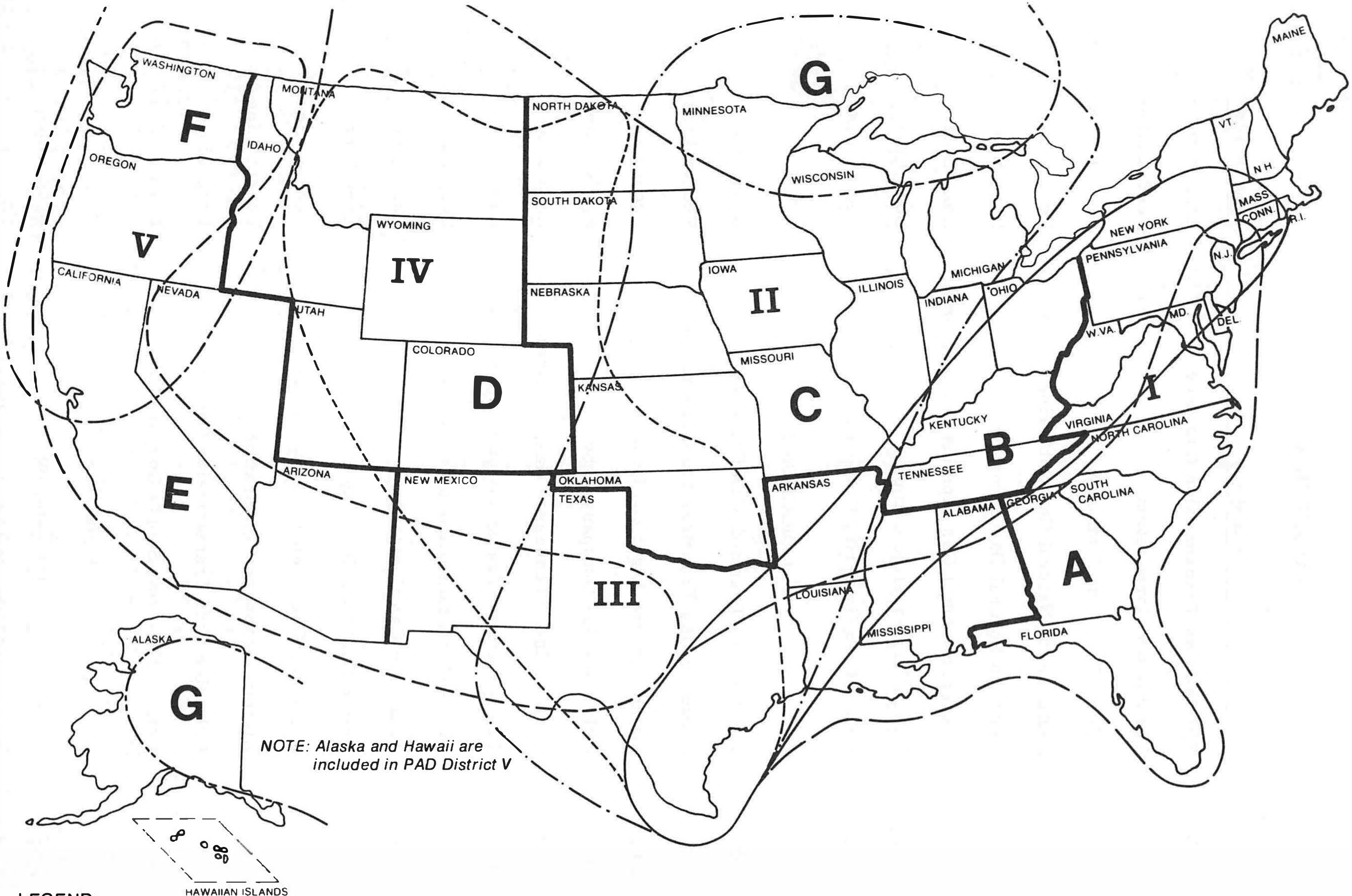
CAPITAL COST FACTORS

Transmission Capital Costs

No valid method was found to correlate distance, volume and cost using historical information on transmission costs. As an alternative, a corridor analysis procedure was developed to analyze historical costs. The major pipelines were assigned to corridors selected to fit the patterns of existing systems. It was assumed that the pipelines within the corridors serving existing markets would continue to do so in the future. In other words, it was assumed that market expansion would be accomplished by expanding existing systems. Additionally, companies were designated as long line or feeder systems to minimize intercompany transactions. A map showing the corridors in relation to the PAD districts is shown in Figure 3. The company assignments to corridors are shown on Table 21.

The inter PAD transmission costs were developed by averaging the incremental increases in gas plants in service for each of the corridors for the years 1966 through 1970. The average costs were escalated to put all dollars on a 1970 basis. The incremental volumes for each corridor were analyzed to eliminate as many intercompany transactions as possible. The corridor costs were allocated to PAD districts based on their geographic location and the markets served by the companies in the corridors. The corridor costs in each PAD district were averaged to develop the inter PAD transmission costs. The corridor assignments used are shown on Figure 3 and Table 21.

The intra PAD transmission costs were estimated based on a ratio of intra PAD to inter PAD mileages. Because the supply schedules resulted in vastly different production volumes by PAD district, it was possible that transmission facilities would be required within a PAD district even though no inter PAD expansion would be required. This would be particularly true where large quantities of LNG or SNG were produced in one PAD district. Even though there were no mileages used for the inter PAD costs, they are certainly mileage dependent. In order to use the same historical base for intra PAD costs as was used for inter PAD, a pseudo mileage ration was developed. The pseudo inter PAD distance is an average scaled distance required to bring intra



LEGEND:
Numbers Refer to PAD Districts (Separated by Heavy Lines)
Letters Refer to Gas Transmission Corridors (Outlined by Lighter Solid or Dashed Lines)

Figure 3. Gas Transmission Corridors.

TABLE 21

CORRIDOR A

Reference Number	Company	Type of Line
1705	Florida Gas Transmission Company	Long Line
2485	The Jupiter Corporation	Feeder Line
4818	Sabine Pipe Line Company	Feeder Line
5260	South Texas Natural Gas Gathering Company	Feeder Line
5340	Southern Natural Gas Company	Long Line
6420	Transcontinental Gas Pipeline Corporation	Long Line
6630	United Gas Pipeline Company	Long Line
6945	West Texas Gathering Company	Feeder Line

CORRIDOR B

Reference Number	Company	Type of Line
2240	Humble Gas Transmission Company	Long Line
2557	Kentucky Gas Transmission Corporation	Feeder Line
3200	Manufacturers Light and Heat Company, The	Feeder Line
3980	Ohio Fuel Gas Company, The	Feeder Line
5902	Tenneco Inc. (Tennessee Gas Pipeline)	Long Line
6090	Texas Eastern Transmission Corporation	Long Line
6210	Texas Gas Transmission Corporation	Long Line
6450	Trunkline Gas Company	Long Line
6600	United Fuel Gas Company	Long Line
0050	Algonquin Gas Transmission Company	Feeder Line
0420	Atlantic Seaboard Corporation	Feeder Line
1010	Columbia Gulf Transmission Company	Long Line
1075	Consolidated Gas Supply Corporation	Feeder Line

CORRIDOR C

Reference Number	Company	Type of Line
0840	Cities Service Gas Company	Long Line
1913	Great Lakes Gas Transmission Company	Long Line

TABLE 21 (Cont'd.)

Reference Number	Company	Type of Line
3250	Michigan Gas Storage Company	Feeder Line
3320	Michigan Wisconsin Pipe Line Company	Long Line
3360	Midwestern Gas Transmission Company	Feeder Line
3382	Mississippi River Transmission Corporation	Feeder Line
3620	Natural Gas Pipeline Company of America	Long Line
3800	Northern Natural Gas Company	Long Line
4160	Panhandle Eastern Pipe Line Company	Long Line
	CORRIDOR D	
0930	Colorado Interstate Corporation	Long Line
1470	El Paso Natural Gas Company	Long Line
6425	Transwestern Pipeline Company	Long Line
	CORRIDOR E	
5450	Southwest Gas Corporation	Feeder Line
1470	El Paso Natural Gas Company	Long Line
6425	Transwestern Pipeline Company	Long Line
	CORRIDOR F	
4135	Pacific Gas Transmission Company	Long Line

PAD DISTRICT-CORRIDOR RELATIONSHIP

PAD I	Corridors A & B
PAD II	Corridor C
PAD III	Corridors C, D & E
PAD IV	Corridors D & E
PAD V	Corridor E & F

Corridor G was not used due to the limited amount of information available.

PAD gas supplies to the major market areas. The pseudo distances and ratio of intra to inter PAD distance is shown below. The intra PAD ratio was applied to the inter PAD transmission cost factor to develop an intra PAD cost factor.

Pseudo PAD Mileages

PAD District	Pseudo Inter PAD Distance	Pseudo Intra PAD Distance	Intra/Inter PAD Mileage Ratio
I	1,200	240	.20
II	950	380	.40
III	950	285	.30
IV	600	180	.30
V	1,200	600	.50

Production Attachment Costs

The onshore attachment costs were developed by summing the incremental production and gathering costs for all corridors for the years 1966 through 1970. These costs were escalated to 1970 dollars. The incremental sales volume, less intercompany transactions, were summed for the same period, divided into the escalated dollars to develop a $/MMCF cost factor. The production attachment costs were based on a U.S. total, rather than on an individual PAD district basis, to improve the accuracy of the total cost estimate because of the poor sample available in some PAD districts. The onshore attachment cost was developed by multiplying the cost factor times the annual new production.

The offshore attachment costs were estimated based on historical costs of existing and proposed offshore systems. The cost factors, $/MMCF, were enormous since many of the pipelines were new systems and were operating at low load factors. In order to make the projections as realistic as possible, 1970 dollars (estimated or actual) were used, divided by a volume estimated to be 80 percent of maximum capacity. An 80-percent load factor was believed to be reasonable for offshore systems operating over the 15-year period from 1971 to 1985. This factor is applied only to the new production in Regions 2-A, 6-A and 11-A.

LNG Attachment Costs

The LNG attachment costs were based on an equivalent 100-mile pipeline system required to connect the vaporization facilities to existing gas transmission or distribution systems.

An equivalent 100-mile connection pipeline was developed by evaluating LNG port-of-entry locations in relation to the existing transmission and distribution systems which could be served.

Based on the port of entry and volumes to be delivered, an equivalent 100-mile system was required for the average regasification and delivery system. The cost of the equivalent system was developed by estimating the cost of a 30-inch diameter and a 36-inch diameter line, each 100 miles long. The cost estimates were based on a total U.S. weighted average cost adjusted to reflect labor and construction differences in each of the PAD districts involved. The cost of each pipeline was divided by its capacity and then averaged to obtain a cost factor in $/MMCF.

SNG Attachments Costs

The SNG attachment costs were based on an equivalent 50-mile connection line from each plant to an existing system. The equivalent length was determined by scaling the distance between proposed plant sites and existing pipeline facilities. Because of the wide range of volumes from SNG plants, three pipeline systems --20-inch, 24-inch and 30-inch diameters--were used to develop the cost factor. Using U.S. average costs, the $/MMCF for each of the three pipelines were averaged to develop the cost factor. This was adjusted to reflect Midwest and East Coast conditions.

Coal Gas Attachment Costs

In general, the attachment costs are based on connecting the coal gas plants to existing transmission systems. The plant locations were estimated based on the locations of coal reserves by state. No specific plant locations were given. The number of plants and reserves by state were supplied by the Coal Task Group.

Two different line sizes--24-inch and 30-inch--were utilized to estimate the cost of transporting gas from the areas of coal reserves. Plant sites were selected in the areas of reserves, and mileages were scaled to connect each plant to an existing transmission system. Plants were assumed to be connected to the nearest major transmission system. It was estimated that coal gas would flow to the West Coast and the Midwest from New Mexico, to the West Coast and the Midwest from Montana and Wyoming and to the Midwest from North Dakota.

The line capacities and horsepower required, assuming a 1.5 compression ratio and 100-mile station spacing, were calculated for each of the line sizes. The cost of the pipeline and compressor facilities was estimated using FPC data for the year 1970. By averaging the costs for the two line sizes, pseudo connection costs for a standard plant (250 MMCF/D) were developed. The plant connection costs per PAD district were averaged to develop a cost factor, $/MMCF. The average distance between the plants and existing systems and computed average costs are shown below:

PAD District	Average Mileage to Connect	Calculated Connection Cost $/MMcf
II	462.5	$988.9
III	108.3	219.6
IV	329.5	739.9

The costs were rounded for use in the computer model.

Alaskan/Canadian Arctic Facilities

A schedule of Alaskan production and Canadian Frontier production was developed by the Gas Supply Task Group. All of the Alaskan gas and a portion of the Canadian gas must be transported across Canada for delivery to the lower 48 states. Since the construction and financing of any Arctic system will be at least partially dependent on the United States, the capital requirements for the Arctic pipelines in both Alaska and Canada required to deliver the volumes for U.S. consumption have been included in this report. The costs of the facilities required to transport Canadian Frontier gas to Canadian markets have *not* been included. Since the costs are dependent on volumes outside of the gas balances, the costs of Arctic facilities have been computed separately and the capital cost requirements inserted in the program. Details of the Arctic cost estimates are included in Section I.

Three major pipeline systems were assumed for analysis. A main trunk system which would be constructed from Alaska's North Slope to Emerson, Manitoba, with a bifurcation line that splits off at approximately Edmonton and runs toward Spokane, Washington. This system would handle all of the Alaskan and Canadian gas produced in the Mackenzie Delta. The length of the system is 2,400 miles with a 600-mile bifurcation line. Three complete 48-inch pipelines would have to be built between 1975 and 1985 for this system.

The second system is an Arctic Islands system to transport gas from the Canadian Arctic Islands. For this study, a line was routed from Ellef Ringnes Island to Winnipeg, using an island stepping stone route. The total line distance is 2,100 miles. Because of the volumes involved, a 48-inch pipeline system was assumed. Trade journal articles have indicated that a route direct to Montreal was being considered. This would add about 500 miles to the estimated system length and about $600 million to the cost. The assumed routing interconnects with TransCanada PipeLine's existing system near Winnipeg. This system was estimated to be in service by 1983.

The third system is a Canadian Atlantic offshore system. This was estimated as an 800-mile system from Sable Island to

Montreal. Again, because of the volumes, a 48-inch pipeline was used. First deliveries were scheduled for 1976 from this system.

The cost estimates were prepared on a year-by-year basis for all three systems taking into account the total and incremental volume, load factor and location of facilities. Details of the estimates are shown in Section I. All costs for Arctic systems were based on costs developed by the Northwest Project Study Group. Permission was received from this group to use their estimates for both onshore and offshore facilities. The estimates used in this study are not escalated; they represent 1970 costs.

Storage Costs and Use Factor

The storage cost factor was developed in a similar manner to the transmission costs. Incremental changes in gas plants in service from both AGA *Gas Facts* and FPC *Statistics of Interstate Natural Gas Pipeline Companies* were reviewed. The 5-year averages from 1966 to 1970 were similar. AGA *Gas Facts* was used as a basis for the costs since it contained a better sample. The 5-year average incremental capital costs escalated to 1970, divided by the incremental increase in "storage use," resulted in a U.S. total storage cost factor in $/MMCF. Storage use is defined as gas delivered to storage. Since gas delivered to storage includes cushion growth as well as working storage growth and replacement, it is more representative of storage use and growth than is storage withdrawal.

The storage use factor for the United States was analyzed from 1955 to 1970 using a linear regression. The U.S. total storage use factor was applied to each PAD district. Total U.S. storage costs are reasonable, but individual PAD district costs may be distorted.

The storage use factor included in the program is

$$Y = .001947X - 3.724442$$

Where Y = Storage Use Factor

X = Year.

Since the storage use factor increases each year, it is possible for storage to increase even when gas supply decreases. The rate of future storage growth will be dependent upon gas supply. The projections may be more valid for Cases II and III than for Cases I and IV. However, the method is reasonable enough to be used in all cases.

Extraction Plant Costs

Most of the processing plant costs were estimated by the Oil and Gas Supply Task Groups. However, the Gas Supply Task Group assumed that the Arctic pipelines would transport high hydrocarbon dewpoint gas. The hydrocarbons must be extracted after the gas enters the lower 48 states. No facilities for these extraction plants were provided by the Gas Supply Task Group.

The costs of existing extraction plants designed to treat similar gas streams were used to develop a cost factor in $/MMCF, adjusted to reflect 1970 costs. The cost factor was multiplied by the volumes of Alaskan and Canadian Arctic gas transported into the United States.

Exhibit I

ALASKAN/CANADIAN FACILITIES COMPUTATIONAL METHOD AND CAPITAL REQUIREMENTS

The Gas Supply Group projected production from the Frontier areas of Alaska and Canada for all supply cases. The areas projected are--

- Alaska--Region 1 North
- Canada Northwest Territories Onshore
- Canada Northwest Territories Offshore--Arctic Islands
- Canada Atlantic Offshore.

In addition, production from traditional sources in Western Canada was projected and included in the total Canadian supply. Total production in Canada exceeded the quantities exported to the United States. In fact, the Canadian Frontier production exceeds the total volumes exported.

The study was to project those costs attributable to the transportation of gas for consumption in the United States. All of the Alaskan gas from Region 1 North was assumed to be transported directly to the United States for consumption. It was assumed that the total cost of any facilities required to transport Alaskan and Canadian Frontier gas to the United States would be financed in the United States. Facilities and costs were estimated to transport all Alaskan and Canadian Frontier gas. No facilities were estimated for new production from traditional sources in western Canada. All of the costs required to transport Alaskan gas and a portion of the costs for Canadian gas were allocated to the United States. The ratio of Frontier gas exported to total Frontier gas produced was applied to the total cost of transporting Frontier gas. The resultant number was the cost of facilities required to transport the Canadian Frontier gas to the United States and was included in the study.

The details of the method used to compute the Alaskan and Canadian facilities follow in four sections, with each section representing one of the Supply Cases. The calculation procedure is described in detail for Case I. Each case was done in a similar fashion, and many of the costs and tables are identical.

METHODOLOGY

The volumes projected from each source were tabulated and assigned to pipeline systems. The volumes shown for Alaska Region 1 North are wellhead production and not marketed production as shown in the primary gas balances. All other volumes shown are marketed production. The assumptions made by the Gas Supply Task Group indicate that the field use and extraction shrinkage for Canadian gas would occur in the producing areas. The pipeline transporting these volumes would carry only marketed production. One of the assumptions for the Alaskan gas was that a stream as rich as possible would be transported to the lower 48 states and stripped after arrival. To allow for any change in gas volume and gas properties due to the rich gas stream, and to allow for fuel use in transportation, wellhead production volumes rather than marketed production were used for Alaska.

The production volumes were assigned to one of three pipeline systems assumed for this study. They are shown on the attached map (Figure 4).

The Alaskan and Northwest Territory onshore gas was assigned to the Mackenzie Valley Pipeline System. The general routing of this line is from Prudhoe Bay, Alaska, into Canada and then along the Mackenzie River. The line splits near Edmonton, with part of the gas flowing to the U.S. West Coast and part to Emerson for the Midwest.

The Northwest Territory Island gas was assigned to a new pipeline system routed through the island group from Ellef Ringnes Island to the mainland and then south to Winnipeg. It was assumed that the line would connect with TransCanada PipeLine or the Mackenzie Valley System at this point. If the Arctic Island system were to be routed directly to Montreal, it would be routed to the east of Hudson Bay rather than the west, adding approximately 500 miles to the 2,100-mile estimated system.

The Atlantic offshore gas was assumed to be found in the Sable Island area off the coast of Nova Scotia. A line was routed from this area to Montreal to connect with TransCanada PipeLine or U.S. facilities.

Supply Case I

Tables 22-27 show the volumes, costs and methods used in developing the capital requirements for Case I. Table 22 is a presentation of the volumes used from the four basic sources and their allocation to the three pipeline systems. Table 23 is a capital cost summary of the facility requirements for Case I. The costs of the Mackenzie Valley Pipeline were split between the Alaskan portion and the Canadian portion. Costs were summed based on Canadian costs and Alaskan costs. The total Canadian costs were allocated to the United States and to Canada based on the ratio of Frontier gas imported to the total Frontier gas. Table 24 shows the method used to develop costs for the Mackenzie Valley Pipeline System. An initial system from Emerson to Prudhoe Bay was developed and the costs estimated based on the initial incremental volume. Each additional increment was handled as a line expansion, and pipe and power were added to the system to

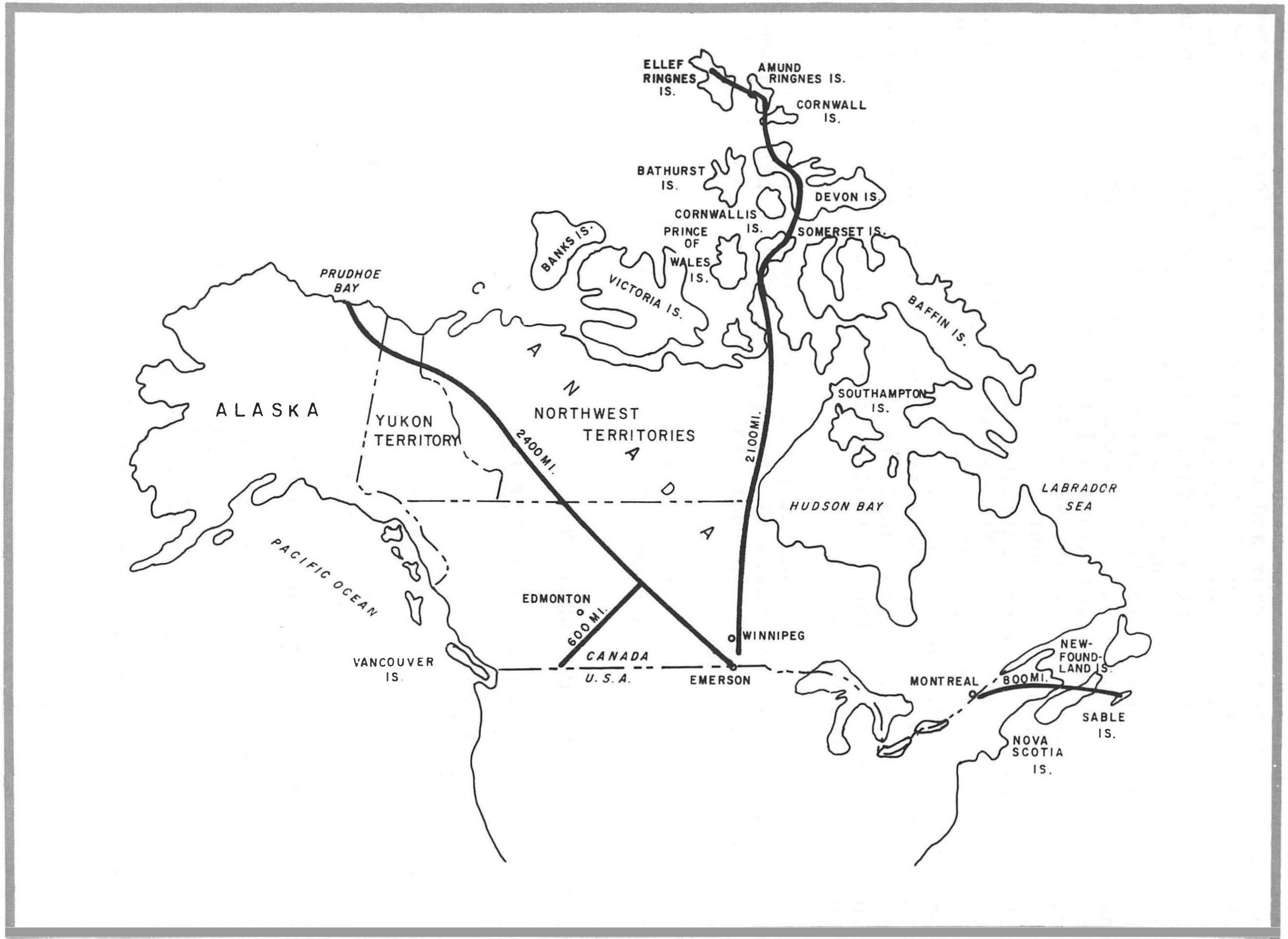


Figure 4. Assumed Routings for Three Major Pipeline Systems Used in Alaskan/Canadian Frontier Projections.

handle the incremental volumes projected. The incremental expansions were computed by year and the cost summed to develop 5-year incremental totals. Table 25 shows the connection costs for the Canadian Northwest Territory onshore gas. The incremental volumes were attached to the Mackenzie Valley Pipeline System based on an assumed average lateral length and an estimated cost per BCF to attach the increment. Table 26 presents the Canadian Arctic Pipeline System. Again, as in the Mackenzie Valley System, an initial line was routed from Ellef Ringnes Island through the island groups south to Winnipeg. The costs were estimated and then each additional increment of volume was computed as an expansion of the primary system. Table 27 is a presentation of the method and costs for the Canadian and Atlantic offshore system. The same basic methodology was used for these costs. An initial system was developed from Sable Island, routed onshore to minimize the water depth problem in the area in the Atlantic Ocean offshore Nova Scotia, and routed entirely within Canada to Montreal. Each increment of volume over and above the initial system was treated as an expansion of the primary system.

Tables 28-45 are presentations of the volumes, costs and methodologies used for Cases II through IV. The method used was identical in each case. In fact, Tables 31-33, 37-39 and 43-45 are identical for each case.

Table 46 is a tabulation of the wellhead production and marketed production from Region 1 North used in each of the cases.

ALASKAN-CANADIAN CONSTRUCTION

Cost Factors and Assumptions for Phase II

Pipeline Mileages

- Main Pipelines--Alaska to U.S. Borders (48-inch pipeline)

Alaska to Emerson	2,400 Miles
Bifurcation Point to United States	600 Miles

- Northwest Territory Canada

Onshore Construction--assumes the construction of short laterals to connect production in the Mackenzie Delta. An average distance of 100 miles to connect each source was assumed.

- Arctic Islands (48-inch pipeline)

Routing from Ellef Ringnes Island to Winnipeg using an island routing	2,100 Miles

TABLE 22

CASE I

ALASKAN-CANADIAN FRONTIER - MARKETED PRODUCTION

Year	Alaska* (1N)	Annual Volume: Canadian: N.W.T. Onshore	N.W.T. Islands	Atlantic Offshore	Total Canadian	Canadian Frontier Gas Imported to U.S.	Annual Volume Per Pipeline System: Mackenzie Valley (Col. 2 & 3) Cum.	Incr.	Island Line (Col. 4) Cum.	Incr.	Atlantic Line (Col. 5) Cum.	Incr.
	←Tcf→						←Tcf→					
1971-1975												
1976				0.08	0.08						0.08	0.08
1977				0.32	0.32						0.32	0.24
1978	0.8	0.08		0.56	0.64	0.1	0.88	0.88			0.56	0.24
1979	1.1	0.32		0.72	1.04	0.4	1.42	0.54			0.72	0.16
1980	1.4	0.56		0.88	1.44	0.6	1.96	0.54			0.88	0.16
1981	1.6	0.80		0.96	1.76	0.8	2.40	0.44			0.96	0.08
1982	2.3	0.96		1.12	2.08	0.9	3.26	0.86			1.12	0.16
1983	2.5	1.12	0.48	1.12	2.72	1.5	3.62	0.36	0.48	0.48	1.12	0.0
1984	3.0	1.12	0.80	1.12	3.04	1.8	4.12	0.50	0.80	0.32	1.12	0.0
1985	3.3	1.28	0.80	1.28	3.36	1.8	4.58	0.46	0.80	0.0	1.28	0.16

*Wellhead Production

TABLE 23

CASE I
ALASKAN-CANADIAN PIPELINES - COST SUMMARIES

Year	Mackenzie Valley P/L's Alaskan Portion	Mackenzie Valley P/L's Canadian Portion	Mackenzie Valley P/L's Total	N.W.T. Onshore Connections	Arctic Islands System	Canadian Atlantic System	Total Canadian Costs (Col. 3, 5, 6 & 7)	Percentage of Canadian Frontier Gas Imported	Canadian Costs Allocated to U.S.	Alaskan Costs Allocated to U.S.	Total Canadian Alaskan Costs
					(All Costs in Millions of U.S. Dollars*)						
1976						640	640.0		343		343
1977						66	66.0		35		35
1978	3,182	318	3,500	14.5		66	398.5		213	3,182	3,395
1979	993	795	1,788	43.5		44	882.5		473	993	1,466
1980	1,401	1,120	2,521	43.5		44	1,207.5	Use: 0.5357	647	1,401	2,048
Sub-Total 1976-80									1,711	5,576	7,287
1981	378	453	831	43.5		22	518.5		278	378	656
1982	3,000	685	3,685	29.0		44	758.0		406	3,000	3,406
1983	360	287	647	29.0	3,506	0	3,822.0		2,047	360	2,407
1984	1,635	0	1,635	0	667	0	667.0		357	1,635	1,992
1985	1,546	825	2,371	29.0	0	44	898.0		481	1,546	2,027
Sub-Total 1981-85									3,569	6,919	10,488
Total									5,280	12,495	17,775

*All costs in 1970 constant dollars.

TABLE 24

CASE I
ALASKAN-CANADIAN GAS TRANSMISSION FACILITIES
Mackenzie Valley Pipeline System From Alaska to Emerson, Manitoba Plus Bifurcation Line to U.S. West Coast

Year	Total Volume N.W.T. & Alaska	Increm. Volume	Line Loading Pattern: Line 1	Line 2	Line 3	Line 4	Cost Factor Application	Estimated Costs: Increm.	Cum.	Portion for Alaska	Notes
	←Tcf/Yr.→							←Millions of Dollars→			
1978	0.88	0.88	.88				Lump Sum	3,500	3,500	3,182	Construct initial pipeline, Alaska to Emerson.
1979	1.42	0.54	.3975	.1425			.3975 x 1100 (Lump for .1425 x 4394 + 725 ("B" Line	1,788	5,288	993	Complete first line-start second. Construct bifurcation line.
1980	1.96	0.54		.54			.54 x 4394 + .54 x 275	2,521	7,809	1,401	Looping second line.
1981	2.40	0.44		.44			.0685 x 4394 .3715 x 1100 + .44 x 275	831	8,640	378	Loop & power second line - expand bifurcation line.
1982	3.26	0.86		.155	.705		.155 x 1100 + .46 x 760 .705 x 4394 + .245 x 275	3,685	12,325	3,000	Complete second line - start third loop line - loop bifurcation line.
1983	3.62	0.36			.36		.046 x 4394 .314 x 1100 + .36 x 275	647	12,972	360	Loop and power - all lines.
1984	4.12	0.50			.2125	.2875	.2125 x 1100 .2875 x 4394 + .50 x 275	1,635	14,607	1,635	Complete third line - start fourth line.
1985	4.58	0.46				.46	.46 x 4394 + .46 x 760	2,371	16,978	1,546	Loop fourth line and bifurcation line.

TABLE 25

CASE I
CANADIAN N.W.T. ONSHORE CONNECTION COSTS

Year	Total Onshore N.W.T.	Incremental Volume	Cost Factor Application	Estimated Cost Incremental	Estimated Cost Cumulative
	---------- Tcf/Yr.	----------		--- Millions of Dollars	---
1978	0.08	0.08		14.5	14.5
1979	0.32	0.24	Assumes lateral construction to attach	43.5	58.0
1980	0.56	0.24	these reserves to the main trunk - Estimated at $181,600/Bcf	43.5	101.5
1981	0.80	0.24		43.5	145.0
1982	0.96	0.16		29.0	174.0
1983	1.12	0.16		29.0	203.0
1984	1.12	0.0		0	203.0
1985	1.28	0.16		29.0	232.0

TABLE 26

CASE I
CANADIAN ARCTIC ISLAND PIPELINE SYSTEM

Year	Total Volume	Incremental Volume	Cost Factors	Estimated Cost Incremental	Estimated Cost Cumulative	Notes
	----- Tcf/Yr. -----			---Millions of Dollars---		
1981						
1982						
1983	.48	.48	Initial construction lump sum.	3,506	3,506	Initial construction of 2,100 mile system to Winnipeg - cost based on a per mile estimate.
1984	.80	.32	Incremental power plus connection costs.	667	4,137	Incremental power added plus connections to other islands.
1985	.80	0		0	4,137	

TABLE 27

CASE I
CANADIAN GAS TRANSMISSION FACILITIES
CANADIAN ATLANTIC OFFSHORE

Year	Total Offshore Volume	Incremental Volume	Cost Factors	Estimated Cost Incremental	Estimated Cost Cumulative	Notes
	------Tcf/Yr.------			---Millions of Dollars---		
1976	0.08	0.08	Lump sum at $800,000/Mile	640	640	Construct 800 mile pipeline from Sable Island to Montreal.
1977	0.32	0.24		66	706	
1978	0.56	0.24		66	772	
1979	0.72	0.16		44	816	
1980	0.88	0.16		44	860	
1981	0.96	0.08	Incr. Vol. x $275/Tcf	22	882	Add power to existing pipeline.
1982	1.12	0.16		44	926	
1983	1.12	0.0		0	926	
1984	1.12	0.0		0	926	
1985	1.28	0.16		44	970	

TABLE 28

CASE II
ALASKAN-CANADIAN FRONTIER - MARKETED PRODUCTION

Year	Alaska* (1N)	Annual Volume: Canadian: N.W.T. Onshore	N.W.T. Islands	Atlantic Offshore	Total Canadian	Canadian Frontier Gas Imported to U.S.	Annual Volume Per Pipeline System: Mackenzie Valley (Col. 2 & 3) Cum.	Incr.	Island Line (Col. 4) Cum.	Incr.	Atlantic Line (Col. 5) Cum.	Incr.
	← Tcf →						← Tcf →					
1971-1975												
1976				0.08	0.08						0.08	0.08
1977				0.32	0.32						0.32	0.24
1978	0.8	0.08		0.56	0.64	0.1	0.88	0.88			0.56	0.24
1979	1.1	0.32		0.72	1.04	0.4	1.42	0.54			0.72	0.16
1980	1.3	0.56		0.88	1.44	0.6	1.86	0.44			0.88	0.16
1981	1.4	0.80		0.96	1.76	0.8	2.20	0.34			0.96	0.08
1982	1.6	0.96		1.12	2.08	0.9	2.56	0.36			1.12	0.16
1983	2.2	1.12	0.48	1.12	2.72	1.5	3.32	0.76	0.48	0.48	1.12	0.0
1984	2.4	1.12	0.80	1.12	3.04	1.8	3.52	0.20	0.80	0.32	1.12	0.0
1985	2.7	1.28	0.80	1.28	3.36	1.8	3.98	0.46	0.80	0.0	1.28	0.16

*Wellhead Production

TABLE 29

CASE II
ALASKAN-CANADIAN PIPELINES - COST SUMMARIES

Year	Mackenzie Valley P/L's: Alaskan Portion	Mackenzie Valley P/L's: Canadian Portion	Mackenzie Valley P/L's: Total	N.W.T. Onshore Connections	Arctic Islands System	Canadian Atlantic System	Total Canadian Costs (Col. 3, 5, 6 & 7)	Percentage of Canadian Frontier Gas Imported	Canadian Costs Allocated to U.S.	Alaskan Costs Allocated to U.S.	Total Canadian Alaskan Costs
	(All Costs in Millions of U.S. Dollars*)										
1976						640	640.0		343	-	343
1977						66	66.0		35	-	35
1978	3,182	318	3,500	14.5		66	398.5	Use: $\frac{\text{1985 Import Volume}}{\text{1985 Canadian Frontier Total}} = 0.5357$	213	3,182	3,395
1979	933	855	1,788	43.5		44	942.5		505	933	1,438
1980	934	1,120	2,054	43.5		44	1,207.5		647	934	1,581
Sub-Total 1976-80									1,743	5,049	6,792
1981	301	772	1,023	43.5		22	787.5		422	301	723
1982	275	220	495	29.0		44	293.0		157	275	432
1983	2,978	794	3,772	29.0	3,506	0	4,329.0		2,319	2,978	5,297
1984	275	0	275	0	667	0	667.0		357	275	632
1985	719	383	1,102	29.0	0	44	456.0		244	719	963
Sub-Total 1981-85									3,499	4,548	8,047
Total									5,242	9,597	14,839

*All costs in 1970 constant dollars.

TABLE 30

CASE II
ALASKAN-CANADIAN GAS TRANSMISSION FACILITIES
Mackenzie Valley Pipeline System From Alaska to Emerson, Manitoba Plus Bifurcation Line to U.S. West Coast

Year	Total Volume N.W.T. & Alaska	Increm. Volume	Line Loading Pattern Line 1	Line 2	Line 3	Line 4	Cost Factor Application	Estimated Costs Increm.	Cum.	Portion for Alaska	Notes
	←Tcf/Yr.→							←Millions of Dollars→			
1978	0.88	0.88	.88				Lump Sum Cost	3,500	3,500	3,182	Construct first pipeline Alaska to Emerson.
1979	1.42	0.54	.3975	.1425			.3975 x 1100 (Lump .1425 x 4394 + 725 (sum for ("B" Line	1,788	5,288		Complete first line, start second line, construct bifurcation line.
1980	1.86	0.44		.44			.44 x 4394 + .44 x 275 ("B" Line)	2,054	7,342		Continue looping of first line.
1981	2.20	0.34		.34			.1685 x 4394 .1715 x 1100 + .34 x 275	1,023	8,365		Complete loop, start power additions.
1982	2.56	0.36		.36			.36 x 1100 + .36 x 275	495	8,860		Complete second full line - complete bifurcation line.
1983	3.32	0.76			.76		.76 x 4394 + .30 x 275	3,772	12,623		Start third line loop, start bifurcation loop.
1984	3.52	0.20			.20		.20 x 1100 + .20 x 275	275	12,907		Add power third line, add power bifurcation line.
1985	3.98	0.46			.3175	.1425	.3175 x 1100 + .46 x 275 .1425 x 4394	1,102	14,009		Complete third line - start fourth line loop.

TABLE 31

CASE II
CANADIAN N.W.T. ONSHORE CONNECTION COSTS

Year	Total Onshore N.W.T.	Incremental Volume	Cost Factor Application	Estimated Cost Incremental	Estimated Cost Cumulative
	---------Tcf/Yr.	----------		---Millions of Dollars---	
1978	0.08	0.08		14.5	14.5
1979	0.32	0.24	Assumes lateral construction to attach these reserves to the main trunk - Estimated at $181,600/Bcf	43.5	58.0
1980	0.56	0.24		43.5	101.5
1981	0.80	0.24		43.5	145.0
1982	0.96	0.16		29.0	174.0
1983	1.12	0.16		29.0	203.0
1984	1.12	0.0		0	203.0
1985	1.28	0.16		29.0	232.0

TABLE 32

CASE II
CANADIAN ARCTIC ISLAND PIPELINE SYSTEM

Year	Total Volume	Incremental Volume	Cost Factors	Estimated Cost: Incremental	Estimated Cost: Cumulative	Notes
	------------ Tcf/Yr.		------------------	---Millions of Dollars---		
1981						
1982						
1983	.48	.48	Initial construction lump sum.	3,506	3,506	Initial construction of 2,100 mile system to Winnipeg - cost based on a per mile estimate.
1984	.80	.32	Incremental power plus connection costs.	667	4,137	Incremental power added plus connections to other islands.
1985	.80	0		0	4,137	

TABLE 33

CASE II
CANADIAN GAS TRANSMISSION FACILITIES
CANADIAN ATLANTIC OFFSHORE

Year	Total Offshore Volume	Incremental Volume	Cost Factors	Estimated Cost Incremental	Estimated Cost Cumulative	Notes
	----- Tcf/Yr. ------			---Millions of Dollars---		
1976	0.08	0.08	Lump sum at $800,000/Mile	640	640	Construct 800 mile pipeline from Sable Island to Montreal.
1977	0.32	0.24		66	706	
1978	0.56	0.24		66	772	
1979	0.72	0.16		44	816	
1980	0.88	0.16		44	860	
1981	0.96	0.08	Incr. Vol. x $275/Tcf	22	882	Add power to existing pipeline.
1982	1.12	0.16		44	926	
1983	1.12	0.0		0	926	
1984	1.12	0.0		0	926	
1985	1.28	0.16		44	970	

TABLE 34

CASE III
ALASKAN-CANADIAN FRONTIER - MARKETED PRODUCTION

Year	Alaska* (1N)	Annual Volume – Canadian: N.W.T. Onshore	N.W.T. Islands	Atlantic Offshore	Total Canadian	Canadian Frontier Gas Imported to U.S.	Annual Volume Per Pipeline System – Mackenzie Valley (Col. 2 & 3): Cum.	Incr.	Island Line (Col. 4): Cum.	Incr.	Atlantic Line (Col. 5): Cum.	Incr.
	←Tcf→						←Tcf→					
1971-1975												
1976				0.08	0.08						0.08	0.08
1977				0.32	0.32						0.32	0.24
1978	0.6	0.08		0.56	0.64	0.1	0.68	0.68			0.56	0.24
1979	1.0	0.32		0.72	1.04	0.4	1.32	0.64			0.72	0.16
1980	1.1	0.56		0.88	1.44	0.6	1.66	0.34			0.88	0.16
1981	1.2	0.80		0.96	1.76	0.8	2.00	0.34			0.96	0.08
1982	1.4	0.96		1.12	2.08	0.9	2.36	0.36			1.12	0.16
1983	1.9	1.12	0.48	1.12	2.72	1.5	3.02	0.66	0.48	0.48	1.12	0.0
1984	2.0	1.12	0.80	1.12	3.04	1.8	3.12	0.10	0.80	0.32	1.12	0.0
1985	2.2	1.28	0.80	1.28	3.36	1.8	3.48	0.36	0.80	0.0	1.28	0.16

*Wellhead Production

TABLE 35

CASE III
ALASKAN-CANADIAN PIPELINES - COST SUMMARIES

(All Costs in Millions of U.S. Dollars*)

Year	Mackenzie Valley P/L's Alaskan Portion	Mackenzie Valley P/L's Canadian Portion	Mackenzie Valley P/L's Total	N.W.T. Onshore Connections	Arctic Islands System	Canadian Atlantic System	Total Canadian Costs (Col. 3, 5, 6 & 7)	Percentage of Canadian Frontier Gas Imported	Canadian Costs Allocated to U.S.	Alaskan Costs Allocated to U.S.	Total Canadian Alaskan Costs
1976						640	640.0		343		343
1977						66	66.0		35		35
1978	2,912	388	3,330	14.5		66	468.5		213	2,912	3,125
1979	1,127	676	1,803	43.5		44	763.5	Use: 0.5357	505	1,127	1,632
1980	467	1,120	1,587	43.5		44	1,207.5		647	467	1,114
Sub-Total 1976-80									1,743	4,506	6,249
1981	467	1,120	1,587	43.5		22	1,185.5		422	467	889
1982	327	262	589	29.0		44	335.0		157	327	484
1983	2,019	646	2,665	29.0	3,506	0	4,181.0		2,319	2,019	4,338
1984	467	0	467	0	667	0	667.0		357	467	824
1985	616	492	1,108	29.0	0	44	565.0		244	616	860
Sub-Total 1981-85									3,499	3,896	7,395
Total									5,242	8,402	13,644

*All costs in 1970 constant dollars.

TABLE 36

CASE III
ALASKAN-CANADIAN GAS TRANSMISSION FACILITIES
Mackenzie Valley Pipeline System From Alaska to Emerson, Manitoba Plus Bifurcation Line to U.S. West Coast

Year	Total Volume N.W.T. & Alaska	Increm. Volume	Line Loading Pattern: Line 1	Line 2	Line 3	Line 4	Cost Factor Application	Estimated Costs: Increm.	Cum.	Portion for Alaska	Notes
	←-------Tcf/Yr.					-------→		← Millions of Dollars		→	
1978	0.68	0.68	.68				Lump Sum Cost	3,300	3,300		Construct first pipeline Alaska to Emerson.
1979	1.32	0.64	.071 .5265	.0425			.071 x4394 (lump sum .5265 x 1100 + 725 (for bifurca- .0425 x 4394 (tion line ("B" Line	1,803	5,103		Complete first line, start second line loop, construct "B" line.
1980	1.66	0.34		.34			.34 x 4394 + .34 x 275	1,587	6,690		Loop and power second line and "B" line.
1981	2.00	0.34		.34			.34 x 4394 + .34 x 275	1,587	8,277		Loop and power second line and power on "B" line.
1982	2.36	0.36		.0285 .3315			.0285 x 4394 .3315 x 1100 + .36 x 275	589	8,866		Loop and power second line and power on "B" line.
1983	3.02	0.66		.1950	.465		.1950 x 1100 .1950 x 275 .465 x 4394 + .465 x 760	2,665	11,531		Complete second line - start third line loop - start "B" line loop.
1984	3.12	0.10			.10		.10 x 4394 + .10 x 275	467	11,998		Loop and power.
1985	3.48	0.36			.186 .174		.186 x 4394 .174 x 1100 + .36 x 275	1,108	13,106		Loop and power.

TABLE 37

CASE III
CANADIAN N.W.T. ONSHORE CONNECTION COSTS

Year	Total Onshore N.W.T.	Incremental Volume	Cost Factor Application	Estimated Cost Incremental	Estimated Cost Cumulative
	---------Tcf/Yr.	----------		---Millions	of Dollars---
1978	0.08	0.08		14.5	14.5
1979	0.32	0.24	Assumes lateral construction to attach these reserves to the main trunk - Estimated at $181,600/Bcf	43.5	58.0
1980	0.56	0.24		43.5	101.5
1981	0.80	0.24		43.5	145.0
1982	0.96	0.16		29.0	174.0
1983	1.12	0.16		29.0	203.0
1984	1.12	0.0		0	203.0
1985	1.28	0.16		29.0	232.0

TABLE 38

CASE III
CANADIAN ARCTIC ISLAND PIPELINE SYSTEM

Year	Total Volume	Incremental Volume	Cost Factors	Estimated Cost Incremental	Estimated Cost Cumulative	Notes
	------------ Tcf/Yr.		------------------	---Millions of Dollars---		
1981						
1982						
1983	.48	.48	Initial construction lump sum.	3,506	3,506	Initial construction of 2,100 mile system to Winnipeg - cost based on a per mile estimate.
1984	.80	.32	Incremental power plus connection costs.	667	4,137	Incremental power added plus connections to other islands.
1985	.80	0		0	4,137	

TABLE 39

CASE III
CANADIAN GAS TRANSMISSION FACILITIES
CANADIAN ATLANTIC OFFSHORE

Year	Total Offshore Volume	Incremental Volume	Cost Factors	Estimated Cost Incremental	Estimated Cost Cumulative	Notes
	----- Tcf/Yr. ------			---Millions of Dollars---		
1976	0.08	0.08	Lump sum at $800,000/Mile	640	640	Construct 800 mile pipeline from Sable Island to Montreal.
1977	0.32	0.24		66	706	
1978	0.56	0.24		66	772	
1979	0.72	0.16		44	816	
1980	0.88	0.16		44	860	
1981	0.96	0.08	Incr. Vol. x $275/Tcf	22	882	Add power to existing pipeline.
1982	1.12	0.16		44	926	
1983	1.12	0.0		0	926	
1984	1.12	0.0		0	926	
1985	1.28	0.16		44	970	

TABLE 40

CASE IV
ALASKAN-CANADIAN FRONTIER - MARKETED PRODUCTION

Year	Alaska* (1N)	Annual Volume – Canadian – N.W.T. Onshore	N.W.T. Islands	Atlantic Offshore	Total Canadian	Canadian Frontier Gas Imported to U.S.	Annual Volume Per Pipeline System – Mackenzie Valley (Col. 2 & 3) Cum.	Incr.	Island Line (Col. 4) Cum.	Incr.	Atlantic Line (Col. 5) Cum.	Incr.
	←------	------	------	Tcf	------	------→	←------	------	Tcf	------	------	------→
1971-1975												
1976				0.08	0.08						0.08	0.08
1977				0.32	0.32						0.32	0.24
1978		0.08		0.56	0.64	0.1	0.08	0.08			0.56	0.24
1979		0.32		0.72	1.04	0.4	0.32	0.24			0.72	0.16
1980		0.56		0.88	1.44	0.6	0.56	0.24			0.88	0.16
1981		0.80		0.96	1.76	0.8	0.80	0.24			0.96	0.08
1982		0.96		1.12	2.08	0.9	0.96	0.16			1.12	0.16
1983	0.7	1.12	0.48	1.12	2.72	1.5	1.82	0.86	0.48	0.48	1.12	0.0
1984	1.1	1.12	0.80	1.12	3.04	1.8	2.22	0.48	0.80	0.32	1.12	0.0
1985	1.3	1.28	0.80	1.28	3.36	1.8	2.58	0.36	0.80	0.0	1.28	0.16

*Wellhead Production

TABLE 41

CASE IV
ALASKAN-CANADIAN PIPELINES - COST SUMMARIES

Year	Mackenzie Valley P/L's: Alaskan Portion	Mackenzie Valley P/L's: Canadian Portion	Mackenzie Valley P/L's: Total	N.W.T. Onshore Connections	Arctic Islands System	Canadian Atlantic System	Total Canadian Costs (Col. 3, 5, 6 & 7)	Percentage of Canadian Frontier Gas Imported	Canadian Costs Allocated to U.S.	Alaskan Costs Allocated to U.S.	Total Canadian Alaskan Costs
						(All Costs in Millions of U.S. Dollars*)					
1976						640	640.0		343		343
1977						66	66.0		35		35
1978		3,300	3,300	14.5		66	3,380.5	Use: 0.5357	1,811		1,811
1979		0	0	43.5		44	87.5		47		47
1980		0	0	43.5		44	87.5		47		47
Sub-Total 1976-80									2,283		2,283
1981		366	366	43.5		22	431.5		231		231
1982		176	176	29.0		44	249.0		133		133
1983	2,815	643	3,458	29.0	3,506	0	4,178.0		2,238	2,815	5,053
1984	1,234	0	1,234	0	667	0	667.0		357	1,234	1,591
1985	321	256	577	29.0	0	44	329.0		176	321	497
Sub-Total 1981-85									3,135	4,370	7,505
Total									5,418	4,370	9,788

*All costs in 1970 constant dollars.

TABLE 42

CASE IV
ALASKAN-CANADIAN GAS TRANSMISSION FACILITIES
Mackenzie Valley Pipeline System From Alaska to Emerson, Manitoba Plus Bifurcation Line to U.S. West Coast

Year	Total Volume N.W.T. & Alaska	Increm. Volume	Line Loading Pattern: Line 1	Line 2	Line 3	Line 4	Cost Factor Application	Estimated Costs: Increm.	Cum.	Portion for Alaska	Notes
	←------	------	Tcf/Yr.	------	------	------→		← Millions	of	Dollars →	
1978	0.08	0.08	.08					3,300	3,300		Construct initial line.
1979	0.32	0.24	.24						3,300		--
1980	0.56	0.24	.24						3,300		--
1981	0.80	0.24	.24				.071 x 4394 .049 x 1100	366	3,666		Expand with power.
1982	0.96	0.16	.16				.16 x 1100	176	3,842		Expand with power.
1983	1.82	0.86	.3175	.5425			.3175 x 1100 (For "B" .5425 x 4394 + 725 (Line	3,458	7,300	2,815	Complete first line - start second line loop - construct bifurcation line.
1984	2.22	0.40		.40			.2075 x 4394 .1925 x 1100 + .40 x 275	1,234	8,534	321	Expand second line and bifurcation line.
1985	2.58	0.36		.335	.025		.325 x 1100 .025 x 4394 + .36 x 275	577	9,111		--

TABLE 43

CASE IV

CANADIAN N.W.T. ONSHORE CONNECTION COSTS

Year	Total Onshore N.W.T.	Incremental Volume	Cost Factor Application	Estimated Cost Incremental	Estimated Cost Cumulative
	---------Tcf/Yr.	----------		---Millions of Dollars---	
1978	0.08	0.08		14.5	14.5
1979	0.32	0.24	Assumes lateral construction to attach these reserves to the main trunk - Estimated at $181,600/Bcf	43.5	58.0
1980	0.56	0.24		43.5	101.5
1981	0.80	0.24		43.5	145.0
1982	0.96	0.16		29.0	174.0
1983	1.12	0.16		29.0	203.0
1984	1.12	0.0		0	203.0
1985	1.28	0.16		29.0	232.0

TABLE 44

CASE IV
CANADIAN ARCTIC ISLAND PIPELINE SYSTEM

Year	Total Volume	Incremental Volume	Cost Factors	Estimated Cost Incremental	Estimated Cost Cumulative	Notes
	Tcf/Yr.			Millions of Dollars		
1981						
1982						
1983	.48	.48	Initial construction lump sum.	3,506	3,506	Initial construction of 2,100 mile system to Winnipeg - cost based on a per mile estimate.
1984	.80	.32	Incremental power plus connection costs.	667	4,137	Incremental power added plus connections to other islands.
1985	.80	0		0	4,137	

TABLE 45

CASE IV
CANADIAN GAS TRANSMISSION FACILITIES
CANADIAN ATLANTIC OFFSHORE

Year	Total Offshore Volume	Incremental Volume	Cost Factors	Estimated Cost Incremental	Estimated Cost Cumulative	Notes
	------Tcf/Yr.------			---Millions of Dollars---		
1976	0.08	0.08	Lump sum at $800,000/Mile	640	640	Construct 800 mile pipeline from Sable Island to Montreal.
1977	0.32	0.24	Incr. Vol. x $275/Tcf	66	706	Add power to existing pipeline.
1978	0.56	0.24		66	772	
1979	0.72	0.16		44	816	
1980	0.88	0.16		44	860	
1981	0.96	0.08		22	882	
1982	1.12	0.16		44	926	
1983	1.12	0.0		0	926	
1984	1.12	0.0		0	926	
1985	1.28	0.16		44	970	

TABLE 46

ALASKA REGION 1N
WELLHEAD AND MARKETED PRODUCTION
(Volumes in Annual Tcf)

Year	Case I		Case II		Case III		Case IV	
	Wellhead	Marketed	Wellhead	Marketed	Wellhead	Marketed	Wellhead	Marketed
1978	0.8	0.7	0.8	1.6	0.6	0.5	-	-
1979	1.1	1.0	1.1	1.0	1.0	0.9	-	-
1980	1.4	1.3	1.3	1.2	1.1	1.0	-	-
1981	1.6	1.5	1.4	1.3	1.2	1.1	-	-
1982	2.3	2.0	1.6	1.5	1.4	1.3	-	-
1983	2.5	2.2	2.2	1.9	1.9	1.7	0.7	0.6
1984	3.0	2.7	2.4	2.1	2.0	1.8	1.1	1.0
1985	3.3	3.0	2.7	2.4	2.2	2.0	1.3	1.2

- Canadian Atlantic Offshore (48-inch pipeline)

  Routing from Sable Island to Montreal, including 140 miles of water and 660 miles of land construction — 800 Miles

Main Pipeline Capacities

Number of 48-inch Lines with Full Power	Sales Capacity at 100% Load Factor TCF/Yr.*
1	1.2775
2	2.555
3	3.8325
4	5.110

* The sales capacity was used as the design capacity of the main pipeline. This represents an approximate 98-percent load factor based on input capacity.

Development of Unescalated Cost Factors

- Main Pipeline--2,400 Miles

  Based on the Northwest Project Study Group estimates, the construction requirements for the first year's capacity were 2,400 miles of 48-inch pipeline and some horsepower. Using their cost estimate of $3,300,000 and capacity of 751 BCF/Year in the first year, a cost factor of $4,394,000/BCF was calculated.

  In the second year, the capacity was increased by 546 BCF requiring additional facilities costing $6,000,000. The resultant cost factor for system additions above a 60-percent load factor was $1,100,000/BCF.

- Bifurcation Line

  All construction is below the 60th Parallel.

  Using Northwest Project Study Group cost studies for facilities South of the 60th Parallel--

  Total estimated cost of a 1,200 mile system including power is $1,616,000,000.

The resultant cost factors for a system with a load factor at 70 percent or below is $1,517,000/BCF.

For expansion above 70 percent, the cost per BCF is $550,000.

Both of these are for a 1,200-mile system. For the 600-mile system required in this study, the costs were reduced by 50 percent.

The cost factors used are--

First year construction--$725,000,000 Lump Sum

Incremental Additions
Below 70 Percent Load Factor-- $760,000/BCF
Above 70 Percent Load Factor-- $275,000/BCF

- <u>Canadian Northwest Territory Onshore</u>

  Using Northwest Project Study Group costs for construction North of the 60th Parallel, estimated costs for a typical 100-mile system were developed.

  The resultant cost factor for a 100-mile system is $ 181,600/BCF

- <u>Canadian Atlantic Offshore</u>

  The total estimated distance of a pipeline from Sable Island, offshore Nova Scotia, to Montreal is 800 miles. It was estimated that this line would require 140 miles of water and 660 miles of land construction. Costs were developed for a 48-inch pipeline system using current construction techniques.

  The resultant cost factors are--

  First year construction--$800,000/BCF
  Incremental expansions--$275,000/BCF

- <u>Canadian Arctic Islands</u>

  The main system was routed from Ellef Ringnes Island to Amund Ringnes Island to Cornwall Island to Devon Island, across Devon to Somerset Island, across Somerset to Boothia Penninsula and then to the Mainland. From there it was routed south to Winnipeg to connect with Trans-Canada PipeLine.

  Total system length was 2,100 miles, broken down into--

  Water and island construction--800 Miles
  Mainland North of 60th Parallel--600 miles
  Mainland South of 60th Parallel--700 miles

Costs were based on an early screening study of Alaskan offshore construction costs made by the Northwest Project Study Group.

The resultant cost factors are--

Water and island construction--$2,100,000/Mile

Land construction North of 60th Parallel--$1,667,000/Mile

Land construction South of 60th Parallel--$1,180,000/Mile

Connection costs for laterals--$2,100,000/Mile

Incremental expansions with power--$1,100,000/BCF

Using the assumed mileages and costs--

First Year Costs	Millions of Dollars
800 Miles x $2,100,000 =	1,680
600 Miles x $1,667,000 =	1,000
700 Miles x $1,180,000 =	826
Total	3,506

Second Year

Incremental expansion
BCF x $1,100,000

Plus connection costs of
Estimated Mileage x $2,100,000/Mile.

EXHIBIT II

COMPUTER MODEL

PADONE PROGRAM DESCRIPTION

Introduction

The Padone program performs arithmetic calculations on data supplied to arrive at 15-year investment cost for industry expansion. The costs are in 1970 dollars, and no allowance is made for inflation. The program also does no analysis or system simulation (modeling); therefore, effects produced by system design or optimization must be accounted for within the data. The approximate run time for a study is (9 sec. CPU) on an IBM System 370/155 operating under OS Version 21.

Program Layout

The program is divided into eight sections whose functions are as follows:

- Section 1000 is responsible for reading data, verifying codes and storing the data in the proper arrays. A count of the number of errors is also maintained. If, after all data is read, more than 25 errors have been encountered, the program is aborted.

- Section 2000 prepares the annual Gas Balance figures. Paragraph 2100 allocates supply volumes from regions to PAD districts and obtains columnar totals. Paragraph 2200 determines the fair share percentage to be used to match demand with supply. If Demand Adjustment Percentages were entered as data, this portion is bypassed. Paragraph 2300 applies the demand adjustment percentage to the unadjusted demand and computes the supply balance. Supply attachment volumes, transmission expansion volumes and storage expansion volumes are prepared in paragraphs 2400, 2500 and 2600, respectively.

- Section 3000 applies the capital costs to the volumes calculated in the 2000 Section and prepares columnar totals.

- Section 4000 controls the output of the program and formats headings as they are needed. Through control of Section 4000, Sections 5000 and 6000 output the Gas Balance and Capital Cost sheets, respectively. Section 7000 outputs the Capital Cost Factors and the Storage Withdrawal equation.

Input Description

The various volumes and costs that are input to the program are identified by a type code. The meaning of the type codes is listed below:

Type Codes

11	Domestic Marketed Production*
12	Alaskan, Canadian, Arctic
13	Other Canadian
14	Mexican
15	LNG
16	SNG
17	Coal Gas
18	Nuclear Stimulation
21	New Domestic Production†
22	
23	New LNG
24	New SNG
25	New Coal Gas
26	New Nuclear Stimulation
31	Unadjusted Demand
33	Demand Adjustment Percentage‡
51	Intra PAD Transmission Capital Cost
52	Inter PAD Transmission Capital Cost
53	Onshore Gathering Capital Cost
54	Offshore Gathering Capital Cost
55	Storage Withdrawal Capital Cost
56	LNG Attachment Capital Cost
57	SNG Attachment Capital Cost
58	Coal Gas Attachment Capital Cost
59	Nuclear Stimulation Attachment Capital Cost
61	Arctic Pipeline Construction‡ $\$ \times 10^6$
70	Storage Use Factor--Intercept
71	Storage Use Factor--Slope
91	Percent of Region Allocated to PAD District Enter PAD District in Year

---

* PAD district entries invalid.
† PAD district entries considered onshore production.
‡ Regional entries invalid.

The valid entries for region are 1-11, 1X (1 South), 2X (Pacific Offshore), 6X (Gulf Coast Offshore) and 11X (Atlantic Offshore). PAD district entries are identified by a "P" in Column 1 and the PAD district in Columns 2 and 3.

The format for input is shown on the sample sheet. Region numbers are right justified. PAD district numbers are left justified. The order of input is entirely at the option of the user.

SAMPLE SHEET FOR

INPUT CODING

REGION	YEAR	TYPE	AMOUNT (TCF-$/MMCF)
1	4	6	8

REGION	YEAR	TYPE	AMOUNT (TCF-$/MMCF)
1	4	6	8

COMPUTER WORK PAPERS

FOR PADONE PROGRAM

```
       IDENTIFICATION DIVISION.                                         00000100
       PROGRAM-ID.        F380P1.                                       00000200
       ENVIRONMENT DIVISION.                                            00000300
       CONFIGURATION SECTION.                                           00000400
       SPECIAL-NAMES.                                                   00000450
           C01 IS TOP.                                                  00000460
       INPUT-OUTPUT SECTION.                                            00000500
       FILE-CONTROL.                                                    00000600
           SELECT CARDIN    ASSIGN UT-S-CARDIN.                         00000700
           SELECT PAPEROT   ASSIGN UT-S-PAPEROT.                        00000800
           SELECT TAPEIN    ASSIGN UT-S-TAPEIN.                         00000900
       DATA DIVISION.                                                   00001000
       FILE SECTION.                                                    00001100
                                                                        00001200
                                                                        00001300
       FD  CARDIN                                                       00001400
           RECORDING F                                                  00001500
           LABEL RECORDS STANDARD                                       00001600
           BLOCK CONTAINS 0 RECORDS                                     00001700
           DATA RECORD IS CARDREC.                                      00001800
                                                                        00001900
       01  CARDREC           PICTURE X(80).                             00002000
                                                                        00002100
       FD  PAPEROT                                                      00002200
           RECORDING U                                                  00002300
           LABEL RECORDS STANDARD                                       00002400
           DATA RECORD IS A-LINE.                                       00002500
                                                                        00002600
       01  A-LINE            PICTURE X(133).                            00002700
                                                                        00002800
       FD  TAPEIN                                                       00002900
           RECORDING F                                                  00003000
           LABEL RECORDS STANDARD                                       00003100
           DATA RECORD IS TAPEREC.                                      00003200
                                                                        00003300
       01  TAPEREC           PICTURE X(80).                             00003400
                                                                        00003500
                                                                        00003600
       WORKING-STORAGE SECTION.                                         00003700
                                                                        00003800
       77  I                 PICTURE S9(7)     COMPUTATIONAL.           00003900
       77  J                 PICTURE S9(7)     COMPUTATIONAL.           00004000
       77  JMAX              PICTURE S9(7)     COMPUTATIONAL.           00004100
       77  K                 PICTURE S9(7)     COMPUTATIONAL.           00004200
       77  L                 PICTURE S9(7)     COMPUTATIONAL.           00004300
       77  M                 PICTURE S9(7)     COMPUTATIONAL.           00004400
       77  N                 PICTURE S9(7)     COMPUTATIONAL.           00004500
       77  Y1                PICTURE S9(7)     COMPUTATIONAL.           00004600
```

```
       77  Y2              PICTURE S9(7)       COMPUTATIONAL.          00004700
       77  TDMAND          PICTURE S9(9)V9(6)  COMPUTATIONAL-3.        00004800
       77  TSPPLY          PICTURE S9(9)V9(6)  COMPUTATIONAL-3.        00004900
       77  TVOLUM          PICTURE S9(7)V9(6)  COMPUTATIONAL-3.        00005000
       77  SLOPE           PICTURE S9(6)V9(6)  COMPUTATIONAL-3.        00005100
       77  INTERCEPT       PICTURE S9(6)V9(6)  COMPUTATIONAL-3.        00005200
       77  GBA             PICTURE X(11)       VALUE 'GAS BALANCE'.    00005300
       77  GBB             PICTURE X(11)       VALUE 'DESCRIPTION'.    00005400
       77  GBC             PICTURE X(11)       VALUE SPACES.           00005500
       77  CCA             PICTURE X(13)       VALUE 'CAPITAL COSTS'.  00005600
       77  CCB             PICTURE X(27)       VALUE                   00005700
               'CAPITAL COST FOR ADDITIONAL'.                          00005800
       77  CCC             PICTURE X(23)       VALUE                   00005900
               'TRANSMISSION FACILITIES'.                              00006000
       77  OUTYP           PICTURE X.                                  00006100
       77  OTLVL           PICTURE X.                                  00006200
       77  ERRCNT          PICTURE S9(3)       COMPUTATIONAL-3         00006300
                           VALUE 0.                                    00006400
       77  TAP             PICTURE X           VALUE SPACE.            00006500
           88  TAPE-IS-OPEN                    VALUE 'X'.              00006600
                                                                       00006700
                                                                       00006800
       01  CARD1.                                                      00006900
           02  CREGION.                                                00007000
             03  PID       PICTURE X.                                  00007100
             03  PAD       PICTURE XX.                                 00007200
           02  CYEAR       PICTURE 99.                                 00007300
           02  CPAD2       REDEFINES CYEAR     PICTURE XX.             00007400
           02  CTYPE       PICTURE 99.                                 00007500
           02  CAMT        PICTURE S9(6)V9(6).                         00007600
           02  CAMT2       REDEFINES CAMT.                             00007700
             03  FILLER    PICTURE X(5).                               00007800
             03  DPAMT     PICTURE 9V9(6).                             00007900
           02  FILLER      PICTURE X(61).                              00008000
                                                                       00008100
       01  HEAD1.                                                      00008200
           02  FILLER      PICTURE X(48)       VALUE SPACES.           00008300
           02  HTTLO       PICTURE X(18)       VALUE                   00008400
               'P A D DISTRICT - '.                                    00008500
           02  HTTLA       PICTURE X(55).                              00008600
           02  FILLER      PICTURE X(5)        VALUE 'PAGE'.           00008700
           02  PAGNO       PICTURE 9(4)        VALUE 0.                00008800
                                                                       00008900
       01  HEAD2.                                                      00009000
           02  FILLER      PICTURE X.                                  00009100
           02  HTTLB       PICTURE X(123).                             00009200
           02  FILLER      PICTURE X(5)        VALUE 'TOTAL'.          00009300
                                                                       00009400
       01  HEAD3.                                                      00009500
           02  FILLER      PICTURE X.                                  00009600
           02  HTTLC       PICTURE X(40).                              00009700
```

```
           02  FILLER        OCCURS 5 TIMES.
               03  HYR       PICTURE Z(4).
               03  FILLER    PICTURE X(12).
           02  HYRA          PICTURE Z(8).
           02  HYRB          PICTURE -99.

       01  HEAD4.
           02  FILLER        PICTURE X            VALUE SPACE.
           02  HTTLD         PICTURE X(38).
           02  FILLER        PICTURE X(32)        VALUE '1971-75'.
           02  FILLER        PICTURE X(32)        VALUE '1976-80'.
           02  FILLER        PICTURE X(21)        VALUE '1981-85'.
           02  FILLER        PICTURE X(7)         VALUE '1971-85'.

       01  HEAD5.
           02  FILLER        PICTURE X(56)        VALUE SPACES.
           02  FILLER        PICTURE X(21)        VALUE
               'C O S T   T A B L E S'.

       01  HEAD6.
           02  FILLER        PICTURE X(65)        VALUE SPACES.
           02  FILLER        PICTURE XXX          VALUE 'AND'.

       01  HEAD7.
           02  FILLER        PICTURE X(54)        VALUE SPACES.
           02  FILLER        PICTURE X(26)        VALUE
               'STORAGE WITHDRAWAL FACTORS'.

       01  HEAD8.
           02  FILLER        PICTURE X(23)        VALUE ' PAD'.
           02  FILLER        PICTURE X(46)        VALUE
               'TRANSMISSION        ONSHORE        OFFSHORE'.
           02  FILLER        PICTURE X(39)        VALUE
               'STORAGE       L N G          S N G'.
           02  FILLER        PICTURE X(20)        VALUE
               'COAL GAS      NUCLEAR'.

       01  HEAD9.
           02  FILLER        PICTURE X(55)        VALUE
               ' DISTRICT             INTRA PAD     INTER PAD    GATHERING'.
           02  FILLER        PICTURE X(52)        VALUE
               'GATHERING      WITHDRAWAL    ATTACHMENT     ATTACHMENT'.
           02  FILLER        PICTURE X(24)        VALUE
               'ATTACHMENT    STIMULATION'.

       01  HEAD10.
           02  FILLER        PICTURE X(10)        VALUE SPACES.
           02  FILLER        PICTURE X(11)        VALUE '     SLOPE'.
           02  LSLOPE        PICTURE -9.999999.

       01  HEAD11.
```

```
           02  FILLER        PICTURE X(10)        VALUE SPACES.           00014900
           02  FILLER        PICTURE X(11)        VALUE 'INTERCEPT'.      00015000
           02  LINTERCEPT    PICTURE -9.999999.                           00015100
                                                                          00015200
                                                                          00015300
       01  LINE-TITLES.                                                   00015400
           02  FILLER        PICTURE X(16)        VALUE                   00015500
               '1P A D DISTRICT '.                                        00015600
           02  PADL          PICTURE XXX.                                 00015700
           02  FILLER        PICTURE X(12)        VALUE ' SUPPLY'.        00015800
           02  FILLER        PICTURE X(31)        VALUE                   00015900
               '2       DOMESTIC PRODUCTION'.                             00016000
           02  FILLER        PICTURE X(18)        VALUE                   00016100
               '1            REGION '.                                    00016200
           02  REGL          PICTURE X(13).                               00016300
           02  FILLER        PICTURE X(31)        VALUE                   00016400
               '1       SUB-TOTAL'.                                       00016500
           02  FILLER        PICTURE X(31)        VALUE                   00016600
               '2       PIPELINE IMPORTS'.                                00016700
           02  FILLER        PICTURE X(31)        VALUE                   00016800
               '1            ALASKA,CANADA,ARCTIC'.                       00016900
           02  FILLER        PICTURE X(31)        VALUE                   00017000
               '1            OTHER CANADIAN'.                             00017100
           02  FILLER        PICTURE X(31)        VALUE                   00017200
               '1            MEXICAN'.                                    00017300
           02  FILLER        PICTURE X(31)        VALUE                   00017400
               '1       SUB-TOTAL'.                                       00017500
           02  FILLER        PICTURE X(31)        VALUE                   00017600
               '1       L N G'.                                           00017700
           02  FILLER        PICTURE X(31)        VALUE                   00017800
               '1       S N G'.                                           00017900
           02  FILLER        PICTURE X(31)        VALUE                   00018000
               '1       COAL GAS'.                                        00018100
           02  FILLER        PICTURE X(31)        VALUE                   00018200
               '1       NUCLEAR STIMULATION'.                             00018300
           02  FILLER        PICTURE X(31)        VALUE                   00018400
               '1TOTAL SUPPLY'.                                           00018500
           02  FILLER        PICTURE X(31)        VALUE                   00018600
               '3ADJUSTED DEMAND'.                                        00018700
           02  FILLER        PICTURE X(31)        VALUE                   00018800
               '3SUPPLY BALANCE'.                                         00018900
           02  FILLER        PICTURE X(31)        VALUE                   00019000
               '3SUPPLY ATTACHMENT VOLUMES'.                              00019100
           02  FILLER        PICTURE X(31)        VALUE                   00019200
               '2       NEW PRODUCTION'.                                  00019300
           02  FILLER        PICTURE X(31)        VALUE                   00019400
               '1            ONSHORE'.                                    00019500
           02  FILLER        PICTURE X(31)        VALUE                   00019600
               '1            OFFSHORE'.                                   00019700
           02  FILLER        PICTURE X(31)        VALUE                   00019800
               '1      LNG IMPORTS'.                                      00019900
```

```
           02  FILLER       PICTURE X(31)       VALUE                    00020000
               '1      SNG PRODUCED'.                                    00020100
           02  FILLER       PICTURE X(31)       VALUE                    00020200
               '1      COAL GAS PRODUCED'.                               00020300
           02  FILLER       PICTURE X(31)       VALUE                    00020400
               '1      NUCLEAR STIMULATION'.                             00020500
           02  FILLER       PICTURE X(31)       VALUE                    00020600
               '1TOTAL'.                                                 00020700
           02  FILLER       PICTURE X(31)       VALUE                    00020800
               '3TRANSMISSION EXPANSION VOLUMES'.                        00020900
           02  FILLER       PICTURE X(31)       VALUE                    00021000
               '2      INTRA P A D'.                                     00021100
           02  FILLER       PICTURE X(31)       VALUE                    00021200
               '1      INTER P A D'.                                     00021300
           02  FILLER       PICTURE X(31)       VALUE                    00021400
               '3STORAGE VOLUMES'.                                       00021500
           02  FILLER       PICTURE X(31)       VALUE                    00021600
               '1      INTRA P A D TRANSMISSION'.                        00021700
           02  FILLER       PICTURE X(31)       VALUE                    00021800
               '2      INTER P A D TRANSMISSION'.                        00021900
           02  FILLER       PICTURE X(31)       VALUE                    00022000
               '1TOTAL'.                                                 00022100
           02  FILLER       PICTURE X(31)       VALUE                    00022200
               '3TRANSMISSION - DOMESTIC'.                               00022300
           02  FILLER       PICTURE X(31)       VALUE                    00022400
               '2      INTRA P A D'.                                     00022500
           02  FILLER       PICTURE X(31)       VALUE                    00022600
               '2      INTER P A D'.                                     00022700
           02  FILLER       PICTURE X(31)       VALUE                    00022800
               '1SUB-TOTAL'.                                             00022900
           02  FILLER       PICTURE X(31)       VALUE                    00023000
               '3TRANSMISSION - IMPORTS'.                                00023100
           02  FILLER       PICTURE X(31)       VALUE                    00023200
               '1            ALASKA,CANADA,ARCTIC'.                      00023300
           02  FILLER       PICTURE X(31)       VALUE                    00023400
               '1            OTHER CANADIAN'.                            00023500
           02  FILLER       PICTURE X(31)       VALUE                    00023600
               '1            MEXICAN'.                                   00023700
           02  FILLER       PICTURE X(31)       VALUE                    00023800
               '1SUB-TOTAL'.                                             00023900
           02  FILLER       PICTURE X(31)       VALUE                    00024000
               '3SUPPLY ATTACHMENTS'.                                    00024100
           02  FILLER       PICTURE X(31)       VALUE                    00024200
               '2      NEW PRODUCTION ATTACHMENT'.                       00024300
           02  FILLER       PICTURE X(31)       VALUE                    00024400
               '1            ONSHORE'.                                   00024500
           02  FILLER       PICTURE X(31)       VALUE                    00024600
               '1            OFFSHORE'.                                  00024700
           02  FILLER       PICTURE X(31)       VALUE                    00024800
               '2      L N G ATTACHMENTS'.                               00024900
           02  FILLER       PICTURE X(31)       VALUE                    00025000
```

```
               '2     S N G ATTACHMENTS'.
           02  FILLER         PICTURE X(31)        VALUE
               '2    COAL GAS ATTACHMENTS'.
           02  FILLER         PICTURE X(31)        VALUE
               '2    NUCLEAR STIM. ATTACHMENTS'.
           02  FILLER         PICTURE X(31)        VALUE
               '1SUB-TOTAL'.
           02  FILLER         PICTURE X(31)        VALUE
               '3NEW STORAGE FACILITIES'.
           02  FILLER         PICTURE X(31)        VALUE
               '3TOTAL NEW FACILITIES'.
       01  LINT               REDEFINES LINE-TITLES.
           02  FILLER         OCCURS 52 TIMES.
            03  H             PICTURE 9.
            03  TITLE         PICTURE X(30).

               .
       01  LINE1.
           02  FILLER         PICTURE X.
           02  LTITL          PICTURE X(30).
           02  LAMT           PICTURE -(11).-(4)   OCCURS 5 TIMES.
           02  FILLER         PICTURE X(5).
           02  TAMT           PICTURE -(11).-(4).

       01  LINE2.
           02  FILLER         PICTURE X(2).
           02  PIJ            PICTURE X(12).
           02  L2AMT          PICTURE Z(13)        OCCURS 9 TIMES.

       01  LINED.
           02  FILLER         PICTURE X(35)        VALUE SPACES.
           02  FILLER         PICTURE X(48)        VALUE
               '------------   ------------     -------------'.
           02  FILLER         PICTURE X(50)        VALUE
               '------------   ------------        ---------------'.

       01  CAP-COST.
           02  CCP            OCCURS 8 TIMES.
            03  CPCST         PICTURE S9(7)        COMPUTATIONAL-3
                              OCCURS 9 TIMES.

       01  REGPADPCT.
           02  REGP           OCCURS 15 TIMES.
            03  RPP           PICTURE S9V9999      COMPUTATIONAL-3
                              OCCURS 8 TIMES.

       01  REGION-TABLE.
           02  R1             PICTURE X(45)        VALUE
               ' 1  2  3  4  5  6  7  8  9 1X 10 11 2X 6X11X'.
           02  R2             REDEFINES R1.
            03  REG           PICTURE X(3)         OCCURS 15 TIMES
```

```
                                ASCENDING KEY REG   INDEXED BY R.

          01  PADD-TABLE.
                02  P1          PICTURE X(3)        OCCURS 8 TIMES
                                INDEXED BY P.


          01  VOLUME-TABLE.
                02  YEARV       OCCURS 16 TIMES.
                  03  PADV      OCCURS 8 TIMES.
                    04  VOL     OCCURS 40 TIMES     COMPUTATIONAL-3
                                PICTURE S9(7)V9(6).


          01  AMOUNT-TABLE.
                02  YEARA       OCCURS 16 TIMES.
                  03  PADA      OCCURS 8 TIMES.
                    04  AMT     OCCURS 16 TIMES     COMPUTATIONAL-3
                                PICTURE S9(7)V9(6).


          01  TEMPORARY.
                02  YEART       OCCURS 16 TIMES.
                  03  REGT      OCCURS 15 TIMES.
                    04  TEMP    OCCURS 15 TIMES     COMPUTATIONAL-3
                                PICTURE S9(7)V9(6).

          01  TOTAL-TABLE       REDEFINES TEMPORARY.
                02  T-BY-YR     OCCURS 4 TIMES.
                  03  T-BY-PAD  OCCURS 8 TIMES.
                    04  VOLT    PICTURE S9(7)V9(6)  COMPUTATIONAL-3
                                OCCURS 40 TIMES.
                    04  AMTT    PICTURE S9(7)V9(6)  COMPUTATIONAL-3
                                OCCURS 16 TIMES.


          01  DEMD-ADJ-PCTAGE.
                02  DAPYEAR     OCCURS 16 TIMES.
                  03  DAP       OCCURS 8 TIMES      COMPUTATIONAL-3
                                PICTURE 9V9(6).



          PROCEDURE DIVISION.


          0010.
                OPEN INPUT      CARDIN.
                OPEN OUTPUT     PAPFROT.
                PERFORM 8010 THRU 801X.
                PERFORM 8020 THRU 802X.
```

```
           PERFORM 8030 THRU 803X.
           PERFORM 8040 THRU 804X.
           MOVE SPACES TO PADD-TABLE.
           MOVE SPACES TO HEAD3.
           MOVE 0 TO SLOPE, INTERCEPT.
       1000.
           GO TO 1005.
       1005.
           READ CARDIN      INTO     CARD1
                            END      GO TO 2000.
           IF CREGION =    'END'     GO TO 2000.
           IF CREGION =    'TAP'     GO TO 1050.
           GO TO 1015.
       1010.
           READ TAPEIN      INTO     CARD1
                            END      GO TO 2000.
       1015.
           EXAMINE CAMT2 REPLACING ALL ' ' BY '0'.
           IF CTYPE   90             GO TO 1900.
           IF CTYPE = 70 OR 71       GO TO 1700.
           IF CTYPE   60             GO TO 1600.
           IF CTYPE   50             GO TO 1500.
           IF CTYPE   30             GO TO 1300.
           IF CTYPE   20             GO TO 1200.
           IF CTYPE   10             GO TO 1100.
           GO TO 8094.
       1050.
           ALTER 1000       TO PROCEED TO        1010.
           OPEN INPUT       TAPEIN.
           DISPLAY CARD1.
           MOVE 'X' TO TAP.
           GO TO 1010.
       1100.
           IF CTYPE   18 GO TO 8094.
           COMPUTE I = CYEAR - 69.
           IF PID = 'P' GO TO 1150.
           SET R TO 1.
           SEARCH REG                AT END GO TO 8090
               WHEN REG (R) = CREGION            NEXT SENTENCE.
           SET J TO R.
           SUBTRACT 10 FROM CTYPE GIVING K.
           ADD CAMT TO TEMP (I, J, K).
           GO TO 1000.
       1150.
           IF CTYPE = 11 GO TO 8092.
           SET P TO 1.
           SEARCH P1                 AT END GO TO 8091
               WHEN P1 (P) = PAD     NEXT SENTENCE
               WHEN P1 (P) = '        ' NEXT SENTENCE.
           MOVE PAD TO P1 (P).
           SET J TO P.
```

```
               IF CTYPE = 12 OR 13 OR 14
                    ADD CTYPE, 5 GIVING K              ELSE
                    ADD CTYPE, 6 GIVING K.
               ADD CAMT TC VOL (I, J, K).
               GO TO 1000.
          1200.
               IF CTYPE   26 GO TO 8094.
               COMPUTE I = CYEAR - 69.
               IF PID = 'P' GO TO 1250.
               SET R TO 1.
               SEARCH REG                  AT END GO TO 8090
                    WHEN REG (R) = CREGION             NEXT SENTENCE.
               SET J TO R.
               SUBTRACT 12 FROM CTYPE GIVING K.
               IF K = 9 AND J   12                     MOVE 10 TO K.
               ADD CAMT TC TEMP (I, J, K).
               GO TO 1000.
          1250.
               SET P TO 1.
               SEARCH P1                   AT END GO TO 8091
                    WHEN P1 (P) = PAD      NEXT SENTENCE
                    WHEN P1 (P) = '       ' NEXT SENTENCE.
               MOVE PAD TO P1 (P).
               SET J TO P.
               ADD 7, CTYPE GIVING K.
               ADD CAMT TO VOL (I, J, K).
               GO TO 1000.
          1300.
               IF CTYPE = 31               GC TO 1310.
               IF CTYPE = 33               GC TO 1330.
               GO TO 8094.
          1310.
               SUBTRACT 69 FROM CYEAR GIVING I.
               IF PID = 'P' GO TO 1315.
               SET R TO 1.
               SEARCH REG                  AT END GO TO 8090
                    WHEN REG (R) = CREGION             NEXT SENTENCE.
               SET J TO R.
               MOVE 15 TO K.
               ADD CAMT TC TEMP (I, J, K).
               GO TO 1000.
          1315.
               MOVE 26 TO K.
               SET P TO 1.
               SEARCH P1                   AT END GO TO 8091
                    WHEN P1 (P) = PAD      NEXT SENTENCE
                    WHEN P1 (P) = '       ' NEXT SENTENCE.
               MOVE PAD TO P1 (P).
               SET J TO P.
               ADD CAMT TC VOL (I, J, K).
               GO TO 1000.
```

```
       1330.
           ALTER 2005 TO PROCEED TO 2007.
           SUBTRACT 69 FROM CYEAR GIVING I.
           SET P TO 1.
           SEARCH P1                    AT END GO TO 8091
               WHEN P1 (P) = PAD        NEXT SENTENCE
               WHEN P1 (P) = '      '   NEXT SENTENCE.
           MOVE PAD TO P1 (P).
           SET J TO P.
           MOVE DPAMT TO DAP (I, J).
           GO TO 1000.
       1500.
           SUBTRACT 50 FROM CTYPE GIVING J.
           IF PID NOT = 'P' GO TO 8093.
           SET P TO 1.
           SEARCH P1                    AT END GO TO 8091
               WHEN P1 (P) = PAD        NEXT SENTENCE
               WHEN P1 (P) = '       '  NEXT SENTENCE.
           MOVE PAD TO P1 (P).
           SET I TO P.
           MOVE CAMT TO CPCST (I, J).
           GO TO 1000.
       1600.
           IF CTYPE NOT = 61 GO TO 8094.
           IF PID NOT = 'P' GO TO 8093.
           SET P TO 1.
           SEARCH P1                    AT END GO TO 8091
               WHEN P1 (P) = PAD        NEXT SENTENCE
               WHEN P1 (P) = '       '  NEXT SENTENCE.
           MOVE PAD TO P1 (P).
           SET J TO P.
           SUBTRACT 69 FROM CYEAR GIVING I.
           ADD CAMT TO AMT (I, J, 4).
           GO TO 1000.
       1700.
           EXAMINE CAMT2 TALLYING ALL '-' REPLACING BY '0'.
           IF TALLY NOT = 0 MULTIPLY -1 BY CAMT.
               IF CTYPE = 70 MOVE CAMT TO INTERCEPT ELSE
                             MOVE CAMT TO SLOPE.
           GO TO 1000.
       1900.
           IF CTYPE NOT = 91 GO TO 8094.
           SET R TO 1.
           SEARCH REG                   AT END GO TO 8090
               WHEN REG (R) = CREGION               NEXT SENTENCE.
           SET P TO 1.
           SEARCH P1                    AT END GO TO 8091
               WHEN P1 (P) = CPAD2                  NEXT SENTENCE
               WHEN P1 (P) = '      '               NEXT SENTENCE.
           MOVE CPAD2 TO P1 (P).
           SET I TO R.
```

```
               SET J TO P.
               MOVE DPAMT TO RPP (I, J).
               GO TO 1000.
           2000 SECTION.
           2001.
               IF TAPE-IS-OPEN         CLOSE TAPEIN.
               MOVE ' ' TO TAP.
               IF ERRCNT   25 GO TO 8098.
               MOVE 1 TO JMAX.
           2002.
               ADD 1 TO JMAX.
               IF JMAX = 8 GO TO 2003.
               IF P1 (JMAX) NOT = '     ' GO TO 2002.
               SUBTRACT 1 FROM JMAX.
           2003.
               PERFORM 2100 THRU 210X                 VARYING
                   I FROM 1 BY 1 UNTIL I   16         AFTER
                   J FROM 1 BY 1 UNTIL J   JMAX.
           2005.
               GO TO 2006.
           2006.
               DISPLAY '****** FAIR SHARE PERCENTAGE COMPUTED ******'.
               PERFORM 2200 THRU 220X                 VARYING
                   I FROM 1 BY 1 UNTIL I   16.
           2007.
               PERFORM 2300 THRU 230X                 VARYING
                   I FROM 1 BY 1 UNTIL I   16.
               PERFORM 2400 THRU 240X                 VARYING
                   I FROM 2 BY 1 UNTIL I   16         AFTER
                   J FROM 1 BY 1 UNTIL J   JMAX.
               PERFORM 2500 THRU 250X                 VARYING
                   I FROM 2 BY 1 UNTIL I   16         AFTER
                   J FROM 1 BY 1 UNTIL J   JMAX.
               PERFORM 2600 THRU 260X                 VARYING
                   I FROM 2 BY 1 UNTIL I   16         AFTER
                   J FROM 1 BY 1 UNTIL J   JMAX.
               GO TO 3000.
           2100.
               PERFORM 2110 THRU 211X                 VARYING
                   K FROM 1 BY 1 UNTIL K   15.
               MOVE 15 TO L.
               PERFORM 2120 THRU 212X                 VARYING
                   K FROM 2 BY 1 UNTIL K   4.
               MOVE 16 TO L.
               PERFORM 2120 THRU 212X                 VARYING
                   K FROM 5 BY 1 UNTIL K   8.
               MOVE 16 TO L.
               PERFORM 8050 THRU 805X                 VARYING
                   K FROM 1 BY 1 UNTIL K   15.
               MOVE 20 TO L.
               PERFORM 8050 THRU 805X                 VARYING
```

```
                K FROM 17 BY 1 UNTIL K   19.
           MOVE 25 TO L.
           MOVE 16 TO K.
           PERFORM 8050 THRU 805X.
           PERFORM 8050 THRU 805X                VARYING
                K FROM 20 BY 1 UNTIL K   24.
           MOVE 11 TO L.
           MOVE 15 TO K.
           PERFORM 2120 THRU 212X.
       210X.
           EXIT.
       2110.
           COMPUTE VOL (I, J, K) = VOL (I, J, K) +
                   TEMP (I, K, 1) * RPP (K, J).
       211X.
           EXIT.
       2120.
           ADD K, L GIVING M.
           PERFORM 2130 THRU 213X                VARYING
                N FROM 1 BY 1 UNTIL N   15.
       212X.
           EXIT.
       2130.
           COMPUTE VOL (I, J, M) = VOL (I, J, M) +
                   TEMP (I, N, K) * RPP (N, J).
       213X.
           EXIT.
       2200.
           MOVE 0 TO TDMAND.
           PERFORM 2210 THRU 221X                VARYING
                J FROM 1 BY 1 UNTIL J   JMAX.
           PERFORM 2220 THRU 222X                VARYING
                J FROM 1 BY 1 UNTIL J   JMAX.
       220X.
           EXIT.
       2210.
           ADD VOL (I, J, 26) TO TDMAND.
       221X.
           EXIT.
       2220.
           IF TDMAND = 0 GO TO 222X.
           DIVIDE TDMAND INTO VOL (I, J, 26) GIVING DAP (I, J).
       222X.
           EXIT.
       2300.
           MOVE 0 TO TDMAND, TSPPLY.
           PERFORM 2310 THRU 231X                VARYING
                J FROM 1 BY 1 UNTIL J   JMAX.
           PERFORM 2320 THRU 232X                VARYING
                J FROM 1 BY 1 UNTIL J   JMAX.
           COMPUTE VOL (I, 1, 26) = VOL (I, 1, 26)
```

```
                + TSPPLY - TDMAND.
            PERFORM 2330 THRU 233X                  VARYING
                J FROM 1 BY 1 UNTIL J   JMAX.
        230X.
            EXIT.
        2310.
            ADD VOL (I, J, 25) TO TSPPLY.
        231X.
            EXIT.
        2320.
            MULTIPLY TSPPLY BY DAP (I, J) GIVING VOL (I, J, 26).
            ADD VCL (I, J, 26) TO TDMAND.
        232X.
            EXIT.
        2330.
            SUBTRACT VOL (I, J, 26) FROM VOL (I, J, 25)
                GIVING VOL (I, J, 27).
            IF I = 1 AND VOL (1, J, 27)   0
                MOVE 0 TO VOL (1, J, 27).
        233X.
            EXIT.
        2400.
            MOVE 19 TO L.
            PERFORM 2120 THRU 212X                  VARYING
                K FROM 9 BY 1 UNTIL K   14.
            PERFORM 2450 THRU 245X                  VARYING
                K FROM 28 BY 1 UNTIL K   33.
            MOVE 34 TO L.
            PERFORM 8050 THRU 805X                  VARYING
                K FROM 28 BY 1 UNTIL K   33.
        240X.
            EXIT.
        2450.
            MOVE VOL (I, J, K) TO TVOLUM.
            IF TVOLUM   VOL (1, J, K) GO TO 2455.
            MOVE 0 TO VOL (I, J, K).
            GO TO 245X.
        2455.
            SUBTRACT VOL (1, J, K) FROM VOL (I, J, K).
            MOVE TVOLUM TO VOL (1, J, K).
        245X.
            EXIT.
        2500.
            COMPUTE TVOLUM = VOL (I, J, 25) - VOL (1, J, 25).
            IF TVOLUM NOT   0 GO TO 2510.
            MOVE VOL (I, J, 25) TO VOL (1, J, 25).
            MOVE TVOLUM TO VOL (I, J, 35).
        2510.
            IF VOL (I, J, 27) NOT   0 GO TO 250X.
            COMPUTE TVOLUM = VOL (1, J, 27) - VOL (I, J, 27).
            IF TVOLUM   0 GO TO 250X.
```

```
           MOVE TVOLUM TO VOL (I, J, 36).
           MOVE VOL (I, J, 27) TO VOL (1, J, 27).
       250X.
           EXIT.
       260C.
           COMPUTE VOL (I, J, 37) = VOL (I, J, 35) *
               ((I + 1969) * SLOPE + INTERCEPT).
           COMPUTE VOL (I, J, 38) = VOL (I, J, 36) *
               ((I + 1969) * SLOPE + INTERCEPT).
           MOVE 39 TO L.
           PERFORM 8050 THRU 805X                 VARYING
               K FROM 37 BY 1 UNTIL K   38.
       260X.
           EXIT.
       3000 SECTION.
       3001.
           PERFORM 3100 THRU 310X                 VARYING
               I FROM 1 BY 1 UNTIL I   16         AFTER
               J FROM 1 BY 1 UNTIL J   JMAX.
           GO TO 4000.
       3100.
           MULTIPLY VOL (I, J, 35) BY CPCST (J, 1)
               GIVING AMT (I, J, 1).
           MULTIPLY VOL (I, J, 36) BY CPCST (J, 2)
               GIVING AMT (I, J, 2).
           MULTIPLY VOL (I, J, 28) BY CPCST (J, 3)
               GIVING AMT (I, J, 8).
           MULTIPLY VOL (I, J, 29) BY CPCST (J, 4)
               GIVING AMT (I, J, 9).
           MULTIPLY VOL (I, J, 30) BY CPCST (J, 6)
               GIVING AMT (I, J, 10).
           MULTIPLY VOL (I, J, 31) BY CPCST (J, 7)
               GIVING AMT (I, J, 11).
           MULTIPLY VCL (I, J, 32) BY CPCST (J, 8)
               GIVING AMT (I, J, 12).
           MULTIPLY VOL (I, J, 33) BY CPCST (J, 9)
               GIVING AMT (I, J, 13).
           MULTIPLY VOL (I, J, 39) BY CPCST (J, 5)
               GIVING AMT (I, J, 15).
           MOVE 3 TO L.
           PERFORM 8060 THRU 806X                 VARYING
               K FROM 1 BY 1 UNTIL K   2.
           MOVE 7 TO L.
           PERFORM 8060 THRU 806X                 VARYING
               K FROM 4 BY 1 UNTIL K   6.
           MOVE 14 TO L.
           PERFORM 8060 THRU 806X                 VARYING
               K FROM 8 BY 1 UNTIL K   13.
           MOVE 16 TO L.
           MOVE 3 TO K.
           PERFORM 8060 THRU 806X.
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```
           MOVE 7 TO K.
           PERFORM 8060 THRU 806X.
           PERFORM 8060 THRU 806X                    VARYING
               K FROM 14 BY 1 UNTIL K    15.
       310X.
           EXIT.
       4000 SECTION.
       4001.
           PERFORM 8010 THRU 801X.
           MOVE ' ' TO OUTYP, OTLVL.
           MOVE 0 TO J.
       4005.
           ADD 1 TO J.
           IF J   JMAX GO TO 4030.
           PERFORM 4100 THRU 410X.
           GO TO 4005.
       4030.
           PERFORM 4930 THRU 493X                    VARYING
               I FROM 1 BY 1 UNTIL I    16          AFTER
               J FROM 2 BY 1 UNTIL J    JMAX        AFTER
               K FROM 1 BY 1 UNTIL K    40.
           PERFORM 4940 THRU 494X                    VARYING
               I FROM 1 BY 1 UNTIL I    16          AFTER
               J FROM 2 BY 1 UNTIL J    JMAX        AFTER
               K FROM 1 BY 1 UNTIL K    16.
           PERFORM 8010 THRU 801X.
           MOVE 1 TO J.
           MOVE ' ' TO OUTYP.
           MOVE 'T' TO OTLVL.
           MOVE 'NATIONAL SUPPLY' TO TITLE (1).
           MOVE 'NATIONAL TOTALS - ' TO HTTLO.
           PERFORM 4100 THRU 410X.
           GO TO 7000.
       4100.
           MOVE 2 TO Y1.
           MOVE 6 TO Y2.
           PERFORM 5000 THRU 500X.
           PERFORM 6000 THRU 600X.
           MOVE 7 TO Y1.
           MOVE 11 TO Y2.
           PERFORM 5000 THRU 500X.
           PERFORM 6000 THRU 600X.
           MOVE 12 TO Y1.
           MOVE 16 TO Y2.
           PERFORM 5000 THRU 500X.
           PERFORM 6000 THRU 600X.
           PERFORM 4950 THRU 495X                    VARYING
               I FROM 1 BY 1 UNTIL I    3           AFTER
               K FROM 1 BY 1 UNTIL K    40.
           PERFORM 4960 THRU 496X                    VARYING
               I FROM 1 BY 1 UNTIL I    3           AFTER
```

```
                K FROM 1 BY 1 UNTIL K   16.
            MOVE 'T' TO OUTYP.
            PERFORM 5000 THRU 500X.
            PERFORM 6000 THRU 600X.
            MOVE ' ' TO OUTYP.
        410X.
            EXIT.
        4920.
            ADD I, Y1, 1968 GIVING HYR (I).
        492X.
            EXIT.
        4930.
            ADD VOL (I, J, K) TO VOL (I, 1, K).
        493X.
            EXIT.
        4940.
            ADD AMT (I, J, K) TO AMT (I, 1, K).
        494X.
            EXIT.
        4950.
            ADD VOLT (I, J, K) TO VOLT (4, J, K).
        495X.
            EXIT.
        4960.
            ADD AMTT (I, J, K) TO AMTT (4, J, K).
        496X.
            EXIT.
        5000 SECTION.
        5010.
            ADD 1 TO PAGNO.
            MOVE GBA TO HTTLA.
            MOVE GBB TO HTTLB.
            MOVE GBC TO HTTLC, HTTLB.
            IF OUTYP = 'T' GO TO 5500.
            PERFORM 4920 THRU 492X                   VARYING
                I FROM 1 BY 1 UNTIL I   5.
            ADD 1969, Y1  GIVING HYRA.
            COMPUTE HYRB = - (69 + Y2).
            WRITE A-LINE     FROM HEAD1              AFTER TOP.
            WRITE A-LINE     FROM HEAD2              AFTER 1.
            WRITE A-LINE     FROM HEAD3              AFTER 1.
        5100.
            IF OTLVL = 'T' GO TO 5103.
            MOVE P1 (J) TO PADL.
            GO TO 5104.
        5103.
            MOVE 1 TO J.
        5104.
            MOVE SPACES TO LINE1.
            MOVE 0 TO L.
            PERFORM 5410 THRU 541X                   2 TIMES.
```

```
           MOVE 0 TO K, M.
       5110.
           ADD 1 TO K.
           IF K   15 GO TO 5120.
           PERFORM 5420 THRU 542X                    VARYING
                I FROM Y1 BY 1 UNTIL I   Y2.
           IF M = 0 GO TO 5110.
           MOVE REG (K) TO REGL.
           SUBTRACT 1 FROM K.
           PERFORM 5490 THRU 549X.
           MOVE 0 TO M.
           SUBTRACT 1 FROM L.
           GO TO 5110.
       5120.
           WRITE A-LINE     FROM LINED               AFTER 1.
           ADD 1 TO L.
           SUBTRACT 1 FROM K.
           PERFORM 5490 THRU 549X.
           PERFORM 5410 THRU 541X.
       5130.
           PERFORM 5490 THRU 549X.
           IF L = 8 OR 13  WRITE A-LINE
                           FROM LINED                AFTER 1.
           IF L   16 GO TO 5130.
           PERFORM 5410 THRU 541X                    2 TIMES.
       5140.
           PERFORM 5490 THRU 549X.
           IF L = 24       WRITE A-LINE
                           FROM LINED                AFTER 1.
           IF L   25 GO TO 5140.
           PERFORM 5410 THRU 541X.
       5150.
           PERFORM 5490 THRU 549X.
           IF L   28 GO TO 5150.
           PERFORM 5410 THRU 541X.
       5160.
           PERFORM 5490 THRU 549X.
           IF L = 31       WRITE A-LINE
                           FROM LINED                AFTER 1.
           IF L   32 GO TO 5160.
           GO TO 500X.
       5410.
           ADD 1 TO L.
           MOVE TITLE (L) TO LTITL.
           WRITE A-LINE     FROM LINE1               AFTER H (L).
           MOVE SPACES TO LINE1.
       541X.
           EXIT.
       5420.
           IF VOL (I, J, K)   0 MOVE 1 TO M.
       542X.
```

```
           EXIT.
       5430.
           COMPUTE I = Y1 + M - 1.
           MOVE VOL (I, J, K) TO LAMT (M).
           ADD VOL (I, J, K) TO TVOLUM.
       543X.
           EXIT.
       5490.
           MOVE 0 TO TVOLUM.
           ADD 1 TO K.
           PERFORM 5430 THRU 543X                  VARYING
               M FROM 1 BY 1 UNTIL M    5.
           COMPUTE M = (Y1 + 3) / 5.
           MOVE TVOLUM TO TAMT, VOLT (M, J, K).
           PERFORM 5410 THRU 541X.
       549X.
           EXIT.
       5500.
           WRITE A-LINE     FROM HEAD1             AFTER TOP.
           WRITE A-LINE     FROM HEAD2             AFTER 1.
           WRITE A-LINE     FROM HEAD4             AFTER 1.
       5600.
           IF OTLVL = 'T' GO TO 5603.
           MOVE P1 (J) TO PADL.
           GO TO 5604.
       5603.
           MOVE 1 TO J.
       5604.
           MOVE SPACES TO LINE1.
           MOVE 0 TO L.
           PERFORM 5410 THRU 541X                  2 TIMES.
           MOVE 0 TO M, K.
       5610.
           ADD 1 TO K.
           IF K    15 GO TO 5620.
           PERFORM 5920 THRU 592X                  VARYING
               I FROM 1 BY 1 UNTIL I    3.
           IF M = 0 GO TO 5610.
           MOVE REG (K) TO REGL.
           SUBTRACT 1 FROM K.
           PERFORM 5990 THRU 599X.
           MOVE 0 TO M.
           SUBTRACT 1 FROM L.
           GO TO 5610.
       5620.
           WRITE A-LINE     FROM LINED             AFTER 1.
           ADD 1 TO L.
           SUBTRACT 1 FROM K.
           PERFORM 5990 THRU 599X.
           PERFORM 5410 THRU 541X.
       5630.
```

```
           PERFORM 5990 THRU 599X.
           IF L = 8 OR 13  WRITE A-LINE
                           FROM LINED          AFTER 1.
           IF L   16 GO TO 5630.
           PERFORM 5410 THRU 541X              2 TIMES.
       5640.
           PERFORM 5990 THRU 599X.
           IF L = 24       WRITE A-LINE
                           FROM LINED          AFTER 1.
           IF L   25 GO TO 5640.
           PERFORM 5410 THRU 541X.
       5650.
           PERFORM 5990 THRU 599X              UNTIL L = 28.
           PERFORM 5410 THRU 541X.
       5660.
           PERFORM 5990 THRU 599X.
           IF L = 31       WRITE A-LINE
                           FROM LINED          AFTER 1.
           IF L   32 GO TO 5660.
           GO TO 500X.
       5920.
           IF VOLT (I, J, K)   0 MOVE 1 TO M.
       592X.
           EXIT.
       5990.
           ADD 1 TO K.
           MOVE VOLT (1, J, K) TO LAMT (1).
           MOVE VOLT (2, J, K) TO LAMT (3).
           MOVE VOLT (3, J, K) TO LAMT (5).
           MOVE VOLT (4, J, K) TO TAMT.
           PERFORM 5410 THRU 541X.
       599X.
           EXIT.
       500X.
           EXIT.
       6000 SECTION.
       6010.
           ADD 1 TO PAGNO.
           MOVE CCA TO HTTLA.
           MOVE CCB TO HTTLB.
           MOVE CCC TO HTTLC, HTTLD.
           IF OUTYP = 'T' GO TO 6500.
           PERFORM 4920 THRU 492X              VARYING
               I FROM 1 BY 1 UNTIL I   5.
           ADD 1969, Y1 GIVING HYRA.
           COMPUTE HYRB = - (69 + Y2).
           WRITE A-LINE    FROM HEAD1          AFTER TOP.
           WRITE A-LINE    FROM HEAD2          AFTER 1.
           WRITE A-LINE    FROM HEAD3          AFTER 1.
       6100.
           MOVE SPACES TO LINE1.
```

```
           MOVE 32 TO L.
           PERFORM 5410 THRU 541X.
           MOVE 0 TO K.
       6110.
           PERFORM 6490 THRU 649X.
           IF L = 35        WRITE A-LINE
                            FROM LINED             AFTER 1.
           IF L   36 GO TO 6110.
           PERFORM 5410 THRU 541X.
       6120.
           PERFORM 6490 THRU 649X.
           IF L = 40        WRITE A-LINE
                            FROM LINED             AFTER 1.
           IF L   41 GO TO 6120.
           PERFORM 5410 THRU 541X                  2 TIMES.
       6130.
           PERFORM 6490 THRU 649X.
           IF L = 49        WRITE A-LINE
                            FROM LINED             AFTER 1.
           IF L   52 GO TO 6130.
           GO TO 600X.
       6430.
           COMPUTE I = Y1 + M - 1.
           MOVE AMT (I, J, K) TO LAMT (M).
           ADD AMT (I, J, K) TO TVOLUM.
       643X.
           EXIT.
       6490.
           ADD 1 TO K.
           MOVE 0 TO TVOLUM.
           PERFORM 6430 THRU 643X                  VARYING
               M FROM 1 BY 1 UNTIL M   5.
           COMPUTE M = (Y1 + 3) / 5.
           MOVE TVOLUM TO TAMT, AMTT (M, J, K).
           PERFORM 5410 THRU 541X.
       649X.
           EXIT.
       6500.
           WRITE A-LINE     FROM HEAD1             AFTER TOP.
           WRITE A-LINE     FROM HEAD2             AFTER 1.
           WRITE A-LINE     FROM HEAD4             AFTER 1.
       6600.
           MOVE SPACES TO LINE1.
           MOVE 32 TO L.
           PERFORM 5410 THRU 541X.
           MOVE 0 TO K.
       6610.
           PERFORM 6990 THRU 699X.
           IF L = 35        WRITE A-LINE
                            FROM LINED             AFTER 1.
           IF L   36 GO TO 6610.
```

```
           PERFORM 5410 THRU 541X.                                  00101500
       6620.                                                        00101600
           PERFORM 6990 THRU 699X.                                  00101700
           IF L = 40        WRITE A-LINE                            00101800
                            FROM LINED          AFTER 1.            00101900
           IF L   41 GO TO 6620.                                    00102000
           PERFORM 5410 THRU 541X               2 TIMES.            00102100
       6630.                                                        00102200
           PERFORM 6990 THRU 699X.                                  00102300
           IF L = 49        WRITE A-LINE                            00102400
                            FROM LINED          AFTER 1.            00102500
           IF L   52 GO TO 6630.                                    00102600
           GO TO 600X.                                              00102700
       6990.                                                        00102800
           ADD 1 TO K.                                              00102900
           MOVE AMTT (1, J, K) TO LAMT (1).                         00103000
           MOVE AMTT (2, J, K) TO LAMT (3).                         00103100
           MOVE AMTT (3, J, K) TO LAMT (5).                         00103200
           MOVE AMTT (4, J, K) TO TAMT.                             00103300
           PERFORM 5410 THRU 541X.                                  00103400
       699X.                                                        00103500
           EXIT.                                                    00103600
       600X.                                                        00103700
           EXIT.                                                    00103800
       7000 SECTION.                                                00103900
       7001.                                                        00104000
           WRITE A-LINE    FROM HEAD5           AFTER TOP.          00104100
           WRITE A-LINE    FROM HEAD6           AFTER 1.            00104200
           WRITE A-LINE    FROM HEAD7           AFTER 1.            00104300
           WRITE A-LINE    FROM HEAD8           AFTER 4.            00104400
           WRITE A-LINE    FROM HEAD9           AFTER 1.            00104500
           MOVE SPACES TO A-LINE.                                   00104600
           WRITE A-LINE                         AFTER 3.            00104700
           PERFORM 7100 THRU 710X               VARYING             00104800
               I FROM 1 BY 1 UNTIL I    JMAX.                       00104900
           MOVE INTERCEPT TO LINTERCEPT.                            00105000
           MOVE SLOPE TO LSLOPE.                                    00105100
           WRITE A-LINE    FROM HEAD10          AFTER 6.            00105200
           WRITE A-LINE    FROM HEAD11          AFTER 2.            00105300
           MOVE SPACES TO A-LINE.                                   00105400
           WRITE A-LINE                         AFTER TOP.          00105500
           MOVE SPACES TO A-LINE.                                   00105600
           WRITE A-LINE                         AFTER TOP.          00105700
           GO TO 8099.                                              00105800
       7100.                                                        00105900
           MOVE SPACES TO LINE2.                                    00106000
           MOVE P1 (I) TO P1J.                                      00106100
           PERFORM 7200 THRU 720X               VARYING             00106200
               J FROM 1 BY 1 UNTIL J    9.                          00106300
           WRITE A-LINE    FROM LINE2           AFTER 2.            00106400
       710X.                                                        00106500
```

```
           EXIT.
       7200.
           MOVE CPCST (I, J) TO L2AMT (J).
       720X.
           EXIT.
       8000 SECTION.
       8010.
           PERFORM 8011 THRU 8012                          VARYING
               K FROM 1 BY 1 UNTIL K   15.
           PERFORM 8013 THRU 8014                          VARYING
               J FROM 2 BY 1 UNTIL J   15.
           PERFORM 8015 THRU 8016                          VARYING
               I FROM 2 BY 1 UNTIL I   16.
           GO TO 801X.
       8011.
           MOVE 0 TO TEMP (1, 1, K).
       8012.
           EXIT.
       8013.
           MOVE REGT (1, 1) TO REGT (1, J).
       8014.
           EXIT.
       8015.
           MOVE YEART (1) TO YEART (I).
       8016.
           EXIT.
       801X.
           EXIT.
       8020.
           PERFORM 8021 THRU 8022                          VARYING
               K FROM 1 BY 1 UNTIL K   40.
           PERFORM 8023 THRU 8024                          VARYING
               J FROM 2 BY 1 UNTIL J   8.
           PERFORM 8025 THRU 8026                          VARYING
               I FROM 2 BY 1 UNTIL I   16.
           GO TO 802X.
       8021.
           MOVE 0 TO VOL (1, 1, K).
       8022.
           EXIT.
       8023.
           MOVE PADV (1, 1) TO PADV (1, J).
       8024.
           EXIT.
       8025.
           MOVE YEARV (1) TO YEARV (I).
       8026.
           EXIT.
       802X.
           EXIT.
       8030.
```

```
           PERFORM 8031 THRU 8032            VARYING                  00111700
                J FROM 1 BY 1 UNTIL J   8.                            00111800
           MOVE 0 TO CPCST (1, 9).                                    00111900
           PERFORM 8033 THRU 8034            VARYING                  00112000
                I FROM 2 BY 1 UNTIL I   8.                            00112100
           GO TO 803X.                                                00112200
       8031.                                                          00112300
           MOVE 0 TO RPP (1, J), CPCST (1, J).                        00112400
       8032.                                                          00112500
           EXIT.                                                      00112600
       8033.                                                          00112700
           ADD 7, I GIVING J.                                         00112800
           MOVE REGP (1) TO REGP (I), REGP (J).                       00112900
           MOVE CCP (1) TO CCP (I).                                   00113000
       8034.                                                          00113100
           EXIT.                                                      00113200
       803X.                                                          00113300
           EXIT.                                                      00113400
       8040.                                                          00113500
           PERFORM 8041 THRU 8042            VARYING                  00113600
                K FROM 1 BY 1 UNTIL K   16.                           00113700
           PERFORM 8043 THRU 8044            VARYING                  00113800
                J FROM 2 BY 1 UNTIL J   8.                            00113900
           PERFORM 8045 THRU 8046            VARYING                  00114000
                I FROM 2 BY 1 UNTIL I   16.                           00114100
           GO TO 804X.                                                00114200
       8041.                                                          00114300
           MOVE 0 TO AMT (1, 1, K).                                   00114400
       8042.                                                          00114500
           EXIT.                                                      00114600
       8043.                                                          00114700
           MOVE PADA (1, 1) TO PADA (1, J).                           00114800
       8044.                                                          00114900
           EXIT.                                                      00115000
       8045.                                                          00115100
           MOVE YEARA (1) TO YEARA (I).                               00115200
       8046.                                                          00115300
           EXIT.                                                      00115400
       804X.                                                          00115500
           EXIT.                                                      00115600
       8050.                                                          00115700
           ADD VOL (I, J, K) TO VOL (I, J, L).                        00115800
       805X.                                                          00115900
           EXIT.                                                      00116000
       8060.                                                          00116100
           ADD AMT (I, J, K) TO AMT (I, J, L).                        00116200
       806X.                                                          00116300
           EXIT.                                                      00116400
       8090.                                                          00116500
           DISPLAY 'INVALID REGION'.                                  00116600
           GO TO 8095.                                                00116700
```

```
       8091.
           DISPLAY 'INVALID PAD DISTRICT'.
           GO TO 8095.
       8092.
           DISPLAY 'TYPE CODE REQUIRES REGIONAL ENTRY'.
           GO TO 8095.
       8093.
           DISPLAY 'TYPE CODE REQUIRES PAD DISTRICT ENTRY'.
           GO TO 8095.
       8094.
           DISPLAY 'INVALID TYPE CODE'.
       8095.
           DISPLAY CARD1.
           ADD 1 TO ERRCNT.
           GO TO 1000.
       8098.
           DISPLAY 'EXCESSIVE ERRORS ... PROGRAM ABORTED ...'.
       8099.
           CLOSE PAPEROT.
           CLOSE CARDIN.
                            STOP  RUN.
```

APPENDIX E

COMPUTER WORK PAPERS

FOR

PROJECTION OF CAPITAL REQUIREMENTS

FOR GAS TRANSMISSION FACILITIES

1971 - 1985

CASE I

PAD I

P A D DISTRICT 1 SUPPLY	1971	1972	1973	1974	1975	TOTAL 1971-75
DOMESTIC PRODUCTION						
REGION 10	.4090	.3980	.4070	.4190	.4300	2.0630
REGION 11	.0010	.0010	.0010	.0010	.0020	.0060
SUB-TOTAL	.4100	.3990	.4080	.4200	.4320	2.0690
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G					.2380	.2380
S N G			.0210	.1920	.3030	.5160
COAL GAS						
NUCLEAR STIMULATION						
TOTAL SUPPLY	.4100	.3990	.4290	.6120	.9730	2.8230
ADJUSTED DEMAND	4.2269	4.3368	4.5056	4.6685	4.8279	22.5660
SUPPLY BALANCE	-3.8169	-3.9378	-4.0766	-4.0565	-3.8549	-19.7430
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE		.0220	.0410	.0380	.0380	.1390
OFFSHORE						
LNG IMPORTS					.2380	.2380
SNG PRODUCED			.0210	.1710	.1110	.3030
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL		.0220	.0620	.2090	.3870	.6800
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.0599		.0190	.1830	.3610	.6229
INTER P A D	.0503	.1208	.1388			.3100
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0067		.0022	.0217	.0436	.0744
INTER P A D TRANSMISSION	.0056	.0139	.0162			.0358
TOTAL	.0124	.0139	.0184	.0217	.0436	.1102

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971	1972	1973	1974	1975	TOTAL 1971-75
TRANSMISSION - DOMESTIC						
INTRA P A D	24.5680		7.7900	75.0300	148.0100	255.3980
INTER P A D	103.2113	247.7527	284.6896			635.6537
SUB-TOTAL	127.7793	247.7527	292.4796	75.0300	148.0100	891.0517
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE		2.2000	4.1000	3.8000	3.8000	13.9000
OFFSHORE						
L N G ATTACHMENTS					20.2300	20.2300
S N G ATTACHMENTS			.9450	7.6950	4.9950	13.6350
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL		2.2000	5.0450	11.4950	29.0250	47.7650
NEW STORAGE FACILITIES	14.3393	15.9884	21.2382	25.0297	50.1837	126.7794
TOTAL NEW FACILITIES	142.1187	265.9412	318.7628	111.5547	227.2187	1065.5962

P A D DISTRICT - GAS BALANCE

	1976	1977	1978	1979	1980	TOTAL 1976-80
P A D DISTRICT 1 SUPPLY						
DOMESTIC PRODUCTION						
REGION 10	.4450	.4600	.4800	.4950	.5200	2.4000
REGION 11	.0030	.0040	.0060	.0080	.0110	.0320
REGION 11X	.0010	.0040	.0070	.0100	.0210	.0430
SUB-TOTAL	.4490	.4680	.4930	.5130	.5520	2.4750
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G	.5300	.9680	1.2780	1.5150	1.6980	5.9890
S N G	.4420	.5810	.7200	.7200	.7200	3.1830
COAL GAS						
NUCLEAR STIMULATION						
TOTAL SUPPLY	1.4210	2.0170	2.4910	2.7480	2.9700	11.6470
ADJUSTED DEMAND	4.9881	5.1608	5.4931	5.7167	5.9761	27.3348
SUPPLY BALANCE	-3.5671	-3.1438	-3.0021	-2.9687	-3.0061	-15.6878
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.0390	.0400	.0710	.0080	.0400	.1980
OFFSHORE	.0010	.0030	.0030	.0040	.0110	.0220
LNG IMPORTS	.2920	.4380	.3100	.2370	.1830	1.4600
SNG PRODUCED	.1390	.1390	.1390			.4170
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL	.4710	.6200	.5230	.2490	.2340	2.0970
TRANSMISSION EXPANSION VOLUMES						
INTRA P A C	.4480	.5960	.4740	.2570	.2220	1.9970
INTER P A C						
STORAGE VOLUMES						
INTRA P A C TRANSMISSION	.0550	.0743	.0600	.0330	.0289	.2515
INTER P A C TRANSMISSION						
TOTAL	.0550	.0743	.0600	.0330	.0289	.2515

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1976	1977	1978	1979	1980	TOTAL 1976-80
TRANSMISSION - DOMESTIC						
INTRA P A D	183.6800	244.3600	194.3400	105.3700	91.0200	818.7700
INTER P A D						
SUB-TOTAL	183.6800	244.3600	194.3400	105.3700	91.0200	818.7700
TRANSMISSION - IMPORTS						
ALASKA, CANADA, ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	3.9000	4.0000	7.1000	.8000	4.0000	19.8000
OFFSHORE	.4500	1.3500	1.3500	1.8000	4.9500	9.9000
L N G ATTACHMENTS	24.8200	37.2300	26.3500	20.1450	15.5550	124.1000
S N G ATTACHMENTS	6.2550	6.2550	6.2550			18.7650
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	35.4250	48.8350	41.0550	22.7450	24.5050	172.5650
NEW STORAGE FACILITIES	63.2810	85.5220	69.0770	38.0282	33.3465	289.2549
TOTAL NEW FACILITIES	282.3860	378.7170	304.4720	166.1432	148.8715	1280.5899

P A D DISTRICT 1 SUPPLY	1981	1982	1983	1984	1985	TOTAL 1981-85
DOMESTIC PRODUCTION						
REGION 10	.5450	.5690	.5920	.6100	.6260	2.9420
REGION 11	.0150	.0190	.0250	.0320	.0400	.1310
REGION 11X	.0500	.1190	.1980	.2860	.3900	1.0430
SUB-TOTAL	.6100	.7070	.8150	.9280	1.0560	4.1160
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G	1.9720	2.2460	2.5190	2.7920	2.9740	12.5030
S N G	.7200	.7200	.7200	.7200	.7200	3.6000
COAL GAS						
NUCLEAR STIMULATION						
TOTAL SUPPLY	3.3020	3.6730	4.0540	4.4400	4.7500	20.2190
ADJUSTED DEMAND	6.2580	6.6694	7.0605	7.4785	7.7912	35.2578
SUPPLY BALANCE	-2.9560	-2.9964	-3.0065	-3.0385	-3.0412	-15.0388
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.0450	.0130	.0790	.0490	.0450	.2310
OFFSHORE	.0320	.0720	.0840	.0950	.1100	.3930
LNG IMPORTS	.2740	.2740	.2730	.2730	.1820	1.2760
SNG PRODUCED						
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL	.3510	.3590	.4360	.4170	.3370	1.9000
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.3320	.3710	.3810	.3860	.3100	1.7800
INTER P A D						
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0440	.0499	.0519	.0534	.0435	.2428
INTER P A D TRANSMISSION						
TOTAL	.0440	.0499	.0519	.0534	.0435	.2428

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1981	1982	1983	1984	1985	TOTAL 1981-85
TRANSMISSION - DOMESTIC						
INTRA P A D	136.1200	152.1100	156.2100	158.2600	127.1000	729.8000
INTER P A D						
SUB-TOTAL	136.1200	152.1100	156.2100	158.2600	127.1000	729.8000
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	4.5000	1.3000	7.9000	4.9000	4.5000	23.1000
OFFSHORE	14.4000	32.4000	37.8000	42.7500	49.5000	176.8500
L N G ATTACHMENTS	23.2900	23.2900	23.2050	23.2050	15.4700	108.4600
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	42.1900	56.9900	68.9050	70.8550	69.4700	308.4100
NEW STORAGE FACILITIES	50.6126	57.3884	59.7885	61.4376	50.0353	279.2625
TOTAL NEW FACILITIES	228.9226	266.4884	284.9035	290.5526	246.6053	1317.4725

TRANSMISSION FACILITIES P A D DISTRICT 1 SUPPLY	1971-75	1976-80	1981-85	TOTAL 1971-85
DOMESTIC PRODUCTION				
REGION 10	2.0630	2.4000	2.9420	7.4050
REGION 11	.0060	.0320	.1310	.1690
REGION 11X		.0430	1.0430	1.0860
SUB-TOTAL	2.0690	2.4750	4.1160	8.6600
PIPELINE IMPORTS				
ALASKA,CANADA,ARCTIC				
OTHER CANADIAN				
MEXICAN				
SUB-TOTAL				
L N G	.2380	5.9890	12.5030	18.7300
S N G	.5160	3.1830	3.6000	7.2990
COAL GAS				
NUCLEAR STIMULATION				
TOTAL SUPPLY	2.8230	11.6470	20.2190	34.6890
ADJUSTED DEMAND	22.5660	27.3348	35.2578	85.1587
SUPPLY BALANCE	-19.7430	-15.6878	-15.0388	-50.4697
SUPPLY ATTACHMENT VOLUMES				
NEW PRODUCTION				
ONSHORE	.1390	.1980	.2310	.5680
OFFSHORE		.0220	.3930	.4150
LNG IMPORTS	.2380	1.4600	1.2760	2.9740
SNG PRODUCED	.3030	.4170		.7200
COAL GAS PRODUCED				
NUCLEAR STIMULATION				
TOTAL	.6800	2.0970	1.9000	4.6770
TRANSMISSION EXPANSION VOLUMES				
INTRA P A D	.6229	1.9970	1.7800	4.3999
INTER P A D	.3100			.3100
STORAGE VOLUMES				
INTRA P A D TRANSMISSION	.0744	.2515	.2428	.5687
INTER P A D TRANSMISSION	.0358			.0358
TOTAL	.1102	.2515	.2428	.6046

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971-75	1976-80	1981-85	TOTAL 1971-85
TRANSMISSION - DOMESTIC				
INTRA P A D	255.3980	818.7700	729.8000	1803.9680
INTER P A D	635.6537			635.6537
SUB-TOTAL	891.0517	818.7700	729.8000	2439.6217
TRANSMISSION - IMPORTS				
ALASKA,CANADA,ARCTIC				
OTHER CANADIAN				
MEXICAN				
SUB-TOTAL				
SUPPLY ATTACHMENTS				
NEW PRODUCTION ATTACHMENT				
ONSHORE	13.9000	19.8000	23.1000	56.8000
OFFSHORE		9.9000	176.8500	186.7500
L N G ATTACHMENTS	20.2300	124.1000	108.4600	252.7900
S N G ATTACHMENTS	13.6350	18.7650		32.4000
COAL GAS ATTACHMENTS				
NUCLEAR STIM. ATTACHMENTS				
SUB-TOTAL	47.7650	172.5650	308.4100	528.7400
NEW STORAGE FACILITIES	126.7794	289.2549	279.2625	695.2969
TOTAL NEW FACILITIES	1065.5962	1280.5899	1317.4725	3663.6586

P A D DISTRICT 2 SUPPLY	1971	1972	1973	1974	1975	TOTAL 1971-75
DOMESTIC PRODUCTION						
REGION 4	.0428	.0429	.0439	.0451	.0464	.2213
REGION 7	3.7990	3.8230	3.6620	3.5690	3.4710	18.3240
REGION 8	.0190	.0190	.0190	.0190	.0190	.0950
SUB-TOTAL	3.8608	3.8849	3.7249	3.6331	3.5364	18.6403
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN	.9000	1.0000	1.0000	1.0000	1.0000	4.9000
MEXICAN						
SUB-TOTAL	.9000	1.0000	1.0000	1.0000	1.0000	4.9000
L N G						
S N G			.0730	.1050	.1870	.3650
COAL GAS						
NUCLEAR STIMULATION						
TOTAL SUPPLY	4.7608	4.8849	4.7979	4.7381	4.7234	23.9053
ADJUSTED DEMAND	7.5868	7.7764	8.0713	8.3568	8.6363	40.4278
SUPPLY BALANCE	-2.8259	-2.8915	-3.2734	-3.6186	-3.9129	-16.5225
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE		.0905	.1552	.1443	.1346	.5248
OFFSHORE						
LNG IMPORTS						
SNG PRODUCED			.0730	.0320	.0820	.1870
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL		.0905	.2282	.1763	.2166	.7118
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.3109	.1240				.4350
INTER P A D			.3261	.3452	.2942	.9656
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0351	.0142				.0494
INTER P A D TRANSMISSION			.0381	.0410	.0355	.1147
TOTAL	.0351	.0142	.0381	.0410	.0355	.1642

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971	1972	1973	1974	1975	TOTAL 1971-75
TRANSMISSION - DOMESTIC						
INTRA P A D	199.0016	79.4214				278.4230
INTER P A D			521.8720	552.3968	470.7552	1545.0240
SUB-TOTAL	199.0016	79.4214	521.8720	552.3968	470.7552	1823.4470
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE		9.0534	15.5206	14.4397	13.4685	52.4822
OFFSHORE						
L N G ATTACHMENTS						
S N G ATTACHMENTS			3.2850	1.4400	3.6900	8.4150
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL		9.0534	18.8056	15.8797	17.1585	60.8972
NEW STORAGE FACILITIES	40.4397	16.4174	43.8817	47.2213	40.9009	188.8610
TOTAL NEW FACILITIES	239.4413	104.8922	584.5593	615.4978	528.8146	2073.2052

P A D DISTRICT 2 SUPPLY	1976	1977	1978	1979	1980	TOTAL 1976-80
DOMESTIC PRODUCTION						
REGION 4	.0476	.0471	.0475	.0488	.0508	.2420
REGION 7	3.3340	3.2040	3.0760	2.9470	2.8590	15.4200
REGION 8	.0190	.0200	.0210	.0220	.0240	.1060
SUB-TOTAL	3.4006	3.2711	3.1445	3.0178	2.9338	15.7680
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC			.4000	.5500	.7000	1.6500
OTHER CANADIAN	1.0000	1.0000	1.0000	1.0000	1.0000	5.0000
MEXICAN						
SUB-TOTAL	1.0000	1.0000	1.4000	1.5500	1.7000	6.6500
L N G						
S N G	.2550	.3220	.3220	.3220	.3220	1.5430
COAL GAS		.0800	.1200	.1600	.1600	.5200
NUCLEAR STIMULATION						
TOTAL SUPPLY	4.6556	4.6731	4.9865	5.0498	5.1158	24.4810
ADJUSTED DEMAND	8.9080	9.2025	9.7840	10.1689	10.6173	48.6809
SUPPLY BALANCE	-4.2524	-4.5293	-4.7974	-5.1191	-5.5015	-24.1998
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.1279	.1343	.1337	.1301	.1334	.6596
OFFSHORE						
LNG IMPORTS						
SNG PRODUCED	.0680	.0670				.1350
COAL GAS PRODUCED	.0800	.0800	.1200	.0400	.0800	.4000
NUCLEAR STIMULATION						
TOTAL	.2759	.2813	.2537	.1701	.2134	1.1946
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D			.1016	.0632	.0660	.2308
INTER P A D	.3395	.2769	.2680	.3216	.3824	1.5886
STORAGE VOLUMES						
INTRA P A D TRANSMISSION			.0128	.0081	.0086	.0296
INTER P A D TRANSMISSION	.0417	.0345	.0339	.0413	.0499	.2015
TOTAL	.0417	.0345	.0468	.0495	.0585	.2312

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1976	1977	1978	1979	1980	TOTAL 1976-80
TRANSMISSION - DOMESTIC						
INTRA P A C			65.0259	40.4780	42.2489	147.7529
INTER P A C	543.2272	443.0784	428.9392	514.6912	611.8400	2541.7760
SUB-TOTAL	543.2272	443.0784	493.9651	555.1692	654.0889	2689.5289
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC	343.0000	35.0000	3395.0000	1466.0000	2048.0000	7287.0000
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL	343.0000	35.0000	3395.0000	1466.0000	2048.0000	7287.0000
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	12.7973	13.4357	13.3740	13.0124	13.3411	65.9605
OFFSHORE						
L N G ATTACHMENTS						
S N G ATTACHMENTS	3.0600	3.0150				6.0750
COAL GAS ATTACHMENTS	80.0000	80.0000	120.0000	40.0000	80.0000	400.0000
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	95.8573	96.4507	133.3740	53.0124	93.3411	472.0355
NEW STORAGE FACILITIES	47.9573	39.7359	53.8752	56.9583	67.3555	265.8823
TOTAL NEW FACILITIES	1030.0418	614.2650	4076.2143	2131.1400	2862.7855	10714.4467

P A D DISTRICT 2 SUPPLY	1981	1982	1983	1984	1985	TOTAL 1981-85
DOMESTIC PRODUCTION						
REGION 4	.0531	.0563	.0598	.0635	.0678	.3007
REGION 7	2.8140	2.7690	2.7230	2.6710	2.6460	13.6230
REGION 8	.0260	.0290	.0310	.0340	.0380	.1580
SUB-TOTAL	2.8931	2.8543	2.8138	2.7685	2.7518	14.0817
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC	.8000	1.1500	1.2500	1.5000	1.6500	6.3500
OTHER CANADIAN	1.0000	.9000	.9000	.9000	.9000	4.6000
MEXICAN						
SUB-TOTAL	1.8000	2.0500	2.1500	2.4000	2.5500	10.9500
L N G						
S N G	.3220	.3220	.3220	.3220	.3220	1.6100
COAL GAS	.2400	.2400	.3200	.3760	.3760	1.5520
NUCLEAR STIMULATION						
TOTAL SUPPLY	5.2551	5.4663	5.6058	5.8665	5.9998	28.1937
ADJUSTED DEMAND	11.0500	11.7077	12.3285	12.9920	13.4730	61.5514
SUPPLY BALANCE	-5.7949	-6.2413	-6.7227	-7.1255	-7.4732	-33.3577
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.1396	.1410	.1383	.1295	.1195	.6681
OFFSHORE						
LNG IMPORTS						
SNG PRODUCED						
COAL GAS PRODUCED	.0800	.0800	.0800	.0560		.2960
NUCLEAR STIMULATION						
TOTAL	.2196	.2210	.2183	.1855	.1195	.9641
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.1393	.2112	.1394	.2607	.1332	.8839
INTER P A D	.2934	.4463	.4813	.4028	.3477	1.9717
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0184	.0284	.0190	.0360	.0186	.1206
INTER P A D TRANSMISSION	.0388	.0600	.0656	.0557	.0488	.2691
TOTAL	.0573	.0884	.0847	.0918	.0675	.3898

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1981	1982	1983	1984	1985	TOTAL 1981-85
TRANSMISSION - DOMESTIC						
INTRA P A D	89.1526	135.2070	89.2492	166.8736	85.2608	565.7433
INTER P A O	469.4864	714.1872	770.2048	644.4944	556.4000	3154.7728
SUB-TOTAL	558.6390	849.3942	859.4540	811.3680	641.6608	3720.5161
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC	656.0000	3406.0000	2407.0000	1992.0000	2027.0000	10488.0000
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL	656.0000	3406.0000	2407.0000	1992.0000	2027.0000	10488.0000
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	13.9603	14.1083	13.8370	12.9562	11.9563	66.8181
OFFSHORE						
L N G ATTACHMENTS						
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS	80.0000	80.0000	80.0000	56.0000		296.0000
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	93.9603	94.1083	93.8370	68.9562	11.9563	362.8181
NEW STORAGE FACILITIES	65.9686	101.7267	97.4245	105.6137	77.6296	448.3631
TOTAL NEW FACILITIES	1374.5679	4451.2292	3457.7156	2977.9379	2758.2467	15019.6974

TRANSMISSION FACILITIES P A D DISTRICT 2 SUPPLY	1971-75	1976-80	1981-85	TOTAL 1971-85
DOMESTIC PRODUCTION				
REGION 4	.2213	.2420	.3007	.7641
REGION 7	18.3240	15.4200	13.6230	47.3670
REGION 8	.0950	.1060	.1580	.3590
SUB-TOTAL	18.6403	15.7680	14.0817	48.4901
PIPELINE IMPORTS				
ALASKA,CANADA,ARCTIC		1.6500	6.3500	8.0000
OTHER CANADIAN	4.9000	5.0000	4.6000	14.5000
MEXICAN				
SUB-TOTAL	4.9000	6.6500	10.9500	22.5000
L N G				
S N G	.3650	1.5430	1.6100	3.5180
COAL GAS		.5200	1.5520	2.0720
NUCLEAR STIMULATION				
TOTAL SUPPLY	23.9053	24.4810	28.1937	76.5801
ADJUSTED DEMAND	40.4278	48.6809	61.5514	150.6603
SUPPLY BALANCE	-16.5225	-24.1998	-33.3577	-74.0801
SUPPLY ATTACHMENT VOLUMES				
NEW PRODUCTION				
ONSHORE	.5248	.6596	.6681	1.8526
OFFSHORE				
LNG IMPORTS				
SNG PRODUCED	.1870	.1350		.3220
COAL GAS PRODUCED		.4000	.2960	.6960
NUCLEAR STIMULATION				
TOTAL	.7118	1.1946	.9641	2.8706
TRANSMISSION EXPANSION VOLUMES				
INTRA P A D	.4350	.2308	.8839	1.5498
INTER P A D	.9656	1.5886	1.9717	4.5259
STORAGE VOLUMES				
INTRA P A D TRANSMISSION	.0494	.0296	.1206	.1997
INTER P A D TRANSMISSION	.1147	.2015	.2691	.5855
TOTAL	.1642	.2312	.3898	.7853

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971-75		1976-80		1981-85	TOTAL 1971-85
TRANSMISSION - DOMESTIC						
INTRA P A D	278.4230		147.7529		565.7433	991.9193
INTER P A D	1545.0240		2541.7760		3154.7728	7241.5728
SUB-TOTAL	1823.4470		2689.5289		3720.5161	8233.4921
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC			7287.0000		10488.0000	17775.0000
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL			7287.0000		10488.0000	17775.0000
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	52.4822		65.9605		66.8181	185.2608
OFFSHORE						
L N G ATTACHMENTS						
S N G ATTACHMENTS	8.4150		6.0750			14.4900
COAL GAS ATTACHMENTS			400.0000		296.0000	696.0000
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	60.8972		472.0355		362.8181	895.7508
NEW STORAGE FACILITIES	188.8610		265.8823		448.3631	903.1065
TOTAL NEW FACILITIES	2073.2052		10714.4467		15019.6974	27807.3494

	1971	1972	1973	1974	1975	TOTAL 1971-75
P A D DISTRICT 3 SUPPLY						
DOMESTIC PRODUCTION						
REGION 3	.5063	.5139	.5253	.5368	.5421	2.6245
REGION 5	2.6530	2.6560	2.6480	2.6750	2.7020	13.3340
REGION 6	8.3240	8.4830	8.8740	9.0720	8.9940	43.7470
REGION 6X	3.1270	3.3330	3.7620	4.1530	4.4600	18.8350
SUB-TOTAL	14.6103	14.9859	15.8093	16.4368	16.6981	78.5405
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN	.0500	.0500	.0500	.0500	.0500	.2500
SUB-TOTAL	.0500	.0500	.0500	.0500	.0500	.2500
L N G						
S N G				.0150	.1460	.1610
COAL GAS						
NUCLEAR STIMULATION						
TOTAL SUPPLY	14.6603	15.0359	15.8593	16.5018	16.8941	78.9515
ADJUSTED DEMAND	5.6341	5.7486	5.9423	6.1303	6.3140	29.7695
SUPPLY BALANCE	9.0261	9.2872	9.9170	10.3714	10.5801	49.1819
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE		.3759	.7177	.6777	.6382	2.4096
OFFSHORE		.3150	.5370	.5510	.5460	1.9490
LNG IMPORTS						
SNG PRODUCED				.0150	.1310	.1460
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL		.6909	1.2547	1.2437	1.3152	4.5046
TRANSMISSION EXPANSION VOLUMES						
INTRA P A C	.0767	.3756	.8234	.6424	.3923	2.3105
INTER P A C						
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0086	.0432	.0963	.0764	.0474	.2720
INTER P A C TRANSMISSION						
TOTAL	.0086	.0432	.0963	.0764	.0474	.2720

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971	1972	1973	1974	1975	TOTAL 1971-75
TRANSMISSION - DOMESTIC						
INTRA P A D	27.6213	135.2250	296.4373	231.2776	141.2413	831.8026
INTER P A D						
SUB-TOTAL	27.6213	135.2250	296.4373	231.2776	141.2413	831.8026
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE		37.5912	71.7725	67.7725	63.8250	240.9612
OFFSHORE		141.7500	241.6500	247.9500	245.7000	877.0500
L N G ATTACHMENTS						
S N G ATTACHMENTS				.6750	5.8950	6.5700
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL		179.3412	313.4225	316.3975	315.4200	1124.5812
NEW STORAGE FACILITIES	9.9785	49.6938	110.7829	87.8703	54.5399	312.8655
TOTAL NEW FACILITIES	37.5999	364.2600	720.6427	635.5455	511.2012	2269.2494

	1976	1977	1978	1979	1980	TOTAL 1976-80
P A D DISTRICT 3 SUPPLY						
DOMESTIC PRODUCTION						
REGION 3	.5413	.5047	.4758	.4544	.4399	2.4163
REGION 5	2.7120	2.7450	2.7820	2.8180	2.8720	13.9290
REGION 6	8.8080	8.6650	8.5340	8.4000	8.3130	42.7200
REGION 6X	4.7350	5.0420	5.3840	5.7480	6.1310	27.0400
SUB-TOTAL	16.7963	16.9567	17.1758	17.4204	17.7559	86.1053
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN	.0500	.0290				.0790
SUB-TOTAL	.0500	.0290				.0790
L N G	.1090	.1090	.1090	.2920	.2920	.9110
S N G	.2100	.2730	.2730	.2730	.2730	1.3020
COAL GAS	.0800	.0800	.1600	.1600	.2400	.7200
NUCLEAR STIMULATION						
TOTAL SUPPLY	17.2453	17.4477	17.7178	18.1454	18.5609	89.1173
ADJUSTED DEMAND	6.6041	6.9096	7.4302	7.8054	8.2301	36.9796
SUPPLY BALANCE	10.6412	10.5381	10.2875	10.3400	10.3308	52.1377
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.6002	.6370	.6477	.6380	.5947	3.1178
OFFSHORE	.5350	.5610	.5920	.6110	.5970	2.8960
LNG IMPORTS	.1090			.1830		.2920
SNG PRODUCED	.0640	.0630				.1270
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL	1.3082	1.2610	1.2397	1.4320	1.1917	6.4328
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.3512	.2024	.2700	.4276	.4155	1.6668
INTER P A D						
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0431	.0252	.0342	.0550	.0542	.2119
INTER P A D TRANSMISSION						
TOTAL	.0431	.0252	.0342	.0550	.0542	.2119

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1976	1977	1978	1979	1980	TOTAL 1976-80
TRANSMISSION - DOMESTIC						
INTRA P A D	126.4456	72.8640	97.2090	153.9540	149.5843	600.0570
INTER P A D						
SUB-TOTAL	126.4456	72.8640	97.2090	153.9540	149.5843	600.0570
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	60.0250	63.7013	64.7775	63.8012	59.4775	311.7825
OFFSHORE	240.7500	252.4500	266.4000	274.9500	268.6500	1303.2000
L N G ATTACHMENTS	8.7200			14.6400		23.3600
S N G ATTACHMENTS	2.8800	2.8350				5.7150
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	312.3750	318.9863	331.1775	353.3912	328.1275	1644.0575
NEW STORAGE FACILITIES	49.6133	29.0421	39.3507	63.2799	62.4139	243.6999
TOTAL NEW FACILITIES	488.4339	420.8924	467.7372	570.6251	540.1257	2487.8144

	1981	1982	1983	1984	1985	TOTAL 1981-85
P A D DISTRICT 3 SUPPLY						
DOMESTIC PRODUCTION						
REGION 3	.4270	.4216	.4163	.4109	.4117	2.0877
REGION 5	2.9440	3.0200	3.0880	3.1360	3.1740	15.3620
REGION 6	8.1140	8.0840	8.0920	7.9510	7.8110	40.0520
REGION 6X	6.4670	6.8490	7.2130	7.4760	7.6410	35.6460
SUB-TOTAL	17.9520	18.3746	18.8093	18.9739	19.0377	93.1477
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G	.2920	.2920	.2920	.2920	.2920	1.4600
S N G	.2730	.2730	.2730	.2730	.2730	1.3650
COAL GAS	.2400	.3200	.3200	.3200	.3200	1.5200
NUCLEAR STIMULATION						
TOTAL SUPPLY	18.7570	19.2596	19.6943	19.8589	19.9227	97.4927
ADJUSTED DEMAND	8.6945	9.3404	9.9613	10.6225	11.1365	49.7554
SUPPLY BALANCE	10.0624	9.9191	9.7329	9.2364	8.7862	47.7372
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.5655	.5433	.4900	.4275	.3355	2.3619
OFFSHORE	.5730	.5530	.5000	.4230	.3170	2.3660
LNG IMPORTS						
SNG PRODUCED						
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL	1.1385	1.0963	.9900	.8505	.6525	4.7279
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.1960	.5026	.4346	.1646	.0637	1.3617
INTER P A D						
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0259	.0676	.0593	.0227	.0089	.1846
INTER P A D TRANSMISSION						
TOTAL	.0259	.0676	.0593	.0227	.0089	.1846

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1981	1982	1983	1984	1985	TOTAL 1981-85
TRANSMISSION - DOMESTIC						
INTRA P A D	70.5736	180.9583	156.4786	59.2783	22.9546	490.2436
INTER P A D						
SUB-TOTAL	70.5736	180.9583	156.4786	59.2783	22.9546	490.2436
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	56.5538	54.3300	49.0062	42.7538	33.5537	236.1975
OFFSHORE	257.8500	248.8500	225.0000	190.3500	142.6500	1064.7000
L N G ATTACHMENTS						
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	314.4038	303.1800	274.0062	233.1038	176.2037	1300.8975
NEW STORAGE FACILITIES	29.8850	77.7561	68.2099	26.2085	10.2913	212.3509
TOTAL NEW FACILITIES	414.8625	561.8944	498.6948	318.5906	209.4497	2003.4921

TRANSMISSION FACILITIES	1971-75	1976-80	1981-85	TOTAL 1971-85
P A D DISTRICT 3 SUPPLY				
DOMESTIC PRODUCTION				
REGION 3	2.6245	2.4163	2.0877	7.1286
REGION 5	13.3340	13.9290	15.3620	42.6250
REGION 6	43.7470	42.7200	40.0520	126.5190
REGICN 6X	18.8350	27.0400	35.6460	81.5210
SUB-TOTAL	78.5405	86.1053	93.1477	257.7936
PIPELINE IMPORTS				
ALASKA,CANADA,ARCTIC				
OTHER CANADIAN				
MEXICAN	.2500	.0790		.3290
SUB-TOTAL	.2500	.0790		.3290
L N G		.9110	1.4600	2.3710
S N G	.1610	1.3020	1.3650	2.8280
COAL GAS		.7200	1.5200	2.2400
NUCLEAR STIMULATION				
TOTAL SUPPLY	78.9515	89.1173	97.4927	265.5616
ADJUSTED DEMANC	29.7695	36.9796	49.7554	116.5046
SUPPLY BALANCE	49.1819	52.1377	47.7372	149.0569
SUPPLY ATTACHMENT VOLUMES				
NEW PRODUCTION				
ONSHORE	2.4096	3.1178	2.3619	7.8894
OFFSHORE	1.9490	2.8960	2.3660	7.2110
LNG IMPORTS		.2920		.2920
SNG PRODUCED	.1460	.1270		.2730
COAL GAS PRODUCED				
NUCLEAR STIMULATION				
TOTAL	4.5046	6.4328	4.7279	15.6654
TRANSMISSION EXPANSION VOLUMES				
INTRA P A D	2.3105	1.6668	1.3617	5.3391
INTER P A C				
STORAGE VOLUMES				
INTRA P A D TRANSMISSION	.2720	.2119	.1846	.6686
INTER P A C TRANSMISSION				
TOTAL	.2720	.2119	.1846	.6686

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971-75		1976-80		1981-85	TOTAL 1971-85
TRANSMISSION - COMESTIC						
INTRA P A C	831.8026		600.0570		490.2436	1922.1033
INTER P A C						
SUB-TOTAL	831.8026		600.0570		490.2436	1922.1033
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	240.9612		311.7825		236.1975	788.9412
OFFSHORE	877.0500		1303.2000		1064.7000	3244.9500
L N G ATTACHMENTS			23.3600			23.3600
S N G ATTACHMENTS	6.5700		5.7150			12.2850
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	1124.5812		1644.0575		1300.8975	4069.5362
NEW STORAGE FACILITIES	312.8655		243.6999		212.3509	768.9164
TOTAL NEW FACILITIES	2269.2494		2487.8144		2003.4921	6760.5560

PAD IV

P A D DISTRICT - GAS BALANCE

	1971	1972	1973	1974	1975	TOTAL 1971-75
P A D DISTRICT 4 SUPPLY						
DOMESTIC PRODUCTION						
REGION 3	.1576	.1600	.1635	.1671	.1687	.8171
REGION 4	.4040	.4049	.4140	.4257	.4375	2.0864
SUB-TOTAL	.5617	.5649	.5776	.5929	.6063	2.9035
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G						
S N G						
COAL GAS						
NUCLEAR STIMULATION					.0050	.0050
TOTAL SUPPLY	.5617	.5649	.5776	.5929	.6113	2.9085
ADJUSTED DEMAND	.5560	.5565	.5664	.5751	.5848	2.8390
SUPPLY BALANCE	.0056	.0084	.0111	.0177	.0264	.0695
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE		.0175	.0250	.0268	.0300	.0995
OFFSHORE						
LNG IMPORTS						
SNG PRODUCED						
COAL GAS PRODUCED						
NUCLEAR STIMULATION					.0050	.0050
TOTAL		.0175	.0250	.0268	.0350	.1045
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.0707	.0032	.0126	.0153	.0184	.1203
INTER P A D						
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0080	.0003	.0014	.0018	.0022	.0138
INTER P A D TRANSMISSION						
TOTAL	.0080	.0003	.0014	.0018	.0022	.0138

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971	1972	1973	1974	1975	TOTAL 1971-75
TRANSMISSION - COMESTIC						
INTRA P A C	22.2849	1.0325	3.9693	4.8235	5.8004	37.9108
INTER P A C						
SUB-TOTAL	22.2849	1.0325	3.9693	4.8235	5.8004	37.9108
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
UNSHORE		1.7550	2.5065	2.6873	3.0060	9.9548
OFFSHCRE						
L N G ATTACHMENTS						
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS					.5000	.5000
SUB-TOTAL		1.7550	2.5065	2.6873	3.5060	10.4548
NEW STORAGE FACILITIES	9.2011	.4335	1.6951	2.0941	2.5587	15.9827
TOTAL NEW FACILITIES	31.4861	3.2211	8.1709	9.6050	11.8651	64.3483

P A D DISTRICT 4 SUPPLY	1976	1977	1978	1979	1980	TOTAL 1976-80
DOMESTIC PRODUCTION						
REGION 3	.1685	.1571	.1481	.1414	.1369	.7523
REGION 4	.4492	.4447	.4483	.4601	.4791	2.2816
SUB-TOTAL	.6178	.6019	.5965	.6016	.6160	3.0340
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G						
S N G						
COAL GAS				.0800	.1600	.2400
NUCLEAR STIMULATION	.0150	.0220	.0440	.1030	.1870	.3710
TOTAL SUPPLY	.6328	.6239	.6405	.7846	.9630	3.6450
ADJUSTED DEMAND	.5951	.6070	.6376	.6554	.6771	3.1724
SUPPLY BALANCE	.0377	.0169	.0028	.1292	.2859	.4725
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.0327	.0366	.0404	.0438	.0468	.2005
OFFSHORE						
LNG IMPORTS						
SNG PRODUCED						
COAL GAS PRODUCED				.0800	.0800	.1600
NUCLEAR STIMULATION	.0100	.0070	.0220	.0590	.0840	.1820
TOTAL	.0427	.0436	.0624	.1828	.2108	.5425
TRANSMISSION EXPANSION VOLUMES						
INTRA P A C	.0215		.0076	.1441	.1784	.3517
INTER P A C						
STORAGE VOLUMES						
INTRA P A C TRANSMISSION	.0026		.0009	.0185	.0233	.0454
INTER P A C TRANSMISSION						
TOTAL	.0026		.0009	.0185	.0233	.0454

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1976	1977	1978	1979	1980	TOTAL 1976-80
TRANSMISSION - DOMESTIC						
INTRA P A D	6.7772		2.4188	45.3930	56.2189	110.8081
INTER P A D						
SUB-TOTAL	6.7772		2.4188	45.3930	56.2189	110.8081
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	3.2772	3.6626	4.0478	4.3858	4.6807	20.0541
OFFSHORE						
L N G ATTACHMENTS						
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS				60.0000	60.0000	120.0000
NUCLEAR STIM. ATTACHMENTS	1.0000	.7000	2.2000	5.9000	8.4000	18.2000
SUB-TOTAL	4.2772	4.3626	6.2478	70.2858	73.0807	158.2541
NEW STORAGE FACILITIES	3.0383		1.1189	21.3233	26.8076	52.2882
TOTAL NEW FACILITIES	14.0927	4.3626	9.7856	137.0021	156.1073	321.3504

	1981	1982	1983	1984	1985	TOTAL 1981-85
P A D DISTRICT 4 SUPPLY						
DOMESTIC PRODUCTION						
REGION 3	.1329	.1312	.1296	.1279	.1281	.6500
REGION 4	.5008	.5315	.5640	.5993	.6391	2.8349
SUB-TOTAL	.6337	.6628	.6937	.7273	.7673	3.4849
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G						
S N G						
COAL GAS	.3200	.5600	.8800	1.3040	1.7840	4.8480
NUCLEAR STIMULATION	.3320	.5280	.7360	.9580	1.1970	3.7510
TOTAL SUPPLY	1.2857	1.7508	2.3097	2.9893	3.7483	12.0839
ADJUSTED DEMAND	.7008	.7396	.7750	.8140	.8404	3.8701
SUPPLY BALANCE	.5849	1.0111	1.5346	2.1752	2.9078	8.2137
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.0488	.0536	.0565	.0578	.0578	.2748
OFFSHORE						
LNG IMPORTS						
SNG PRODUCED						
COAL GAS PRODUCED	.1600	.2400	.3200	.4240	.4800	1.6240
NUCLEAR STIMULATION	.1450	.1960	.2080	.2220	.2390	1.0100
TOTAL	.3538	.4896	.5845	.7038	.7768	2.9088
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.3226	.4650	.5588	.6795	.7590	2.7852
INTER P A D						
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0427	.0625	.0762	.0940	.1065	.3821
INTER P A D TRANSMISSION						
TOTAL	.0427	.0625	.0762	.0940	.1065	.3821

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1981	1982	1983	1984	1985	TOTAL 1981-85
TRANSMISSION - DOMESTIC						
INTRA P A D	101.6382	146.4983	176.0478	214.0721	239.0894	877.3458
INTER P A D						
SUB-TOTAL	101.6382	146.4983	176.0478	214.0721	239.0894	877.3458
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
UNSHORE	4.8852	5.3609	5.6559	5.7893	5.7892	27.4805
OFFSHORE						
L N G ATTACHMENTS						
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS	120.0000	180.0000	240.0000	318.0000	360.0000	1218.0000
NUCLEAR STIM. ATTACHMENTS	14.5000	19.6000	20.8000	22.2000	23.9000	101.0000
SUB-TOTAL	139.3852	204.9609	266.4559	345.9893	389.6892	1346.4805
NEW STORAGE FACILITIES	49.1889	71.9417	87.7036	108.1678	122.5083	439.5104
TOTAL NEW FACILITIES	290.2123	423.4009	530.2073	668.2292	751.2869	2663.3368

TRANSMISSION FACILITIES	1971-75		1976-80		1981-85	TOTAL 1971-85
P A D DISTRICT 4 SUPPLY						
DOMESTIC PRODUCTION						
REGION 3	.8171		.7523		.6500	2.2194
REGION 4	2.0864		2.2816		2.8349	7.2030
SUB-TOTAL	2.9035		3.0340		3.4849	9.4225
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G						
S N G						
COAL GAS			.2400		4.8480	5.0880
NUCLEAR STIMULATION	.0050		.3710		3.7510	4.1270
TOTAL SUPPLY	2.9085		3.6450		12.0839	18.6375
ADJUSTED DEMAND	2.8390		3.1724		3.8701	9.8816
SUPPLY BALANCE	.0695		.4725		8.2137	8.7558
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.0995		.2005		.2748	.5748
OFFSHORE						
LNG IMPORTS						
SNG PRODUCED						
COAL GAS PRODUCED			.1600		1.6240	1.7840
NUCLEAR STIMULATION	.0050		.1820		1.0100	1.1970
TOTAL	.1045		.5425		2.9088	3.5558
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.1203		.3517		2.7852	3.2573
INTER P A D						
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0138		.0454		.3821	.4415
INTER P A D TRANSMISSION						
TOTAL	.0138		.0454		.3821	.4415

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971-75		1976-80		1981-85	TOTAL 1971-85
TRANSMISSION - DOMESTIC						
INTRA P A D	37.9108		110.8081		877.3458	1026.0649
INTER P A D						
SUB-TOTAL	37.9108		110.8081		877.3458	1026.0649
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	9.9548		20.0541		27.4805	57.4894
OFFSHORE						
L N G ATTACHMENTS						
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS			120.0000		1218.0000	1338.0000
NUCLEAR STIM. ATTACHMENTS	.5000		18.2000		101.0000	119.7000
SUB-TOTAL	10.4548		158.2541		1346.4805	1515.1894
NEW STORAGE FACILITIES	15.9827		52.2882		439.5104	507.7813
TOTAL NEW FACILITIES	64.3483		321.3504		2663.3368	3049.0356

P A D DISTRICT 5 SUPPLY	1971	1972	1973	1974	1975	TOTAL 1971-75
DOMESTIC PRODUCTION						
REGION 2	.4950	.4870	.4860	.4510	.4200	2.3390
REGION 2X	.0350	.0330	.0320	.0360	.0450	.1810
SUB-TOTAL	.5300	.5200	.5180	.4870	.4650	2.5200
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
L N G						
S N G						
COAL GAS						
NUCLEAR STIMULATION						
TOTAL SUPPLY	.5300	.5200	.5180	.4870	.4650	2.5200
ADJUSTED DEMAND	2.9188	2.9863	3.0960	3.2009	3.3037	15.5058
SUPPLY BALANCE	-2.3888	-2.4663	-2.5780	-2.7139	-2.8387	-12.9858
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE		.0060	.0130	.0110	.0110	.0410
OFFSHORE		.0020	.0030	.0060	.0120	.0230
LNG IMPORTS						
SNG PRODUCED						
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL		.0080	.0160	.0170	.0230	.0640
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D						
INTER P A D	.1068	.0775	.1116	.1358	.1247	.5567
STORAGE VOLUMES						
INTRA P A D TRANSMISSION						
INTER P A D TRANSMISSION	.0120	.0089	.0130	.0161	.0150	.0653
TOTAL	.0120	.0089	.0130	.0161	.0150	.0653

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971	1972	1973	1974	1975	TOTAL 1971-75
TRANSMISSION - DOMESTIC						
INTRA P A D						
INTER P A D	112.2408	81.4180	117.2524	142.6813	131.0221	584.6148
SUB-TOTAL	112.2408	81.4180	117.2524	142.6813	131.0221	584.6148
TRANSMISSION - IMPORTS						
ALASKA, CANADA, ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE		.6000	1.3000	1.1000	1.1000	4.1000
OFFSHORE		.9000	1.3500	2.7000	5.4000	10.3500
L N G ATTACHMENTS						
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL		1.5000	2.6500	3.8000	6.5000	14.4500
NEW STORAGE FACILITIES	13.9023	10.2580	15.0236	18.5851	17.3466	75.1157
TOTAL NEW FACILITIES	126.1431	93.1760	134.9260	165.0665	154.8687	674.1805

P A D DISTRICT - GAS BALANCE

	1976	1977	1978	1979	1980	TOTAL 1976-80
P A D DISTRICT 5 SUPPLY						
DOMESTIC PRODUCTION						
REGION 2	.3960	.3760	.3590	.3470	.3350	1.8130
REGION 2X	.0590	.0780	.1000	.1240	.1480	.5090
SUB-TOTAL	.4550	.4540	.4590	.4710	.4830	2.3220
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC			.4000	.5500	.7000	1.6500
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL			.4000	.5500	.7000	1.6500
L N G			.1090	.1090	.2920	.5100
S N G						
COAL GAS						
NUCLEAR STIMULATION						
TOTAL SUPPLY	.4550	.4540	.9680	1.1300	1.4750	4.4820
ADJUSTED DEMAND	3.3143	3.3359	3.4588	3.5113	3.5841	17.2045
SUPPLY BALANCE	-2.8593	-2.8819	-2.4908	-2.3813	-2.1091	-12.7225
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.0110	.0120	.0130	.0130	.0130	.0620
OFFSHORE	.0170	.0180	.0250	.0260	.0250	.1110
LNG IMPORTS			.1090		.1830	.2920
SNG PRODUCED						
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL	.0280	.0300	.1470	.0390	.2210	.4650
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D			.3981	.1620	.3450	.9051
INTER P A D	.0206	.0225				.0432
STORAGE VOLUMES						
INTRA P A D TRANSMISSION			.0504	.0208	.0450	.1163
INTER P A D TRANSMISSION	.0025	.0028				.0053
TOTAL	.0025	.0028	.0504	.0208	.0450	.1217

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1976	1977	1978	1979	1980	TOTAL 1976-80
TRANSMISSION - DOMESTIC						
INTRA P A D			209.0481	85.0500	181.1250	475.2231
INTER P A D	21.7003	23.6638				45.3642
SUB-TOTAL	21.7003	23.6638	209.0481	85.0500	181.1250	520.5873
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	1.1000	1.2000	1.3000	1.3000	1.3000	6.2000
OFFSHORE	7.6500	8.1000	11.2500	11.7000	11.2500	49.9500
L N G ATTACHMENTS			9.2650		15.5550	24.8200
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	8.7500	9.3000	21.8150	13.0000	28.1050	80.9700
NEW STORAGE FACILITIES	2.9187	3.2338	58.0278	23.9706	51.8224	139.9734
TOTAL NEW FACILITIES	33.3690	36.1976	288.8910	122.0206	261.0524	741.5307

P A D DISTRICT 5 SUPPLY	1981	1982	1983	1984	1985	TOTAL 1981-85
DOMESTIC PRODUCTION						
REGION 2	.3280	.3170	.3100	.3000	.2920	1.5470
REGION 2X	.1710	.1950	.2180	.2420	.2650	1.0910
SUB-TOTAL	.4990	.5120	.5280	.5420	.5570	2.6380
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC	.8000	1.1500	1.2500	1.5000	1.6500	6.3500
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL	.8000	1.1500	1.2500	1.5000	1.6500	6.3500
L N G	.4750	.4750	.6580	.8410	.8410	3.2900
S N G						
COAL GAS						
NUCLEAR STIMULATION						
TOTAL SUPPLY	1.7740	2.1370	2.4360	2.8830	3.0480	12.2780
ADJUSTED DEMAND	3.6703	3.8295	3.9743	4.1306	4.2275	19.8324
SUPPLY BALANCE	-1.8963	-1.6925	-1.5383	-1.2476	-1.1795	-7.5544
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.0130	.0140	.0140	.0130	.0120	.0660
OFFSHORE	.0240	.0250	.0240	.0240	.0230	.1200
LNG IMPORTS	.1830		.1830	.1830		.5490
SNG PRODUCED						
COAL GAS PRODUCED						
NUCLEAR STIMULATION						
TOTAL	.2200	.0390	.2210	.2200	.0350	.7350
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.2990	.3630	.2990	.4470	.1650	1.5730
INTER P A D						
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0396	.0488	.0408	.0618	.0231	.2142
INTER P A D TRANSMISSION						
TOTAL	.0396	.0488	.0408	.0618	.0231	.2142

P A D DISTRICT - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1981	1982	1983	1984	1985	TOTAL 1981-85
TRANSMISSION - DOMESTIC						
INTRA P A D	156.9750	190.5750	156.9750	234.6750	86.6250	825.8250
INTER P A D						
SUB-TOTAL	156.9750	190.5750	156.9750	234.6750	86.6250	825.8250
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	1.3000	1.4000	1.4000	1.3000	1.2000	6.6000
OFFSHORE	10.8000	11.2500	10.8000	10.8000	10.3500	54.0000
L N G ATTACHMENTS	15.5550		15.5550	15.5550		46.6650
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	27.6550	12.6500	27.7550	27.6550	11.5500	107.2650
NEW STORAGE FACILITIES	45.5814	56.1510	46.9211	71.147[illegible]	26.6317	246.4323
TOTAL NEW FACILITIES	230.2114	259.3760	231.6511	333.4770	124.8067	1179.5223

TRANSMISSION FACILITIES P A D DISTRICT 5 SUPPLY	1971-75	1976-80	1981-85	TOTAL 1971-85
DOMESTIC PRODUCTION				
REGION 2	2.3390	1.8130	1.5470	5.6990
REGION 2X	.1810	.5090	1.0910	1.7810
SUB-TOTAL	2.5200	2.3220	2.6380	7.4800
PIPELINE IMPORTS				
ALASKA,CANADA,ARCTIC		1.6500	6.3500	8.0000
OTHER CANADIAN				
MEXICAN				
SUB-TOTAL		1.6500	6.3500	8.0000
L N G		.5100	3.2900	3.8000
S N G				
COAL GAS				
NUCLEAR STIMULATION				
TOTAL SUPPLY	2.5200	4.4820	12.2780	19.2800
ADJUSTED DEMAND	15.5058	17.2045	19.8324	52.5428
SUPPLY BALANCE	-12.9858	-12.7225	-7.5544	-33.2628
SUPPLY ATTACHMENT VOLUMES				
NEW PRODUCTION				
ONSHORE	.0410	.0620	.0660	.1690
OFFSHORE	.0230	.1110	.1200	.2540
LNG IMPORTS		.2920	.5490	.8410
SNG PRODUCED				
COAL GAS PRODUCED				
NUCLEAR STIMULATION				
TOTAL	.0640	.4650	.7350	1.2640
TRANSMISSION EXPANSION VOLUMES				
INTRA P A D		.9051	1.5730	2.4781
INTER P A D	.5567	.0432		.5999
STORAGE VOLUMES				
INTRA P A D TRANSMISSION		.1163	.2142	.3306
INTER P A D TRANSMISSION	.0653	.0053		.0706
TOTAL	.0653	.1217	.2142	.4013

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971-75		1976-80		1981-85	TOTAL 1971-85
TRANSMISSION - DOMESTIC						
INTRA P A D			475.2231		825.8250	1301.0481
INTER P A D	584.6148		45.3642			629.9790
SUB-TOTAL	584.6148		520.5873		825.8250	1931.0271
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	4.1000		6.2000		6.6000	16.9000
OFFSHORE	10.3500		49.9500		54.0000	114.3000
L N G ATTACHMENTS			24.8200		46.6650	71.4850
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS						
SUB-TOTAL	14.4500		80.9700		107.2650	202.6850
NEW STORAGE FACILITIES	75.1157		139.9734		246.4323	461.5214
TOTAL NEW FACILITIES	674.1805		741.5307		1179.5223	2595.2336

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NATIONAL TOTALS

NATIONAL TOTALS - GAS BALANCE

	1971	1972	1973	1974	1975	TOTAL 1971-75
NATIONAL SUPPLY						
DOMESTIC PRODUCTION						
REGION 2	.4950	.4870	.4860	.4510	.4200	2.3390
REGION 3	.6639	.6739	.6889	.7039	.7109	3.4416
REGION 4	.4469	.4479	.4579	.4709	.4839	2.3077
REGION 5	2.6530	2.6560	2.6480	2.6750	2.7020	13.3340
REGION 6	8.3240	8.4830	8.8740	9.0720	8.9940	43.7470
REGION 7	3.7990	3.8230	3.6620	3.5690	3.4710	18.3240
REGION 8	.0190	.0190	.0190	.0190	.0190	.0950
REGION 10	.4090	.3980	.4070	.4190	.4300	2.0630
REGION 11	.0010	.0010	.0010	.0010	.0020	.0060
REGION 2X	.0350	.0330	.0320	.0360	.0450	.1810
REGION 6X	3.1270	3.3330	3.7620	4.1530	4.4600	18.8350
SUB-TOTAL	19.9728	20.3548	21.0378	21.5698	21.7378	104.6734
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN	.9000	1.0000	1.0000	1.0000	1.0000	4.9000
MEXICAN	.0500	.0500	.0500	.0500	.0500	.2500
SUB-TOTAL	.9500	1.0500	1.0500	1.0500	1.0500	5.1500
L N G					.2380	.2380
S N G			.0940	.3120	.6360	1.0420
COAL GAS						
NUCLEAR STIMULATION					.0050	.0050
TOTAL SUPPLY	20.9228	21.4048	22.1818	22.9318	23.6668	111.1084
ADJUSTED DEMAND	20.9228	21.4048	22.1818	22.9318	23.6668	111.1084
SUPPLY BALANCE						
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE		.5119	.9519	.8979	.8519	3.2139
OFFSHORE		.3170	.5400	.5570	.5580	1.9720
LNG IMPORTS					.2380	.2380
SNG PRODUCED			.0940	.2180	.3240	.6360
COAL GAS PRODUCED						
NUCLEAR STIMULATION					.0050	.0050
TOTAL		.8289	1.5859	1.6729	1.9769	6.0649
TRANSMISSION EXPANSION VOLUMES						
INTRA P A C	.5183	.5029	.8550	.8407	.7717	3.4888
INTER P A C	.1572	.1983	.5767	.4811	.4190	1.8324
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.0586	.0578	.1000	.0999	.0932	.4097
INTER P A C TRANSMISSION	.0177	.0228	.0674	.0572	.0506	.2159
TOTAL	.0764	.0806	.1674	.1572	.1439	.6257

NATIONAL TOTALS - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971	1972	1973	1974	1975	TOTAL 1971-75
TRANSMISSION - DOMESTIC						
INTRA P A C	273.4759	215.6790	308.1966	311.1312	295.0517	1403.5346
INTER P A C	215.4521	329.1708	923.8141	695.0781	601.7773	2765.2925
SUB-TOTAL	488.9281	544.8498	1232.0107	1006.2094	896.8290	4168.8271
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC						
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL						
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE		51.1996	95.1996	89.7995	85.1995	321.3982
OFFSHORE		142.6500	243.0000	250.6500	251.1000	887.4000
L N G ATTACHMENTS					20.2300	20.2300
S N G ATTACHMENTS			4.2300	9.8100	14.5800	28.6200
COAL GAS ATTACHMENTS						
NUCLEAR STIM. ATTACHMENTS					.5000	.5000
SUB-TOTAL		193.8496	342.4296	350.2595	371.6095	1258.1482
NEW STORAGE FACILITIES	87.8611	92.7912	192.6215	180.8007	165.5298	719.6044
TOTAL NEW FACILITIES	576.7892	831.4906	1767.0618	1537.2696	1433.9684	6146.5798

	1976	1977	1978	1979	1980	TOTAL 1976-80
NATIONAL SUPPLY						
DOMESTIC PRODUCTION						
REGION 2	.3960	.3760	.3590	.3470	.3350	1.8130
REGION 3	.7099	.6619	.6239	.5959	.5769	3.1686
REGION 4	.4969	.4919	.4959	.5089	.5299	2.5237
REGION 5	2.7120	2.7450	2.7820	2.8180	2.8720	13.9290
REGION 6	8.8080	8.6650	8.5340	8.4000	8.3130	42.7200
REGION 7	3.3340	3.2040	3.0760	2.9470	2.8590	15.4200
REGION 8	.0190	.0200	.0210	.0220	.0240	.1060
REGION 10	.4450	.4600	.4800	.4950	.5200	2.4000
REGION 11	.0030	.0040	.0060	.0080	.0110	.0320
REGION 2X	.0590	.0780	.1000	.1240	.1480	.5090
REGION 6X	4.7350	5.0420	5.3840	5.7480	6.1310	27.0400
REGION 11X	.0010	.0040	.0070	.0100	.0210	.0430
SUB-TOTAL	21.7188	21.7518	21.8688	22.0238	22.3408	109.7044
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC			.8000	1.1000	1.4000	3.3000
OTHER CANADIAN	1.0000	1.0000	1.0000	1.0000	1.0000	5.0000
MEXICAN	.0500	.0290				.0790
SUB-TOTAL	1.0500	1.0290	1.8000	2.1000	2.4000	8.3790
L N G	.6390	1.0770	1.4960	1.9160	2.2820	7.4100
S N G	.9070	1.1760	1.3150	1.3150	1.3150	6.0280
COAL GAS	.0800	.1600	.2800	.4000	.5600	1.4800
NUCLEAR STIMULATION	.0150	.0220	.0440	.1030	.1870	.3710
TOTAL SUPPLY	24.4098	25.2158	26.8038	27.8578	29.0848	133.3724
ADJUSTED DEMAND	24.4098	25.2158	26.8038	27.8578	29.0848	133.3724
SUPPLY BALANCE						
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.8109	.8599	.9059	.8329	.8279	4.2379
OFFSHORE	.5530	.5820	.6200	.6410	.6330	3.0290
LNG IMPORTS	.4010	.4380	.4190	.4200	.3660	2.0440
SNG PRODUCED	.2710	.2690	.1390			.6790
COAL GAS PRODUCED	.0800	.0800	.1200	.1200	.1600	.5600
NUCLEAR STIMULATION	.0100	.0070	.0220	.0590	.0840	.1820
TOTAL	2.1259	2.2359	2.2259	2.0729	2.0709	10.7319
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	.8207	.7984	1.2514	1.0540	1.2269	5.1516
INTER P A D	.3601	.2994	.2680	.3216	.3824	1.6318
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.1008	.0996	.1585	.1356	.1602	.6549
INTER P A D TRANSMISSION	.0442	.0373	.0339	.0413	.0499	.2069
TOTAL	.1450	.1369	.1925	.1770	.2102	.8618

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1976	1977	1978	1979	1980	TOTAL 1976-80
TRANSMISSION - DOMESTIC						
INTRA P A D	316.9029	317.2240	568.0419	430.2451	520.1972	2152.6113
INTER P A D	564.9275	466.7422	428.9392	514.6912	611.8400	2587.1402
SUB-TOTAL	881.8304	783.9662	996.9811	944.9363	1132.0372	4739.7515
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC	343.0000	35.0000	3395.0000	1466.0000	2048.0000	7287.0000
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL	343.0000	35.0000	3395.0000	1466.0000	2048.0000	7287.0000
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	81.0995	85.9996	90.5993	83.2994	82.7993	423.7971
OFFSHORE	248.8500	261.9000	279.0000	288.4500	284.8500	1363.0500
L N G ATTACHMENTS	33.5400	37.2300	35.6150	34.7850	31.1100	172.2800
S N G ATTACHMENTS	12.1950	12.1050	6.2550			30.5550
COAL GAS ATTACHMENTS	80.0000	80.0000	120.0000	100.0000	140.0000	520.0000
NUCLEAR STIM. ATTACHMENTS	1.0000	.7000	2.2000	5.9000	8.4000	18.2000
SUB-TOTAL	456.6845	477.9346	533.6693	512.4344	547.1593	2527.8821
NEW STORAGE FACILITIES	166.8086	157.5339	221.4497	203.5603	241.7461	991.0987
TOTAL NEW FACILITIES	1848.3236	1454.4347	5147.1002	3126.9311	3968.9426	15545.7323

	1981	1982	1983	1984	1985	TOTAL 1981-85
NATIONAL SUPPLY						
DOMESTIC PRODUCTION						
REGION 2	.3280	.3170	.3100	.3000	.2920	1.5470
REGION 3	.5599	.5529	.5459	.5389	.5399	2.7377
REGION 4	.5539	.5879	.6239	.6629	.7069	3.1356
REGION 5	2.9440	3.0200	3.0880	3.1360	3.1740	15.3620
REGION 6	8.1140	8.0840	8.0920	7.9510	7.8110	40.0520
REGION 7	2.8140	2.7690	2.7230	2.6710	2.6460	13.6230
REGION 8	.0260	.0290	.0310	.0340	.0380	.1580
REGION 10	.5450	.5690	.5920	.6100	.6260	2.9420
REGION 11	.0150	.0190	.0250	.0320	.0400	.1310
REGION 2X	.1710	.1950	.2180	.2420	.2650	1.0910
REGION 6X	6.4670	6.8490	7.2130	7.4760	7.6410	35.6460
REGION 11X	.0500	.1190	.1980	.2860	.3900	1.0430
SUB-TOTAL	22.5878	23.1108	23.6598	23.9398	24.1698	117.4684
PIPELINE IMPORTS						
ALASKA,CANADA,ARCTIC	1.6000	2.3000	2.5000	3.0000	3.3000	12.7000
OTHER CANADIAN	1.0000	.9000	.9000	.9000	.9000	4.6000
MEXICAN						
SUB-TOTAL	2.6000	3.2000	3.4000	3.9000	4.2000	17.3000
L N G	2.7390	3.0130	3.4690	3.9250	4.1070	17.2530
S N G	1.3150	1.3150	1.3150	1.3150	1.3150	6.5750
COAL GAS	.8000	1.1200	1.5200	2.0000	2.4800	7.9200
NUCLEAR STIMULATION	.3320	.5280	.7360	.9580	1.1970	3.7510
TOTAL SUPPLY	30.3738	32.2868	34.0998	36.0378	37.4688	170.2674
ADJUSTED DEMAND	30.3738	32.2868	34.0998	36.0378	37.4688	170.2674
SUPPLY BALANCE						
SUPPLY ATTACHMENT VOLUMES						
NEW PRODUCTION						
ONSHORE	.8119	.7649	.7779	.6769	.5699	3.6019
OFFSHORE	.6290	.6500	.6080	.5420	.4500	2.8790
LNG IMPORTS	.4570	.2740	.4560	.4560	.1820	1.8250
SNG PRODUCED						
COAL GAS PRODUCED	.2400	.3200	.4000	.4800	.4800	1.9200
NUCLEAR STIMULATION	.1450	.1960	.2080	.2220	.2390	1.0100
TOTAL	2.2829	2.2049	2.4499	2.3769	1.9209	11.2359
TRANSMISSION EXPANSION VOLUMES						
INTRA P A D	1.2890	1.9129	1.8129	1.9379	1.4309	8.3839
INTER P A D	.2934	.4463	.4813	.4028	.3477	1.9717
STORAGE VOLUMES						
INTRA P A D TRANSMISSION	.1708	.2573	.2473	.2682	.2008	1.1446
INTER P A D TRANSMISSION	.0388	.0600	.0656	.0557	.0488	.2691
TOTAL	.2097	.3173	.3130	.3239	.2496	1.4138

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1981	1982	1983	1984	1985	TOTAL 1981-85
TRANSMISSION - DOMESTIC						
INTRA P A D	554.4595	805.3486	734.9607	833.1590	561.0298	3488.9579
INTER P A D	469.4864	714.1872	770.2048	644.4944	556.4000	3154.7728
SUB-TOTAL	1023.9459	1519.5358	1505.1655	1477.6534	1117.4298	6643.7307
TRANSMISSION - IMPORTS						
ALASKA,CANADA,ARCTIC	656.0000	3406.0000	2407.0000	1992.0000	2027.0000	10488.0000
OTHER CANADIAN						
MEXICAN						
SUB-TOTAL	656.0000	3406.0000	2407.0000	1992.0000	2027.0000	10488.0000
SUPPLY ATTACHMENTS						
NEW PRODUCTION ATTACHMENT						
ONSHORE	81.1993	76.4992	77.7991	67.6993	56.9992	360.1961
OFFSHORE	283.0500	292.5000	273.6000	243.9000	202.5000	1295.5500
L N G ATTACHMENTS	38.8450	23.2900	38.7600	38.7600	15.4700	155.1250
S N G ATTACHMENTS						
COAL GAS ATTACHMENTS	200.0000	260.0000	320.0000	374.0000	360.0000	1514.0000
NUCLEAR STIM. ATTACHMENTS	14.5000	19.6000	20.8000	22.2000	23.9000	101.0000
SUB-TOTAL	617.5943	671.8892	730.9591	746.5593	658.8692	3425.8711
NEW STORAGE FACILITIES	241.2366	364.9640	360.0477	372.5747	287.0963	1625.9194
TOTAL NEW FACILITIES	2538.7768	5962.3890	5003.1724	4588.7874	4090.3954	22183.5212

TRANSMISSION FACILITIES	1971-75	1976-80	1981-85	TOTAL 1971-85
NATIONAL SUPPLY				
DOMESTIC PRODUCTION				
REGION 2	2.3390	1.8130	1.5470	5.6990
REGION 3	3.4416	3.1686	2.7377	9.3480
REGION 4	2.3077	2.5237	3.1356	7.9671
REGION 5	13.3340	13.9290	15.3620	42.6250
REGION 6	43.7470	42.7200	40.0520	126.5190
REGION 7	18.3240	15.4200	13.6230	47.3670
REGION 8	.0950	.1060	.1580	.3590
REGION 10	2.0630	2.4000	2.9420	7.4050
REGION 11	.0060	.0320	.1310	.1690
REGION 2X	.1810	.5090	1.0910	1.7810
REGION 6X	18.8350	27.0400	35.6460	81.5210
REGION 11X		.0430	1.0430	1.0860
SUB-TOTAL	104.6734	109.7044	117.4684	331.8462
PIPELINE IMPORTS				
ALASKA,CANADA,ARCTIC		3.3000	12.7000	16.0000
OTHER CANADIAN	4.9000	5.0000	4.6000	14.5000
MEXICAN	.2500	.0790		.3290
SUB-TOTAL	5.1500	8.3790	17.3000	30.8290
L N G	.2380	7.4100	17.2530	24.9010
S N G	1.0420	6.0280	6.5750	13.6450
COAL GAS		1.4800	7.9200	9.4000
NUCLEAR STIMULATION	.0050	.3710	3.7510	4.1270
TOTAL SUPPLY	111.1084	133.3724	170.2674	414.7482
ADJUSTED DEMAND	111.1084	133.3724	170.2674	414.7482
SUPPLY BALANCE				
SUPPLY ATTACHMENT VOLUMES				
NEW PRODUCTION				
ONSHORE	3.2139	4.2379	3.6019	11.0539
OFFSHORE	1.9720	3.0290	2.8790	7.8800
LNG IMPORTS	.2380	2.0440	1.8250	4.1070
SNG PRODUCED	.6360	.6790		1.3150
COAL GAS PRODUCED		.5600	1.9200	2.4800
NUCLEAR STIMULATION	.0050	.1820	1.0100	1.1970
TOTAL	6.0649	10.7319	11.2359	28.0329
TRANSMISSION EXPANSION VOLUMES				
INTRA P A D	3.4888	5.1516	8.3839	17.0245
INTER P A D	1.8324	1.6318	1.9717	5.4360
STORAGE VOLUMES				
INTRA P A D TRANSMISSION	.4097	.6549	1.1446	2.2093
INTER P A D TRANSMISSION	.2159	.2069	.2691	.6920

NATIONAL TOTALS - CAPITAL COSTS

CAPITAL COST FOR ADDITIONAL TRANSMISSION FACILITIES	1971-75	1976-80	1981-85	TOTAL 1971-85
TRANSMISSION - DOMESTIC				
INTRA P A D	1403.5346	2152.6113	3488.9579	7045.1038
INTER P A D	2765.2925	2587.1402	3154.7728	8507.2055
SUB-TOTAL	4168.8271	4739.7515	6643.7307	15552.3094
TRANSMISSION - IMPORTS				
ALASKA,CANADA,ARCTIC		7287.0000	10488.0000	17775.0000
OTHER CANADIAN				
MEXICAN				
SUB-TOTAL		7287.0000	10488.0000	17775.0000
SUPPLY ATTACHMENTS				
NEW PRODUCTION ATTACHMENT				
ONSHORE	321.3982	423.7971	360.1961	1105.3914
OFFSHORE	887.4000	1363.0500	1295.5500	3546.0000
L N G ATTACHMENTS	20.2300	172.2800	155.1250	347.6350
S N G ATTACHMENTS	28.6200	30.5550		59.1750
COAL GAS ATTACHMENTS		520.0000	1514.0000	2034.0000
NUCLEAR STIM. ATTACHMENTS	.5000	18.2000	101.0000	119.7000
SUB-TOTAL	1258.1482	2527.8821	3425.8711	7211.9014
NEW STORAGE FACILITIES	719.6044	991.0987	1625.9194	3336.6226
TOTAL NEW FACILITIES	6146.5798	15545.7323	22183.5212	43875.8334

COST TABLES
AND
STORAGE WITHDRAWAL FACTORS

PAD DISTRICT	TRANSMISSION INTRA PAD	TRANSMISSION INTER PAD	ONSHORE GATHERING	OFFSHORE GATHERING	STORAGE WITHDRAWAL	L N G ATTACHMENT	S N G ATTACHMENT	COAL GAS ATTACHMENT	NUCLEAR STIMULATION
2	640	1600	100		1150		45	1000	
3	360	1200	100	450	1150	80	45	225	
4	315	1050	100		1150			750	100
1	410	2050	100	450	1150	85	45		
5	525	1050	100	450	1150	85			

SLOPE 0.001947

INTERCEPT -3.724442

LNG METHODOLOGY

LNG quantities, points of entry and shipping points were furnished by the Gas Supply Task Group for 5-year periods as shown in Table 3 in Chapter Two of this report. In addition to these quantities, it is anticipated that by the end of 1975 there will be 110 billion cubic feet (BCF) per year--0.30 BCF per day--imported to the East Coast for peaking service. No capital requirements have been calculated for this service since liquefaction and shipping facilities are already constructed, and no new pipeline facilities will be required.

Number and size of ships required were calculated as outlined later in this section. A sample follows:

Algeria to Cove Point, Maryland
0.350 BCF per day, 127.75 BCF per year
Round trip distance - 7,300 nautical miles
Ship speed - 20 knots
Round trip sailing time =

7,300 miles ÷ 20 knots - 365 hours	=	15.2 days
Loading and unloading	=	3.0 days
Weather delay	=	0.5 days
Total time per round trip		18.7 days

345 Operating days per year ÷ 18.7 days =	18.45 round trips per year
Boil-off 0.25% per day x 18.7 days =	4.68 percent
Quantity shipped = 127.75 ÷ 95.32% =	134.02 BCF per year
U.S. Coast Guard requirement = 98 percent of total ship capacity	
134.02 ÷ 98 =	136.76 BCF per year
3 Ships = 136.76 ÷ 3 =	45.59 BCF per year per ship
45.59 ÷ 18.45 =	2.47 BCF per voyage
2.47 BCF ÷ 22,000 (methane factor) =	112,300 cubic meters per ship

Costs of ships were computed using as a basis the escalated cost of the Alaskan ships, *Arctic Tokyo* and *Polar Alaska*. The equation uses the 0.67 power rule. As an example, for a 120,000 cubic meter vessel this cost equals to:

$$\left(\frac{120,000}{71,600}\right)^{.67} \times \$37,500,000 = \$52,800,000$$

This cost figure includes the following:

- Shipyard costs
- Owner-supplied equipment, supervision and inspection during construction

- Initial stores and spare parts

- Gas trials

- Positioning voyage costs.

The attached Figure 5 shows a cost curve for LNG tankers built in foreign yards developed as follows:

- Actual costs associated with *Arctic Tokyo* and *Polar Alaska* updated to 1970 were used.

- The cost of various sized vessels using the equation explained above were calculated.

- The curve was plotted and checked with prices quoted in the literature for various LNG ships on order. As an example, the cost of a 120,000-cubic meter ship taken from the curve is $52,800,000 for 1970. This cost, escalated at 4.5 percent per year, equates to $60,000,000, the quoted price for the El Paso ships for delivery in 1973 or 1974.

If ships are constructed in U.S. yards, even if they are government subsidized, total capital requirements will be considerably greater. The U.S. Government subsidy for U.S. construction at present is 28-29 percent of the yard cost. This will in fact be an additional capital requirement for the United States, but the balance of payments effect is of greater significance.

Foreign yard costs were used to determine the capital requirements shown in Table 3 (Chapter Two) except for ships proposed for service from Alaska to Portland. Costs of these ships were increased by 40 percent (1970 basis) to cover U.S. construction as required under the "Jones Act." As of the present time, there is no subsidy available for vessels in U.S. intercoastal service.

Costs of liquefaction plants were developed as follows:

- Costs were developed for four basic plants with 300, 600, 900 and 1,200 MMCF per day liquefaction capacity. A work curve was plotted from these four points, and an adjusted cost curve was obtained to reflect cost versus delivered value.

- Basic cost data was taken from the detailed, as built, Phillips-Marathon Kenai LNG Plant cost. This cost was escalated to 1970 costs.

- Cost estimates were developed for the following categories:

  Refrigeration modules
  Wharf and loading facilities
  Utilities
  Land

Storage tanks
Engineering and management.

- Plant storage requirements were estimated as being equal to one 120,000-cubic meter ship (755,000 barrels) plus two days production. Cost of storage was taken at $15 per barrel.

- The cost curve for liquefaction plants (Figure 6) is a function of liquefaction capacity in terms of MMCF per day delivered to the unloading terminal. To determine the cost of a specific plant, the boil-off during the loaded voyage and cool-down requirements (i.e., transportation shrinkage plus plant storage losses) must be added to the delivered quantity to obtain the size of liquefaction plant required. For example, to deliver 350 MMCF per day to Cove Point from Arzew requires a liquefaction plant capable of liquefying
$$\frac{350}{1-(0.468+.01)} = 371 \text{ MMCF/D.}$$

The cost curve has been adjusted to take care of shrinkage and plant losses. Thus, the cost can be obtained by reading the value direct for 350 MMCF/D delivered volume. (In this example, approximately $131,000,000.) Also, in Table 3 (p. 10), the liquefaction plant cost for the same delivered volume is constant. This is due to using the highest calculated plant cost for a given delivered volume for all projects of the same delivered volume.

The last two items in Table 3 are exceptions to this methodology. In these cases, voyage distances are out of proportion to the other projects so that separate computations were made.

Costs of unloading terminal and regasification facilities were determined as following:

- Engineering estimates were prepared for terminals of three sizes--those with 250 MMCF/D capacity, those with 500 MMCF/D capacity and those with 1,000 MMCF/D. These costs were plotted and a curve (Figure 7) was drawn through the three points.

- Categories included in these estimates are as follows:

  Vaporizer
  Marine and unloading facilities
  Utilities
  Land
  Engineering and management.

- Unloading terminal costs used consist of the cost taken from the curve for regasification terminals plus the storage equivalent to two shiploads at $15 per barrel. Under this system, the storage under all cases varies from 900,000 barrels to 2,000,000 barrels.

- As an example, the regasification terminal cost located at Cove Point is determined as follows:

  Capacity - 350 MMCF/D
  Require 3 ships at 112,300 cubic meters each
  Storage required, 2 shiploads - 224, 600 cubic meters
  x 6.29 bbl/cubic meter = 1,412,700 barrels

1,412,700 bbl @ $15	=	$21,190,000
Regasification from curve	=	28,000,000
Total Terminal		$49,190,000 (Used $49,000,000)

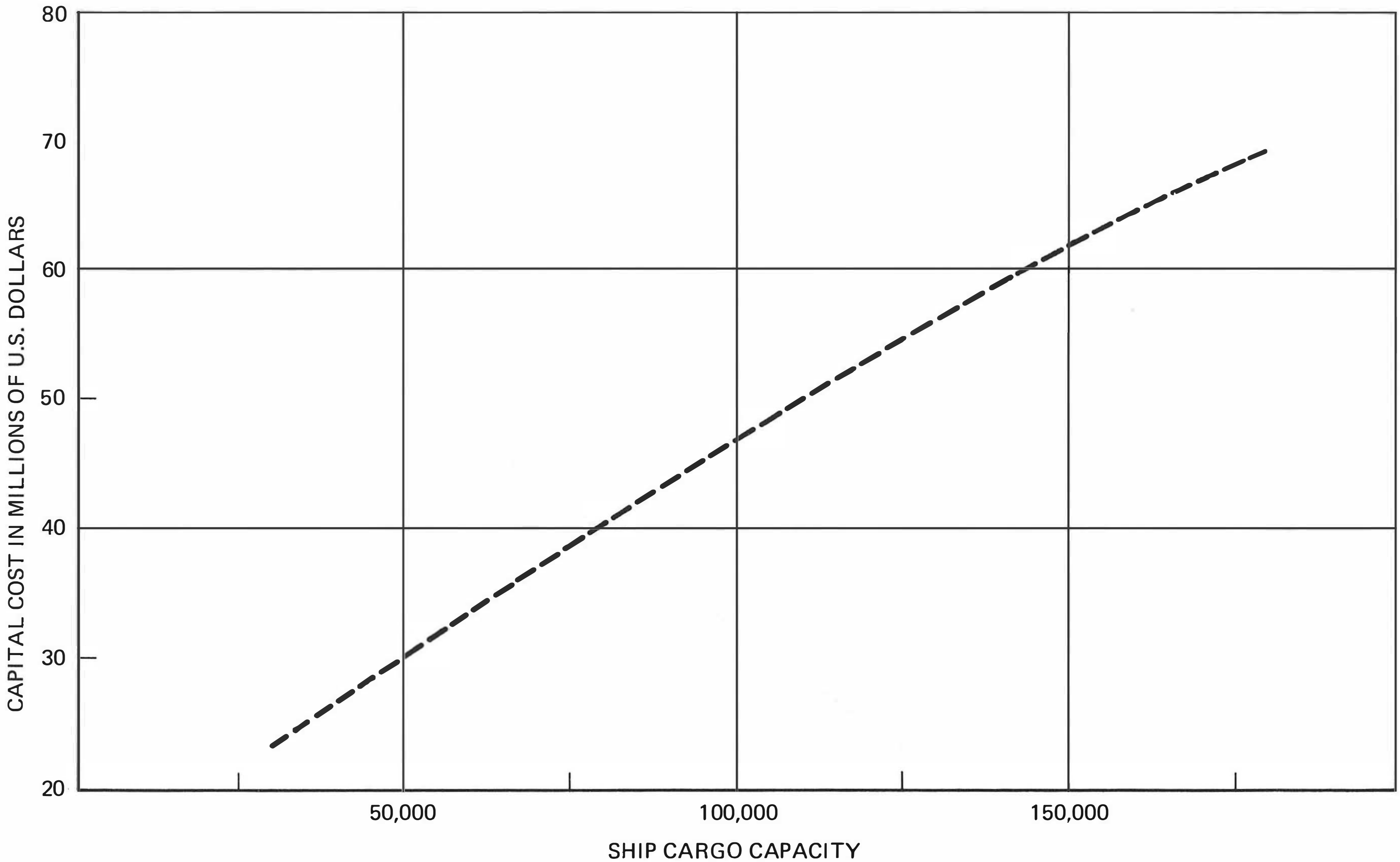

Figure 5. LNG Tankers Construction Costs Foreign Yards (1970).

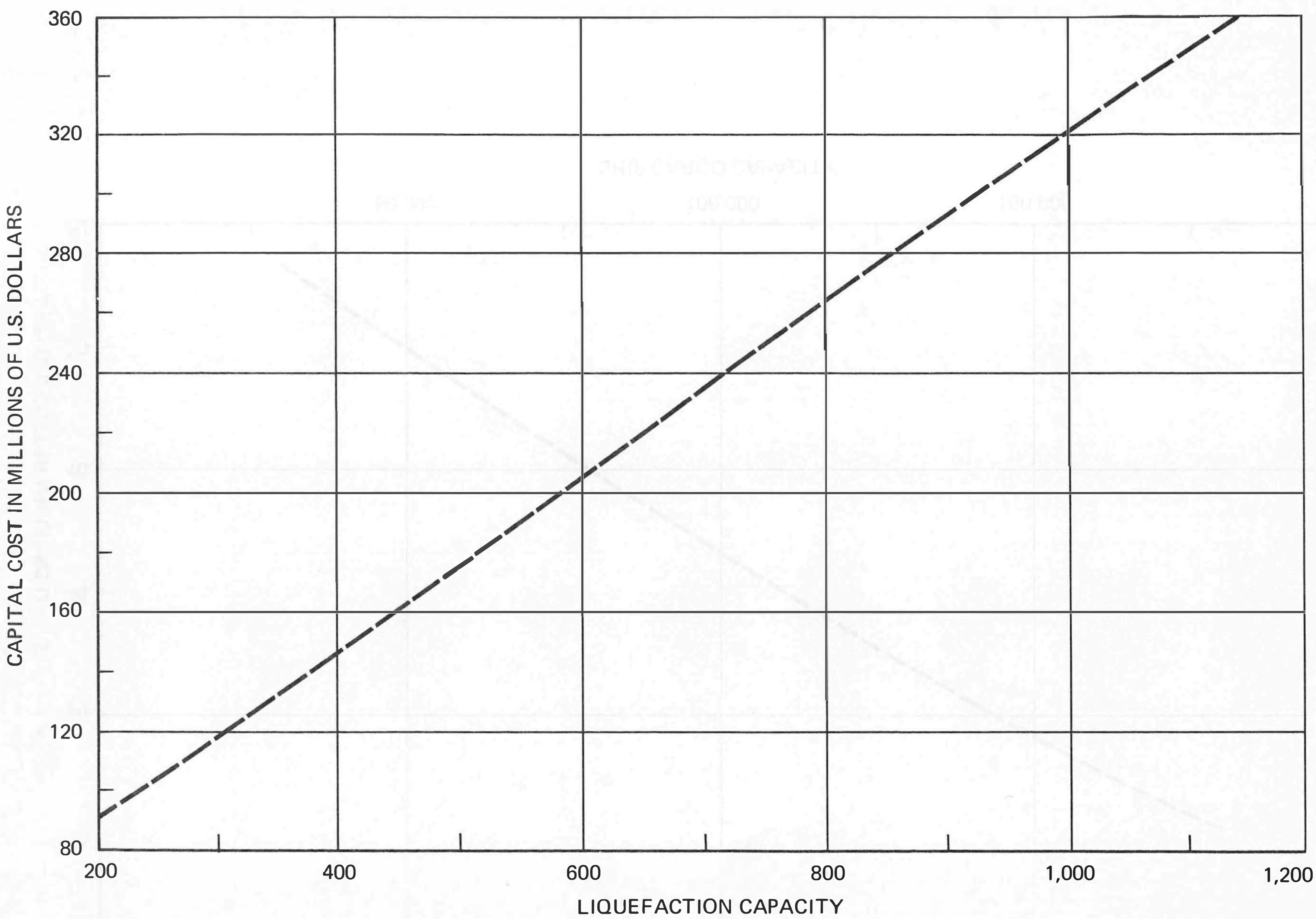

Figure 6. LNG Liquefaction Plants Costs vs. Liquid Output Capacity (1970).

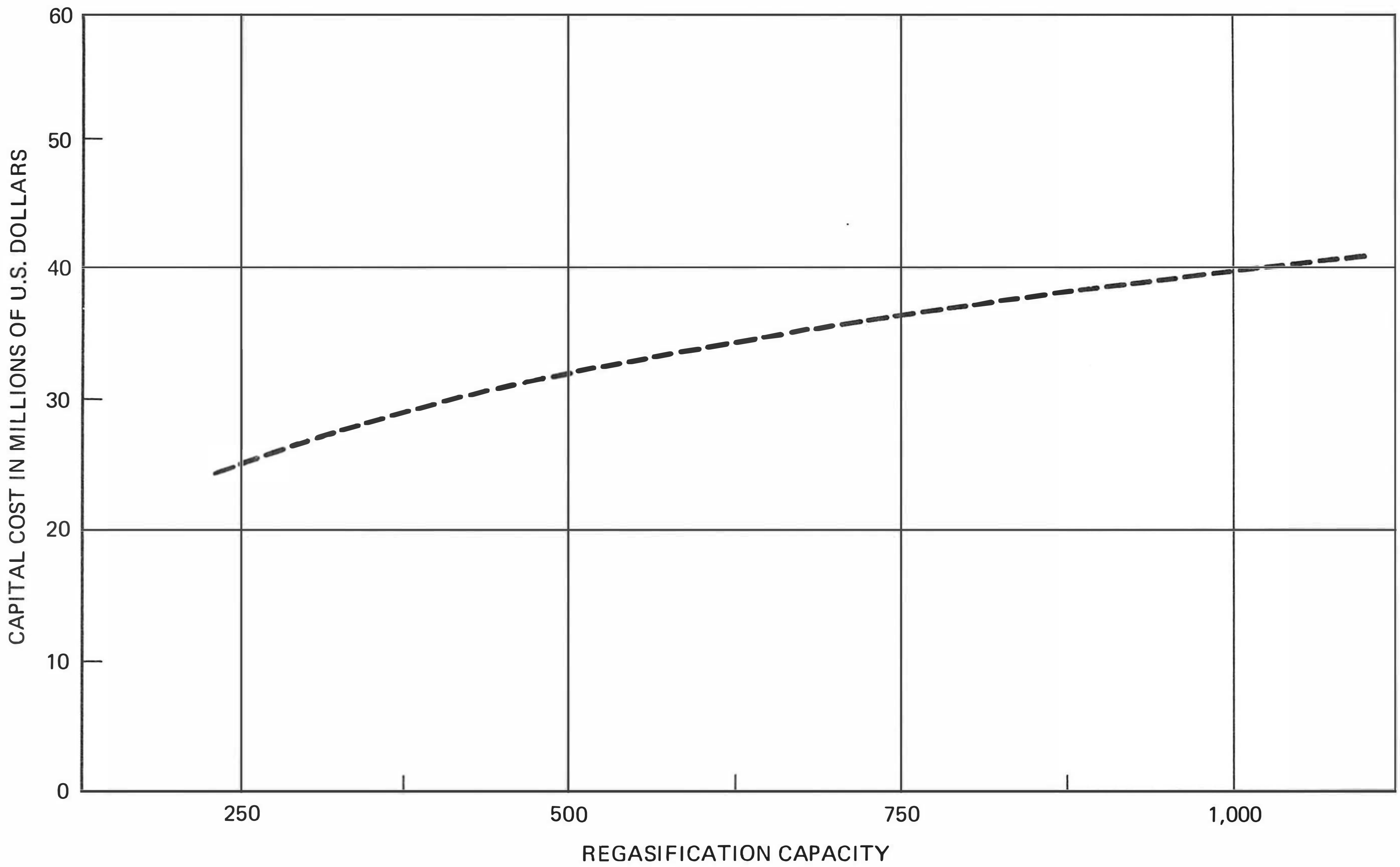

Figure 7. Regasification Terminals (Less Storage) Cost vs. Capacity (1970).

LIQUEFIED PETROLEUM GAS METHODOLOGY

LPG PIPELINES, TANKER AND BARGE FACILITIES

Liquefied petroleum gas, for the purposes of this report, is interpreted to consist of only the following products: (1) ethane, (2) propane, (3) butanes or (4) mixes of the above.

LPG supply quantities expected from non-associated and associated and dissolved gas were furnished by the Gas Supply Task Group (see Table 4, Chapter Three, of this report).

Supply quantities expected from refinery operations were estimated at 3 percent of crude runs. Since crude runs, as furnished by the Oil Logistics Task Group, were only furnished for one case, the same supply quantities from this source are used for all cases (Cases I through IV). These quantities are also shown in Table 4, as are imports of LPG by liquid pipelines estimated by the Gas Supply Task Group.

Imports of LPG in suspension in natural gas pipelines were computed from gas volumes projected by the Gas Supply Task Group. It was estimated that gas from the Alaskan North Slope would contain 24 barrels of LPG per million cubic feet and that Canadian Atlantic offshore gas would contain 18 barrels per million cubic feet. Since present indications are that Canadian Arctic Island gas is completely dry, no LPG was considered from this source. Volumes of LPG from these sources are estimated as shown in the tabulation below.

	Volumes in Millions of Barrels Per Year			
	Case I	Case II	Case III	Case IV
Alaskan North Slope				
1980	31.2	31.2	26.4	0.0
1985	72.0	64.8	52.8	28.8
Canadian Atlantic Offshore				
1980	19.8	19.8	19.8	19.8
1985	28.8	28.8	28.8	28.8
Total				
1980	51.0	51.0	46.2	19.8
1985	100.8	93.6	81.6	57.6

Quantities of LPG to be imported by tankers and barges were also projected by the Gas Supply Task Group.

Projections of LPG requirements for chemical use and for conventional uses (except for motor gasoline at refineries) were furnished by the Gas Demand Task Group, by PAD Districts. These projections are shown in Tables 47 and 48.

Projections of LPG requirements for syn-gas plants were made by the Gas Subcommittee on the assumption that one-third of all the announced projects would be in operation by 1975 and one-half of those projects would be in operation by 1980 and 1985. These announced projects proposing to use LPG as feedstocks were as follows:

Company	Feedstock Bbl/Day	Source
Boston Gas Company	10,000	Domestic
Northern Illinois Gas Co.	36,000	"
Peoples Gas Company	80,000	"
Commonwealth Natural Gas Co.	7,600	Foreign
Continental Oil Company	66,000	"
Columbia LNG Corp.	87,000	Canadian
Consumers Power Co.	50,000	"
	336,600	

1/3 in Operation in 1975 = 112,200 bbl/Day = 40.95 MMB/Year

1/2 in Operation in 1980 = 168,300 bbl/Day = 61.43 MMB/Year

With these supply and demand figures available, estimates of costs of facilities were made based on historical costs updated to 1970. All quantities of syn-gas plant feedstocks were assumed to be delivered by pipeline while historical percentages were used to divide the remaining supplies between pipelines, tank trucks and rail tank cars, barges and related facilities.

Capital requirements for LPG pipelines, tankers, barges and related facilities are estimated in Table 49.

Tank Truck Facilities - Methodology

The number of tank trucks required for transportation of LPG was estimated by projecting the 1971 ratio of total units in service to the total supply of LPG transported by truck without reference to the distances transported. This ratio was applied to the projected increase (or decrease) in the supply volumes shown in Table 4 (Chapter Three) to determine the number of new tractor trailer units required. Table 50 in this appendix shows the

TABLE 47

LPG ENERGY REQUIREMENTS*
(BTU x 10^{12})

	PAD I				PAD II							
	New England	Mid-Atlantic	South Atlantic	Total	E. N. Central	W. N. Central	Other	Total	PAD III	PAD IV	PAD V	Total
1965	19	31	83	133	118	134	46	298	216	27	54	728
1969	23	42	107	172	185	210	66	461	289	42	61	1,025
1970	24	45	110	179	190	210	73	473	298	41	62	1,053
1971	24	45	113	182	197	210	74	481	304	41	62	1,070
1972	24	46	115	185	203	216	76	495	310	44	64	1,098
1973	25	46	118	189	210	222	78	510	321	45	67	1,132
1974	25	47	121	193	216	228	80	524	331	47	70	1,165
1975	26	48	123	197	221	234	83	538	341	49	72	1,197
1980	29	51	134	214	249	259	92	600	385	56	86	1,341
1985	31	54	146	231	281	288	101	670	421	63	98	1,483

* Butane, propane and mixes; includes residential and commercial, internal combustion, utility gas, other and miscellaneous; excludes LPG to motor gasoline at refineries; excludes chemicals; energy based on average of 98,000 BTU/gallon.

TABLE 48

LPG CHEMICAL REQUIREMENTS*
(BTU x 10^{12})

	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
1965	38	34	276	0	15	363
1969	38	36	523	0	17	614
1970	40	40	515	0	14	609
1971	40	55	512	0	13	620
1972	40	72	521	0	13	646
1973	45	75	545	0	13	678
1974	48	84	593	0	13	738
1975	49	86	656	0	12	803
1980	49	96	865	0	13	1,023
1985	49	146	987	0	14	1,196

* Includes ethane, propane and butane from gas plants and refineries; excludes refinery ethylene, propylene and butylenes.

TABLE 49

CAPITAL REQUIREMENTS
(Millions of 1970 Dollars)

	Case I				Case II			
	1971-1975	1975-1980	1980-1985	Total	1971-1975	1975-1980	1980-1985	Total
New Tankers, Barges and Marine Terminals, Including Terminal Storage	50.0	77.0	73.0	200.0	50.0	77.0	73.0	200.0
Subtotal	**50.0**	**77.0**	**73.0**	**200.0**	**50.0**	**77.0**	**73.0**	**200.0**
New Pipelines (U.S. Portion Only)	145.0	30.0	30.0	205.0	145.0	20.0	20.0	185.0
New LPG Storage	0.0	43.0	43.0	86.0	0.0	38.0	34.0	72.0
Replacement of Existing Facilities	50.0	50.0	50.0	150.0	35.0	50.0	50.0	135.0
Subtotal	**195.0**	**123.0**	**123.0**	**441.0**	**180.0**	**108.0**	**104.0**	**392.0**
Grand Total	**245.0**	**200.0**	**196.0**	**641.0**	**230.0**	**185.0**	**177.0**	**592.0**

	Case III				Case IV			
	1971-1975	1975-1980	1980-1985	Total	1971-1975	1975-1980	1980-1985	Total
New Tankers, Barges and Marine Terminals, Including Terminal Storage	50.0	77.0	73.0	200.0	50.0	77.0	73.0	200.0
Subtotal	**50.0**	**77.0**	**73.0**	**200.0**	**50.0**	**77.0**	**73.0**	**200.0**
New Pipelines (U.S. Portion Only)	145.0	10.0	10.0	165.0	145.0	5.0	5.0	155.0
New LPG Storage	0.0	22.0	24.0	46.0	0.0	7.0	16.0	23.0
Replacement of Existing Facilities	25.0	35.0	35.0	95.0	25.0	25.0	25.0	75.0
Subtotal	**170.0**	**67.0**	**69.0**	**306.0**	**170.0**	**37.0**	**46.0**	**253.0**
Grand Total	**220.0**	**144.0**	**142.0**	**506.0**	**220.0**	**114.0**	**119.0**	**453.0**

computations involved in estimating the new and replacement units which will be required through 1985 for transporting LPG in each Case (I through IV). Calculations are based on:

- The total volumes of LPG to be transported
- The total number of LPG truck units in service at the end of 1970
- Average life of tractor - 7-1/2 years
- Average life of trailer - 15 years.

While the life of a unit will depend on utilization, and it is obvious that for-hire carrier life will be shorter because of a higher utilization factor, we believe that the figures used will represent the industry average.

Table 51 shows the calculation of total costs of the new and replacement average units shown in Table 50 for each of the Cases (I through IV). These costs are calculated from the 1970 costs of such units. For example--

- Tractor - $20,000
- Trailer - $18,000
- Combination - $38,000.

This methodology could not reasonably be used for projection of LNG trucks required because of the limited experience background and because requirements are not particularly supply oriented. Rather, it was concluded that the number of units required would be more dependent on the number of satellite LNG storage plants and the amounts of peaking service. Moreover, while it is obvious that bulk LNG supplies imported from overseas will be revaporized at points of entry and transported by pipeline to ultimate consumers, it is reasonable to assume that some of this supply will ultimately be transported by tank truck, as LNG, to tank facilities operated by companies located in the Mid-America region. Therefore, all available information on announced or discussed projects was reviewed, and best judgment of those experienced in the industry was applied to estimate the units required. Since the growth of this activity is expected to be independent of the possible varying supplies of conventional natural gas, only one set of figures was prepared for all Cases (I through IV).

The number of new and replacement trucking units was calculated as shown in Table 52. Costs were then determined using a 1970 tractor price of $20,000 and trailer price of $50,000, with tractor and trailer life the same as for LPG equipment. These calculations are shown in Table 53.

The basic assumptions and reasoning back of the calculations shown in Tables 50, 51, and 52 are as follows:

Truck Factors

Distance	Hrs/Trip	LDS/Day*	LPG Gals/Day	Hrs/Trip	LDS/Day	LNG Gals/Day
25 mi	5	4	34,000	4	5	47,500
50 mi	6.5	3	25,500	5.5	3.5	33,250
100 mi	9.5	2	17,000	8.5	2	19,000
200 mi	13	1.5	12,750	12	1.5	14,250

* Includes fueling, maintenance and shift changes.

To show the effect that peak saving requirements have on volume to be transported, we cite the following examples:

		LPG	
Example 1	50-mile haul	300 Days	7,650,000 gallons
Example 2	50-mile haul	78 Days	1,989,000 gallons

LPG tends to move in a 13-week period during the winter months.

		LNG	
Example 1	50-mile haul	300 Days	9,975,000 gallons
Example 2	50-mile haul	150 Days	4,987,500 gallons

LNG tends to move in summer over six-month period.

Table 54 summarizes and totals the expenditures calculated in Tables 51 and 53.

Rail Tank Car Facilities - Methodology

The following tabulation summarizes the estimation of capital requirements for the transportation of LPG by rail tank car for the three periods from 1971 to 1975, 1976 to 1980 and 1981 to 1985 for Cases I through IV.

Capital Requirements - Millions of 1970 Dollars

Period	Case I	Case II	Case III	Case IV
1971-75	0	0	0	0
1976-80	44.7	38.8	22.0	5.4
1981-85	55.9	45.9	35.4	26.5
Total	100.6	84.7	57.4	31.9

TABLE 50

CALCULATION OF NEW AND REPLACEMENT TANK TRUCK UNITS
REQUIRED TO TRANSPORT FORECAST SUPPLIES OF LPG

		Annual Supply		Number of Units			
		Thousands of Barrels	% Inc. or Dec. over 1971	Total in Service	Replacement Units Required: Tractor	Replacement Units Required: Trailer	New Units Tractor and Trailer
Case I	1971	533,440	–	4,103	–	–	–
	1975	519,275	De Minimus	4,103	2,735	1,368	0
	1980	677,037	+ 27%	5,211	2,735	1,368	1,108
	1985	821,255	+ 54%	6,319	3,473	1,738	1,108
Case II	1971	533,440	–	4,103	–	–	–
	1975	516,775	De Minimus	4,103	2,735	1,368	0
	1980	656,435	+ 23%	5,047	2,735	1,368	944
	1985	764,955	+ 44%	5,908	3,364	1,683	861
Case III	1971	533,440	–	4,103	–	–	–
	1975	499,375	– 6%	3,857	2,571	1,286	0
	1980	604,635	+ 13%	4,636	2,571	1,286	779
	1985	683,355	+ 28%	5,252	3,090	1,546	616
Case IV	1971	533,440	–	4,103	–	–	–
	1975	495,275	– 7%	3,730	2,486	1,244	0
	1980	565,235	+ 6%	4,349	2,486	1,244	619
	1985	610,155	+ 14%	4,677	2,899	1,450	328

Note: Number of replacement units based on: Tractor Life 7.5 Years
Trailer Life 15.0 Years.

TABLE 51

CALCULATION OF NEW AND REPLACEMENT TANK TRUCK COSTS FOR LPG TRANSPORTATION
(Thousands of 1970 Dollars)

		Replacement Units		New	Replacement Costs		New Unit	Total
	Period	Tractors	Trailers	Combined Units	Tractors	Trailers	Costs	Costs
Case I	1971-75	2,735	1,368	0	54,700	24,624	0	79,324
	1976-80	2,735	1,368	1,108	54,700	24,624	42,104	121,428
	1981-85	3,473	1,738	1,108	69,460	31,286	42,104	142,850
Case II	1971-75	2,735	1,368	0	54,700	24,624	0	79,324
	1976-80	2,735	1,368	944	54,700	24,624	35,872	115,196
	1981-85	3,364	1,683	861	67,280	30,296	32,718	130,294
Case III	1971-75	2,571	1,286	0	51,420	23,145	0	74,565
	1976-80	2,571	1,286	779	51,420	23,145	29,602	104,167
	1981-85	3,090	1,546	616	61,800	27,830	23,408	113,038
Case IV	1971-75	2,486	1,244	0	49,720	22,392	0	72,112
	1976-80	2,486	1,244	619	49,720	22,392	23,522	95,634
	1981-85	2,899	1,450	328	57,980	26,100	12,464	96,544

Note: Unit Costs: Tractor $20,000
Trailer 18,000.

TABLE 52

CALCULATION OF NEW AND REPLACEMENT TANK TRUCK UNITS REQUIRED TO TRANSPORT FORECAST SUPPLIES OF LNG

	Total Units in Service	Replacement Units Required: Tractors	Replacement Units Required: Trailers	New Units Required
1971	25	—	—	—
1975	200	16.66	8.33	175
1980	450	133.30	66.70	250
1985	800	300.00	150.00	350

Note: Based on: Tractor Life 7.5 Years
Trailer Life 15.0 Years.

TABLE 53

CALCULATION OF NEW AND REPLACEMENT TANK TRUCK COSTS FOR LNG TRANSPORTATION
(Thousands of 1970 Dollars)

Period	Replacement Costs: Tractors	Replacement Costs: Trailers	New Unit Costs	Total Costs
1971-75	333	416	12,250	12,999
1976-80	2,665	3,334	17,500	23,499
1981-85	6,000	7,500	24,500	38,000

Note: Based on: Tractor Cost \$20,000
Trailer Cost 50,000.

TABLE 54

TOTAL CAPITAL EXPENDITURES FOR LPG AND LNG TANK TRUCKS
(Thousands of 1970 Dollars)

	Period	LPG	LNG	Total
Case I	1971-75	79,324	12,999	93,323
	1976-80	121,428	23,499	144,927
	1981-85	142,850	38,000	180,850
Case II	1971-75	79,324	12,999	93,323
	1976-80	115,196	23,499	138,695
	1981-85	130,294	38,000	168,294
Case III	1971-75	74,565	12,999	87,564
	1976-80	104,167	23,499	127,666
	1981-85	113,038	38,000	151,038
Case IV	1971-75	72,112	12,999	85,111
	1976-80	95,634	23,499	119,133
	1981-85	96,544	38,000	134,544

The data above is based primarily on the LPG supply figures furnished by the Supply and Logistics Task Groups as shown in Table 4 in Chapter Three of this report. The volumes to be transported by tank car were determined by reducing the total supply by that used in syn-gas plants and multiplying the remainder by 12 percent. This assumes that tank cars will not participate in the transportation of LPG for syn-gas plants, but will continue to move approximately 12 percent of the remaining volume. The 12 percent factor is based on historical data from the LP Gas Association.

Capital requirements for the transportation of the volumes determined in the manner described above, particularly replacement costs, were more difficult to calculate. It was assumed in the cost calculations that all new units constructed would be built to a capacity of 33.8 thousand gallons at a cost (in 1970 dollars) of $24 thousand.

To determine replacement costs, other assumptions had to be incorporated in the calculations. While 11-thousand-gallon pressure cars were originally built for the transportation of LPG in the 1940's and would reach the end of depreciated life during the period considered by this study, the vast majority of these cars have been placed in other pressure services or have been converted to transport non-pressure commodities. Tank cars in service for

TABLE 55

CALCULATION OF NEW AND REPLACEMENT RAILROAD TANK CAR UNITS
FOR TRANSPORTATION OF LPG AND COSTS
(Thousands of 1970 Dollars)

	Year or Period	Total LPG Supply MMB per Year	Tank Car Transport MMB per Year	Units Required		Cost of Units		
				Replacement	New	Replacement	New	Total
Case I	1971	533,440	64,013	–	–	–	–	–
	1975	519,275	57,399	0	0	0	0	0
	1980	677,037	73,873	750	1,113	18,000	26,712	44,712
	1985	821,255	91,179	375	1,955	9,000	46,920	55,920
Case II	1971	533,440	64,013	–	–	–	–	–
	1975	516,775	57,099	0	0	0	0	0
	1980	658,835	71,689	750	867	18,000	20,808	38,808
	1985	772,155	85,287	375	1,536	9,000	36,864	45,864
Case III	1971	533,440	64,013	–	–	–	–	–
	1975	499,375	55,011	0	0	0	0	0
	1980	607,035	65,473	750	165	18,000	3,960	21,960
	1985	688,155	75,207	375	1,100	9,000	26,400	35,400
Case IV	1971	533,440	64,013	–	–	–	–	–
	1975	495,275	54,519	0	0	0	0	0
	1980	556,235	59,377	226	0	5,424	0	5,424
	1985	610,155	65,847	899	207	21,576	4,968	26,544

LPG today are 30-33.8 thousand-gallon jumbo cars. The earliest of this breed of LPG tank car was built in the early 1960's. Therefore, with a 30-year depreciated life, these cars will not require replacement due to age factors during the period considered by the study.

Replacement costs for this study were based on jumbo LPG cars that are deleted from the fleet due to placement in service for other commodities, railroad wrecks, etc. It was assumed that these replacements would amount to 75 jumbo LPG tank cars per year. This, however, does not infer that 75 cars were automatically replaced each year. In some cases, particularly in the 1971-1975 period, the volumes to be moved by tank cars dropped to such an extent that replacements were not required. These cars would not be replaced until indicated by volume requirements in the period that followed.

Table 55 which follows is a work sheet showing capital requirements for both replacement and new unit costs.

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