DRAFT REPORT

on

STATE REGULATION OF DISTRIBUTION:
Part VII of A Study of Natural Gas Regulation

for the

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PART VII

STATE REGULATION OF NATURAL GAS DISTRIBUTION UTILITIES

Although Federal legislation and regulation have been the dominant factors in controlling the prices and service policies of natural gas producers and natural gas transmission companies, State regulation is the dominant factor in controlling the prices and service policies of the public utilities that distribute natural gas to local customers.

During the mid-nineteenth century, local governments began granting local franchises to permit the local manufacture and distribution of gas, and in 1885 the State of Massachusetts established for the first time a Board of Gas Commissioners with state-wide supervisory powers over corporations manufacturing gas for fuel and lighting. By the end of World War I, most states had established a commission, usually called either a public service commission or a public utility commission, to ensure adequate service at a fair price from holders of gas and other utility franchises.

As the technology for long distance pipeline transmission of gas matured in the decades after 1920, locally manufactured gas gave way to underground natural gas as the commodity distributed by local utilities. Until the 1970's, the well-head price of natural gas and the cost of pipeline transmission were low, hence prices to the end user were low. As these costs increased during the 1970's, state regulatory agencies felt increasing frustration in their efforts to regulate local gas rates because control of well-head prices and transmission rates lay in Federal hands.

In this part of the report, three aspects of state regulation of gas distribution are examined. First, the current status of the regulation of natural gas distribution utilities by regulatory agencies in the fifty states and the District of Columbia is discussed. This discussion covers the scope of state authority and also the major issues and problems currently faced by state regulators. Second, the extent to which gas distribution utilities qualify for "natural monopoly" status and for exclusive franchises to serve an area is examined. The main focus of this analysis is on the characteristics and behavior of the companies in the industry and on the opportunities for competition. Third, the impact of Federal regulation on State regulation is considered.

The Scope of State Authority

State public utility commissions have a wide range of authority for regulating the gas industry. Most state public utility commissions have the authority to regulate retail rates for natural gas charged to the ultimate customer. The authority of state commissions to regulate wholesale rates for natural gas, however, is much more limited. Most states also regulate rates for gas transmission for other distribution companies. State commissions also have the authority to initiate gas rate investigations and often to prescribe temporary rates, as well as to suspend proposed rate filings.

State public utility commissions often have authority to approve the issuance of major securities before issuance and to approve major corporate transactions.

Most state public utility commissions have the authority to regulate safety standards for gas, to regulate interconnections of privately-owned companies, to regulate the attachment of new customers and loads, and to prescribe regulations concerning shortfalls and curtailments of gas service. Also, most state public service commissions require certification of convenience and necessity before allowing major additions to gas transmission lines. The detail of state public utility authority to regulate gas is discussed below.

Most state public utility commissions have the authority to regulate retail rates for natural gas charged by gas companies to final users. As indicated in column one of table 1, all state utility commissions (with the exception of Nebraska, which does not regulate electric or gas utilities) have authority over retail rates charged to ultimate consumers by investor-owned utilities. However, only one-third of the state commissions may regulate the rates charged to ultimate consumers by publicly-owned gas companies. The least frequently regulated retail rates are on sales to industrial customers by interstate pipeline companies and gas producers that are under commission ratemaking authority in 22% and 14% of the states respectively. As shown in the last four columns of the table, sales by private gas companies to the U.S. government and to public authorities are under the ratemaking authority of state commissions in 94% of the states, while approximately 36% of the states have authority to regulate these rates when the vendor is a publicly-owned utility.

The authority of state commissions to regulate wholesale rates for natural gas is more limited as illustrated in table 2. The term, wholesale rates, refers to the prices charged by natural gas suppliers on gas intended for resale. The first two columns of table 2 indicate that 55%

TABLE 1

STATE AGENCY AUTHORITY TO REGULATE RETAIL RATES FOR NATURAL GAS SALES BY STATE, 1979

Column / Agency	(1) Sales to Ultimate Consumers by Private Companies	(2) Sales to Ultimate Consumers by Public Companies	(3) Sales to Industrial Customers by Interstate Pipeline Company	(4) Sales to Industrial Customers by Gas Producers	(5) Sales to Public Authorities by Private Companies	(6) Sales to Public Authorities by Public Companies	(7) Sales to the U.S. Government by Private Companies	(8) Sales to the U.S. Government by Public Companies
Alabama	Y				Y		Y	N
Alaska	Y	Y	Y	Y	Y	Y	Y	Y
Arizona	Y	N	N	Y	Y	N	Y	N
Arkansas	Y	N	N	Y	N	N	Y	N
California	Y	N	N	N	Y	N	Y	N
Colorado	Y	Y 1/	N	N	Y	Y 1/	Y	Y 1/
Connecticut	Y	N	N	N	Y	N	Y	N
Delaware	Y	N	N	N	Y	N	Y	N
D.C.	Y	N	N	N	Y	N	Y	N
Florida	Y	N	N	N	Y	N	Y	N
Georgia	Y	N	N	N	Y	N	Y	N
Hawaii	Y	N	N	N	Y	N	Y	N
Idaho	Y	N	N	N	Y	N	Y	N
Illinois	Y	N	Y	N	Y	N	Y	N
Indiana	Y	Y	N	N	Y	Y	Y	Y
Iowa	Y	N	Y	N	Y	N	Y	N
Kansas	Y	2/	N	N	Y	2/	Y	2/
Kentucky	Y	N	N	N	Y	N	Y	N
Louisiana	Y 3/	N	N	N	Y	N	Y	N
Maine	Y	Y 4/	N	N	Y	Y 4/	Y	Y 4/
Maryland	Y	Y	N	N	Y	N	Y	Y
Massachusetts	Y	5/	N	N	Y	5/	Y	5/
Michigan	Y	N	Y	N	Y 6/	N	Y	N
Minnesota	Y	N	N	N	Y	N	N	N
Mississippi	Y	Y	N	N	Y	Y	Y	Y
Missouri	Y	N	N	N	Y	N	Y	N
Montana	Y	Y	Y	Y	Y	Y	Y	Y
Nebraska 7/	N	N	N	N	N	N	N	N
Nevada	Y	8/	Y	N	Y	8/	Y	8/
New Hampshire	Y	N	N	N	Y	N	Y	N
New Jersey	Y	N	N	N	Y	N	Y	N
New Mexico	Y	9/	Y 10/	N	Y	9/	Y	9/
New York	Y	Y	N	N	Y 11/	Y 11/	Y 11/	Y 11/
North Carolina	Y	N	Y	N	Y	N	Y	N
North Dakota	Y	N	N	N	Y	N	Y	N
Ohio	Y	N	N	N	Y	N	Y	N
Oklahoma	Y	N	N	N	Y	N	Y	N
Oregon	Y	4/	N	N	Y	4/	Y	4/
Pennsylvania	Y	Y 12/	N	N	Y	Y 12/	Y	Y 12/
Rhode Island	Y	Y	N	N	Y	Y	Y	Y
South Carolina	Y	N	N	N	Y	N	Y	N
South Dakota	Y	N	N	N	Y	N	Y	N
Tennessee	Y	N	Y	N	Y	N	Y	N
Texas	Y	Y	N	Y	Y	Y	Y	Y
Utah	Y	N	Y	Y	Y	N	Y	N
Vermont	Y	Y	N	N	Y	Y	Y	Y
Virginia	Y	N	N	N	N	N	N	N
Washington	Y	N	N	Y	Y	N	Y	N
West Virginia	Y	N	N	N	Y	Y	Y	Y
Wisconsin	Y	Y	4/	4/	Y	Y	Y	Y
Wyoming	Y	Y 14/	Y 15/	N	Y	Y 14/	Y	Y 14/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980) pp. 392-7.

1/ Public utilities regulated when outside of municipal boundary only.
2/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
3/ Except no authority over rates charges to industrial customers by any gas company.
4/ None in state.
5/ Only if earnings exceed 8 percent of original cost of plant in service or if discrimination between classes of customers.
6/ Commission jurisdiction excluded from rates covered by special agreements with municipalities.
7/ Telephone is the only regulated utility.
8. Municipal utilities exempt from state regulation.
9. Intercommunity natural gas association (owned by 2 or more municipals) should be answered the same as private gas utilities.
10/ Authority not exercised.
11/ Jurisdiction over all rates either by tariff or contract.
12/ Only when service extends beyond the corporate limits of a publicly owned utility company.
13/ The Railraod Commission of Texas has safety jurisdiction over municipally owned gas utilities and appellate rate jurisdiction over these utilities outside the corporate limits of the city.
14/ Public utilities regulated in so far as they are owned and operated outside corporate limits.
15/ To the extent not regulated by FERC.

TABLE 2

STATE AGENCY AUTHORITY TO REGULATE WHOLESALE RATES FOR NATURAL GAS SALES BY STATE, 1979

Column Agency	(1) Sales to Public Authorities by Private Companies	(2) Sales to Public Authorities by Public Companies	(3) Sales to U.S. Government by Private Companies	(4) Sales to U.S. Government by Public Companies	(5) Sales to Privately-Owned Companies by Private Companies	(6) Sales to Privately-Owned Companies by Public Companies	(7) Sales to Publicly-Owned Companies by Private Companies	(8) Sales to Publicly-Owned Companies by Public Companies
Alabama	Y	N	Y	N	Y	N	Y	N
Alaska	Y	Y	Y	Y	Y	Y	Y	Y
Arizona	Y	N	Y	N	Y	N	Y	N
Arkansas	N	N	N	N	N	N	N	N
California	Y	N	Y	N	Y	N	Y	N
Colorado	Y	Y 2/	Y	Y 2/	Y	Y 2/	Y	Y 2/
Connecticut	N	N	N	N	N	N	N	N
Delaware	N	N	Y	N	Y	N	N	N
D.C.	N	N	N	N	N	N	N	N
Florida	N	N	N	N	N	N	N	N
Georgia	Y	N	Y	N	Y	N	N	N
Hawaii	Y	N	Y	N	Y	N	Y	N
Idaho	N	N	Y	N	Y	N	N	N
Illinois	Y	N	Y	N	Y	N	Y	N
Indiana	N	N	N	N	N	N	N	N
Iowa	N	N	N	N	N	N	N	N
Kansas	Y	3/	Y	3/	Y	3/	Y	3/
Kentucky	N	N	N	N	N	N	Y	N
Louisiana	N	N	N	N	N	N	N	N
Maine	Y	Y 4/	Y	Y 4/	Y	Y 4/	Y	Y 4/
Maryland	N	N	N	N	N	N	N	N
Massachusetts	Y	5/	6/	6/	6/	6/	6/	6/
Michigan	7/	N	7/	N	7/	N	7/	N
Minnesota	N	N	N	N	N	N	N	N
Mississippi	N	N	N	N	N	N	N	N
Missouri	N	N	Y	N	Y	N	N	N
Montana	Y	Y	Y	Y	Y	Y	Y	Y
Nebraska 8/	N	N	N	N	N	N	N	N
Nevada	Y	9/	Y	9/	Y	9/	Y	9/
New Hampshire	Y	N	Y	N	Y	N	Y	N
New Jersey	Y	N	Y	N	Y	N	Y	N
New Mexico	Y 10/	11/	Y 10/	11/	Y 10/	11/	Y 10/	11/
New York	Y	Y	Y	Y	Y	Y	Y	Y
North Carolina	N	N	N	N	N	N	N	N
North Dakota	N	N	N	N	N	N	N	N
Ohio	N	N	Y	N	Y	N	N	N
Oklahoma	Y	N	Y	N	Y	N	Y	N
Oregon	N	12/	N	12/	N	12/	N	12/
Pennsylvania	Y	Y 13/	N	N	N	N	N	N
Rhode Island	Y	Y	Y	Y	Y	Y	Y	Y
South Carolina	Y	N	Y	N	Y	N	Y	N
South Dakota	N	N	N	N	N	N	N	N
Tennessee	Y	N	Y	N	Y	N	Y	N
Texas	Y	Y	Y	Y	Y	Y	Y	Y
Utah	Y	N	Y	N	Y	N	Y	N
Vermont	N	N	N	N	N	N	N	N
Virginia	N	N	N	N	N	N	N	N
Washington	Y	N	Y	N	Y	N	Y	N
West Virginia	Y	Y	Y	Y	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y	Y	Y	Y	Y
Wyoming	15/	15/	15/	15/	15/	15/	15/	15/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington D.C., 1980) pp.392-7.

1/ Rates for interstate sales are subject to the jurisdiction of the FERC; intrastate rates are subject to state regulation.
2/ Public utilities regulated when outside of municipal boundary only.
3/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
4/ None in state.
5/ Only if earnings exceed 8 percent of original cost of plant in service or if discrimination between class of customers.
6/ Primarily Federal Energy Regulatory Commission jurisdiction.
7/ Commission jurisdiction excluded from rates for intrastate service covered by special agreements with municipalities and rates for intrastate services subject to the Federal Energy Regulatory Commission.
8/ Telephone is the only regulated utility.
9/ Municipal utilities exempt from state regulation.
10/ Authority limited to rate charged and manner of delivery.
11/ Intercommunity natural gas association (owned by 2 or more municipals) should be answered same as private gas utilities.
12/ None in state.
13/ Only when service extends beyond the corporate limits of a publicly owned utility company.
14/ The Railroad Commission of Texas has safety jurisdiction over these utilities outside the corporate limits of the city.
15/ Wyoming Supreme Court decision to effect that PSC cannot regulate gas sale for resale.

of all state commissions have authority to regulate wholesale rates for gas sales to public authorities by privately-owned companies. Only 27% of states that have publicly-owned gas utilities regulate the wholesale rates of these public companies on sales for resale made to public authorities. Maine and Oregon have no publicly-owned gas utilities.

Columns 3 and 4 of table 2 indicate that 61% of state commissions have authority to regulate wholesale rates charged to the U.S. government by investor-owned gas companies, while only 25% of states have authority to regulate their wholesale rates charged by publicly-owned gas companies to the federal government. Columns 5 and 6 show that 61% of the state commissions have authority to regulate wholesale rates charged for sales to privately-owned gas companies for sales by private gas companies, while only 25% of the state commissions have authority to regulate sales by publicly-owned gas companies. Sales to publicly-owned companies are subject to rate regulation in 53% of the states when the vendor is a private company. This proportion declines to 24% of states when the vendor is a publicly-owned company.

More than half of the state public utility commissions regulate rates for gas transmission on account of others. Gas transmission on account of others concerns transmission by companies under state jurisdiction to ultimate end users. Table 3 presents the listing of state agencies' authority to regulate rates for gas transmission on account of others by privately-owned and publicly-owned companies. As shown by table 3, twenty-one state agencies regulate rates for transmission for neither privately-owned or publicly-owned companies, while eleven state agencies have regulations for both types of companies. The remaining eighteen

TABLE 3

STATE AGENCY AUTHORITY TO REGULATE RATES FOR GAS TRANSMISSION ON ACCOUNT OF OTHERS BY STATE, 1979

Column Agency	(1) Regulation of Rates for Transmission by a Privately-Owned Company	(2) Regulation of Rates for Transmission by a Publicly-Owned Company
Alabama	Y	N
Alaska	Y	Y
Arizona	Y	N
Arkansas	N	N
California	Y	N
Colorado	Y	Y 1/
Connecticut	N	N
Delaware	N	N
D.C.	N	N
Florida	N	N
Georgia	Y	N
Hawaii	N	N
Idaho	N	N
Illinois	Y	N
Indiana	N	N
Iowa	N	N
Kansas	Y	2/
Kentucky	Y	N
Louisiana	N	N
Maine	Y	Y 3/
Maryland	N	N
Massachusetts	Y	Y
Michigan	Y	N
Minnesota	N	N
Mississippi	N	N
Missouri	N	N
Montana	N	N
Nebraska 4/		
Nevada	Y	5/
New Hampshire	Y	N
New Jersey	Y	N
New Mexico	Y	6/
New York	Y	Y
North Carolina	N	N
North Dakota	N	N
Ohio	N	N
Oklahoma	Y	N
Oregon	N	N
Pennsylvania	Y	Y 7/
Rhode Island	Y	Y
South Carolina	Y	N
South Dakota	N	Y
Tennessee	Y	Y
Texas 8/	Y	Y
Utah	Y	N
Vermont	Y	Y
Virginia	N	N
Washington	Y	N
West Virginia	Y	Y
Wisconsin	Y	Y
Wyoming	Y	Y 9/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 392-7.

1. Public utilities regulated when outside of municipal boundary only.
2. Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
3. None in state.
4. Telephone is the only regulated utility.
5. Municipal utilities exempt from state regulation.
6. Intercommunity natural gas association (owned by 2 or more municipals) should be answered same as private gas utilities.
7. Only when service extends beyond the corporate limits of a publicly owned utility company.
8. The Railroad Commission of Texas has safety jurisdiction over municipally owned gas utilities and appellate rate jurisdiction over these utilities outside the corporate limits of the city.
9. Public utilities regulated insofar as they are owned and operated outside of corporate limits of the city.

states have certain qualifiers pertaining to their regulatory authority. These qualifiers are explained in the footnotes. In a categorical breakdown, twenty-two states have no rate regulations for transmission by privately-owned companies, and thirty-four states have no regulations for publicly-owned companies.

Most state utility commissions have the authority to initiate gas rate investigations and prescribe temporary rates. As shown in table 4, all public utility commissions can initiate gas rate investigations of investor-owned gas companies, while only 38% of states commissions have the authority to initiate such inquiries of publicly-owned companies. Public utility commissions in 88% of the states can prescribe temporary rates for investor-owned gas utilities, while 34% of the state commissions can prescribe temporary rates for publicly-owned gas companies.

Most state public utility commissions have the authority to require prior authorization of gas rate charges and to suspend proposed rates filed by privately-owned utilities. As shown in table 5, only one state agency, Arkansas, does not have authority to require the prior authorization of gas rate charges by privately-owned companies, whereas twenty-nine state agencies do not have similar authority over publicly-owned companies. Two state agencies have no authority over privately-owned companies, and twenty-nine state agencies have no authority over publicly-owned companies in the suspension of proposed gas rate changes. The average amount of time for which state agency may suspend rate charges is five and one-half months. Alaska allows the longest defined suspension period, eighteen months (the period for Hawaii is indefinite and for Louisiana and Oklahoma

TABLE 4

STATE AGENCY AUTHORITY TO INITIATE GAS RATE INVESTIGATIONS AND PRESCRIBE TEMPORARY RATES BY STATE, 1979

Column Agency	(1) Agency's Own Motion Initiates Gas Rate Investigation of Private Companies	(2) Agency's Own Motion Initiates Gas Rate Investigation of Public Companies	(3) Authority to Prescribe Temporary Gas Rates Pending Investigation for Private Companies	(4) Authority to Prescribe Temporary Gas Rates Pending Investigation for Public Companies
Alabama	Y	N	Y	N
Alaska	Y	Y	Y	Y
Arizona	Y	N	Y	N
Arkansas	Y	N	Y	N
California	Y	N	Y 1/	N
Colorado	Y	Y 2/	Y 3/	Y 2/, 3/
Connecticut	Y	N	Y	N
Delaware	Y	N	Y	N
D.C.	Y	N	N	N
Florida	Y	N	Y	N
Georgia	Y	N	Y	N.
Hawaii	Y	N	Y	N
Idaho	Y	N	Y	N
Illinois	Y	N	Y	N
Indiana	Y	Y	N	N
Iowa	Y	N	Y 4/	N
Kansas	Y	Y 5/	Y	5/
Kentucky	Y	N	Y	N
Louisiana	Y	N	Y	N
Maine	Y	Y 6/	Y	Y 6/
Maryland	Y	Y	Y	Y
Massachusetts	Y	Y	Y	Y
Michigan	Y	N	Y 7/	N
Minnesota	Y	8/	Y	N
Mississippi	Y	N	N	N
Missouri	Y	N	Y	N
Montana	Y	Y	Y	Y
Nebraska 9/	N	N	N	N
Nevada	Y	10/	N	10/
New Hampshire	Y	N	Y	N
New Jersey	Y	N	Y	N
New Mexico	Y	11/	Y	11/
New York	Y	N	Y	Y
North Carolina	Y	N	Y	N
North Dakota	Y	N	Y	N
Ohio	Y	N	Y	N
Oklahoma	Y	N	Y	N
Oregon	Y	13/	N	13/
Pennsylvania	Y	Y 14/	Y 12/	Y 14/
Rhode Island	Y	Y	Y	Y
South Carolina	Y	N	Y	N
South Dakota	Y	Y	Y	N
Tennessee	Y	N	Y	N
Texas 15/	Y	Y	Y	Y
Utah	Y	N	Y	N
Vermont	Y	Y	Y	Y
Virginia	Y	N	Y	N
Washington	Y	N	Y	N
West Virginia	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y
Wyoming	Y	Y 16/	Y	Y 16/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980) pp. 395-6.

1/ May fix temporary rates, but practice is not followed.
2/ Public utilities regulated when outside of municipal boundary only.
3/ No specific statutory authority.
4/ Application rates are temporary and are collected under bond subject to refund, from one to ninety days after suspension.
5/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
6/ None in state.
7/ Commission has authority to grant partial and immediate rate relief during pending of final order, after statutory requirements are met.
8/ Municipal utilities exempt from state regulation.
9/ Telephone is the only regulated utility.
10/ Municipal utilities exempt from state regulation.
11/ Intercommunity natural gas association (owned by 2 or more municipals) should be answered. Same as private utilities.
12/ Grant emergency increases only.
13/ None in state.
14/ Only when service extends beyond the corporate limits of a public, owned utility company.
15/ The Railroad Commission of Texas has safety jurisdiction over municipally owned gas utilities and appellate rate jurisdiction over these utilities outside the corporate limits of the city.
16/ Public utilities regulated in so far as they are owned and operated outside corporate limits.

TABLE 5

STATE AGENCY AUTHORITY TO REQUIRE PRIOR AUTHORIZATION OF GAS RATE CHANGES AND TO SUSPEND PROPOSED RATE CHANGES, 1979

Column	(1)	(2)	(3)	(4)	(5)
Agency	Require Prior Authorization of Gas Rate Changes by Privately-Owned Companies	Require Prior Authorization of Gas Rate Changes by Publicly-Owned Companies	Suspend Porposed Gas Rate Changes by Privately-Owned Companies	Suspend Proposed Gas Rate Changes by Publicly-Owned Companies	Maximum Period of Rate Change Suspension
Alabama	Y	N	Y	N	6 months
Alaska	Y	Y	Y	Y	18 months
Arizona 1/					
Arkansas	N	N	Y	N	6 months
California	Y	N	Y	N	
Colorado	Y	Y 2/	Y	Y 2/	210 days
Connecticut	Y	N	Y	N	150 days
Delaware	Y	N	Y	N	Indefinite
D.C.	Y	N	Y	N	
Florida	Y	N	Y	N	8 months
Georgia	Y	N	Y	N	5 months
Hawaii	Y	N	N	N	Indefinite 3/
Idaho	Y	N	Y	N	6 months
Illinois	Y	N	Y	N	10 months
Indiana	Y	Y	Y	Y	
Iowa	Y	Y	Y	N	12 months
Kansas	Y	4/	Y	4/	Indefinite
Kentucky	Y	N	Y	N	5 months
Louisiana	Y	N	Y	N	No limit
Maine	Y	Y 5/	Y	Y 5/	8 months
Maryland	Y	Y	Y	Y	180 days
Massachusetts	Y	6/	Y	Y	6 months
Michigan	Y	N	7/	N	7/
Minnesota	Y	N	Y	8/	9 months
Mississippi	Y	N	Y	N	6 months
Missouri	Y	N	Y	N	10 months
Montana	Y	Y	Y	Y	9 months
Nebraska 9/					
Nevada	Y	10/	Y	10/	150 days
New Hampshire	Y	N	Y	N	6 months
New Jersey	Y	N	Y	N	8 months
New Mexico	Y	11/	Y	11/	9 months
New York	Y	Y	Y	Y	10 months
North Carolina	Y	N	Y	N	9 months
North Dakota	Y	N	Y	N	11 months
Ohio	Y	N	N	N	9 months
Oklahoma	Y	N	Y	N	No Limit
Oregon	Y	12/	Y	12/	10 months
Pennsylvania	Y	Y 13/	Y	Y 13/	9 months
Rhode Island	Y	Y	Y	Y	8 months
South Carolina	Y	N	Y	N	60 days
South Dakota	Y	N	Y	N	6 months
Tennessee	Y	N	Y	N	90 days 14/
Texas 15/	Y	Y	Y	Y	150 days
Utah	Y	N	Y	N	8 months
Vermont	Y	Y	Y	Y	6 months
Virginia	Y	N	Y	N	12 months
Washington	Y	N	Y	N	10 months
West Virginia	Y	Y	Y	Y	120 days
Wisconsin	Y	Y	16/	16/	16/
Wyoming	Y	Y 17/	Y	Y 17/	10 months

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 392-9.

1. Rates cannot be increased without hearings and a subsequent order of the Commission, consequently, no suspension is required.
2. Public utilities regulated when outside of municipal boundary only.
3. Hawaii law provides that rate increases may not go into effect until approved by the Commission.
4. Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
5. None in state.
6. Required to advertise 30 days prior to change.
7. Specific authority required to change rates. Rates do not become effective after a specified period, consequently, no suspension is required.
8. Municipal utilities exempt from state regulation.
9. Telephone is the only regulated utility.
10. Municipal utilities from state regulation.
11. Intercommunity natural gas association (owned by 2 or more municipals)should be answered same as private gas utilities.
12. None in state.
13. Only when service extends beyond the corporate limits of a publicly owned utility company.
14. 90 days at a time; up to a total of 6 months.
15. The Railroad Commission of Texas has safety jurisdiction over municipally owned gas utilities and appellate rate jurisdiction over those utilities outside the corporate limits of the city.
16. Specific authority required to change rates. Rates do not become effective after a specified period, consequently, no suspension is required.
17. Public utilities regulated in so far as they are owned and operated outside corporate limits.

the period has no limit). West Virginia has the shortest defined suspension period, four months.[1]

Most state public utility commissions require approval prior to the issuance of certain securities. Mortgage bonds are backed by specific assets of the utility. As shown in table 6, the prior approval of mortgage bonds is required by 86% of state commissions. Debentures, which are general obligation bonds not secured by any claim or specific assets, must be approved prior to issuance in 84% of the states. Funds borrowed by the utility using notes with maturities greater than one year must be approved in 84% of the states prior to issuance. If these notes mature in less than one year, their approval by state commissions is required in only 25% of the states. The sale of preferred and common stock must be approved by the public utility commission in 86% and 80% of the states, respectively. Preapproval of restricted stock options is required in 71% of the states as indicated in the last column of table 6.

Most state public utility commissions require commission approval prior to major corporate transactions. Types of corporate transactions that may require prior state agency approval, and which are listed in table 7, are sale and purchase of facilities, mergers or consolidations, security purchases of other utilities, purchase or issuance by utilities operating in one state but incorporated in another, and entrance into lease transactions. Seven state agencies do not require prior approval for the sale of facilities and eight state agencies do not require prior approval for the purchase of facilities. Four states require no prior approval for

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[1] Special qualifications of these statements and of statements relating to other tables are listed in the footnotes of the tables

TABLE 6

STATE AGENCIES THAT REQUIRE APPROVAL PRIOR TO THE ISSUANCE OF SECURITIES BY TYPE OF SECURITY, 1979

Column	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Agency	Mortgage Bonds	Debentures	Notes Over One Year	Notes Under One Year	Preferred Stock	The Underwriting of New Common Stock	The Issuance of Restricted Stock Options
Alabama	Y	Y	Y	Y 1/	Y	Y	Y
Alaska	N	N	N	N	N	N	N
Arizona	Y	Y	Y	N	Y	Y	Y
Arkansas	Y	Y	Y	N	Y	Y	Y
California	Y	Y	Y	2/ N	Y	Y	Y
Colorado	Y	Y	Y	N	Y	Y	Y
Connecticut	Y	Y	Y	N	Y	Y	Y
Delaware	Y	Y	Y	N	Y	N	N
D.C.	Y	Y	Y	N	Y	Y	Y
Florida	Y	Y	Y	Y	Y	Y	Y
Georgia	Y	Y	Y	N	Y	Y	Y
Hawaii	Y	Y	Y	N	Y	Y	Y
Idaho	Y	Y	Y	Y	Y	Y	Y
Illinois	Y	Y	Y	N	Y	Y	Y
Indiana	Y	Y	Y	N	Y	Y	Y
Iowa	N	N	N	N	N	N	N
Kansas	Y	Y	Y	N	Y	Y	Y
Kentucky	Y	Y	Y	N	Y	Y	Y
Louisiana	Y	Y	Y	N	Y	Y	Y
Maine	Y	Y	Y	3/ N	Y	Y	Y
Maryland	Y	Y	Y	N	Y	N	Y
Massachusetts	Y	Y	Y	N	Y	Y	Y
Michigan	Y	Y	Y	N	Y	Y	Y
Minnesota	Y	Y	Y	Y	Y	Y	Y
Mississippi	N	N	N	N	N	N	N
Missouri	Y	Y	Y	N	Y	Y	Y
Montana	Y	Y	Y	Y	Y	Y	Y 4/
Nebraska 5/	N	N	N	N	N	N	N
Nevada	Y	Y	Y	Y	Y	Y	N
New Hampshire	Y	Y	Y	Y	Y	Y	Y
New Jersey	Y	Y	Y	N	Y	Y	Y
New Mexico	Y	Y	6/ Y	N	Y	Y	N
New York	Y	Y	Y	N	Y	Y	Y
North Carolina	Y	Y	7/ Y	N	Y	Y	Y
North Dakota	Y	Y	Y	N	Y	Y	Y
Ohio	Y	Y	Y	N	Y	Y	8/ N
Oklahoma	N	N	N	N	N	N	N
Oregon	Y	Y	Y	N	Y	Y	Y
Pennsylvania	Y	Y	Y	N	Y	Y	N
Rhode Island	Y	Y	Y	N	Y	Y	Y
South Carolina	Y	Y	Y	N	Y	Y	Y
South Dakota	Y 9/	N	N	Y 9/	Y 9/	N	N
Tennessee	Y	Y	Y	N	Y	Y	N
Texas	N	N	N	N	N	N	N
Utah	Y	Y	Y	Y	Y	Y	N
Vermont	Y	Y	Y	Y 10/	Y	Y	Y
Virginia	Y	Y	Y	N	Y	Y	N
Washington	Y	Y	Y	Y 11/	Y 11/	Y	Y
West Virginia	N	N	N	N	N	N	N
Wisconsin	Y	Y	Y	Y	Y	Y	Y
Wyoming	Y	Y	Y 12/	N	Y	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C., 1980) pp.482-484.

1/ Approval required only if short-term exceeds 5% of total capitalization.
2/ "No" unless to refund other notes, the combined terms of which exceeds one year.
3/ "Yes" if utility subject to Federal Power Act and notes exceed five percent limitations.
4/ Interim approval.
5/ If new stock issued.
6/ No Commission regulation of electric or gas utilities.
7/ Notes under 18 months require no approval. Over 18 months require approval.
8/ Commission requires approval to issue notes in excess of two year maturity.
9/ If new issue of stock is involved, the plan must be approved.
10/ Black Hills Power Light Company only.
11/ If short-term debt exceeds 20% of assets. 30 V.S.A. section 108.
12/ When combined terms of original and refunding notes exceed 12 months or the proposed notes together with outstanding notes exceed 5% of total capitalization of a utility subject to regulation by the FERC. Over 18 months.

TABLE 7

STATE AGENCIES APPROVAL PRIOR TO CORPORATE TRANSACTIONS BY TYPE OF TRANSACTION AND BY STATE, 1979

Column Agency	(1) Sale of Facilities (Entire Operating Units)	(2) Purchase of Facilities (Entire Operating Units)	(3) Merger or Consolidation	(4) Purchase of Securities of Other Utilities	(5) Purchase or Issuance of Securities by Utilities Operating in One State but Incorporated in Another	(6) Entrance Into Lease Transactions
Alabama	Y	Y	Y	Y	Y	Y
Alaska	Y	Y	Y	N	N	Y
Arizona	Y	Y	Y	Y	Y	N
Arkansas	Y	Y	Y	Y	Y	Y
California	Y	Y	Y	Y	Y	1/
Colorado	Y	Y	Y	N	Y	N
Connecticut	Y	Y	Y	Y	Y	Y
Delaware	Y	N	Y	N	Y	N
D.C.	N	N	Y	Y	Y	N
Florida	N	N	N	N	Y	N
Georgia	Y	Y	Y	N	Y	Y
Hawaii	Y	Y	Y	Y	Y	Y
Idaho	Y	Y	Y	N	Y	N
Illinois	Y	Y	Y	Y	Y	Y
Indiana	Y 2/	Y 3/	Y	Y	Y	Y
Iowa	Y	Y	Y	N	N	N
Kansas	Y	Y	Y	Y	Y	N
Kentucky	Y	Y	Y	N	Y	N
Louisiana	Y	Y	Y	Y	N	N
Maine	Y	Y	Y	Y	Y	Y
Maryland	Y	Y	Y	N	N	Y
Massachusetts	Y	Y	Y	Y	N	N
Michigan	N	N	Y	N	Y	Y
Minnesota	Y	Y	Y	Y	Y	Y
Mississippi	Y	Y	Y	N	N	N
Missouri	Y	Y	Y	Y	Y	Y
Montana	N	N	N	N	Y	N
Nebraska 4/	N	N	N	N	N	N
Nevada	N	N	Y	N	N	N
New Hampshire	Y	Y	Y	Y	Y	N
New Jersey	Y	Y	Y	Y	Y	5/
New Mexico	Y	Y	Y	Y	Y	N
New York	Y	Y	Y	Y	Y	Y
North Carolina	Y	Y	Y	Y	Y	Y
North Dakota	Y	Y	Y	Y	Y	6/
Ohio	Y	Y	Y	Y	Y	7/
Oklahoma	Y	Y	Y	N	N	N
Oregon	Y	8/	Y	Y	Y	Y
Pennsylvania	Y	Y	Y	Y	Y	Y
Rhode Island	Y	Y	Y	Y 8/	9/	10/
South Carolina	Y	Y	Y	Y	Y	Y
South Dakota	N	N	N	N	N	Y 11/
Tennessee	Y	Y	Y	N	N	Y
Texas	Y	Y	Y	Y	N	N
Utah	Y	Y	Y	Y	Y	Y 12/
Vermont	Y	Y	Y	Y	Y	Y
Virginia	Y	Y	Y	Y	N	Y
Washington	Y 13/	Y 14/	Y	Y	Y	Y 15/
West Virginia	Y	Y	Y	Y	N	Y
Wisconsin	Y	Y	Y	Y	N	Y
Wyoming	Y	Y	Y	N	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C: NARUC, 1980) pp. 482,484.

1/ "Yes," as lessor of operating unit.
2/ To a public utility.
3/ For a public utility.
4/ No Commission regulation of electric or gas utilities.
5/ Major units of property.
6/ Matter has yet to appear.
7/ Depends on particular transaction.
8/ Purchase of stock requires approval.
9/ No approval necessary for issuance of securities.
10/ Among utilities only.
11/ Black Hills Power Light Company only.
12/ Applies if lease is between two utilities engaged in the same general line of business in the state.
13/ When used in utility service.
14/ From other utilities.
15/ When leases are with affiliated interest.

mergers and acquisitions. Eighteen states have no prior approval requirements regarding the purchase of securities of other utilities. Fifteen states have no prior approval requirements for the purchase or issuance of securities by utilities operating in one state, but incorporated in another. Nineteen states have no prior approval requirements for corporate transactions dealing with entrance into lease agreements.

Most state public utility commissions have the authority to regulate safety standards for gas, particularly if the gas is sold by privately-owned companies. Table 8 sets forth a listing of the authority state agencies have in regulating safety standards. These standards relate to BTU content of gas sold, pressure of gas sold, and gas safety for gas sold by privately-owned and publicly-owned companies. Fifteen state agencies have established standards for safety regulation in all six categories. Two states, Minnesota and Nebraska, have not established gas safety standards. In a category-by-category breakdown, the following results become evident. Only four states have not established standards for BTU content of gas sold by privately-owned companies, whereas nineteen states have not set BTU standards for publicly-owned companies (Michigan has no public gas utilities). In the establishment of standards for pressure of gas sold by privately-owned and publicly-owned companies, the numbers of states having no standards set are four and thirty-one respectively. The final categories, establishment of standards for gas safety for gas sold by privately-owned and publicly-owned companies shows negative responses for two and nineteen state agencies, respectively. Indicators point to the fact that there are more safety standards

TABLE 8

STATE AGENCIES WITH AUTHORITY TO REGULATE SAFETY STANDARDS FOR GAS BY STATE, 1979

Column / Agency	Establishment of standards for					
	(1) BTU Content of Gas Sold by Privately-Owned Companies	(2) BTU Content of Gas Sold by Publicly-Owned Companies	(3) Pressure of Gas Sold by Privately-Owned Companies	(4) Pressure of Gas Sold by Publicly-Owned Companies	(5) Gas Safety for Gas Sold by Privately-Owned Companies	(6) Gas Safety for Gas Sold by Publicly-Owned Companies
Alabama	Y	N	Y	N	Y	Y
Alaska	Y	Y	Y	Y	Y	Y
Arizona	Y	N	Y	N	Y	Y
Arkansas	Y	N	Y	Y	Y	Y
California	Y	N	Y	N	Y	N
Colorado 1/	Y	Y	Y	Y	Y	Y
Connecticut	Y	N	Y	N	Y	Y
Delaware	N	N	N	N	Y	N
D.C.	Y	N	Y	N	Y	N
Florida	Y	N	Y	N	Y	Y
Georgia	Y	N	Y	N	Y	N
Hawaii	Y	N	Y	N	Y	N
Idaho	Y	N	Y	N	Y	N
Illinois	Y	N	Y	Y	Y	Y
Indiana	Y	Y	Y	Y	Y	Y
Iowa	Y	Y	Y	Y	Y	Y
Kansas	Y	Y 2/	Y	Y 2/	Y	Y
Kentucky	Y	N	Y	N	Y	N
Louisiana	Y	N	Y	N	Y	N
Maine	Y	Y	Y	Y	Y	Y
Maryland	Y	Y	Y	Y	Y	Y
Massachusetts	Y	Y	Y	Y	Y	Y
Michigan	Y	3	Y	3	Y	3/
Minnesota	N	N	N	N	N	N
Mississippi	N	N	N	N	Y	Y
Missouri	Y	N	Y	N	Y	Y
Montana	Y	Y	Y	Y	Y	Y
Nebraska	N	N	N	N	N	N
Nevada	Y	Y	Y	N	Y	N
New Hampshire	Y	N	Y	N	Y	N
New Jersey	Y	Y 4/	Y	Y 4/	Y	Y 4/
New Mexico	Y	N	Y	N	Y	N
New York	Y	Y	Y	Y	Y	Y
North Carolina	Y	N	Y	N	Y	Y
North Dakota	Y	N	Y	N	Y	Y
Ohio	Y	N	Y 5/	N	Y	N
Oklahoma	Y	N	Y	N	Y	N
Oregon	Y	N	Y	N	Y	Y
Pennsylvania	Y	N	Y	N	Y	N
Rhode Island	Y	N	Y	Y	Y	Y
South Carolina	Y	N	Y	Y	Y	Y
South Dakota	Y	N	Y	N	Y	N
Tennessee	Y	N	Y	N	Y	Y
Texas	Y	Y	Y	Y	Y	Y
Utah	Y	N	Y	N	Y	N
Vermont	Y	Y	Y	N	Y	6/
Virginia	Y	N	Y	N	Y	N
Washington	Y	N	Y	N	Y	Y
West Virginia	Y	Y	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y	Y	Y
Wyoming	Y	Y	Y 7/	Y 7/	Y 7/	Y 7/

SOURCE: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980), pp. 496, 497, 499.

1/ Colorado Public Utilities Commission has no jurisdiction over publicly-owned (municipal)utilities inside corporate limits, except for gas safety. Public Utilities regulated outside of minicipal boundary only.

2/ Same as for private utilities and cooperatives for facilities outside of 3 miles from the corporate limit of municipalities—Commission has no jurisdiction within the 3 mile limit.

3/ There are no public gas utilities in Michigan.

4/ However, there are no public gas suppliers within the state.

5/ DOT gas safety standards now apply.

6/ Have authority, but there are no gas public companies operating in Vermont.

7/ DOT gas safety standards now apply.

established for privately-owned than publicly-owned companies by state agencies.

Most state public utility commissions have authority to regulate the adequacy of gas service of privately-owned companies. Fewer state public utility commission regulate the adequacy of service of publicly-owned companies. Adequacy of gas service concerns state agency authority to authorize and to regulate gas interconnections between privately-owned companies and between publicly-owned companies and state agency authority to test meters or set standards for accuracy of meters of privately-owned and publicly-owned companies. As shown in table 9, state agencies have less authority over publicly-owned companies than they do over privately-owned companies. Thirteen state agencies have no authority in the authorization of gas interconnections between privately-owned companies, whereas thirty-two state agencies have no authority over the authorization of gas interconnections between publicly-owned companies. In the area of state agency authority to regulate gas interconnections a larger number of state agencies responded negatively in both privately-owned and publicly-owned categories. Twenty-four state agencies have no authority over privately-owned companies, and thirty-six state agencies have no authority over publicly-owned companies in the regulation of gas interconnections between the two types of utilities. State agencies are more stringent with privately-owned companies in relation to the authority to test meters or set accuracy standards of meters than they are with publicly-owned companies. Only three state agencies have no authority over privately-owned companies whereas thirty-two state agencies have no authority over publicly-owned companies in relation to the testing and standard setting of meters.

TABLE 9

STATE AGENCIES WITH AUTHORITY TO REGULATE ADEQUACY OF GAS SERVICE BY STATE, 1979

Column Agency	(1) Authorize Gas Interconnections between Privately-Owned Companies	(2) Authorize Gas Interconnections between Publicly-Owned Companies	(3) Require Gas Interconnections between Privately-Owned Companies	(4) Require Gas Interconnections between Publicly-Owned Companies	(5) Test Meters or Set Standards for Accuracy of Meters of Privately-Owned Companied	(6) Test Meters or Set Standards for Accuracy for Meters of Publicly-Owned Companies
Alabama	Y	N	Y	N	Y	N
Alaska	Y	Y	Y	Y	Y	Y
Arizona	Y	Y	N	Y	N	N
Arkansas	N	N	N	N	Y	N
California	Y	N	Y	N	Y	N
Colorado 1/	Y	Y	Y	Y	Y	Y
Connecticut	N	N	N	N	Y	N
Delaware	Y	N	N	N	Y	N
D.C.	N	N	N	N	Y	N
Florida	Y	N	Y	N	Y	N
Georgia	N	N	N	N	Y	N
Hawaii	N	N	N	N	Y	N
Idaho	N	N	N	N	Y	N
Illinois	Y	N	Y	N	Y	N
Indiana	N	N	N	N	Y	Y
Iowa	Y	Y	2/	2/	Y	Y
Kansas	Y	Y 3/	Y	Y 3/	Y	Y 3/
Kentucky	Y	N	Y	N	Y	N
Louisiana	Y	N	Y	N	Y	N
Maine	Y	Y	Y	Y	Y	Y
Maryland	Y	Y	Y	Y	Y	Y
Massachusetts	Y	Y	Y	N	Y	Y
Michigan	Y	4/	N	4/	Y	4/
Minnesota	N	N	N	N	Y	N
Mississippi	Y	Y	N	N	Y	Y
Missouri	Y	N	N	N	Y	N
Montana	N	N	N	N	Y	Y
Nebraska	N	N	N	N	N	N
Nevada	N	N	N	N	Y	N
New Hampshire	Y	N	N	N	N	N
New Jersey	Y	Y 5/	Y	Y 5/	Y	Y 5/
New Mexico	Y	N	Y	N	Y	N
New York	Y	Y	Y	Y	Y	Y
North Carolina	Y	N	Y	N	Y	N
North Dakota	Y	N	N	N	Y	N
Ohio	Y	N	N	N	Y	N
Oklahoma	Y	N	Y	N	Y	N
Oregon	Y	Y	Y	Y	Y	N
Pennsylvania	N	N	N	N	Y	N
Rhode Island	Y	N	N	N	Y	Y
South Carolina	Y	N	Y	N	Y	N
South Dakota	Y	N	Y	N	Y	N
Tennessee	N	N	N	N	Y	N
Texas	Y	Y	Y	Y	Y	Y
Utah	Y	N	Y	N	Y	N
Vermont	Y	6/	Y	6/	Y	Y
Virginia	Y	N	Y	N	Y	N
Washington	Y	Y	N	N	Y	N
West Virginia	Y	Y	N	N	Y	Y
Wisconsin	Y	Y	Y	Y	Y	Y
Wyoming	Y	Y 7/	Y	Y 7/	Y	Y 7/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the NationalAssociation of Regulatory Utility Commissioners (Washington, D.C: NARUC, 1980)

1/ Colorado Public Utilities Commission has no jurisdiction over publicly-owned (municipal) utilities inside corporate limits, except for gas safety. Public utilities regulated when outside of municipal boundary only.
2/ This commission may after hearing require these things, not a blanket requirements.
3/ Same as for private utilities and cooperatives for facilities outside of 3 miles from the corporate limit of municipalities--Commission has no jurisdiction within the 3 mile limit.
4/ There are no public gas utilities in Michigan.
5/ However, there are no public gas suppliers within the state.
6/ Have authority, but there are no gas public companies operating in Vermont.
7/ Commission regulates municipal utilities outside corporate limits.

Except for the construction of gas transmission lines by privately-owned companies, less than one-half of the state agencies have authority to require certification in the other major construction addition categories. The authority to require certificates of convenience and necessity for construction of major additions by state agencies is presented in table 10. The major addition categories listed in this table are construction of gas generating plant, transmission and distribution lines, and other plant by privately-owned and publicly-owned companies. Table 10 indicates thirty state agencies have no authority to require convenience and necessity certifiates for the construction of gas generating plants by privately-owned companies and even fewer state agencies have the authority over publicly-owned companies in this category. The state agency certification authority over gas transmission line construction by privately-owned companies is the most regulated of all these categories with only twenty-three states having no authority. However, for publicly-owned companies in this category, thirty-eight state agencies have no convenience and necessity certification requirement authority. In the construction of gas distribution lines by privately-owned companies slightly more than half the state agencies, twenty-seven, have no certification authority. Thirty-eight state agencies have no authority over publicly-owned companies in this category. For the construction of other plant, thirty state agencies have no authority over privately-owned companies, and forty state agencies have no authority over publicly-owned companies to require certification of convenience and necessity.

Twenty-two states have no authority to require certification in any of the eight categories listed in table 10. Five states, Alaska, Mississippi, Rhode Island, Wisconsin, and Wyoming, have authority to require

TABLE 10

STATE AGENCY AUTHORITY TO REQUIRE CERTIFICATES OF CONVENIENCE AND NECESSITY FOR CONSTRUCTING MAJOR ADDITIONS BY STATE, 1979

Column Agency	(1) Construction of Gas Generating Plant by Privately-Owned Companies	(2) Construction of Gas Generating Plant by Publicly-Owned Companies	(3) Construction of Gas Transmission Lines by Privately-Owned Companies	(4) Construction of Gas Transmission Lines by Publicly-Owned Companies	(5) Construction of Gas Distribution Lines by Privately-Owned Companies	(6) Construction of Gas Distribution Lines by Publicly-Owned Companies	(7) Construction of Other Plant by Privately-Owned Companies	(8) Construction of Other Plant by Privately-Owned Companies
Alabama	N	N	Y	N	N	N	Y	N
Alaska	Y	Y	Y	Y	Y	Y	Y	Y
Arizona	N	N	N	N	N	N	N	N
Arkansas	N	N	Y	N	N	N	Y	N
California	N	N	N	N	N	N	N	N
Colorado 1/	2/	2/	2/	2/	2/	2/	2/	2/
Connecticut	3/	3/	3/	3/	3/	3/	3/	3/
Delaware	N	N	N	N	N	N	N	N
D.C.	N	N	N	N	N	N	N	N
Florida	N	N	N	N	N	N	N	N
Georgia	N	N	Y	N	Y	N	N	N
Hawaii	4/	N	4/	N	4/	N	4/	N
Idaho	N	N	Y	N	Y	N	Y	N
Illinois	Y	N	Y	N	Y	N	Y	N
Indiana	N	N	N	N	N	N	N	N
Iowa	N	N	Y	N	Y	Y	N	N
Kansas	N	N	N	N	N	N	N	N
Kentucky	Y	N	Y	N	Y	N	Y	N
Louisiana	N	N	N	N	N	N	N	N
Maine	N	N	N	N	N	N	N	N
Maryland	N	N	N	N	N	N	N	N
Massachusetts	N	N	Y 5/	N	N	N	N	N
Michigan	N	N	Y	N	N	Y	N	N
Minnesota	N	N	N	N	N	N	N	N
Mississippi	Y	Y	Y	Y	Y	Y	Y	N
Missouri	Y	N	Y	N	Y	N	Y	N
Montana 6/	N	N	N	N	N	N	N	N
Nebraska	N	N	N	N	N	N	N	N
Nevada	Y	N	Y	N	Y	N	N	N
New Hampshire	N	N	N	N	N	N	N	N
New Jersey 7/								
New Mexico	Y	N	Y	N	8/	8/	8/	8/
New York	N	N	Y	Y	9/	9/, 10/	9/	9/, 10/
North Carolina	N	N	N	N	N	N	N	N
North Dakota	Y	Y	Y	Y	Y	N	N	N
Ohio	11/	11/	11/	11/	N	N	N	N
Oklahoma	N	N	N	N	N	N	N	N
Oregon	N	N	N	N	N	N	N	N
Pennsylvania	N	N	N	N	N	Y	N	N
Rhode Island	Y	Y	Y	Y	Y	Y	Y	Y
South Carolina	N	N	N	N	Y	N	Y	N
South Dakota	N	N	N	N	N	N	N	N
Tennessee 12/	Y	N	Y	N	Y	N	Y	N
Texas	N	N	N	N	N	N	N	N
Utah	Y	N	N	N	N	N	N	N
Vermont	Y	N	Y	13/	Y	N	Y 14/	Y 14/
Virginia	Y	N	Y	N	Y	N	N	N
Washington	N	N	N	N	N	N	N	N
West Virginia	Y	Y	Y	Y	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y	Y	Y	Y	Y
Wyoming	Y	Y	Y	Y	Y	Y	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 505-509.

1/ Colorado Public Utilities Commission has no jurisdiction over municipally owned utilities operating inside corporate limits except as to gas safety.

2/ Not necessary to obtain certificate for extension of its line, plant or system if contiguous to its existing system and if such extension is not into area of another utility of like character, and if extension is necessary in the ordinary course of its business.

3/ Participates through membership on Power Facilities Evaluation Council which has authority indicated.

4/ Although certification is not required, all capital expenditures in excess of $500,000 or 10 percent of the total plant in service must be submitted to the commission for review.

5/ Department has power to rezone property for construction of utility facilities and make takings in Eminent Domain Proceedings.

6/ Certificates, Permits, and Licenses - None in Montana.

7/ The key word here is authority. The commission can do all these things on the basis that utilities must provide safe, adequate and proper service.

8/ Certificate needed for extensions into new territory not contiguous to existing service of being served by another utility.

9/ The certificates of public convenience and necessity heretofore issued by the commission for the most part authorize construction of minor electric, gas and telephone plant of all sorts, without time limit, within specified municipalities. Therefore, the utility needs no additional certificate, other than for a major steam electric generating facility under Public Service Law, Article 8, and a transmission line under Public Service Law, Article 7, to construct additional plant within its previously certified area. A certificate is required, however, before a utility may construct palnt of any sort outside its previously certified area. In 1972 the State's Public Service Law was amended to establish within the Department of Public Service a Board on Electric Generation Siting and the Environment, intended to have one-stop siting jurisdiction. The Chairman of the Public Service Commission acts as Chairman of the Board. The other members are the Commissioners of Environmental Conservation, Health and Commerce, and an ad hoc member appointed by the Governor, who shall be a resident of the judicial district in which the facility as primarily proposed is to be located. The Commissioner of Health now participates in pending Article VIII cases only. The State Legislature amended Article VIII of the Public Service Law in 1978; pursuant to that amendment, the Commissioner of the New York State Energy Office participates in new Article VIII cases (in lieu of the Commissioner of Health).

10/ "No", except for service outside the municipality. General Municipal Law, Sec, 361, 364; Public Service Law, Sec. 68.

11/ Participates through membership on Power Siting Commission, which has authority as indicated.

12/ The term "certificate of convenience and necessity" does not apply for construction, but the agency does approve major additions of all regulated utilities.

13/ Have authority, but no public gas companies in Vermont.

14/ If significant environmental impact.

15/ The key word here is authority. The commission can do all these things on the basis that utilities must provide safe, adequate, and proper service.

certification in all eight categories. New Jersey has broad authority to regulate in many areas. This authority stems of the agency's mandate to ensure safe, adequate and proper service by the utilities.

Most state public utility commissions have the authority to require privately-owned utilities to acquire a certification of convenience and necessity to initiate new gas service or to abandon gas service. Table 11 shows that fourteen state agencies have no authority to require certification of privately-owned companies for initiating gas service; whereas 38 states have no authority over publicly-owned companies in this category. Thirteen state agencies have no authority to require certification of abandonment of gas facilities or services by privately- owned companies, and 37 states have no similar authority over publicly- owned companies.

Overall, nine state agencies have no authority to require certification for initiating or abandoning gas services or facilities by either privately- or publicly-owned companies. Six state agencies have authority in all of these areas. The New Jersey agency has a broad mandate that gives it the authority to ensure safe, adequate, and proper service by the utilities.

A large number of gas utilities and gas pipelines are under agency jurisdiction. Table 12 shows there are 1,328 privately-owned and 1,064 publicly-owned utilities operating within state jurisdictions. Texas contains the largest number of privately-owned utilities (325), and Florida contains the largest number of publicly-owned utilities (111). On the average each jurisdiction contains 26 privately-owned and 21 publicly-owned utilities. Hawaii and the District of Columbia have the least number of

TABLE 11

STATE AGENCY AUTHORITY TO REQUIRE CERTIFICATES OF CONVENIENCE AND NECESSITY FOR INITIATING GAS SERVICE AND ABANDONING SERVICE AND FACILITIES BY STATE, 1979

Column Agency	(1) Initiating Gas Service by Privately-Owned Company	(2) Initiating Gas Service by Publicly-Owned Company	(3) Abandonment of Gas Facilities or Services by Privately-Owned Company	(4) Abandonment of Gas Facilities or Services by Publicly-Owned Company
Alabama	Y	N	Y	N
Alaska	Y	Y	Y	Y
Arizona	Y	N	Y	N
Arkansas	Y	N	Y	N
California	Y	N	Y	N
Colorado 1/	Y	Y	Y	Y
Connecticut	N	N	N	N
Delaware	Y	N	Y	N
D.C.	N	N	N	N
Florida	N	N	N	N
Georgia	Y	N	Y	N
Hawaii	N	N	N	N
Idaho	Y	N	Y	N
Illinois	Y	N	Y	N
Indiana	N	N	N	N
Iowa	N	N	Y	Y
Kansas	Y	2/	Y	2/
Kentucky	Y	N	Y	N
Louisiana 3/	N	N	N	N
Maine	Y 4/	Y 4/	5/	5/
Maryland	Y 6/	Y 6/	N	N
Massachusetts	N	N	Y	Y
Michigan	7/	N	7/	N
Minnesota	Y	N	N	N
Mississippi	Y	Y	Y	Y
Missouri	Y	N	Y	N
Montana 8/	N	N	Y	Y
Nebraska	N	N	N	N
Nevada	Y	N	Y	N
New Hampshire	Y	N	Y	N
New Jersey 9/				
New Mexico	Y	N	Y	N
New York	Y	10/	Y	Y
North Carolina	Y	N	Y	N
North Dakota	Y	N	Y	N
Ohio	N	N	Y 11/	N
Oklahoma	N	N	Y	N
Oregon	N	N	N	N
Pennsylvania	Y	N	Y	N
Rhode Island	Y	Y	N	N
South Carolina	Y	N	Y	N
South Dakota	Y	N	Y	N
Tennessee	Y	N	Y	N
Texas	N	N	Y	Y
Utah	Y	N	Y	N
Vermont	Y	N	Y	N
Virginia 12/	Y	N	N	N
Washington	Y	Y	N	N
West Virginia	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y
Wyoming	Y	Y	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1980) pp. 504-509.

1/ Colorado Public Utilities Commission has no jurisdiction over municipally owned utilities operating outside corporate limits except as to gas safety.

2/ Same as for private utilities and cooperatives for facilities outside of 3 miles from the corporate limits of municipalities--Commission has no jurisdiction within the 3 mile limit.

3/ Louisiana Constitution of 1974 grants wide and plenary authority to "regulate" but no specific certification authority is provided except by statute to radio common carriers. Authority may be implied.

4/ Finding of public convenience and necessity required if another utility is already offered or is authorized to offer a comparable service in the same area. 35 M.R.S.A. 13-A.

5/ 35 M.R.S.A., Sec. 212.

6/ Authorize exercise of franchise rather than issue certificate of Public Convenience and Necessity.

7/ Present certificate authority limited to gas transmission pipelines, gas storage fields, and to situations where one utility proposes to extend service from another utility.

8/ Certificates, Permits, and Licenses - None in Montana.

9/ The key word here is authority. The commission can do all these things on the basis that utilities must provide safe, adequate, and proper service.

10/ "No", except for service outside the municipality. General Municipal Law, Sec. 361, 164; Public Service Law, Sec. 68.

11/ Limited Authority.

12/ The key word here is authority. The commission can do all these things on the basis that utilities must provide safe, adequate, and proper service.

TABLE 12

IE NUMBER OF GAS UTILITIES OPERATING WITHIN EACH STATE AND THE NUMBER OF GAS PIPELINES UNDER AGENCY JURISDICTION, 1979

Column Agency	(1) Number of Utilities Operating in the State Privately-Owned Companies	(2) Number of Utilities Operating in the State Publicly-Owned Companies	(3) Number of Gas Pipelines Under Agency Jurisdiction Privately-Owned Companies	(4) Number of Gas Pipelines Under Agency Jurisdiction Publicly-Owned Companies
Alabama	4	103	4	0
Alaska	4	1	4	0
Arizona	10	5	10	0
Arkansas	7	15	7	15 7/
California	7	3	7 1/	0
Colorado	10	10	10	2
Connecticut	5	1	5	0
Delaware	3	0	3	0
D.C.	1	0	1	0
Florida	14	111	14	111 7/
Georgia	4	89	4	28
Hawaii	1	0	1	0
Idaho	2	0	2	0
Illinois	19 2/	66	11	0
Indiana	26	20	26	20
Iowa	11	41	11	41 8/
Kansas	26	64	26	18
Kentucky	45	45	45	0
Louisiana	42	97	42	0
Maine	2	0	2	0
Maryland	10	1	10	1
Massachusetts	14	4	14	4
Michigan	10	0	10	0
Minnesota	13 3/	16	13 9/	16 9/
Mississippi	9	46	9	19 10/
Missouri	14	33	14	33
Montana	13	2	13	2
Nebraska	4/	10	0	0
Nevada	3	0	3	0
New Hampshire	7	0	7	0
New Jersey	4	0	4	0
New Mexico	6	10	6	4/
New York	24 5/	2	20 11/	2
North Carolina	5	8	5	0
North Dakota	4	5	4	0
Ohio	28	6/	28	0
Oklahoma	42	56	42	0
Oregon	3	0	3	0
Pennsylvania	43	0	43	0
Rhode Island	5	0	5	0
South Carolina	6	15	6	0
South Dakota	4	1	4	0
Tennessee	7	93	7	0
Texas	325	84	325	84 7/
Utah	4	0	4	0
Vermont	5	0	5	0
Virginia	14	3	14	0
Washington	4	3	4	3 12/
West Virginia	41	0	41	0
Wisconsin	16	1	16	1
Wyoming	22	0	22	0

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 387, 389-391.

1/ Not regulated by the California Public Utilities Commission.
2/ Includes eight combination electric and gas companies.
3/ Includes two combination electric and gas companies.
4/ Not Available.
5/ Includes seven combination electric and gas companies. Also four small private gas concerns have their own local production and sell to themsleves and one or two other customers.
6/ Includes nine cooperatives.
7/ Pipeline safety only.
8/ Service regulation only; not rates.
9/ Gas regulation established April 12, 1974; rate regulation became effective January 1, 1975.
10/ Municipal-18; District-1.
11/ Includes seven combination electric and gas companies.
12/ Certification and safety only.

privately-owned utilities, 1 each, and 16 agencies have no publicly owned utilities.

There are 936 privately-owned gas pipeline companies and 400 publicly-owned pipeline companies under state agency jurisdiction. Texas contains the largest number of privately-owned gas pipeline companies (325), and Florida contains the largest number of publicly-owned gas pipeline companies (111), with Texas second to Florida in the publicly-owned category (84). The average number of privately-owned and publicly-owned gas pipeline companies under agency jurisdiction are 18 and 8, respectively. The Nebraska commission is the one agency with neither privately-owned or publicly-owned gas pipeline companies under its jurisdiction. Only one state, Nebraska regulates no privately-owned companies and 33 states regulate no publicly-owned gas pipeline companies.

Most state public utility commissions have the authority to prescribe regulations concerning shortfalls and curtailments of gas service. Table 13, columns one and two show that 53% of the state commissions have prescribed emergency regulations for gas outages, and 73% of the commissions have regulations dealing with gas curtailment. Columns three and four of table 13 indicate that 90% of public utility commissions have authority to establish priorities for customer classes served by investor-owned utilities, while only 32% of commissions have such authority with respect to publicly-owned utilities. The last column of the table indicates that 65% of public utility commissions have established standards for attaching new gas customers during shortages.

Most state public utility commissions regulate policies and company practices concerning attachment of new gas customers and loads. Table 14 shows that gas service upon request is mandated by state law in 55% of the

TABLE 13

STATE AGENCY REGULATION OF GAS UTILITIES DURING SHORTFALLS AND CURTAILMENTS OF SERVICE, 1979

Column Agency	(1) The Agency has prescribed emergency regulation during outages	(2) The Agency has prescribed emergency regulation during curtailments	(3) The Agency has authority to establich priorities for customers classes served by private companies	(4) The Agency has authority to establish priorities for customers classes served by public companies	(5) The Agency has established standards for attaching new customers during shortages
Alabama	N	Y	Y	N	N
Alaska	Y	Y	N	N	Y
Arizona	Y	N	Y	N	Y
Arkansas	N	Y	Y	N	N
California	Y 1/	Y 1/	Y	N	Y
Colorado	N	N	Y	4/	Y
Connecticut	Y	Y	Y	N	N
Delaware	N	N	N	N	N
D.C.	N	Y	Y	N	Y
Florida	Y	Y	Y	N	N
Georgia	Y	Y	Y	N	Y
Hawaii	Y	N	Y	N	N
Idaho	Y	Y	Y	N	Y
Illinois	N	Y	Y	N	Y
Indiana	N	Y	Y	N	N
Iowa	Y	Y	Y	Y	1/
Kansas	N	Y	Y	Y 5/	Y
Kentucky	N	Y	Y	N	Y
Louisiana	N	N	Y	N	N
Maine	N	N	Y	Y	N
Maryland	N	Y	Y	Y	Y
Massachusetts	N	N	Y	Y	N
Michigan	Y	Y	Y	6/	Y
Minnesota	N	N	N	N	N
Mississippi	N	N	Y	Y	N
Missouri	Y	Y	Y	N	N
Montana	Y	Y	Y	Y	N
Nebraska	N	N	N	N	N
Nevada	1/	Y	Y	N	N
New Hampshire	N	N	Y	N	N
New Jersey	N	Y	Y	Y 6/	Y
New Mexico	Y	Y	Y	N	Y
New York	2/	Y	Y	Y	Y
North Carolina	Y	Y	Y	N	Y
North Dakota	N	Y	Y	N	Y
Ohio	Y	Y	Y	N	Y
Oklahoma	1/	1/	Y	N	N
Oregon	Y	Y	Y	N	Y
Pennsylvania	Y	Y	Y	N	Y
Rhode Island	Y	Y	Y	Y	Y
South Carolina	Y	Y	Y	N	Y
South Dakota	N	N	N	N	N
Tennessee	Y	Y	Y	N	Y
Texas	Y	Y	Y	Y	Y
Utah	Y	Y	Y	N	Y
Vermont	N	N	Y	Y	N
Virginia	N	Y	Y	N	Y
Washington	N	N	Y	N	Y
West Virginia	N	Y	Y	Y	Y
Wisconsin	Y	Y	Y	Y	Y
Wyoming	3/	Y	Y	Y	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C., 1980) pp. 501-2.

1/ The rules of the gas utilities contain priority of service during outages and curtailments.
2/ New York PSC case 25766 covers emergency regulations governing gas service.
3/ Commission and utilities have produced an emergency operation plan.
4/ Only outside municipal limit.
5/ Municipalities participate voluntarily.
6/ The state has no public gas utilities.

TABLE 14

STATE POLICY AND COMPANY PRACTICES ON THE ATTACHMENT OF NEW GAS CUSTOMERS AND LOADS, 1979

Column Agency	(1) Gas on Request Mandated by State Law	(2) Gas on Request Mandated by Commission Rules	(3) Companies can refuse Service if gas is Available	(4) Number of Companies Serving the States	(5) Number of Companies Attaching New Customers/ Loads	(6) Number of Companies With Writing Lists
Alabama	Y	Y	N	1/	5	1/
Alaska	Y	N	N	3	3	0
Arizona	N	Y	N	12	11	2
Arkansas	N	Y	Y 7/	7	4	1/
California	Y	Y	N	3	3	1/
Colorado	Y	Y	N	23	23	23
Connecticut	N	Y	N	6	6	6
Delaware	1/	Y	N	2	2	2
D.C.	N	N	N 8/	1	1	1
Florida	Y	Y	Y	77	77	1/
Georgia	Y	Y	Y	4	4	0
Hawaii	1/	1/	1/	1/	1/	1/
Idaho	Y	Y	N	2	2	0
Illinois	Y	4/	N	7	7	7
Indiana	N	N	Y	46	46	1/
Iowa	N	N	N	11	11	11
Kansas	Y	Y	N	5	5	5
Kentucky	N	N	N	4	1/	4
Louisiana	N	N	Y 9/	42	42	0
Maine	Y	Y	Y	1	1	0
Maryland	1/	1/	Y 9/	11	0	1/
Massachusetts	Y	Y	Y	13	5	5
Michigan	N	Y	Y 10/	10	9	10
Minnesota	Y	Y	N	21	21	21
Mississippi	Y	Y	N	3	3	3
Missouri	N	1/	N	14	1/	1/
Montana	Y	N	N	2	2	1
Nebraska 5/	N	N	N	5/	5/	5/
Nevada	1/	1/	N	3	0	1/
New Hampshire	Y 2/	Y 2/	N	4	4	4
New Jersey	Y	Y	N	4	4	4
New Mexico	1/	1/	N	6	0	1/
New York	N	N	N	14	14	4
North Carolina	Y	Y	N	5	5	0
North Dakota	N	N	N	3	3	1
Ohio	N	N	N	8	8	8
Oklahoma	N	Y	Y 7/	4	4	1/
Oregon	Y	Y	N	3	3	13/
Pennsylvania	N	Y	N	43	10	43
Rhode Island	Y	Y 6/	N	6 11/	6 11/	0
South Carolina	Y 3/	Y 3/	Y 3/	6	6	6
South Dakota	N	N	Y	4	4	4
Tennessee	N	N	Y	7	4	1/
Texas	Y	N	N	59 12/	59	0
Utah	N	Y	Y	2	2	0
Vermont	1/	Y	N	7	7	1
Virginia	N	Y 3/	Y	12	12	0
Washington	Y	Y	N	4	4	0
West Virginia	1/	1/	N	5	1/	5
Wisconsin	Y	Y	N	7	6	3
Wyoming	Y	Y	N	5	5	0

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C., 1980) pp.

1/ Not available.
2/ Subject to tariff.
3/ Unless otherwise ruled by the state commission.
4/ Not applicable.
5/ Telephone is the only regulated utility.
6/ Subject to line extension policy.
7/ When unreasonable costs are involved.
8/ Except for reasons other than service such as the cost of the service line.
9/ If don't comply with the distribution company's extension plan.
10/ Must be authorized by the commission.
11/ Each of six operating division of a single gas company are reported as separate companies.
12/ Distribution companies only.
13/ Companies must keep waiting lists on requests for firm service in excess of 500 therms per day.

responding states and is required under public utility commission rules in 67% of the states. As indicated by columns one and two of table 14, in only eleven states is gas service upon request not mandated by either state law, commission rules, or both. In 30% of the states, excluding Hawaii[1], gas companies can refuse to provide service even when gas is available. This discretion on the part of the gas companies is usually intended to allow them to avoid unreasonable distribution costs.

Column four of table 14 shows the reported number of gas utilities serving the state ranging from 1 in Maine to 77 in Florida. Special care must be taken in interpreting this figure because some states appear to report only major gas utilities. In most states, almost all the utilities serving each state are currently attaching new customers. The states where a significant number of gas utilities are not attaching new customers are Maryland, Nevada, New Mexico, Pensylvania and Tennessee. In the thirty-eight states reporting on the existence of waiting lists for new service, eleven states have gas utilities with no waiting lists.

Most state public utility commissions also have authority to regulate gas cost adjustment clause increases. Table 15 shows the categories of authority relating to the establishment of automatic adjustment clauses in the tariff, the permission to allow utilities to recover the changes in purchased gas costs through the automatic adjustment clause, and the requirement for a hearing before adjustment clauses can be used to recover changes in purchased gas costs. Only four state agencies lack the authority to establish these adjustments in tariffs, but 11 states do not allow for the use of automatic adjustment clauses by utilities to recover

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[1]Information on Hawaii is unavailable.

TABLE 15

STATE AGENCY AUTHORITY TO REGULATE GAS COST ADJUSTMENT CLAUSE INCREASES BY STATE, 1979

Column	(1)	(2)	(3)
Agency	Authority to Establish Automatic Adjustment Clause in Tariff	Allows Automatic Adjustment Clause to Permit Utilities to Recover Changes in Purchased Gas	Requires Adjustment Clause Hearing before Recovery of Changes in Purchased Gas
Alabama	Y	Y	N
Alaska	Y	Y	N
Arizona	Y	Y	N
Arkansas	Y	Y	N
California	Y	N	Y
Colorado	Y	N	Y
Connecticut	N	N	Y
Delaware	Y	N	Y
D.C.	Y	Y	N
Florida	Y	Y	N
Georgia	Y	Y	N
Hawaii	Y	Y	N
Idaho	Y	1/	1/
Illinois	Y	Y	N
Indiana	Y	N	Y
Iowa	Y	Y	N
Kansas	Y	Y	N
Kentucky	Y	N	Y 2/
Louisiana	Y	Y	N
Maine	Y	Y	N
Maryland	Y	Y	N
Massachusetts	Y	N	Y
Michigan	Y	Y	N
Minnesota	Y 3/	Y	N
Mississippi	Y	Y	N
Missouri	Y	Y	N
Montana	N	1/	1/
Nebraska	5/	5/	5/
Nevada	Y	N	Y
New Hampshire	Y	N	Y
New Jersey	Y	N	Y
New Mexico	Y	Y	N
New York	Y	Y	N
North Carolina	N	Y	N
North Dakota	Y	Y	N
Ohio	Y	Y	N
Oklahoma	Y	Y	N
Oregon	Y	1/	1/
Pennsylvania	Y	Y	N
Rhode Island	Y	Y	N
South Carolina	Y	Y	N
South Dakota	Y	Y	N
Tennessee	Y	Y	N
Texas	Y	Y	N
Utah	N	1/	1/
Vermont	Y	Y	N
Virginia	Y	Y	N
Washington	Y	1/	1/
West Virginia	Y	Y	N
Wisconsin	Y	Y	N 4/
Wyoming	Y	N	Y

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 505-509

1/ Not Applicable--no adjustment clause in effect.

2/ No change may be made by any utility except upon twenty (20) days notice to the commission If after examination of the data provided the rate is justified, public hearing is waived and or Order of the Commission the change in rate is made.

3. The Commission permits the utilities to file rate schedules containing provisions for the automatic adjustment of charges.

4. The Wisconsin Legislature recently regulated the Attorney General's opinion on the legality of automatic pass through of costs without hearing.

5. Not Available.

changes in purchased gas costs. A majority of the state agencies, 34, do not require hearings before adjustment clauses are implemented to recover the changes in purchased gas costs.

Most state public utility commissions prescribe special accounting or reporting requirements for transactions by gas distribution companies with affiliate companies. As table 16 shows, of the forty-four state commissions responding, twenty-eight commissions indicated that they have special accounting requirements that are in accordance with their own system of accounts. Five additional state public utility commissions indicated that they presently have the option of requiring special accounting if the occasion requires. Finally, two state commissions have indicated that they have the authority to require special accounting for transactions with affiliates.

Thirty state commissions indicated that they either had special reporting requirements for transactions with affiliates or that transactions with affiliates must be reported in a utility's annual report. In addition, five commissions indicated that they presently have the option of requiring special reports if the occasion requires. One commission indicated that it has the authority to require special reporting requirements for transactions with affiliates.

While there is broad state agency authority to regulate natural gas production usually this authority rests in state agencies other than the state public utility commissions. Table 17 shows the categories of authority to regulate. Listed are the volume and rate of production, the spacing of wells, and the rates on well-head contracts. The final column lists the state agencies with authority to regulate in any or all of the previously mentioned areas, where such authority does not rest in the state

TABLE 16

STATE POLICY CONCERNING TRANSACTIONS WITH AFFILIATES, 1979

Column	(1)	(2)
	State Agency prescribes special requirements for transactions with affiliates	
Agency	Accounting	Reporting
Alabama	Yes.	Investigation by staff.
Alaska	Yes for the Alaska Public Service Commission. Policy for the Alaska Pipeline Commission.	Investigation by staff for the Alaska Public Service Commission
Arizona	No response.	No response.
Arkansas	Per system of accounts and annual reports, Same requirements as FERC.	Per system of accounts and annual reports. Same requirements as FERC.
California	Accounting requirements same as FERC.	Reporting requirements same as FERC.
Colorado	No.	Reasonableness of affiliate transactions are considered in rate cases.
Connecticut	No.	Service contract charges from affiliates are reported in the utilities annual reports.
Delaware	No response.	No response.
D.C.	Any special accounting treatment it requires.	The Commission can set those reporting requirements necessary to carry out its statutory responsibilities.
Florida	Yes.	Yes.
Georgia	No response.	No response.
Hawaii	Yes.	Must submit consolidating statements with explanation of transactions and basis of allocation of common expenses.
Idaho	No.	No.
Illinois	Approval of all transaciton except those specifically excluded by section 8(a) of the Public Utilities Act.	File reports relative to such transactions as the commission may prescribe.
Indiana	Yes.	Yes.
Iowa	Records of transactions must be preserved in the same manner as for the utility. Extraordinary documentation may be required and pricing is subject to greater scrutiny.	Same as FERC.
Kansas	Statute requires full disclosure. Adjustments are made for ratemaking.	Must identify related companies in annual report file all contracts and keep commission fully informed of transaction.
Kentucky	No response.	No response.
Louisiana	Yes, insofar as certain transactions are concerned.	No.
Maine	Only as occasion requires.	Only as occasion requires.
Maryland	Follow requirements of the uniform system of accounts.	Follow requirements of report forms.
Massachusetts	To the extent that they affect the regulated utility adversely.	Requires an abbreviated report from from each affiliate.
Michigan	Per system of accounts.	Yes, in rate case filing requirements and annual reports
Minnesota	Per system of accounts.	Part of Annual report.
Mississippi	No.	No.
Missouri	Yes.	Yes.
Montana	Must be absolutely separate.	All transactions are kept seperately.
Nebraska	All transactions deemed necessary.	All transactions deemed necessary
Nevada	No.	No.
New Hampshire	Depends on specific transactions.	Must submit various contracts which affect New Hampshire utilities-such as contract for services rendered and charged to utility.
New Jersey	Transaction must be reasonable and provide for elimination of unsupportable gains.	Description required to be given in annual report plus supplemental reports if deemed necessary.
New Mexico	No response.	No response.
New York	Companies are required to keep accounts so as to be able to accurately and expeditiously produce statements of all transactions with associates.	Commission has authority under its general powers to require any special reports to keep the commission informed.
North Carolina	The type and dollar amount of the goods and services represented by transactions between the regulated company and its affiliate must be identifiable in the books of account of the regulated company.	Annually the regulated companies must report the type, dollar amount and the name of the affiliate from which goods and services were received.
North Dakota	No prescription.	No prescription.
Ohio	Commission has authority but no standards have been adopted. Not significant in Ohio.	Part of annual report. The commission has authority to require report.
Oklahoma	As required by uniform system of accounts.	As required by uniform system of accounts.
Oregon	Furnish detail of costs and profit between affiliates.	File detail of all transactions showing costs and other pertinent data.
Pennsylvania	No response.	No response.
Rhode Island	Yes.	Yes.
South Carolina	All necessary steps to protect consumers.	Reports and other transaction filed and reviewed by the commission.
South Dakota	Yes.	
Tennessee	Yes.	Yes.
Texas	Yes.	Yes.
Utah	There are no specific provisions in Utah law but the commission is of the opinion it has adequate authority under the section of the law relating to accounts to prescribe such requirements.	There are no specific provisions in Utah law but the commission is of the opinion it has adequate authority under the section of the law relating to reports to prescribe such requirements.
Vermont	No response.	No response.
Virginia	Yes.	Yes.
Washington	Maintain record of the cost of the services provided by the affiliate and if ascertainable the cost of all items sold to the utility.	All services and things should be provided at cost by the affiliate and the annual reports of the cost thereof are filed with the commission.
West Virginia	As required by the uniform system of accounts.	As required by annual reports.
Wisconsin	Highly intensive.	Yes.
Wyoming	Generally, complete seperation of operations with only benefits flowing to utility.	Requirements patterned to facts of each case.

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) p. 487.

TABLE 17

STATE AGENCY AUTHORITY TO REGULATE NATURAL GAS PRODUCTION, 1979

Column Agency	(1) The Agency has the Authority to Regulate: the Volume and Rate of Production	(2) The Agency has the Authority to Regulate: the Spacing of wells	(3) The Agency has the Authority to Regulate: the Rates on well-head contracts	(4) Foregoing Authority Rests with State Agency other than the State Public Utility Commission
Alabama	N	N	N	Oil and Gas Board
Alaska	Y	N	Y	Department of Natural Resources
Arizona	N	N	N	Oil and Gas Conservation Commission
Arkansas	N	N	N	Oil and Gas Commission 1/
California	N	N	N	Division of Oil and Gas 1/
Colorado	N	N	N	Oil and Gas Conservation Commission 2/
Connecticut	N	N	N	
Delaware	N	N	N	
D.C.	N	N	N	
Florida	N	N	N	Internal Improvement Board
Georgia	N	N	N	
Hawaii	N	N	N	
Idaho	N	N	N	
Illinois	N	N	N	Department of Mines and Minerals 3/
Indiana	N	N	N	Natural Resources Commission and State Board of Health
Iowa	N	N	N	Natural Resources Council
Kansas	Y 4/	Y	N	
Kentucky	N	N	Y 5/	Department of Mines and Minerals
Louisiana	N	N	N	Conservation Department
Maine	N	N	N	
Maryland	N	N	N	
Massachusetts	N	N	N	
Michigan	Y 6/	N	Y 7/	Department of Natural Resources
Minnesota	N	N	N	
Mississippi	N	N	N	Oil and Gas Board
Missouri	N	N	N	
Montana	N	N	N	
Nebraska	N	N	N	
Nevada	N	N	N	
New Hampshire	N	N	N	
New Jersey	N	N	N	
New Mexico	N	N	N	Oil Conservation Commission 1/
New York	N	Y 8/	N	Department of Environmental Conservation
North Carolina	N	N	N	Department of Natural and Economic Resources
North Dakota	N	N	N	Industrial Commission 1/
Ohio	N	N	N	Department of Natural Resources regulated spacing of wells.
Oklahoma	Y 9/	Y	N	
Oregon	N	N	N	
Pennsylvania	N	N	N	
Rhode Island	Y 10/	N	N	
South Carolina	N	N	N	
South Dakota	N	N	N	
Tennessee	N	N	N	Department of Gas Conservation, Geology Div., Oil and Gas Board
Texas	Y 11/	Y	N	
Utah	N	N	N	The Division of Oil and Gas Conservation 5/
Vermont	N	N	N	
Virginia	N	N	N	
Washington	N	N	N	
West Virginia	N	N	N	
Wisconsin	N	N	N	
Wyoming	N	N	12/	

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 645.

1/ Authority to regulate the volume and rate of production and the spacing of wells.
2/ Regulates volume and rate of production, with rateable tale pm a statewide basis and regulated the spacing of wells.
3/ Regulates the spacing of wells and well-head prices.
4/ Rateable take is on a reservior basis. Rate of production is determined by hearings based on market demands.
5/ Some jurisdiction.
6/ Maximum rate of gas well gas production based on percdntage of open flow capacity. Oil well gas production, where restricted, based on gas oil ratios. No rateable take for oil well gas production. Rateable take for gas well gas production under standard commission rules, based on formula giving equal weight to open flow capacity and acreage factor. Acreage factor is dependent on size or producing unit and location of well on unit. Majority of gas well gas production is state pro-rated, based on formula giving dominant weight to pay rock volume attributable to producing unit.
7/ Limited to changes in central filed rates for conditions of service.
8/ Well spacing is regulated on fields discovered after October 1963, by New York Department of Environmental Conservation.
9/ Rateable take is on a reservoir and statewide basis. Rate of production is determined by market demand.
10/ LPG and LNG only.
11/ Rateable take is on a reservoir basis.
12/ Authority eliminated by 1976 Wyoming Supreme Court ruling.

public utility commission. Six, four, and three state public utility commissions have regulatory authority in production, well-spacing, and well-head contract rates, respectively. In 21 states, agencies other than the state public utility commission have the authority to regulate in any or all of the three areas.

Table 18 presents a composite picture of selected statistics for all privately-owned gas utilities under state agency jurisdiction. The selected statistics include the yearly average number of intrastate customers (industrial and total); residential information pertaining to average annual use (MCF) and average monthly billing; the original cost value for intrastate plants by plant inservice, construction work in progress, and net book costs; and, income statement figures reflecting operating revenue, total operating expenses, net operating income, and net income.

The number of intrastate industrial customers of privately-owned regulated gas utilities was 322,345 in 1979. This represents an average of 10,070 for the 32 states responding. The number of intrastate customers (residential, industrial, and other) served by privately-owned regulated gas utilities was 37,770,368 in 1979; and the average is 899,295 customers for the 42 states responding in this category.

The range of average annual residential gas usage in 1979 was from 1017 MCF in the District of Columbia to 26 MCF in Montana. The median gas usage was 103 MCF. The average monthly bill was $29.29 for residential usage in 1979.

Columns 5, 6, 7 show the plant in service, construction work in progress, and the net book costs of intrastate plant. Columns 8, 9, 10,

TABLE 18

COMPOSITE OF SELECTED STATISTICS FOR ALL PRIVATELY OWNED GAS UTILITIES UNDER AGENCY JURISDICTION, 1979

Column	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Intrastate Cusotmers YEARLY AVERAGE		Residential Statistics		Intrastate Plant (ooo omitted)			Intrastate Revenues and Expenses (ooo omitted)			
Agency	Industrial	Total	Average Annual Use-MCF	Average Monthly Bill($)	Plant in Service	Construction Work in Progress	Net Book Costs	Operating Revenue	Total Operating Expenses	Net Operating Income	Net Income
Alabama 1/	43	349,709	2/	24.50	162,496	885	120,786	237,348	2/	2/	2/
Alaska 2/											
Arizona	1,090	552,907	71.27	20.62	220,779	8,034	215,513	238,992	225,112	13,810	9,781
Arkansas	234	69,971	108	19.34	57,411	435	39,269	58,179	53,142	5,037	4,396
California	31,831	6,966,262	88	18.00	3,764,019	47,262	2,473,707	4,468,234	4,263,327	204,907	144,621
Colorado	1,693	738,583	154	27.61	399,463	7,178	281,771	431,564	419,317	12,247	11,190
Connecticut 2/											
Delaware	165	76,165	96	32.00	63,985	689	44,949	53,858	48,938	4,920	4,930
D.C.	2/	2/	1,017 3/	3743 4/	133,288	2/	96,994	95,146	91,752	3,394	3,394
Florida	45	21,735	2/	2/	207,005	3,876	154,299	149,889	139,162	10,727	6,209
Georgia	671	825,150	89.23	20.89	489,838	2,021	354,902	580,307	552,754	27,553	14,847
Hawaii	2/	33,341	252 4/	23.00	50,150	70	38,197	32,940	28,843	4,097	2,966
Idaho	460	108,859	90	28.92	123,987	148	88,462	144,434	136,162	8,272	5,102
Illinois	246,792	3,211,028	175	43.25	3,186,576	37,388	2,306,867	3,218,388	3,001,232	217,156	2/
Indiana	1,059	460,843 5/	2/	2/	359,961	3,166	274,827	376,877	348,890	27,987	21,202
Iowa 6/	1,573	700,760	146	32.73	413,870	6,905	320,693	615,974	541,357	24,617	2/
Kansas	3,239	667,688	167	23.90	411,932	3,769	291,844	518,753	502,320	16,433	46,566
Kentucky	760	539,223	139.5	27.99	475,205	6,654	263,257	421,256	395,466	25,790	37,592
Louisiana 2/											
Maine 7/	2/	15,000	42	18.90	14,952	107	12,971	8,342	7,511	831	143
Maryland	5,204	1,082,645	99	31.86	879,165	7,980	635,253	696,743	643,661	53,082	146,644
Massachusetts	2,542	932,440	2/	37.58	741,887	3,934	574,961	715,353	662,943	52,410	2/
Michigan 7/	9,375	2,373,602	147.8	38.65	2,429,020	39,813	1,834,756	2,232,072	2,111,977	120,095	69,399
Minnesota	5,505	742,448	156	37.31	513,684	7,386	376,170	607,424	571,774	35,650	25,425
Mississippi 2/											
Missouri	765	1,073,234	150.9	32.50	643,260	2,206	457,465	732,686	692,958	39,727	25,157
Montana	2/	184,852	26	38.53	288,586	2/	2/	182,222	176,738	2/	5,484
Nebraska 8/											
Nevada	20	151,015	95.2	23.15	162,397	13,065	140,211	220,619	206,699	13,920	9,975
New Hampshire	245	46,159	2/	30.12	40,191	137	29,591	30,162	28,474	1,688	854
New Jersey	2/	1,843,693	86.59	24.89	1,307,688	13,501	856,237	1,102,190	1,016,510	85,680	58,308
New Mexico	2/	288,819	103	23.80	2/	2/	2/	277,083	2/	7,404	2/
New York 9/	2/	4,119,238	93,5	30.87	2,595,758	68,587	2,130,545	2,459,745	2,278,894	180,852	860,392*
North Carolina	1,809	333,054	97 D.T.	28.80	345,110	3,009	254,234	343,889	319,166	24,723	14,416
North Dakota	37	82,669	164	38.11	83,176	1,806	56,447	67,512	61,765	5,747	8,933
Ohio	2/	2,693,037	2/	2/	1,511,955	14,748	993,703	2,463,954	2,333,912	130,042	109,882
Oklahoma 2/											
Oregon	610	266,093	2/	31.07	2/	2/	2/	310,924	285,164	25,760	2/
Pennsylvania 2/											
Rhode Island 6/	1,500	163,242	88.7	31.24	106,194	309	78,989	102,404	96,040	6,364	6,276
South Carolina	781	228,706	2/	2/	230,147	2,203	161,652	282,467	266,691	15,776	8,190
South Dakota	2/	95,226	140	30.22	65,186	917	44,463	60,735	57,723	3,012	2,366
Tennessee	1,288	248,727	113.49	24.88	111,334	636	75,724	150,428	143,543	6,885	3,854
Texas	1,568	3,151,923	88.65	21.83	3,430,588	2/	2/	6,891,936	6,699,360	192,576	2/
Utah 10/	625	361,017	170	31.56	424,748	22,030	346,074	261,354	237,150	24,204	25,887
Vermont	25	15,638	2/	36.07	16,105	2/	10,308	17,445	16,378	1,067	902
Virginia	567	426,395	100	30.01	351,296	1,630	251,904	406,914	380,875	26,309	26,099
Washington	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/	2/
West Virginia	2/	391,696	2/	2/	856,233	2/	2/	429,465	628,216	198,751	2/
Wisconsin	2/	1,010,700	137	34.45	875,667	2/	2/	987,121	932,979	54,142	2/
Wyoming	113	126,876	2/	32.00	119,329	2/	2/	167,814	161,013	6,801	2/

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.:NARUC, 1980) pp. 658-659.

1/ Data for Alabama Gas Corporation
2/ Not Available
3/ Meters.
4/ Therm.
5/ No information on 3 Class D companies.
6/ Fiscal year ended June 30, 1979.
7/ Fiscal year ended September 30, 1979.
8/ Not applicable.
9/ Composite of statistics for all Class A and B privately owned gas utilities under agency jurisdiction (systemwide). *Please note that this statement is a composite of fourteen companies - seven companies whcih sell gas only and seven companies which sell gas, electricity, and, for two companies, steam also. The figures shown are gas only, with the exception of the starred item, which is a total figure.
10/ Approximately 7% of the "Plant" figures represent Wyoming plant; company does not segregate plant by state. Approximately 8% of "Revenues" represents Wyoming revenue. The major company, Mountain Fuel Supply Co., does not segregate expenses by state. Income taxes and other taxes.

and 11 show the operating revenue, total operating expense, net operating income, and net income, respectively.

Finally, the first two columns of table 19 contain information on the supplemental gas supply pricing practices in each state[1] with column 1 showing that 88% of the states use roll-in pricing, 18% use some form of incremental price, and 16% of the states use both. Many of the states which use incremental pricing at all restrict its use to special cases such as emergency gas purchases.

The last five columns of table 19 show gas prices and alternative fuel prices in cents per them. Number 2 oil prices, number 6 oil prices, and propane prices are converted to an equivalent cents per therm. In 1979, the average price across the states for residential gas was 35.2 ¢/therm; and for industrial gas customers 30.8 ¢/therm. The price range across the states for number two oil was 25 to 72 ¢/therm and 16.9 to 58.1 ¢/therm for number 6 oil. Propane showed the widest range across the states of 11.8 to 105 ¢/therm in 1979, with most of states falling in the 40 to 70 ¢/ therm range.

Major Issues and Problems of State Regulators

In this section, the major issues and problems currently faced by states regulators of the gas distribution utilities are identified and discussed. For the most part, these issues are ratemaking issues. At present, securities issuance, pipeline safety, and other areas do not represent areas of significant difficulty. At the 93rd Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC),

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[1]Excluding Delaware (not available) and Nebraska (not applicable).

TABLE 19

SUPPLEMENTAL GAS SUPPLY PRICING PRACTICES AND AVERAGE FUEL PRICES FOR SAMPLE URBAN AREAS, 1979

Column	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Agency	A Least part of The Supplemental Gas Supply is Priced 1/ Using a Roll-in	A Least part of The Supplemental Gas Supply is Priced 1/ Incrimentally	Residential Gas Prices (¢/Therm)	Industrial Gas Prices (¢/Therm)	No. 2 Oil (¢/Therm)	No. 6 Oil (¢/Therm)	Propane (¢/Therm)
Alabama	Y	Y	33.34	24.56	30.30	20 to 22	35 to 45
Alaska	N	N	2/	2/	2/	2/	2/
Arizona	Y	Y	29.53	21.39	25.7	2/	59.2
Arkansas	Y	N	2/	2/	2/	2/	2/
California	Y	N	25.70	35.45	28.9	25.2	44 to 47
Colorado	Y	N	32.27	2/	51.8	35.0	48.4
Connecticut	Y	N	47.38	43.25	31.38	36.74	2/
Delaware	2/	2/	43.40	36.90	38.90	2/	2/
D.C.	Y	N	2/	2/	2/	2/	2/
Florida	Y	N	31.43	26.98	27.40	26.40	556 to 708
Georgia	Y	Y	27.70	25.15	32.45	2/	47.25
Hawaii	N	N	2/	2/	2/	2/	2/
Idaho	Y	N	37.46	34.32	2/	2/	474.49
Illinois	Y	N	29.68	24.29	35.20	26 to 28	33.5
Indiana	Y	N	28.90	26.10	62.30	37.94	58.6
Iowa	N	N	28.89	23.09	68.40	28.0	58.84
Kansas	Y	N	22.64	20.19	58.40	24.19	60.88
Kentucky	Y	3/	26.02	20.16	33.9	2/	44.7
Louisiana	Y	N	24.68	20.74	32.1	23.5	40.8
Maine	Y	N	53.19	46.26	37.4to 39.7	2/	34.6
Maryland	Y	N	38.96	35.58	46.47	34.3	55.72
Massachusetts	N	N	43.38	39.95	43.17	24.13	64.52
Michigan	Y	N	28.53	42.55 5/	36.	22.3	43.1
Minnesota	Y	Y	28.53	24.19	37.4	22.1 to23.5	40.8
Mississippi	Y	N	27.90	24.05	28.9	18.	44.8
Missouri	Y	N	33.36	28.79	35.3	2/	2/
Montana	Y	N	24.20	21.31	28.7	2/	57.2
Nebraska	4/	4/	23.71	21.00	28.1	17.9	38.7
Nevada	Y	N	20.53	17.20	24.7 to 26.1	2/	67.9
New Hampshire	N	N	47.3	40.6	74.1	2/	2/
New Jersey	Y	N	41.82	36.09	31.6 to 40.2	30 to 31.4	56.6
New Mexico	Y	N	32.08	29.33	2/	2/	2/
New York	Y	N	62.49	49.79	66.3 to 72.	39.6to58.1	75.6 to105.
North Carolina	Y	N	37.55	28.35	60.7	35.8	69.1
North Dakota	Y	N	51.50	47.28	70.0	34.5	2/
Ohio	Y	N	37.7	30.59	50.0	28.0 to 30.6	49.2 to74.8
Oklahoma	Y	N	48.26	20.40	32.4 to 33.8	22.3to23.9	38.7to41.8
Oregon	Y	N	47.69	45.30	25.	2/	40.
Pennsylvania	Y	N	2/	2/	2/	2/	2/
Rhode Island	Y	Y	56.01	51.31	72.	52.	65 to 75
South Carolina	Y	Y	29.53	24.03	26.6 to 31	16.9 to 23.5	11.8to18
South Dakota	Y	N	28.75	2/	65.0	2/	59.8 to 61.9
Tennessee	Y	Y	24.11	25.56	29.2	2/	33.5 to 44.5
Texas	Y	N	25.93	25.84	2/	2/	2/
Utah	Y	N	31.57	22.79	60.76	2/	67.43
Vermont	N	N	41.60	34.18	40.3 to 41.8	2/	41.8 to 68
Virginia	Y	Y	41.4	31.3	70	50	62
Washington	Y	N	48.17	41.24	86	2/	73.2
West Virginia	Y	N	26.56	25.48	31.7 to 35.3	14.1to24.8	27. to 37.6
Wisconsin	Y	N	33.92	30.25	65 to 58	32 to 34.3	39.3 to 47
Wyoming	Y	N	2/	2/	27.2 to 31	18.6 to 22	42.5to5356

Source: Paul Rodgers, 1979 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C. 1980) pp. 661-4.

1/ Supplimental gas supply include synthetic, liquid and pertoleum gas, local funded gas emergency gas, ethane, storage, exploration and development and other.
2/ Not available.
3/ Only for industrial customers
4/ Telephone is the only regulated utility.
5/ 22.9 %/Therm for 5,000 Therms.

two ratemaking issues in particular were forcefully debated by the NARUC Committee on Gas on November 17, 1981. Both related to State commission "rubber stamping" of certain Federal decisions: one related to take-or-pay contracts and the other to the Alaska Natural Gas Transportation System (ANGTS).

Contracts for gas supply between producers and interstate pipelines are often on a take-or-pay basis, that is, the pipeline agrees to buy at a certain fraction of the maximum contract amount or to pay for that fraction even if it does not actually take the gas. Normally, there is both an annual and a daily purchase obligation. The Committee on Gas received a written subcommittee report on take or pay contracts, discussed certain factual questions, and debated the value of the use of such contracts. It was asserted by some that many "new" gas contracts (gas contracts signed after passage of the Natural Gas Policy Act of 1978, NGPA) contain an unusually high take-or-pay clause percentage, requiring pipelines to buy 90 to 95% of the maximum contract amount, and that this contrasts with a historically lower figures of 75% or so. It was further asserted that the rapid rise in retail gas rates is, in part, due to the use of take-or-pay provisions: new gas is more costly and has more rapid price increases, but when demand for gas drops the lower cost "old" gas under a 75% provision is curtailed ahead of higher cost "new" gas under a 95% provision. Some contended that accelerated deregulation of well-head prices would exacerbate this effect.

Because these contracts are between producers and pipelines, the high cost gas is passed along to the distribution companies, which may in turn have take-or-pay contracts with the pipeline companies. Distribution companies--and the state agencies that regulate them--would like to have

disclosure of the terms of the producer-pipeline contracts, including the take-or-pay provisions and the price escalation provisions. But, because the pipelines are regulated by the Federal Energy Regulatory Commission (FERC) which does not require such disclosure, States feel required to pass along the resulting gas cost increases, without State review, in distribution company rates.

States may also be required to pass along pipeline capacity costs for ANGTS without review. According to its sponsors and the major banks arranging financing, the 4800-mile pipeline system for carrying gas from the North Slope of Alaska cannot be privately financed unless certain normal requirements of law and regulatory practice are waived by the Federal government. The most difficult waiver for some state regulators is one to allow the FERC to include in the rates of the sponsoring pipeline companies the costs of sections of ANGTS as they are completed. The result would be to "pre-bill" customers for the costs of ANGTS, years before the gas flows. Many state regulatory agencies believe that such a ratemaking practice is contrary to state law, which typically requires that the agency find a facility to be "used and useful" before allowing it in rates. However, it appears that after the FERC has approved a rate charged by a pipeline, the due-process clause of the Fourteenth Amendment and the Supremacy Clause would preclude any state action that would prevent recovery of ANGTS costs from distribution company customers.

While these two ratemaking issues are of great concern to state regulators, they may be problems beyond state control. The ratemaking issues currently of importance that are within state control are the following:

1. Whether to use marginal or embedded costs for ratemaking purposes.
2. Whether to institute a lifeline rate either for the poor or for all low volume users.
3. Whether to have declining block rates, flat rates, or inverted rates.
4. Whether purchased gas adjustment clauses are properly designed and monitored.

An elaboration of each of these issues follows.

Marginal versus Embedded Costs. - There are two distinct methodologies for determining the cost of gas distribution service: the allocation of embedded cost and the calculation of marginal cost. Within either methodology there can be several methods for determining the cost of service. Advocates of the two approaches differ on what it is that should be calculated: they differ regarding the meaning of the word "cost."

In traditional cost accounting, the total costs experienced by the utility during a historical test year are allocated among the various categories of service offered by the utility. Some costs are easily allocable. For example, the cost of large recording meters is allocated to the industrial class of customers because only such customers use these meters. Other costs, such as the cost of administration, are for the benefit of all customers and must be allocated according to traditionally accepted methods of cost accounting. Differences regarding which method to use for the allocation of these common costs underlie different espoused methods for traditional cost-of-service studies.

From the economist's viewpoint, costs calculated in this way have no meaning. There is no theoretically correct way to allocate common costs. The allocated cost of serving an individual (customer or class of customer) is a fictitious number that should have no relation to the price of the service, in economic theory.

The economist views the cost of serving an individual as the amount of cost-savings the utility would realize if it did not serve him. It is the reduction in total costs by removing him from the distribution system. Stated another way, it is the additional cost of adding to the system another customer with the same usage characteristics as the customer in question. This additional cost is called the marginal cost for the customer. Economists contend that the marginal costs are the proper basis for setting rates.

A difficulty with setting prices equal to marginal costs is that the resulting annual revenues may be either too much (yielding an excess profit) or too little (threatening the utility's ability to continue service). State regulatory agencies traditionally determine an annual "revenue requirement" that covers costs and allows for a fair return on investments in the utility. Rates based on embedded costs are designed by an allocation procedure to be, in some sense, fair but primarily to yield the annual revenue requirement target. Most advocates of marginal cost pricing concede that rates should be allowed to deviate from marginal costs just enough so that the revenue requirement is attained.

Proponents of embedded cost ratemaking advance several reasons for continuing this practice. First and foremost, such costs are familiar to both utilities and utility commissions, having evolved as a nationally accepted approach during the history of gas distribution regulation.

Second, proponents claim that the issues relating to embedded cost methods are clearer, easier to understand, and more suited to the administrative procedures that characterize a gas distribution rate case than the issues involved in marginal cost ratemaking. The use of a historic test year negates any need for difficult analysis concerning forecasting methodologies to determine costs in a projected test year. In particular, it avoids the calculation of system expansion costs, which may be required in a marginal cost calculation. Also avoided is the issue of how to adjust marginal-cost-based rates to meet the revenue requirement. Because embedded cost issues are clearer and precedents have often been established on how to resolve them, these issues will be more easily and expediously resolved.

Third, embedded costs are said to provide reasonable estimates of the cost responsibility of each class of gas customer and are easily adaptable, by altering the allocation procedure, to changing utility and regulatory concerns.

The principle argument in favor of marginal cost ratemaking is that it promotes "economic efficiency." That is, it encourages the best use of society's resources (labor, capital, land, fuels, and so on). The idea is that prices, either low or high, induce customers to consume either more or less natural gas (and, with their remaining dollars, more or less of other goods and services). With gas prices equal to marginal costs, customers are induced to consume the "right" amount of gas because the value placed by each customer on additional gas consumption just equals the value he places on additional consumption of other goods (assuming other goods are priced at their marginal costs also). If gas rates are unequal to marginal

costs, customers will consume too little or too much gas--inducing utilities to over- or under-invest in natural gas distribution.

The effect of Federal legislation on State consideration of this issue is discussed later in this chapter.

Lifeline Rates. - Lifeline rates are often thought of as the same as inverted rates, which are discussed in the next subsection. In this report, lifeline rates are considered quite distinct, even though lifeline rate structures are almost always inverted. A lifeline rate is a social rate design that has as its goal the furnishing of a quantity of gas sufficient to meet the basic energy needs of residential customers at an admittedly subsidized cost. If it is intended to cover space heating needs, the quantity of gas covered by the low rate would vary according to geographical location and season of the year. It is usually agreed that the lifeline rate should not be less than the distribution utility's variable cost, principally the cost it pays to its supplier for the gas. The rate may cover a portion of the utility's fixed plant costs, depending on the amount of the subsidy. The costs not covered by the lifeline rate are spread over the rates of other customers, either the high-use residential customers only or all other customers including commercial and industrial. In theory, state government could cover the subsidized costs, but in practice government subsidized energy use is not implemented through a lifeline rate program.

Advocates of lifeline rates contend that the practice is desirable because it avoids the administrative costs of direct government aid, such as welfare or energy stamps. Also, lifeline rates for all, or just poor,

residential customers enable the recipients to receive essential aid without the demeaning aspects of visiting a welfare agency.

Critics of lifeline rates contend that the program is based on the assumption that most low-volume residential users are poor and most high-volume users are not--and that the assumption is often untrue. Wealthy customers may qualify for lifeline rates for their low-use vacation cottage, while large, poor families in large homes and elderly customers in older, poorly insulated homes are high-volume users that must cover not only high gas costs but also the lifeline subsidy. Even when customers must be "certified" as poor to qualify for lifeline, opponents contend that the administrative costs are then large.

Whether lifeline is for all residential customers or just the poor, critics contend that the program is opposed to economic efficiency and that the harm done by price distortion is not balanced by the benefits received. Most economists believe that, if a subsidy is necessary, it should come as an income supplement rather than as a gas price reduction. The supplement allows the recipient the freedom of choice to use the extra income to pay for natural gas, to pay for insulation, to buy warmer clothing, or by conserving gas to direct the funds to his or her own higher priority needs.

Rate Structure. A current issue before many state regulatory agencies is whether the structure of natural gas rates should be declining, flat, or inverted. Declining block rates are designed so that prices decline with increasing consumption. For example, the following is a declining block rate: $5 per thousand cubic feet of gas (i.e., per MCF) for the first 4 or less MCF: $4 per MCF for the next 6 MCF (i.e., up to 10 MCF); and $3 for all additional consumption. Each downward step is called a rate block;

some tariffs may have many blocks. The declining block rate for natural gas distribution utilities evolved from earlier rate forms in the first few decades of this century and was the most commonly used rate form through the 1970's.

While most utilities still defend the declining block rate, various customer groups champion either flat or inverted rates. A flat rate is a single price (e.g., $3.25 per MCF) that does not depend on the level of consumption; it is usually used together with a fixed customer charge, also independent of usage (e.g., a customer charge of $4 per month plus a flat rate of $3.25 per MCF). Inverted rates are designed so that prices increase with increasing consumption, as if the traditional declining block rate were inverted.

Utilities, and others, defend declining block rates on the grounds that they reflect declining service costs. A utility incurs certain fixed costs in serving a customer, primarily for pumps and pipeline capacity, regardless of the customer's gas usage level, and the initial rate blocks are intended to recover not only the variable cost of gas but also the customer's share of these fixed costs. Occasionally, utilities have argued that the load of large use customers is steadier, less variable, than low use customers, so that as energy use increases a declining fixed-cost surcharge is appropriate.

Opponents of declining block rates assert that the rate is primarily a promotional tool. In the early days of the industry, when the cost of supplying gas was low and gas was abundant, utilities realized that they could achieve economies of scale if they could continue to expand the size of their facilities. To promote growth in gas sales, declining block prices were instituted. Critics contend that this may have been

economically justified when gas was abundant, but that it is inappropriate today.

Instead, some argue that flat rates are now the most appropriate, with certain fixed costs covered by the fixed customer charge. During the late 1970's, there has been a trend to "flatten" gas rates in most states; that is, to reduce the number of rate blocks and the price differences between blocks--or to institute a true flat rate.

Where rates have been flattened, the size of the customer charge is usually an issue. On the one hand, some argue that most fixed costs should be included in the customer charge so that the flat rate would cover little more than the utility's cost of gas from its supplier. This approach, on the other hand, results in a large gas bill--on a dollar per MCF basis--for small users. Hence, some consumer advocates may argue for spreading more of the fixed costs over the flat rate portion of the tariff.

Still others argue for an inverted rate. With an inverted rate, the last block is set at a price above the average cost of service, possibly at marginal cost. Price for the initial block is below average, possibly chosen so as to meet the revenue requirement of the company. Inverted rates are generally designed to encourage conservation of natural gas. Such rates are not admitted surcharges or subsidies, but are asserted to be based on the cost of service using a variant of marginal cost pricing principles. Supporters of inverted rates cite economic efficiency and low-rates-for-low-volume-users as secondary advantages of this rate scheme.

However, many economists reject the notion that price should vary with an individual's level of consumption. Some lifeline supporters, who believe that aid should be targeted to the poor, do not support inverted rates. Such rates are usually opposed also by large commercial and

industrial customers who claim that inverted rates are an attempt to shift more of the fixed costs of the gas distribution system from residential to other tariffs. In addition, it is difficult to demonstrate that conservation will result, i.e., that the effect of the rate increase in later rate blocks will not be offset by the effect of the rate decrease in the early blocks.

For these reasons, the inverted rate has not been adopted to any great extent.

Purchased Gas Adjustment Clauses. Purchased gas adjustment clauses for natural gas, like fuel adjustment clauses for electric service, are a vehicle for passing through to customers increases in energy costs faced by a regulated utility, without having a full rate case hearing to decide the issue. Most natural gas distribution utilities purchase all or most of their gas from a producer or a transmission company. The price of gas is typically specified under long-term contract with an escalator clause that permits the supplier to pass along his own cost increases to the distribution company. Many regulators believe that it is unreasonable to have a lengthy and costly rate case, which involves re-examination of all the company's costs and asset values, whenever one known cost, that of the gas itself, changes--especially during a period of frequent gas price increases.

Several issues are faced by state regulatory agencies regarding purchased gas adjustment clauses (PGA's). One is whether there should be a PGA at all. Opponents of PGA's contend that they are antithetical to good regulation. Traditionally, utility rates were in effect for several years at a time, and the ability of utility management to control cost

increases--or to reduce costs--determined the profitability of the company during those years. This "regulatory lag" between the incurrence of a cost increase or decrease and its reflection in new rates of the monopoly utility is the regulatory substitute for the competition of the marketplace. Opponents of PGA's contend that PGA's reduce the motivation of utility management to hold down costs aggressively.

Another PGA issue is to what degree the cost pass-through should be automatic. In some cases, the utility is permitted simply to raise rates. But, totally automatic clauses are uncommon. In most cases, the utility is authorized to pass on increased costs, but is subject to having the increase in rates reviewed by the regulatory agency and suspended prior to actual implementation. In a few cases, hearings are required periodically to sanction the cost pass-through, and such hearings can take on the character of a mini-rate case focussing on gas costs.

Still another issue faced by the states concerns what costs to include in the PGA calculation. The adjustment may be based on costs actually experienced in the recent past or projected costs for the period when the PGA rate is to be in effect. The adjustment may cover all or a portion of increased costs; it may include or exclude gas from utility-owned wells; and it may account for gas withdrawn from storage on the basis of different accounting principles (LIFO, FIFO, other).

The PGA's adopted across the nation may differ greatly in detail, even though they are designed to accomplish the same basic goal. This variety leads to a variety of issues that may be state-specific or even utility specific: the treatment of the over-recovery of gas costs, when rate changes are reflected in customers bills, what percentage of adjustment is

allowed without hearings, for what maximum time limit may an adjusted rate be maintained before hearings are required.

In addition to the design and operation of the PGA, state agencies face the issue of what level of monitoring of the utility by the agency is required to ensure that management is reasonably aggressive in looking for the lowest cost gas suppliers, engaging in contracts with escalator clauses favorable to ratepayers, and accurately reporting costs. Among the monitoring activities that the state agency may undertake are the following:

1. Reporting. Uniform reporting of key cost, revenue and operating data may be required for each adjustment.
2. Review. A review of each set of reported data by the staff of the state agency may be needed to ensure completeness of reporting, to test the correctness of the company's calculational method and arithmetic, and to compare the result with that expected from comparison with other periods or other utilities.
3. Audit. Periodically, the agency staff may conduct an in-depth audit of the gas acquisition practices of the company, including financial and operating practices.
4. Hearing. Subsequent to the audit a formal gas cost hearing before the commission may be required.

Each of these four monitoring activities may be undertaken or not by the state agency observing a utility with a PGA, and each activity may be carried out with various degrees of thoroughness. An issue faced by state agencies is to choose the appropriate level of each activity--to decide whether additional monitoring costs yield compensating ratepayer benefits.

Other Issues. - In addition to these current ratemaking issues, it is worthwhile to consider a major problem of the recent past faced by state utility regulatory agencies: the allocation of gas under supply curtailment. If gas supplies should decline in the future, similar issues will emerge again.

During the early and middle 1970's, the demand for interstate natural gas by the consuming states exceeded the available interstate supply. There was relatively little that state agencies in the consuming states could do to increase supply--control of supply was, in part, in federal hands--but states were faced with the difficulty of allocating the limited supply.

In most states, the first response was to impose restrictions on hooking up new customers to the system in order to limit the growth in demand and protect supplies for existing customers. The next step was relatively easy--to ban the use of gas as a fuel in large boilers that had alternate fuel capability. Next came smaller boilers of commercial and industrial customers with alternate fuel capability, and this led to several issues. In general, there was no good data on which customers had alternate fuel capability. Schools, hospitals, libraries, and other public service institutions often were billed under the "commercial" tariff, and requested special allocations from the state agencies.

After boiler curtailments, curtailments were generally according to a priority scheme that had to be devised by each state. During the early 1970's, the Federal Power Commission, FPC, (now the FERC) had the authority to determine how the curtailment burden of a transmission company should be distributed among the distribution utilities served by that transmission company. The FPC chose a scheme based on the customer characteristics of

the distribution companies. However, once a distribution company received the gas under this scheme, the state agency was free to implement its own allocation plan for dispensing the gas received.

In addition to the issue of who received gas, two other issues emerged that were related to curtailments. First was the issue of how to treat any high-priced gas that became available to alleviate curtailments: on the basis of "roll-in" pricing or on the basis of "incremental" pricing. In the first case, the cost of the additional gas was averaged in (rolled in) with low cost of the bulk of the supply--so that every customer's rate increased slightly. In the second case, certain curtailed customers were allowed to receive the gas only if they would bear the full extra (incremental) cost of new supplies. Different states adopted different approaches, but the decisions involved considerable controversy.

The second issue related to curtailments involved how to cover the fixed costs of excess distribution pipeline capacity. Under the traditional ratemaking formula, the annual revenue requirement of a utility is composed of a fixed and a variable portion. The average price of gas is simply the quotient of the revenue requirement divided by the volume of gas sold. As the volume is curtailed, the variable portion of the revenue requirement (primarily, the cost of gas) decreases, but the fixed portion (the cost of fixed system) remains constant. As a result, the average price of gas increases as the supply decreases.

Some states instituted a "curtailment tracking adjustment clause" or a "volumetric variation adjustment" to rates, which permitted a utility to raise its rates so that supply curtailments would not lead to revenue losses and to inability to satisfy company stockholders or even bondholders. Consumer groups were outraged that some state agencies were

permitting price hikes during a period of declining quality of service by the gas industry. They raised the question of whether the industry should be "held harmless" during a period of poor supply performance.

This issue was, perhaps, never satisfactorily resolved, but simply faded away along with the need for curtailments. It may re-emerge, however, during the 1980's if either supplies are curtailed or, more likely, some existing customers leave the system because gas prices rise faster than the price of alternate fuels. Then, customers "locked in" to gas may raise this issue again.

Recent activities. Three recent activities of state regulators of natural gas distribution companies should be mentioned, not because they involved major policy issues in most states, but simply because they have taken a great deal of regulators' time recently. Each was mandated by the National Energy Act (1978). They are (1) conducting hearings on the PURPA standard regarding the elimination of master metering in residential buildings, (2) conducting hearings on the PURPA standard regarding the establishment of customer disconnect policies, and (3) establishing rules, as required by the Fuel Use Act, relating to a ban on outdoor decorative gas lighting.

Monopoly Characteristics and Behavior

Public utility regulation by controlling the entry of new gas distributors in a service territory supplants competition among gas distributors. The primary tools of the public utility commission and local authorities for limiting competition are the market franchise and the certificate of

convenience and necessity. By controlling entry, two policy objectives are facilitated. First, the benefits of economies of scale can be realized or the wastes of competition can be avoided by having a gas distributor who serves the franchised market area be a monopolist. Second, restrictions on entry effectively control investment in distribution facililties. This control enhances the commission's ability to regulate prices and profits for a gas distributor.

The validity of the policy of having a monopoly for gas distribution in a given market area depends on several technological factors. The physical connection between the producer's facilities and the consumers' premise is a feature unique to utilities that has several substantive consequences. First, *de nova* entry into natural gas distribution or expansion of facilities is characterized by indivisibilities. Second, once this investment in a distribution system is made, the resources are sunk and relatively immobile. Third, rights of way must be acquired and maintained. Finally, the physical connection creates conditions favorable to the practice of price discrimination. Each of these consequences of the physical connection between the producer and the consumers can lead to costly or wasteful competition or impose undue burdens on the consumers if competition were allowed. In conjunction with the consequences of the physical connection, economies of scale are the most often advanced rationale for monopoly in the provision of natural gas distribution services. According to this concept, one distributor can supply distribution services to the market at a lower cost than two or more distributors. Monopoly is considered to be the natural outcome of market forces in these circumstances. Public utility regulation by establishing

monopoly and supplanting competition avoids the wastes and undue burdens of an unregulated market.

In this section, the rationale for monopoly in the provision of distribution services and the feasibility of intraproduct and interproduct competition are examined. The section is divided into seven parts. The use of the franchise, the certificate of convenience and necessity, and anti-piracy laws is examined in the first part. In the second part, the competitive implications of the physical connection between the producer and the consumers are covered. A theoretical and empirical investigation of economies of scale is presented in the third part of the section. The fourth part contains a disucssion of rights-of-way as a scarce community resource. In the fifth part, the possibilities for price discrimination are examined. The role of vertical integration in dampening competitive forces and in complicating the regulation of prices and profits is examined in the sixth part. Finally, the potential for intraproduct and interproduct competition is addressed. Particular attention is given to the performance problems attributable to existing and potential structure and behavioral problems.

Legal Barriers to Intraproduct Competition

Three general steps are required for a utility to enter a market. They are the corporate charter, the franchise, and the certificate of convenience and necessity. As mentioned, the franchise and the certificate are legal methods by which the state and local authorities can control entry into a market. Supplementing these controls are anti-piracy laws in most states. These statutes, agreements, or case law prevent competition

among gas distributors in a market area. These controls on entry are discussed below.

The franchise is an ordinance or a contract specifying the conditions under which a utility provides service to a given area. Franchises are necessary because a utility in most cases cannot render service without using city streets and thoroughfares. The franchise constitutes permission for the utility to use its streets. It can be an exclusive franchise. In this case, the utility becomes the sole supplier of the service to the locality. In turn, the utility must give some assurance of reasonable service qualilty and rates, as well as provide some services to the city at favorable rates. Without the grant of a franchise, a firm seeking to render the utility's service would be illegally using the city's streets and thoroughfares.

The certificate of convenience and necessity is an equally potent legal barrier to entry if state authorities use it in this way. The certificate is obtained from state public utility commissions. The application by the potential entrant must demonstrate that its facilities are needed, and that it, as a utility, could provide adequate service at a reasonable price. To accomplish this, the applicant must submit the plans of its proposed facility, show that it would meet minimum quality and performance standards, submit the estimated cost of construction and operating expenses, present a financial strategy to raise necessary funds, and file a proposed set of rates for rendering service. The issuance of a certificate of convenience and necessity authorizes the construction to proceed and also defines the service area.

Both state and local authorities as a matter of policy could authorize more than one utililty to render service in a specific area. This is not

done in the belief that a regulated monopoly can render service at a lower social cost per unit of gas delivered than can two or more firms in competition. This policy is supported by agreements, federal and state regulatory commission decisions, federal and state court decisions, and statutes. The general rationale focuses on the wastes of competition associated with duplicate facilities. Several examples are given below.

The Montanta Public Service Commission asserted in the case, Montana Public Service Commission v Blue Flame Gas Co. (Mon) PUR 1926D 314, 319, that competition is not in all circumstances the best protector of the public interest. It stated:

> ...(I)t has been conclusively demonstrated in almost every small community where the experiment was to be tried that the grant of franchises to competing public utilities is wrong in principle and invariably results in unsatisfactory service. Competition has long ceased to be potent as a regulatory factor in public utility operations. Where it was relied upon, it proved to bad in the long run for consumers of utility service, as too often it meant duplication of facilities in a field not large enough to support more than one company. The usual outcome of this was consolidation, followed by recoupment, by means of higher rates, of losses due to competition.

This opinion by the Montana commission sugests that the validity of a monopoly might be limited by the size of the relevant market. However, competition is deemed bad for both consumers and investors. Destructive competition destroys the value of investments in plant and equipment. Investors lose money and become leery of investing in a competitive utility industry. Consumers lose because the increased risks drive up costs, result in inferior and unreliable service, and eventually drive up rates.

At the federal and state level, the distinction between areas of commerce in which monopoly is appropriate and competition is inappropriate

has been made several times. Judge Prettyman of the United States Court of Appeals for the District of Columbia distinguishes public utilities from other businesses. In the case of People of California v Federal Power Commission (1961) 111 US App DC 226, 42 PUR3d 288,295, 296 F2d 348,353, 354, Judge Prettyman writes

> Public utilities are treated as public services. The principle requirement is service, and service is not a necessary result of competition bent on mutual destruction.... The antitrust laws and the regulatory laws are not in conflict; they are complementary. Both have as their objective the public interest.

Regulated monopoly in the provision of utility services can supplant the marketplace and serve the public interest.

In the case City Gas Co v Peoples Gas System Inc. Fl Supr Crt (1965) 62 PUR3d 518, 182 So 2d 429, Judge O'Connell writing for the Florida Supreme Court upheld an agreement between two gas companies with contiguous service areas that forbade competition and specified the markets that each could serve. Previously, both gas distributors had serviced a common area in competition with each other. The agreement was approved by the Florida Public Service Commission. When City Gas company violated ths agreement, a series of cases was initiated. This agreement was upheld, found not to be in conflict with the antitrust statues, and held to be in the public interest. The Florida Supreme Court's decision rested on the implied power of the commission to fix service territories through its issuance of the certificate of convenience and necessity.

Each of the decisions sets public utility service apart from other businesses. Public utilities provide services where reliable, high quality service is paramount to the public interest. Competition is viewed as

wasteful, destructive, and not in the public interest. Instead, protected markets coupled with price and profit regulation is held to be conducive to low-cost, reliable service. State public utility commission can protect the public interest by restricting entry and regulating prices and profits. The wisdom of using regulated monopoly to provide natural gas distribution services depends on several technological factor that preclude competition. It is to these considerations attention is now turned.

Monopoly, Technology, and High Investments Costs

Natural gas distribution entails the delivery of natural gas from a city gate to consumers at a pressure compatible with their end-use appliances. The distributor's plant, equipment, and structures primarily consist of a system of transmission, trunk, feeder, and distribution mains which transport gas at various pressure levels. The investment in mains is characterized by the indivisibility of certain costs. As a result, distributors have an incentive to install unused capacity. In addition, distribution is capital intensive and resources, once committed, are sunk and relatively immobile. Thus, very little of the investment can be recovered in uses other than natural gas distribution. Each of these characteristics of natural gas distribution is closely related to the fact a physical connection exists between the producer and the consumer. The implications of this for monopoly or competition are examined in this section.

The costs of constructing a one-mile segment of distribution mains can be broken down into several cost components. Each of the components can be categorized by the unit of measurement by which the costs are incurred. This information is presented in table 20. Costs can be incurred by the

TABLE 1 20

UNITS OF MEASUREMENT

~~DIMENSIONS~~ BY WHICH COSTS ARE INCURRED WHEN CONSTRUCTING A SEGMENT OF DISTRIBUTION MAINS, BY COST COMPONENT

Column # Cost Component	(1) # Dollars per Mile	(2) # Dollars per Inch-Diameter Mile	(3) # Dollars per Ton
Engineering and Survey	x		
Cost of Pipe		x	x
Freight			x
Laying Costs	x	x	
Valves, Flanges, Bolts, Welding Rod		x	
Inspection and Supervision	x	x	
Painting and Wrapping	x	x	
Rights of Way and Damages	x	x	

Source: Gas Engineers Handbook, The Industrial Press, 1966.

ton, the inch-diameter per mile, and the mile. A substantial portion of the first investment costs for a segment of main is incurred on a per-mile basis. As such, these costs do not vary with the installed capacity of the main; they are indivisible. In particular, most of the costs of acquiring the rights of way, doing the engineering and survey work, and laying the mains are incurred on a per-mile basis. Laying costs weigh heavily into the cost of distribution mains. The laying costs include the costs of clearing and ditching the land, laying and welding the pipe, and back-filling and restoring the land. In most cases, a minimum of 50% of the first investment cost is independent of the capacity of the distribution mains.

This indivisibility of a major portion of the first investment costs creates an incentive for distributors to install unused capacity.[1] As a monopolist, the distributor can rationally anticipate the amount of unused capacity to hold for future use. This amount depends on the present value of installing more capacity in the future. The relevant time period depends on the growth rate of the coincident peak hourly demand along the segment of main. This planning is facilitated by the fact that the distributor, as a monoplist, serves all incremental demands along this segment of the distribution system.

In a competitive situation with two or more distributors serving an area, this indivisibility of investment costs can lead to a condition of chronic excess capacity. In these circumstances, competition can be destructive and cut-throat. This contention is discussed more fully below.

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[1]This incentive is not related to the Averch-Johnson effect. It is a technological phenomenon.

Natural gas distribution is a capital intensive business. A measure of this intensity is the capital turnover ratio. This ratio tells one the gross revenues generated by a dollar of investment in plant, equipment, and structures. The capital turnover ratio for natural gas distributors for 1977 was 0.95.[1] This compares to a capital turnover ratio of 2.0 for most manufacturing activities. Thus, a dollar invested in distribution facilities will generate less than a dollar in revenues; while a dollar invested in manufacturing will, on average, generate two dollars in revenues.

Compounding the commitment of a large investment in facilities is the fact that these resources are highly specialized and immobile. Once committed, the pipes, valves, gauges, services, and meters have little, if any, alternate uses. Furthermore, the removal of mains from a community is costly and impractical. Thus, investors must not only commit a large amount of funds, they must be assured the that risks of committing their resources to gas distribution are adequately compensated.

With the indivisibility of investment costs, capital intensive operations, and specialized, immobile resources, natural gas distribution has the conditions conducive to destructive competition. The major prerequistes for destructive competition are long sustained periods of excess capacity and investment costs that are a large percentage of total cost. Another necessary ingredient is independent competitive behavior by all firms in the industry. Such an industry would have a record of instability for prices and producer incomes. One prominent market imperfection leading to this result is the inability of capital to move out

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[1]Calculated from information available in the American Gas Association, Gas Facts: 1977 data, Arlington, VA, the American Gas Assocation, 1977.

of a situation of excess capacity.[1] Thus, the period of excess capacity is prolonged during which the rate of return to firms remains below normal.

Natural gas distribution has many of the characteristics necessary for destructive competition. These characteristics are very apparent. However, other characteristics are important. In particular, independent behavior on the part of distributors is not necessarily guaranteed. Furthermore, the decisions that lead to excess capacity for the industry are conscious decisions by each distributor to install unused capacity. In evaluating whether these conditions would be met in a competitive gas distribution market, one can only speculate. The market that the industry serves in this case is either a community or contiguous set of communities. This geographical proximity of competitors lessens the potential for independent action. For a conclusive determination, one must, at least, assess the minimum optimal scale for a distributor. Independent action requires numerous competitors. If a market can only support few gas distributors, the competition in all likelihood would gravitate toward oligopoly or collusive monopoly. However, a period of destructive competition may be necessary before the distributors would coalesce.

In summary, the technology of natural gas distribution creates conditions similar to those associated with destructive competition. The physical connection between the consumer and producer has substantive implications. Some of the investment costs are indivisible. This creates incentives to install unused capacity. In addition, the technology of distribution is capital intense and the resources once committed have few

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[1]An assumption of the theory of perfect competition is the perfect, instantaneous mobility of all resources in the long run.

alternate uses. These circumstances are the prerequisites for destructive competition except for one. Independent action requires numerous competitors. The number of distributors a community can support depends on the minimum optimal scale of a distribution system. Unfortunately, no empirical studies have investigated this scale of operation.

Economies of Scale and Natural Monopoly

Natural gas distribution is often considered a natural monopoly. Accordingly, one distributor can serve a market area at a lower social cost than can two or more suppliers because of economies of scale. Duplicative investments are wasteful, and monopoly is the outcome of natural market forces. Substantial economies of scale preclude any other outcome. Thus, public utility commissions by limiting entry and controlling prices and profits act in the public interest.

The validity of viewing natural gas distributors as natural monopolies depends on the extent to which economies of scale are in fact present in distribution. Economies of scale refer to the reduction in the total social cost per unit of output attributable to expanding the production capacity of an entity. The use of the term "entity" in this context indicates that economies of scale can occur at different levels of aggregation. Economies can be plant specific, product specific, or multiplant (system wide) economies. The plant of a gas distributor is defined for purpose of this paper as the system of mains from a community's city gate to the customers' premises. Plant-specific economies are the reductions in the average cost of delivering volume of gas as the capacity of the community's system expands. A multiplant operation is a distributor who financially and operationally integrates the distribution services for

two or more communities under a single corporate charter. Multiplant economies are the reductions in the average total cost of delivering a volume of gas as the aggregate capacity of the company's system expands. The product of a natural gas distributor is the delivery of gas to an end-use appliance. For purpose of this discussion, the delivery of gas to a residential customer is a different product than delivery to a nonresidential consumer. Product-specific economies refer to the reductions in the average total cost of delivering a volume of gas to one customer class as the capacity to deliver gas to that class expands. This framework is the basis for discussing and analyzing economies of scale in natural gas distribution.

The discussion and analysis here (though not necessarily the conclusions) draws heavily from the empirical investigation of statistical cost functions for natural gas distribution by Dr. Jean-Michel Guldmann.[1] He has developed statistical cost functions for various expense and investment accounts for national gas distributors at the community and company level.

Plant-Specific Economies. - The empirical investigation of economies of scale at the plant or community level is severely hampered by the existence of common and joint costs. Gas distribution companies are typically multiplant or multicommunity operations. Certain items of plant, equipment, and structures, operating and maintenance expenses, and administrative and general expenses are incurred in order to serve several

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*Chapters 3 and 4 of Guldmann, J-M, R. Tybout, and William Pollard, Marginal Cost Pricing for Natural Gas Distribution, The National Regulatory Research Institute, forthcoming.

communities simultaneously. These costs conceivably could be allocated among the communities to achieve a rough rule-of-thumb approximation of the actual costs for which each community is responsible. However, such rough approximations are not adequate to determine objectively the extent to which plant-specific economies of scale exist.

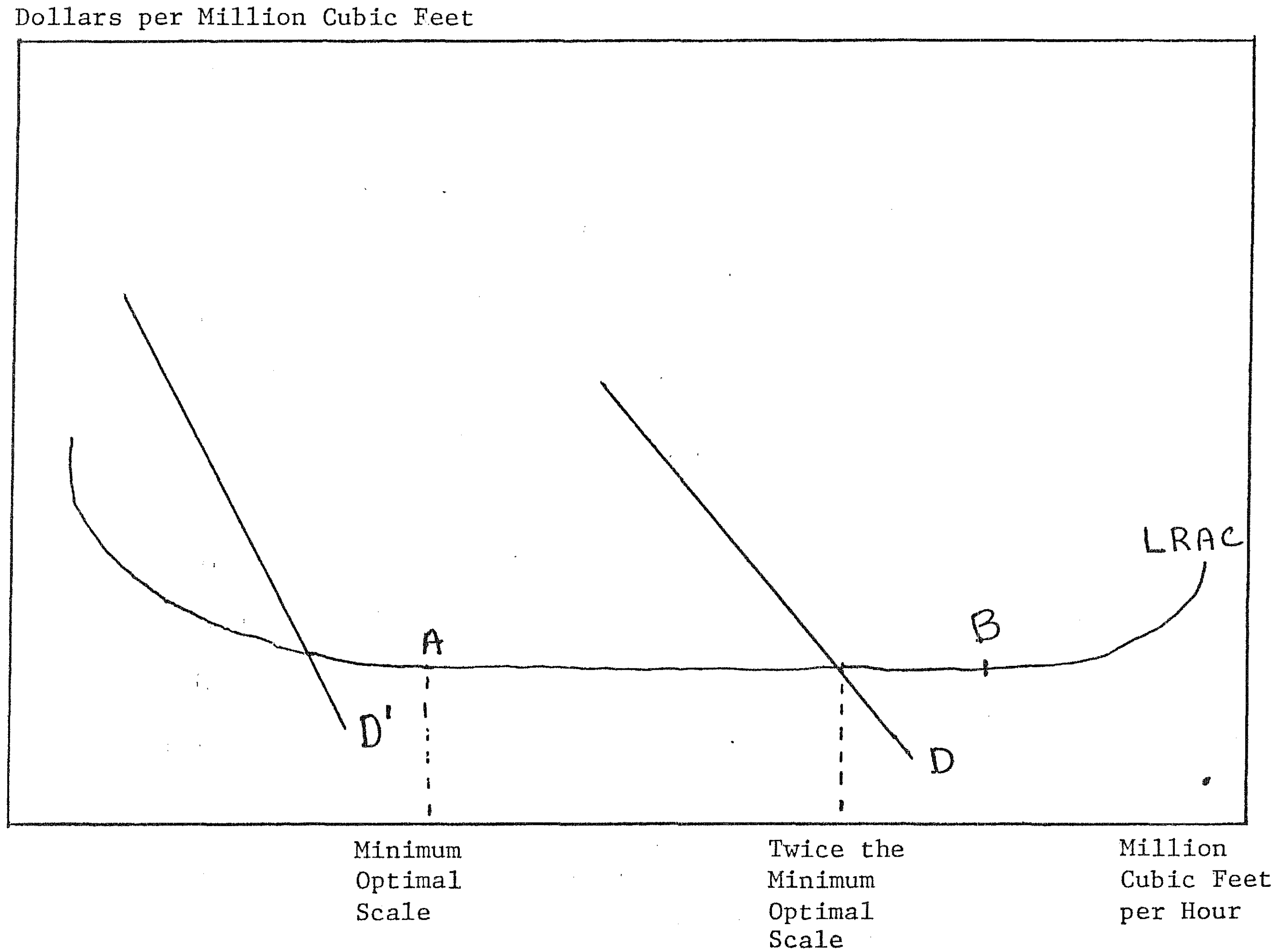
Until adequate data becomes available, several important questions remain unanswered. The most important question concerns the minimum optimal scale of operation at the community level. The minimum optimal scale can be defined as the smallest scale at which all economies of scale are realized. It is expressed in terms of rate of output. For natural gas distribution, the ideal measure would be a volume of gas per hour. However, data limitations may greatly inhibit the attainment of this ideal. The minimum optimal scale can be used to determine the number of viable distributors a community can support.

The minimum optimal scale is that size of operations at which the average total cost of output ceases to fall. It can become flat (constant returns to scale) or increase (diseconomies of scale). Figure 1 depicts this phenomena. At point A, the long run average cost (LRAC) reaches its minimum value for the first time. If a plant were built to this scale and operated at capacity, it could serve consumers at the same cost as a plant the size of B. Plants larger than B or smaller than A incur a higher unit costs cost. To the left of point A economies of scale are experienced.

In order to determine the number of distributors a community can support, market demand is introduced. If total market demand is D^1 (see figure 1), economies of scale are present and monopoly would be considered natural. On the other hand, if total market demand is D (see figure 1) constant returns to scale are experienced. In this case, competition as a

FIGURE 1

LONG RUN AVERAGE COST (LRAC) RELATIVE TO MARKET DEMAND AND THE MINIMUM OPTIMAL SCALE



matter of policy cannot be ruled out. In fact, the diagram is constructed to justify duopoly. The number of distributors a market can support is determined by dividing the total demand per time period by the minimum optimal scale. Competition cannot be ruled out on this basis when the number of distributors exceeds two.

In summary, plant-specific economies for natural gas distribution are difficult to analyze empirically. Data limitations due to the existence of common and joint cost in multiplant operations preclude the exact determination of the cost of rendering service to a community. The estimation of the minimum optimal scale of operations is an important first step to understanding the competitive possibilities at a given point in time. Without knowledge of the minimum optimal scale, even a conclusion of non-increasing returns to scale (constant returns or diseconomies) does not necessarily support desirability of competition. If two firms were to enter, both firms might operate at a scale at which each experiences economies of scale. Here, competition is unstable and will lead to monopoly. By determining the minimum optimal scale for gas distributors, one can determine the number of distributors the market can support.

Multiplant Economies. - By focusing attention on the distribution company, statistical investigation of economies of scale is feasible. In this subsection, the nature of multiplant economies in nature gas distribution is discussed, and tests for its existence are presented. Multiplant economies can emananate from several sources. Potential economies are cost reductions from pooling and coordinating the operation of several plants, capital-raising economies, and procurement economies. In his empirical work, J-M Guldmann developed statistical cost functions

for natural gas distribution at the company level. These results do not refute the existence of constant returns to scales at the company (multiplant) level.

Integrating the operation of distribution services for several communities under a single corporate charter can have several benefits. First, by pooling decision-making resources, administrative overhead and general expenses may be reduced because fewer resources will be devoted to this activity. This centralized decision-making could facilitate the planning future capacity additions and replacements. Potential cost reductions are achievable by strategically expanding the capacity serving more than one community. For instance, transmission mains and storage fields could be developed and shared. Furthermore, if there is substantial diversity in the temporal pattern of demand, the economies of sharing plant, equipment, and structures are enhanced.

The coordinated procurement of gas supplies for several communities could yield some economies. Transaction costs could be reduced. By contracting for all communities simultaneously, resources devoted to negotiating these contracts may be reduced. In addition, by contracting for larger requirements, the risk to the suppliers to the distribution company could be reduced. For instance, production from a field can be dedicated to the company. Other sources of cost savings to the distributor can be an income redistribution at the expense of the supplier. Larger requirements and coordinated purchasing increases the bargaining strength of the distributor. The horizontal integration of natural gas distributors permits them to capture the benefits of the temporal diversity of demand. This can improve their annual load factor if the actual maximum daily demand for a year is smaller than the sum of each community's maximum daily

demand. In this case, the distribution company can offer a transmisssion company a higher rate of utilization of its pipeline than could each community separately. This could lead to concession in the demand charges and other capacity-related prices. This shifts the benefits of diversity from the transmission company forward to the distributor. It is only an income redistribution, however, and as such does not reduce resources devoted to either activity.

Finally, multiplant operations can confer risk-pooling economies on the distribution company. The increased size of the distributor's market and the corresponding benefits of the temporal diversity in demand could reduce the risk to which investors are exposed by purchasing the distributor's securities. Lower risks lead to reductions in the cost of capital.

Each of these potential cost savings could emanate from horizontally integrating distribution service for several communities. Data that would allow the investigation of each of these potential multiplant economies are not available readily, if at all. However, the results of Guldmann's analysis allow inferences to be drawn about overall economies rather than these specific types of multiplant economies.

Professor Guldmann gathered data on 119 U.S. gas distribution utilities. All of his data were for the year 1979 and drawn from the 1979 Annual Reports of the utilities to their state regulatory commissions. And the 1979 Uniform Statistical Reports prepared by the utilities for the American Gas Association. The data used in the analysis can be grouped into three categories.

(a) Plant in service data, characterizing the historical cost values of different plant components at the end of 1979.

(b) Operation and maintenance (O&M) costs data, characterizing the O&M cost incurred during 1979.

(c) Market sales and numbers of customers at the aggregate and sectoral levels during 1979.

In table 21, the elasticities for each of his regressions are presented. The explanatory variables are displayed down the left side of the table, while the dependent variables are across the top. The table contains the results of twenty separate regressions. These can be separated into two categories. Eleven of these regressions had aggregated variables as the independent variable. Total sales (TMCF) and total customer size (TCUZ) were used in five regressions, while total sales (TMCF) was used by itself in two regressions. The total number of customers (TCUS) was the independent variable for regressions against general plant (TGEN), customer accounts expenses (CAO), and sales expense (SAO). The remaining ten regressions separated total sales, total cutomer size, and number of customers into the residential and nonresidential sectors. Similar regressions were run using the sectorial variables. These latter regressions are discussed in the next section on product-specific economies.

The first row of table 21 presents the elasticity of the various cost categories with respect to total sales. The distribution plant and distribution operating and maintenance expenses exhibit constant returns to scale as total sales expand. General plant and administrative and general expenses exhibit constant to mildly increasing returns to scale, while customer service expenses related to total output exhibit constant returns to scale. The significance of the mildly increase returns to scale is questionable. The general plant accounts for only 4.37% of total plant on average. The expense accounts account for 33.34% of total expenses

TABLE 21

THE ELASTICITY OF VARIOUS INVESTMENT AND EXPENSE ACCOUNTS WITH RESPECT TO SELECTED EXPLANATORY VARIABLES

Column	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Explanatory Variable (Xi)	INVESTMENT AND EXPENSE ACCOUNTS (Y)								
	TDIST	TDOXP	TDMXP	TGEN	CAO	CSO	SAO	AGO	AGM
TMCF	1.0042	1.0029	1.0849	.9273	------	1.1002	------	.9576	.9527
TCUZ	-.9387	-.9207	-1.0635	-----	------	------	-----	-.7916	-.7901
RMCF	.8777	.9192	1.0788	.5021	------	.7291	-----	.8202	.9453
CIMCF	.1167	.0751	-----	.4210	------	.3843	-----	.1313	-----
RCUZ	-.9897	-.8782	-.8878	-----	------	------	-----	-.6922	-.6297
CICUZ	-----	-----	-----	-----	------	------	-----	.6403	-----
TCUS	-----	-----	-----	1.031	1.0183	------	.9797	-----	-----
RCUS	-----	-----	-----	1.049	1.0123	------	.9731	-----	-----
CICUS	-----	-----	-----	-----	-----	------	-----	-----	-----

Source: Guldmann, J-M, R. Tybout, and W. Pollard, Marginal Cost Pricing for Natural Gas Distribution Utilities, The National Regulatory Research Institute, ~~forthcoming~~, Chapter 4.
1981

excluding the cost of purchased gas. The cost of purchased gas is a substantial percentage of the variable cost. Thus, the mildly increasing economies could have little overall impact. From the view of statistical hypothesis testing, it is safe to conclude that one cannot refute the existence of constant returns to scale in natural gas distribution.

The elasticities of the various cost categories with respect to the total customer size variables (TCUZ) suggest there exist substantial cost advantages from serving larger as opposed to smaller customers. In fact, a 1% increase in average customer size lowers total cost by 1% or less. These results, while not pertinent to economies of scale, are relevant to the character of a competitive market. Customers with high average sale would be desired customers, while small customers would be shunned. These circumstances could raise issues of cream-skimming in a competitive environment.

In summary, this analysis of the empirical work by Guldmann does not support the hypothesis of economies of scale in natural gas distribution at the company (multiplant) level. Multiplant economies are defined as the reductions in the average cost of delivering a volume of gas attributable to increased sales. In this case, competition as a policy cannot be ruled out using the economies of scale rationale for a natural monopoly.

Product-Specific Economies. - Product-specific economies are linked to individual product volume rather than overall output. As previously mentioned, a product for a natural gas distributor is defined as the sale of gas to a specific customer class. Two products are defined: residential and nonresidential. Nonresidential customers consist of a distributor's commercial and industrial customers. Thus, product-specific economies

refer to reductions in the average cost of delivering a volume of gas to a residential customer or to a commercial customer as the capacity to serve that class expands.

To the extent that this characerization is valid, the problem of common cost is relevant. Common costs refer to investments and expense incurred that serve both classes of customers. What differentiates common cost from joint cost[1] is the fact that common cost can vary in the proportion serving each class. An increase in residential sales displaces capacity that could serve nonresidential. When common costs are present, each customer class has its own separate identifiable marginal cost curve.

If characterizing sales to residential and nonresidential customers as two products is valid, inferences can be drawn about product-specific economies. The statistical work by Professor Guldmann is again used as a basis for drawing these inferences. Returning to table 21, the relevant rows are those for residential sales (RMCF) and nonresidential sales (CIMCF). Each entry in the table, is the elasticity for the corresponding cost category with respect to class sales. Each elasticity taken separately suggests economies of scale. However, sales to each sector utilize common plant, equipment, and structures. In order to assess the impact of an increased volume of gas, one must add the elasticities for each sector. Thus, a one percent (1%) increase in sales for each sector adds approximately one percent (e.g., .8777 + .1167) to total cost for distribution plant and operating and maintenance expenses. General plant

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[1]Joint cost refer to the costs of investments that yield capacity in fixed proportions. So much for product A necessarily entails the requisition of some amount for B. Capacity to serve the peak is available in the off-peak, a joint cost.

and administrative and general operating expense again show evidence of the same mildly increasing economies of scale. From the standpoint of balanced growth, the conclusion pertaining to economies of scale is left intact--constant returns to scale cannot be clearly refuted.

Conclusion: Economies of Scale. - The natural monopoly justification for the monopoly provision of natural gas distribution depends on the existence of economies of scale in distribution. This reduction in the average cost of delivering a volume of gas can be plant specific, multiplant (system specific), or product specific. Empirical work to date does not lend convincing support for this natural monopoly justification when considering multiplant (company level) and product-specific economies. In fact, the existence of constant returns to scale for both types of economies cannot be refuted out of hand.

Constant returns to scale are characteristic of long-run equilibrium in a perfectly competitive market. In practice, constant returns suggest further study might be necessary. One of the most important pieces of information needed to be determined is the minimum optimal scale for a distribution company. This scale would allow one to determine how many distributors could be supported by a given volume of sales. If two or more firms can be supported, competition as a policy cannot be entirely ruled out.

Rights of Way: A Case of A Scarce Community Resource

Monopoly in natural gas distribution might be desirable if rights of way are a scarce community resource with substantial external costs (borne by society but not the gas company) associated with their use. External

costs may occur as a result of nonexistent or ill-defined property rights. Unregulated markets can potentially create external costs because producers can obtain the use of a resource without having to pay the full social cost for its use. Air and water are good examples of such a resource. External cost are costs not borne by the producer, but by groups in society whether they are users ~~are~~ OR not. Air or water pollution is an example.

In the case of rights of way, the convenience, safety, peace and health of the community are affected by work on mains along streets and throughfares where most rights of way are located. The franchise, as a policy tool for limiting entry, minimizes this disruption.

Whether the size of the external costs associated with rights of way for gas distribution constitutes an adequate justification for monopoly is an open question. Intuitively, one can imagine the disruptive activities of several competitive utilities performing maintenance on their mains. Unfettered entry or use of rights of way is definitely not in the public interest, but it may be the market is misperceived. A policy option for state or local government might be to auction the use of rights of way rather than issue franchises. In this way, the price of the rights of way would control entry. Potential entrants would be forced to evaluate the desirability of entry by assessing the potential profits net of the price for using right of way. Issuance of franchises does not necessarily encourage such cost-benefit comparisons.

In summary, limited entry can be viewed as a method of rationing the scarce community resource of rights of way. Even though limited use may be desirable, creation of monopoly as a matter of policy may not necessarily be in the public interest. The use of the franchise is a direct form of rationing. Price can ration also. Possibilities exist for a competitive

bidding process for rights of ways. This method could potentially lead to net benefits for a community, because potential entrants are acting in their own self-interest.

Price Discrimination

Price discrimination frequently is used as a policy tool to achieve social objectives in the regulation of natural gas distribution. Judiciously applied, price discrimination can increase the use of a service throughout a regulatory jurisdiction, promote economies of utilization for the existing system, promote economies of scale, and reduce rates to all customer classes.[1] When applied by an unregulated monopoly, price discrimination can sap the economic vitality of a market and cause a lot of social harm. The following discussion examines the issues of price discrimination in natural gas distribution and its implications for a competitive policy.

Price discrimination is defined as charging different purchasers prices that differ by varying proportions from the respective marginal costs of serving them.[2] Pricing below the marginal cost of serving a customer constitutes predatory pricing. With natural gas distribution, the nature of the end-use to which gas is put is e basis for price discrimination. In this case, charging customer classes prices that are not justified by corresponding variations in the marginal costs of service constitutes its practice.

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[1]See Phillips, Charles F. Jr., The Economics of Regulation, Richard D. Irwin Co., pp. 303-310.

[2]Kahn, Alfred, The Economics of Regulation, Vol. 1, p. 123.

Natural gas distribution has certain features that may lean the industry toward practice of price discrimination. In particular, the physical connection between the producer and the consumer is a potent instrument for facilitating its practice. The necessary conditions for it are the following:

1. Monopoly or near-monopoly in rendering the service.
2. Markets capable of being separated by the elasticity of demand for each submarket.
3. Prevention of resale from the low-priced market to the high-price market, that is, preventing arbitrage.

Each of these conditions and the related circumstances for natural gas distribution are discussed below, and the implications of these for competitive policy are also addressed.

Markets for natural gas distribution can be separated by elasticity of demand by examining the uses for gas. Elasticity of demand primarily depends on the number of substitutes available, percentage of income spent on the good, the necessity of the good, and the postponability of the purchase. Since gas cannot be stored by consumers, purchase cannot necesarily be postponed or expedited. This tends to reduce the responsiveness of the quantity demand to changes in the price of gas. The total purchase price of gas, or any energy source, requires the consumer to purchase or lease an end-use appliance. The prices for end-use appliances are subject to competitive market forces. A rational consumer evaluates the use of one energy source relative to another by weighing the present value of the expense of using one source, including the annual cost of the end-use applicance, relative to another. However, once the investment in

the end-use appliance is made, the consumer has limited substitution possibilities. (The substitution of one energy source for another would be cost effective only if the present value of the increment in the cost of using gas exceeds the cost of a new end-use appliance for an alternative energy source less the salvage value of the existing gas appliance.) A substitution presumably requires a substantial change in the conditions that initially induced the consumer to choose gas. This demand side of the gas market results in a certain latitude with which gas prices can be varied without having most customers switch to another fuel.

Both of the foregoing considerations indicate that natural gas users may have limited flexibility in responding to price changes. Adjustments can be made, but with a time lag. The implication of this for a competitive policy in natural gas distribution is as follows.

The role of elasticity of demand in price discrimination is fairly straightforward. Price can deviate more from marginal costs in submarkets where customers lack a sufficient degree of flexibility (less elastic demand). Prices are set closer to marginal costs where customers have sufficient flexibility. Such a pricing scheme enables the distributor to earn profits above and beyond those available if he were to charge a price that deviated equally for all customers from the marginal cost of serving them.

For price discrimination to be effective, competition must be minimal and the submarkets prevented from selling to one another. Arbitrage of the high and low priced markets is prevented under current regulatory practices by the existence of the physical connection and laws preventing unauthorized hookups. Such legal provision can be justified on safety and health grounds. These reasons should prevail irrespective of competitive policy.

The ability of competitive gas distributors to check price discrimination in the provision of service through abritrage is not readily obvious. In particular, the number of competitive distributors a market can support is an important consideration. As stated previously, oligopoly or collusive monopoly could be the probable outcome of a competitive market for distribution services. This would probably only eliminate the most virulent and unjust discriminatory practices.

Entry of distributors could make matters worse. Cream-skimming and entry to selected markets could accentuate certain discriminatory practices. Existing distributors could alter the relative prices for gas amond markets. Excess profits could be earned in markets where competition is less intense to support the company in the more competitive markets. This cross-subsidization of markets and the corresponding potential for predatory pricing would be a clear danger. As a result, any potential for competition is dampened by the possibilities for price discrimination.

Vertical and Horizontal Integration

The shortages of natural gas and the accompanying curtailments during the 1970's prompted natural gas distributors to form joint ventures to explore and develop natural gas fields. This behavior can have potentially far reaching effects on the structure of the natural gas industry and create potential monopoly problems for state and federal regulators. In particular, by gaining control over the source of supply at the wellhead, the distributor's potential for earning monopoly profits is enhanced.

Backward integration by a natural gas distributor destroys the arms-length bargaining relationship between a pipeline and a distributor. When the distributor has no financial interest in the natural gas he

purchases from a pipeline, he has a clear incentive to bargain strenuously for his gas supplies. As a result, he has little to gain by restricting gas services to customers. In fact, one can expect distributors to file complaints and intervene in rate cases affecting the price of gas from interstate and intrastate piplelines. This is, in fact, the case. This arm-length relationship can be a fairly dependable tool with which public utility commissions can be assured gas supplies are reasonably priced, providing that adequate price information is available to all. However, once a distributor has a financial interest in selling gas, as well as buying it, state commissions can no longer depend on the arms-length relationship. It is in the distributor's interest to restrict the supply of natural gas and purchase it at an unreasonably high price. In doing this, he can extract monopoly profits from his distribution customers and earn them on his investment in production. Thus, backward integration enables a distributor to realize monopoly profits from his regulated markets.

Joint ventures among distributors exacerbate the problems associated with backward integration. Joint ownership of gas wells diminishes the possibility that any one distributor would protest the price of that gas. Furthermore, it distorts the standard of comparability for prices of gas. If distributors in a given pricing area are obtaining incremental supplies of gas from a well they jointly own, regulatory commissions would find it more difficult to develop standards by which to evaluate the reasonableness of the price of gas.

Interproduct Competition

Competition among energy suppliers has been quite effective in eroding the market share of natural gas. Shortages and subsequent curtailments of gas, particularly to interruptible customers, led to declining sales and revenues in the latter part of the 1970's. As a result, gas distributors have come to embrace the goal of revenue stability. This goal manifests itself in several ways. One objective of distributors is to gain credibility with industrial customers; distributors want to prove themselves a reliable source of energy. As discussed above, backward integration into production is one method of assuring a reliable source of gas. Interproduct competition has also led to attempts to engage in certain anticompetitive pricing practices. These pricing schemes, while subject to regulatory control, represent attempts to foreclose their markets to competitive inroads.

Two instances are presented below. One is specific, while the other simply describes a set of circumstances. The first involves an attempt by Columbia Gas of Ohio (a distribution company) to foreclose the combination of heat pump and gas heat in residential homes. The other is about a distributor and an industrial customer on the west coast.

Columbia Gas of Ohio tried to impose a $12 surcharge on gas space-heating customers who also installed electric heat pumps. Columbia's rationale focused on the low load factor that this type of customer would exhibit. Gas heat in such homes is used to supplement heating needs only during the coldest periods. It would be used in lieu of high cost electric

resistance heating. Columbia argued that such a use of gas imposed a cost on all the other customers in its system.[1]

The problem that gave rise to the situation was the artificially low price of gas as regulated at the wellhead. A competitive pricing problem existed that required adjustments in the rates for gas and/or electric space heating. The outcome was that Columbia dropped its request for the surcharge, which the Public Utilities Commission of Ohio might well have denied. Public outcry prevented this request from getting to a rate case. If put into effect, however, the surcharge would have inhibited a competitive use of electricity for gas.

In another situation, a west coast industrial firm wished to take advantage of the glut of oil experienced on the west coast. Previously, it had obtained all of its energy requirements from the local gas distributor. The industrial customer installed fuel switching capabilities to use both gas and oil. This cost-effective strategy enabled the customer to hedge his commitment to either gas or oil because of the uncertainty surrounding the supply or price of both.

The gas distributor's reaction was predictable. It feared the loss of revenues to a competitive source of energy. Upon being informed, the distributor's spokeman informed the industrial customer that the gas company would be out to remove the meter at the service drop. This threat of withdrawal of service had its impact. The industrial customer's investment in end-use equipment would be rendered useless. The situation required negotiation.

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[1]See Columbia Gas Distribution Companies, New Load Evaluation Techniques, Mimeo.

The distributor won contract concessions with the industrial customer. Something similar to a take-or-pay charge was negotiated. The industrial customer had to pay for a certain percentage of his peak gas demand whether he used it or not. The distributor, by virtue of his monopoly position, was able to enhance his revenue stability in the face of competitive inroads. State regulation of gas distribution has the potential to control this monopoly behavior when brought to its attention.

Conclusions on Monopoly in Natural Gas Distribution

State public utility commissions and local authorities enforce monopoly in the provision of natural gas distribution service with the certifcate of convenience and necessity and the franchises. Monopoly and limited entry are believed to be in the public interest for three somewhat interrelated reasons. Duplicate facilities are alleged to be wasteful either because economies of scale exist and monopoly is therefore natural or because competition is destructive. The scant empirical evidence that is available does not support the hypothesis of economies of scale. In fact, constant returns to scale seems to prevail. This implies that competition is feasible. Offsetting this conclusion, however, is circumstantial evidence supporting the hypothesis of destructive competition. Indivisibilities of certain investment costs create incentives to install unused or excess capacity. This fact coupled with the high investment cost in a specialized and relatively immobile resource creates conditions favorable to destructive competition. In these circumstances, monopoly might best serve the public interest. A conclusive demonstration of the potential for competition would entail the estimation

of the minimum optimal scale of a distribution system. This scale of operation would enable one to determine the number of firms a given market could sustain. Beyond these reasons for monopoly and even if competition is feasible, state and local policymakers recognize that rights of way are scarce community resources. Unregulated use of the rights of way could be disruptive to the safety, health, and peace of a community. Thus, the potential for destructive competition and the limited availability of rights of way tend to support monopoly in natural gas distribution as being in the public interest.

The physical connection between the distributor's supply point and the consumers' premises constitutes a majority of the distributor's plant and equipment. This connection and cost are inextricably intertwined with the above reasons supporting monopoly and have important implications. The physical connection and laws preventing unauthorized hookups create conditions favorable for price discrimination. Intraproduct and interproduct competition may not constitute sufficient market forces to check price discrimination. In fact, intraproduct competition may lead to cross-subsidization between markets to foreclose competition through limit or predatory pricing.

Vertical integration backward into gas production by distributors has escalated in the past few years. An interest in revenue stability and assured supplies of gas has led distributors to develop their own sources of supply through direct investment or joint ventures with other distributors. This tendency threatens the arms-length bargaining relationship that has often previously facilitated state regulation of distributors. At risk are the standards of comparability that public utility commissions can rely on to assure that gas is purchased at reasonable prices.

Finally, interproduct competition raises a potpourri of issues. At the forefront are issues of competitive rate structures for natural gas and threats of withdrawals of service. State public utility commissions frequently take an active role in addressing and resolving these issues.

The alternatives of a regulated, quasi-regulated, or competitive gas distribution industry can be considered in view of these factors. Interproduct and intraproduct competition in natural gas distribution does not necessarily offer a better alternative to regulation for resolving these issues.

Impact of Federal Regulation on State Regulation

The effect of federal regulation on state regulation of natural gas distribution has been pervasive. Federal regulation determines wellhead prices. Because federal regulation controls wellhead prices, states have been essentially helpless to control a major portion of costs and, hence, prices to the end users. Federal regulation also affects pipeline transmission rates because the Federal Energy Regulatory Commission (FERC) regulates the pipeline transmission rates of interstate gas and intrastate gas in interstate pipelines. In addition, the Natural Gas Policy Act of 1978 places additional restrictions on state ratemaking authority over intrastate utilities. These major impacts of federal regulation upon state public utilities are discussed below.

The Effect of Federal Regulation of Wellhead Prices

Prior to enactment of the National Energy Act in 1978, the Federal Energy Regulatory Commission (FERC) regulated the wellhead price of gas

consumed in the interstate pipeline system. The wellhead price of gas not in the interstate pipeline system, that is, intrastate gas production, was either unregulated or regulated by state regulatory commissions.

The Natural Gas Policy Act of 1978 (NGPA), however, changed this scheme. NGPA brought wellhead pricing of all gas produced within the United States under federal jurisdiction. Under NGPA, FERC lost its authority to set wellhead prices, but was charged with identifying and enforcing the legal prices to be charged for various categories of gas spelled out in the NGPA.

The NGPA sets out several categories of gas. These categories include (1) new natural gas from new Outer Continental Shelf Leases, New Onshore Wells meeting certain requirements, and New Onshore Reservoirs, as well as qualifying natural gas produced from an old lease on the Outer Continental Shelf (NGPA, Section 102); (2) New Onshore Production Wells drilled on or after February 19, 1977 (NGPA, Section 103); (3) Natural Gas Dedicated to Interstate Commerce before enactment of the NGPA (NGPA, Section 104); (4) Natural Gas Sold Under Existing Intrastate Contracts before the enactment of the NGPA (NGPA, Section 105); (5) interstate and intrastate natural gas sold under rollover contracts before the enactment of the NGPA (NGPA, Section 106); (6) high cost natural gas drilled on or after February 19, 1977 including, wells drilled to a depth of more than 15,000 feet, geopressured brine, natural gas from coal seams, natural gas produced from Devonian shale, and natural gas produced under any other conditions that FERC determines to present extraordinary risks or costs (NGPA, Section 107); gas from stripper wells (NGPA, Section 108), and gas fitting in other categories (NGPA, Section 109). Each of these categories can be further

subdivided. All in all, there are about two dozen categories of gas under the NGPA. The FERC delegated to the states the initial identification of the price categories for gas produced within the states.

The delegation of identification of price categories for new wells usually went to state agencies more familiar with drilling and production activities than state utility regulatory commissions. Some believe that these state authorities are often understaffed, and without sufficient personnel to check each well in production.

As noted above, the primary effect of federal regulation of wellhead prices is that states are essentially helpless to control a major portion of costs, the costs of gas production, and hence are helpless to control a major portion of prices to the end users. The NGPA has been blamed for distortions in the gas market. For example, by deregulating high-cost gas, while keeping most other gas prices depressed, the NGPA induces production of high cost gas at a price that is much higher than the market clearing price of gas. This is possible because the deregulated gas is rolled-in with the price of regulated gas. Thus, the NGPA has created a powerful incentive for the most expensive gas to be produced before the cheapest gas. This has been labeled a misallocation of resources. State utility regulatory commissions are left with little choice but to pass the cost of gas priced according to federal wellhead pricing on to the end users.

Another effect of federal determination of wellhead pricing is that most of the intrastate gas production was essentially deregulated at the time of the passage of the NGPA. Thus, the NGPA puts intrastate pipelines at a disadvantage because they have little cheap gas to roll in with expensive new sources of gas. This disadvantage could cause significant

economic disruptions to industry and gas distribution companies dependent upon intrastate gas. Furthermore, if the NGPA runs its course in 1985, the greater portion of intrastate gas will be decontrolled, compounding this problem. State utility regulatory commissions are, once again, essentially helpless to solve these potential problems.

The Effect of Federal Regulation of Pipeline Rates

The Federal Energy Regulatory Commission, prior to the enactment of the National Energy Act in 1978, regulated the pipeline transmission rates of interstate pipelines. State utility regulatory commission regulated the pipeline transmission rates of intrastate pipelines.

Congress made provision for the phased deregulation of certain categories of new natural gas in Title I of the NGPA. In order to soften the impact of deregulation and in order to prepare the marketplace for an orderly transition, Congress also enacted Title II of the NGPA that provides for the imposition of surcharges to be paid by certain industrial customers. Title II of the NGPA provides that initially all large industrial boiler fuel consumers of gas served off the interstate pipeline system either directly or <u>indirectly</u>, except agricultural users, would be assigned the incremental cost of new gas. The NGPA provides that each of these industrial facilities would continue to be assessed the higher cost of new gas until their gas cost equaled the cost of alternative fuel, number 2 oil. However, if the FERC found that a lower price was necessary to prevent a migration of industry switching to another fuel, the FERC could set the cost of the alternate fuel to the equivalent cost of number 6 oil.

Phase one of the incremental pricing became effective on January 1, 1980, and the FERC designated high sulfur number 6 oil as the alternate fuel.

The NGPA also provides for extension of incremental pricing to all industrial customers regardless of the end use application of the gas. The implementation date of this phase will occur only after the Congress has had an opportunity to review the proposed plan. Either house of the Congress may veto Phase II. Thus far, the only plan submitted to the Congress by the FERC has been vetoed by the House of Representatives.

The primary effect on state utility regulatory commissions concerning FERC setting the rates charged by interstate gas pipeline company is that state utility regulatory commissions must flow these charges through to the ultimate end users. While the state utility regulatory commission has some discretion on spreading the interstate pipeline charges to various customer classes, there are restrictions placed upon state ratemaking authority by the NGPA. These are noted below.

The state utility regulatory commission is free to set the rates charged by intrastate gas pipeline companies for transmissions. However, as noted above the state utility regulatory authority is not free to set the wellhead price of intrastate gas, the major component of the cost of gas. State utility regulatory commissions still have full discretion to regulate the price of gas from intrastate supplies and to spread costs to customers as they see fit.

The Effect of Federal Regulation on Distribution Rates

The principal restriction imposed by the NGPA on state ratemaking authority over intrastate gas distribution companies concerns incremental

pricing. Section 205 of the NGPA requires that any surcharge under Title II of the NGPA paid by a local gas distribution company, due to gas being indirectly delivered by an interstate pipeline to an incrementally priced industrial customer of the local distribution company, be directly passed through to the incrementally priced industrial customer. Section 205 also prohibits the state utility regulatory commissions from making any modifications to the rates charged to incrementally priced industrial customers that has the effect of offsetting the surcharge. Also, section 205 of the NGPA, provides for federal preemption of any state or local law that would preclude the passthrough of the surcharge to the industrial customer.

Title II of the NGPA has placed an additional administrative burden upon state utility regulatory commissions. The state commissions are required by the NGPA to require the flow through of any surcharge to utilities facing an incrementally priced supply and are prohibited from allowing any rates or charges to take effect that would offset the surcharge. Because of the gas supply "bubble" on the market in 1981, most gas distributors are attempting to market their gas supply. In particular, gas distribution companies are likely to view the industrial market as an appealing market offering new opportunities especially as oil prices escalate. Because of these marketing pressures, a gas distribution company is likely to be tempted to design rates for industrial customers so as to offset the effect of the NGPA Title II surcharge. To prevent gas distribution companies from enacting tariffs violating NGPA Title II, state utility regulatory commissions need to be vigilant and devote staff resources to this issue.

In effect, Title II of the NGPA preempts a portion of state ratemaking authority by prohibiting the use of any costing methodologies that would have the effect of offsetting the flow through of the NGPA Title II surcharge. For instance, if a state utility regulatory commission wanted to price according to a marginal cost methodology, it would need to guarantee that the results of the methodology did not offset the effect of the NGPA Title II on incrementally priced industrial customers. State utility regulatory commissions thus are not completely free to exercise their ratemaking authority when setting rates for gas from interstate pipelines. State utility regulatory commissions, however, are fully free to exercise their ratemaking authority when designing rates concerning gas from intrastate pipelines.

The Effects of Other Federal Regulations on State Regulation

Federal regulations regarding taxes and the environment have an effect on state regulation. Federally prescribed accelerated depreciation, investment tax credits and tax policies bear on state utility regulatory commission regulation. Also, past federal environmental regulation has had secondary effects on state utility commission regulation of natural gas distribution. Federal regulation has also addressed rate reform by state regulatory commissions because of the studies required by the Public Utility Regulatory Policies Act of 1978 (PURPA). Also, federal regulation of the end use of gas has restricted certain classes of natural gas consumption, while the Natural Gas Policy Act of 1978 (NGPA) has provided for curtailment of certain end uses of gas in the case of a severe gas shortage.

The Effects of Federally Prescribed Depreciation, Investment, and Tax Policies. - Tax normalization is the regulatory counterpart of the financial accounting concept of comprehensive allocation. Tax normalization involves charging to tax expense each year the tax liability the company would have incurred if, instead of using an accelerated method of depreciation for tax purposes, it had used the straight-line method. During the early life of the asset, the excess of the hypothetical straight-line tax amount over the actual tax paid is accumulated in a reserve for deferred taxes. Later, when the actual tax bill rises over the straight-line figure, the reserve is written off. The net result of using normalized taxes and straight-line depreciation for ratemaking is to give the utility the equivalent of an interest-free loan. Prior to the Economic Recovery Tax Act of 1981, the Tax Reform Act of 1969 placed certain limitations on the use of accelerated depreciation methods for post-1969 public utility property (public utility property that was public utility property in the hands of any person after December 31, 1969). A utility could only use an accelerated method of depreciation if the utility engaged in tax normalization or if the utility elected to engage in flow-through accounting and if flow-through was used for similar property previously. The useful life of public utility property with accelerated depreciation that is normalized could be set by the Asset Depreciation Range System (ADR). Under the Revenue Act of 1971, a 10% investment tax credit was available for certain qualifying public utility property if neither rate base nor the cost of service is reduced or under certain other limited circumstances.

The Economic Recovery Tax Act of 1981 has a mandatory system for assets placed in service after December 31, 1980. This Act shortens the service life of assets for depreciation purposes. The Act provides that public utility property with a current ADR life of 18 years or less becomes 5-year property, public utility property with a current ADR life of 18 - 25 years becomes 10-year property, and that public utility property with an ADR class life of over 25 years becomes 15-year property for the purposes of depreciation. The Act also provides for accelerated depreciation methods on the property. It requires that the accelerated depreciation be normalized and provides a transition until December 31, 1982 for companies presently using a "flow-through" method to normalize.

The Economic Recovery Tax Act of 1981 also provides for a 10% investment tax credit for all property except 3-year property. The Act also enacts new safe harbor rules concerning personal property leasing that has the effect of expanding personal property leasing.

Federal tax regulation has had the effect of encouraging, if not requiring, state public utility commission to allow normalization of accelerated depreciation and investment tax credits, and to discourage, if not prohibit, flow-through of the benefits of accelerated depreciation to the ratepayers. Some analysts contend that normalized tax treatment of accelerated depreciation and investment credits may create an unintended incentive for utilities to overestimate forecasted demand growth and to build excess capacity. Most state public utility commissions have the responsibility of ratemaking with tax normalization. Most commissions also review the utilities expansion plans.

The new tax act will also have the effect of encouraging personal property leasing of capacity of public utilities. State public utility commissions will probably need to decide whether or not a qualifying corporate lessor becomes a "public utility" and thus falls under the state utility commission's jurisdiction.

<u>The Secondary Effects of Past Environmental Regulation</u>. - The Clean Air Act of 1970 subjects all major new or modified stationary sources of air pollution, such as a power plant, to new source performance standards. New source performance standards effectively limit emissions of sulfur dioxide, nitrogen oxides, particulates, and other pollutants. In addition to meeting the new source performance standards, a new or modified power plant must have the lowest achievable emission rate for a particular pollutant if the new or modified plant is located in a nonattainment area for that pollutant. If the new or modified plant is located in a "clean area", and the net change in emissions of a particular pollutant is above certain de minimis levels, then the new or modified plant must be equipped with the best available control technology for that particular pollutant. In order to meet these regulations and other Environmental Protection Agency regulations concerning water and solid waste, electric utilities spent nearly $7.2 billion in 1980. Because of the expense of pollution control devices, such utilities often built gas peaking units to meet demand growth rather than high-sulfur oil, or coal plants, which often require massive investments in pollution control devices to meet the requirements of the Clean Air Act of 1970. However, the Fuel Use Act of 1978 prohibited the use of natural gas as a primary fuel for new electric power plants, and limited the use of natural gas in existing power plants

to the average yearly usage between 1974 through 1976. These limitations have contributed in some areas to excess capacity and higher costs. State utility commissions set rates for gas utilities affected by the Fuel Use Act of 1978.

Possible Future Effects of Certain Other Existing Federal Laws. - The Fuel Use Act of 1978 has the present and future effect of prohibiting new electric power plants using natural gas as a primary energy source, unless there is an exemption. The reasons for granting exemptions include lack of alternative fuel supply, site limitations, the plant being in the public interest, the plant being granted a permanent exemption as a peakload plant, the plant being granted a permanent exemption as an intermediate load power plant, the plant burning certain fuel mixtures containing natural gas, the plant being necessary to meet scheduled equipment outages, the plant cogenerates, the power plant being maintained and operated only for emergency purposes, the power plant being necessary to maintain reliability, or the installation being based upon product or process requirements.

Section 301, the Off-Gas Provision, of the Fuel Use Act of 1978 was repealed in the Omnibus Budget Act of 1981. A new section 301 requires utilities using natural gas as a primary energy source in an existing power plant to submit to the U.S. Department of Energy a conservation plan which will reduce by 10%, in five years, the utility's electric output attributable to natural gas. Utilities experiencing load growth need only to plan for a reduction in the trend line of their gas use. While the utilities are required to implement their plans, there are no penalties if the 10% reduction in gas usage is not achieved.

Title III, Section 306 of PURPA required the Department of Energy to undertake a gas utility rate design study addressing several approaches to rate design including marginal cost pricing, demand-commodity rate design, declining block rates, interruptible service, seasonal rate differentials and end-user rate studies. The study was also required to address three other issues: incremental pricing, wellhead natural gas pricing policies, and end-user consumption taxes. Each of the general approaches to rate design and the three issues were to be evaluated in terms of the three objectives of PURPA--equity, conservation, and utility efficiency. The report was presented to Congress in May 1980.

Upon completion of the study, the Secretary of the Department of Energy is required to develop proposals and legislative recommendations to improve gas utility rate design and encourage conservation of natural gas. The proposals and legislative recommendation are to be transmitted to the Congress by November 1980. Congress is not required to take action upon the recommendations of the Secretary of the Department of Energy, and has not taken action, thus far. If Congress takes no action, then the state utility commissions are free to continue to set their own gas pricing policies subject to the constraints imposed by the NGPA. If, however, Congress elects to endorse some of the recommendations, rate design to end-use consumers could be mandated by federal legislation.

Finally, under Sections 301 through 304 of the Natural Gas Policy Act of 1978, the President has the authority to declare a natural gas supply emergency whenever the supply of natural gas for high priority users is endangered in any region of the United States. High priority users include those who use natural gas in a residence; in a commercial establishment at

volumes of less than 50 MCF on a peak day; in any school, hospital, or similar institution; or, in any other location that the Secretary of Energy determines is important to life, health, or maintenance of physical property. If the President declares a natural gas emergency, he can authorize interstate pipelines and local distribution companies served by interstate pipelines to make emergency sales. If high priority users are still not satisfied, the President can then reallocate boiler fuel gas.

In addition, all curtailment plans of interstate pipelines must meet the minimum standards of Section 401 and 402 of the Natural Gas Policy Act of 1978. These requirements could reflect state public utility regulation in the future by effectively foreclosing the options of a state public utility commission during a natural gas supply shortage.