3-25-1983

Interstate Gas Pipeline Ratemaking and Contract Implications

Henry E. Brown

Follow this and additional works at: http://scholar.law.colorado.edu/natural-gas-symposium-contract-solutions-for-future-of-regulatory-environment

Part of the Administrative Law Commons, Antitrust and Trade Regulation Commons, Bankruptcy Law Commons, Commercial Law Commons, Contracts Commons, Courts Commons, Dispute Resolution and Arbitration Commons, Energy Law Commons, Energy Policy Commons, Law and Economics Commons, Legislation Commons, Marketing Commons, Natural Resource Economics Commons, Natural Resources Law Commons, Natural Resources Management and Policy Commons, Oil, Gas, and Energy Commons, Oil, Gas, and Mineral Law Commons, Operations Research, Systems Engineering and Industrial Engineering Commons, Remedies Commons, and the Transportation Law Commons

Citation Information

Reproduced with permission of the Getches-Wilkinson Center for Natural Resources, Energy, and the Environment (formerly the Natural Resources Law Center) at the University of Colorado Law School.

Reproduced with permission of the Getches-Wilkinson Center for Natural Resources, Energy, and the Environment (formerly the Natural Resources Law Center) at the University of Colorado Law School.
INTERSTATE GAS PIPELINE RATEMAKING

AND

CONTRACT IMPLICATIONS

Henry E. Brown
Vice President, Secretary
and General Counsel
Colorado Interstate Gas Company

-I-
I. Understanding Ratemaking

A. Ground Rules

1. "Allocation of costs is not a matter for the slide rule. It involves a myriad of facts. It has no claim to an exact science." Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 589 (1945).

2. "... neither method was entirely satisfactory, but the same could be said with respect to any method which might be proposed. Mathematical exactness in the apportionment of cost is an impossibility. Because a method may have some infirmities does not itself condemn it as a proper method. It is the duty of the Commission to select a method which in its considered judgment more nearly reaches a just and sound result." Colorado Interstate Gas Co. v. FPC, 209 F.2d 717, 726 (10 Cir., 1953).

3. a. The method selected should assign a fair share of the total system cost of service ..., 

b. The method selected should be a practical one. It should not be so complex as to require long, tedious studies involving speculations and assumptions, but
rather should be a method which can be expeditiously applied to the facts quickly ascertainable.

c. The results reached, through applying such method, should make sense. **Tennessee Gas Transmission Co., 27 FPC 202, 208 (1962).**

B. Objectives (As much as things change, they remain the same).

1. The rate must sell the gas under the varying conditions which are met from time to time.

2. The rate must recover the actual costs of rendering the service and a fair return.

3. The structure of the rate should follow as closely as practicable the general behavior of pipeline costs.

4. The rate must meet the criterion of being nondiscriminatory.

5. The rate must meet the test of general customer and regulatory agency's acceptance. **American Gas Association, Report of Rate Committee, (1956-57), p. 52.**

C. Cost of Service

1. A pipeline cost of service is developed based on a recent twelve months of actual experience (the base period) adjusted for known and measurable changes in revenues and costs that will occur during the nine months immediately following the last month of actual experience. This twelve-month period as adjusted is known as the test period.

2. Exhibit A is CIG's filed Cost of Service for the test period used in its last rate case.
a. Operation (Operation and Maintenance) includes:
   (i) Labor, materials, power, fuel, etc.
   (ii) Purchased gas costs - largest single component in cost of service
   (iii) Administrative and General Expenses

b. Depreciation, depletion and amortization

c. Taxes
   (i) Federal
   (ii) State
   (iii) Other - property, payroll (FICA, unemployment), production, windfall profits, franchise, etc.

d. Donations

e. Return (14.23 weighted average)
   (i) Debt costs (9.18)
   (ii) Preferred stock dividends (7.30)
   (iii) Return to common equity (19.00)

f. Revenue credits
   (i) Processing Plant revenues
   (ii) Other
      (a) Transportation of gas by others
      (b) Revenues from gas processed by others
      (c) Drip sales
II. Ratemaking Components

A. Functionalization of Costs

1. Functionalization is the assignment of costs to three major functions (production and gathering, storage, and transmission) to develop a basis for equitable apportionment of costs based on use of and benefits derived from various types of facilities. The functionalization of Cost of Service is also shown in Exhibit A. As shown, each function has its own separate cost of service.

2. For example, a customer served directly from a source of supply, which is not transported through the pipelines' transmission system or stored in the pipelines storage fields, may not be assigned costs from these two functions.

B. Classification of Costs - Two Steps

1. First, it must be determined whether costs are fixed or variable.

   a. Fixed Costs - Generally remain constant over the relatively short term. They tend not to fluctuate in accordance with the varying volumes of gas passing through the system. Examples are labor expenses, overhead costs, depreciation expense, return on investment, and associated income taxes.

   b. Variable Costs - Change in direct proportion to volumes of gas passing through the system. Examples are most purchase gas costs and Compressor Station fuel.
2. Second, fixed and variable costs are apportioned between demand and commodity.
   a. Demand - Costs allocated to customers based upon use of gas during a peak period or system design for a peak period.
   b. Commodity - Costs allocated on the basis of general use of gas, or annual sales.

3. Methods of classifying costs - Generally all variable costs are deemed commodity related. The main issue is whether the fixed costs should be deemed demand-related or commodity-related.
   a. Volumetric
      (i) All fixed and variable costs to commodity. Single rate.
      (ii) City of Cleveland v. Hope Natural Gas Co., 3 FPC 150 (1942).
      (iii) During the earliest period of pipeline ratemaking, pipelines had obligations to supply customers' full requirements. Cost responsibility was proportioned to the customers' annual volumes.
   b. Fixed-variable (peak responsibility)
      (i) 100% of fixed costs are deemed demand-related.
      (ii) Adopted by Commission in Canadian River Gas Company et al., 3 FPC 32 (1942)
generally to encourage investment in increased pipeline capacity. Fixed costs were recovered without reference to throughput.

(iii) **Modified fixed-variable.**

(a) All fixed costs deemed demand-related except 50% of return and associated taxes.

(b) Adopted in *Interstate Natural Gas Co., Inc.*, 3 FPC 416 (1942).

(c) An answer to allegations that interruptibles and seasonal customers who were not served during the peak period were not being assessed any of the pipeline's fixed costs.

(d) Challenged that cost classification was being used as a means of achieving a desired end, irrespective of the nature or behavior of costs being classified (i.e., discourage industrial use).

c. **Atlantic Seaboard 50/50 formula**

   (i) In *Atlantic Seaboard Corp. et al.*, 11 FPC 43 (1952) the Commission classified transmission fixed cost equally between demand and commodity. The premise of such
classification was that pipelines were built and other fixed costs incurred to provide both peak and annual service. Therefore, transmission fixed costs should be apportioned to both services. The 50/50 split was evidence of the Commission's inability to determine which service should bear the majority of such cost.

(ii) During World War II prices of all fuels were high. Gas was a bargain. It simply didn't matter how the FPC classified costs. Following World War II, existing pipelines expanded at a rapid rate at high costs. The price of gas shot up and it became necessary to price gas so that it was competitive with other fuels.

(iii) The result was that in the rate design step (after costs were allocated between jurisdictional and nonjurisdictional sales) the rates were "tilted" by assigning to the demand charge a portion of the costs which under Seaboard would have been assigned to the commodity charge. See, e.g., Midwestern Gas Transmission Co., 34 FPC 973 (1965) and cases cited therein.
This enabled gas to be more marketable to industrials.

(iv) The 50/50 cost classification formula was extended to the storage function in *American Louisiana Pipe Line Co.*, 29 FPC 932 (1963).

(v) A "modified Seaboard" was also introduced, in which a portion of the production costs were assigned to the demand category rather than assigned 100% to the commodity category. While settlements were approved on that basis, the Commission, after adopting the approach, reversed itself due to the changing circumstances with regard to the impending shortage of gas supply. *El Paso Natural Gas Company*, 47 FPC 1157 (1972).

(vi) As the price of competitive fuels increased relative to natural gas, the justification for "tilting" was eliminated. By the late 1960s and early 1970s, most pipeline rates reflected Seaboard in both cost classification and rate design.

d. United 25/75 formula

(i) The *United* method assigns pipeline transmission and storage fixed costs 75% to the
commodity component and 25% to the demand component. Production and gathering fixed costs (except for the demand component of purchases) were continued to be classified 100% to commodity. United Gas Pipe Line Co., 50 FPC 1348 (1973). The Commission's decision was premised on lesser importance of the peak use of the pipeline due to natural gas shortages. The decision was a compromise between Seaboard (50/50) and Staff's recommended volumetric rate (100% fixed costs to commodity).

(ii) Recent developments: In three recent cases the Commission approved the use of Seaboard for cost classification. All three cases were before the Commission on remand from the District of Columbia Circuit in light of Columbia Gas Transmission Corp. v. FERC, 628 F.2d 578 (D.C. Cir. 1979).


(b) Texas Gas Transmission Corp., Docket No. RP75-19 (Remand) February 15, 1983. (Exhibit B)
4. Apply the principles for cost classification for the four methods outlined above (allocation will be covered later):

**Worksheet 1**

<table>
<thead>
<tr>
<th>Cost</th>
<th>Total</th>
<th>Fixed-variable Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Production</td>
<td>$1,000</td>
<td>Demand</td>
</tr>
<tr>
<td>2. Purchased Gas - Demand</td>
<td>1,000</td>
<td>Commodity</td>
</tr>
<tr>
<td>3. Purchased Gas - Commodity</td>
<td>3,000</td>
<td></td>
</tr>
<tr>
<td>4. O &amp; M - Variable</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>5. O &amp; M - Fixed</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>6. Depreciation</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>7. Other taxes</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>8. Income taxes</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>9. Return</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>10. Total</td>
<td>$10,000</td>
<td></td>
</tr>
</tbody>
</table>

**Derivation of Allocation Factors**

<table>
<thead>
<tr>
<th></th>
<th>3-day peak</th>
<th>Annual</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mcf</td>
<td>Factor</td>
</tr>
<tr>
<td>11. Jurisdictional</td>
<td>20,000</td>
<td>90%</td>
</tr>
<tr>
<td>12. Non-jurisdictional</td>
<td>2,222</td>
<td>10%</td>
</tr>
<tr>
<td>13. Total</td>
<td>22,222</td>
<td>100%</td>
</tr>
</tbody>
</table>

**Allocation of Total Cost of Service to Classes of Customers**

<table>
<thead>
<tr>
<th></th>
<th>Demand</th>
<th>Commodity</th>
</tr>
</thead>
<tbody>
<tr>
<td>14. Jurisdictional cost of service</td>
<td></td>
<td></td>
</tr>
<tr>
<td>15. Non-jurisdictional cost of service</td>
<td></td>
<td></td>
</tr>
<tr>
<td>16. Total cost of service</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

I-11
### Worksheet 2

<table>
<thead>
<tr>
<th>Cost</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Production</td>
<td>$1,000</td>
</tr>
<tr>
<td>2. Purchased Gas - Demand</td>
<td>1,000</td>
</tr>
<tr>
<td>3. Purchased Gas - Commodity</td>
<td>3,000</td>
</tr>
<tr>
<td>4. O &amp; M - Variable</td>
<td>700</td>
</tr>
<tr>
<td>5. O &amp; M - Fixed</td>
<td>1,000</td>
</tr>
<tr>
<td>6. Depreciation</td>
<td>1,000</td>
</tr>
<tr>
<td>7. Other taxes</td>
<td>300</td>
</tr>
<tr>
<td>8. Income taxes</td>
<td>1,000</td>
</tr>
<tr>
<td>9. Return</td>
<td>1,000</td>
</tr>
<tr>
<td>10. Total</td>
<td>$10,000</td>
</tr>
</tbody>
</table>

#### Seaboard Method

<table>
<thead>
<tr>
<th>Demand</th>
<th>Commodity</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-day peak Mcf</td>
<td>Factor</td>
</tr>
<tr>
<td>---------</td>
<td>---------</td>
</tr>
<tr>
<td>Jurisdictional</td>
<td>20,000</td>
</tr>
<tr>
<td>Non-jurisdictional</td>
<td>2,222</td>
</tr>
<tr>
<td>Total</td>
<td>22,222</td>
</tr>
</tbody>
</table>

#### Allocation of Total Cost of Service

<table>
<thead>
<tr>
<th>Demand</th>
<th>Commodity</th>
</tr>
</thead>
<tbody>
<tr>
<td>14. Jurisdictional cost of service</td>
<td></td>
</tr>
<tr>
<td>15. Non-jurisdictional cost of service</td>
<td></td>
</tr>
<tr>
<td>16. Total cost of service</td>
<td></td>
</tr>
</tbody>
</table>
Worksheet 3

<table>
<thead>
<tr>
<th>Cost</th>
<th>Demand</th>
<th>Commodity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Production</td>
<td>$1,000</td>
<td></td>
</tr>
<tr>
<td>2. Purchased Gas - Demand</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>3. Purchased Gas - Commodity</td>
<td>3,000</td>
<td></td>
</tr>
<tr>
<td>4. O &amp; M - Variable</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>5. O &amp; M - Fixed</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>6. Depreciation</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>7. Other taxes</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>8. Income taxes</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>9. Return</td>
<td>1,000</td>
<td></td>
</tr>
<tr>
<td>10. Total</td>
<td>$10,000</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Derivation of Allocation Factors</th>
<th>3-day peak</th>
<th>Annual</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mcf</td>
<td>Factor</td>
</tr>
<tr>
<td>11. Jurisdictional</td>
<td>20,000</td>
<td>90%</td>
</tr>
<tr>
<td>12. Non-jurisdictional</td>
<td>2,222</td>
<td>10%</td>
</tr>
<tr>
<td>13. Total</td>
<td>22,222</td>
<td>100%</td>
</tr>
</tbody>
</table>

Allocation of Total Cost of Service to Classes of Customers

<table>
<thead>
<tr>
<th></th>
<th>Demand</th>
<th>Commodity</th>
</tr>
</thead>
<tbody>
<tr>
<td>14. Jurisdictional cost of service</td>
<td></td>
<td></td>
</tr>
<tr>
<td>15. Non-jurisdictional cost of service</td>
<td></td>
<td></td>
</tr>
<tr>
<td>16. Total cost of service</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

I - 13
Worksheet 4

<table>
<thead>
<tr>
<th>Cost</th>
<th>Total</th>
<th>Demand</th>
<th>Commodity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Production</td>
<td>$1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Purchased Gas - Demand</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Purchased Gas - Commodity</td>
<td>3,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4. O &amp; M - Variable</td>
<td>700</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5. O &amp; M - Fixed</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6. Depreciation</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7. Other taxes</td>
<td>300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8. Income taxes</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9. Return</td>
<td>1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10. Total</td>
<td>$10,000</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Volumetric Method

<table>
<thead>
<tr>
<th>Derivation of Allocation Factors</th>
<th>3-day peak</th>
<th>Annual</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mcf</td>
<td>Factor</td>
</tr>
<tr>
<td>11. Jurisdictional</td>
<td>20,000</td>
<td>90%</td>
</tr>
<tr>
<td>12. Non-jurisdictional</td>
<td>2,222</td>
<td>10%</td>
</tr>
<tr>
<td>13. Total</td>
<td>22,222</td>
<td>100%</td>
</tr>
</tbody>
</table>

Allocation of Total Cost of Service to Classes of Customers

| 14. Jurisdictional cost of service | Demand | Commodity |
| 15. Non-jurisdictional cost of service |        |           |
| 16. Total cost of service        |        |           |
C. Allocation of Costs Between Jurisdictional and Non-jurisdictional Service

1. Production and gathering
   a. Commodity - Annual sales
   b. Demand - ("as billed") - 3-day peak

2. Transmission
   a. Demand - Generally in proportion to the average of the coincidental demands during a 3-day continuous peak on the pipeline system.
      (i) Other - Single-day peak, 2-day peak, contract demand, firm service peak day.
   b. Commodity - Generally annual sales.
   c. Demand and commodity - Mcf-mile (Southern Natural Gas Co., 29 FPC 323 (1963)), zoning (El Paso Natural Gas Co., 22 FPC 260 (1959)), zone-gate (United Gas Pipe Line Co., 51 FPC 1014 (1974)).

3. Storage
   a. Commodity - Seasonal sales (5-month period of storage withdrawals)
   b. Demand - 3-day peak

4. Return to worksheets 1-4 and allocate Production and Transmission commodity costs based on annual sales and Transmission demand costs based on 3-day peak. Check with Exhibit C.
D. Rate Design – Allocation Among the Various Jurisdictional Sales and Services and Customers

1. Generally two-part rate—demand-commodity
   a. Demand rate – divide jurisdictional demand costs by sum of contract demands (times 12) of jurisdictional customers. Demand charges are generally a fixed dollar amount due each month, regardless of amount of gas purchased.
   b. Commodity rate – divide jurisdictional production, storage, and transmission commodity costs by annual sales. Commodity charges are billed on the basis of actual quantity of gas taken by customers.

2. Straight line volumetric charges
   a. Include an amount of imputed demand costs.
   b. May be adjusted for load factors – Small general service customers might buy at a 40% load factor, thus the demand costs are more per Mcf than those of a 100% load factor customer.

III. Concerns of Different Parties in Interest

A. Industrials
   1. Want more allocated to demand (e.g., fixed/variable) which allocates more to low load factor customers.
      Industrials tend to be high load factor customers.

B. Distributors
   1. High load factor jurisdictional customers.
      a. Want a higher demand rate (e.g., fixed/variable)
2. Low load factor customers.
   a. Want a lower demand rate (e.g., United)
   b. Some may accept unloading the commodity (e.g., fixed/variable) to promote sales to industrials.

C. Pipeline
1. Risk of recovering costs.
   a. The more shifted to demand (e.g., fixed/variable), the less risk of under-recovery.
2. Effect on marketability.
   a. The lower the commodity cost (e.g., fixed/variable), the easier it will be to market gas to high load factor industrials, particularly if interruptible.
   b. This is difficult to accomplish when a high percentage of overall costs is seemingly inextricably stuck in the commodity (e.g., purchased gas costs).
3. Frequency of filings.
   a. In theory, the more costs which are recovered through demand charges (e.g., fixed/variable), the less susceptible the pipeline is to falling sales and less likely to need to file. This is primarily due to pipeline PGA filings.

IV. Following Future Rate Issues
A. Pending Rate Design Cases
   1. Columbia Gas Transmission Corp., Docket No. RP81-83, et al. Columbia proposed a modified fixed-variable; all variable costs and 50% of the return on equity and
associated taxes would be included in the commodity. The demand component would consist of all remaining fixed costs. The Commission Staff's modified fixed-variable rate design differs from Columbia's modified fixed-variable proposal in three significant respects:

a. The Staff assigns 100% of return on equity and associated taxes to the commodity component as compared to Columbia's proposal of assigning only 50% of return on equity and associated taxes to the commodity component. The Staff's proposal in this respect places all of the return on equity at risk.

b. The Staff assigns all costs in the production function, including production fixed costs, to the commodity component, while Columbia assigns production fixed costs to the demand component. The Staff's proposal reflects a long line of Commission precedent, but continues to place such fixed costs at risk.

c. The Staff allocates costs classified as demand costs in two ways:

i) it allocates 50% of demand on an average 3-day peak basis; and

ii) it allocates 50% of demand on a volumetric basis,

while Columbia allocates demand solely on the basis of peak deliveries.

I-18
Staff argues that its method recognizes the dual nature of the pipeline and the fundamental principle of ratemaking that costs should be allocated to customers responsible for the cost incurrence. This methodology would result in additional costs being allocated low load factor customers.

2. **Natural Gas Pipeline Company of America**, Docket No. RP81-49. Natural proposed a modified fixed-variable method of rate design, with all fixed costs classified to the demand component and all variable costs, including equity and associated taxes, classified to commodity. Staff generally proposes a modified fixed-variable rate design, with some variation for certain customers where the potential for marketing industrial sales exists. Staff proposes its own cost classification and allocation methodology. Fixed storage and transmission costs are assigned to demand and commodity components based on the type of service for which they are incurred. Then Staff, in a "refunctionalization" process, assigns to the commodity component certain fixed costs which were related to recent investments to attach gas supply. The remaining fixed costs were split 50/50 between the demand and commodity to recognize peak day and annual service.

3. **Tennessee Gas Pipeline Co.**, Docket No. RP81-54 et al. Staff would prefer the refunctionalization method noted for NGPL, but recommends a modified fixed-variable...
because of the overriding importance of the marketability issue. Fixed costs should be covered through a combination of three demand charges: a peak-day demand charge based on customer contract demand or maximum daily quantity; an average-day demand charge based on customers' annual volumetric limitations; and a seasonal variability demand charge, the difference between customers' maximum daily quantity and their average daily quantity.

4. **Texas Eastern Transmission Corp.**, Docket No. RP83-35. Another lead case on gas pipeline rate design and purchasing practices. Commissioner Richard has been named hearing officer in the case. Charles Moore, Commission General Counsel, has been Staff trial lawyer.

5. See also **Panhandle Eastern Pipe Line Co.**, Docket No. RP82-58, **Tennessee Gas Pipeline Co.**, Docket No. RP82-125, **El Paso Natural Gas Co.**, Docket Nos. RP82-33 and RP83-6.

B. Incentive Rates for Industrial Sales

1. **Michigan Wisconsin Pipe Line Company** (CP82-542). Michigan Wisconsin Pipe Line Company became the first pipeline for which interim industrial rates were approved. This signal honor has been accompanied by the ups and downs associated with implementation of new FERC policy, especially the threat of stockholder loss due to underrecovery. Attached as Exhibit D hereto, see the Order issued October 29, 1982; the Order Rejecting
Compliance Filing Without Prejudice and Clarifying Prior Order, issued November 5, 1982; the Order Instituting Proceeding and Granting Motions to Intervene, issued December 22, 1982 (listing 13 issues for hearing on permanent rates); and the Order Denying Requests for Rehearing, issued February 22, 1983.

2. In December, 1982, the Commission approved similar temporary certificates for Columbia Gas Transmission Corp. (CP82-485) and Northern Natural Gas Co. (CP83-14). Two applications (CP83-16, CP82-33) by Northern for special rates for ammonia-fertilizer plants were not granted temporary certificates but were set for hearing. Columbia later withdrew its application following a FERC February 9, 1983, denial of rehearing of the December 22 Order. Northern's temporary certificate was rescinded on the basis that an emergency did not exist.

3. In January, Panhandle Eastern Pipe Line Co. and Trunkline Gas Co. (CP83-157) and Northwest Pipeline Corp. (CP83-136) applied for discount rates to avoid losing industrial customers.

4. In designing rates the FERC has issued two guidelines, one for interim rate design and one for a final rate design.

Interim rate: pipeline must recover:

   a. Current cost of purchased gas, including current
      Account No. 191 surcharge
b. Current GRI surcharge

c. Any out-of-pocket costs associated with making the
gas sale (fixed, as well as variable).

Final rate: pipeline must recover:

a. Actual cost of purchased gas attributable to the
sale

b. GRI surcharge

c. Any out-of-pocket costs

d. Any fixed costs necessary to assure that other
customers or classes of customers do not suffer
undue adverse impact as a result of the sale.

C. Rates for customers who undertake spot purchases of gas from
other suppliers (i.e., no longer full requirements). See

D. Incentive transportation rates - Pipelines should be indifferent
whether they sell gas or simply transport for others. See

E. Providing market signal from consumer through pipeline to
producer.

1. NGPL Netback Basis. See Inside FERC, December 20,
1982, p. 5.

2. United Distribution Companies propose to address pipeline
accountability through a Congressional mandate for the
FERC to develop a new approach to rate design.


H. Minimum Bills –


REFERENCES


<table>
<thead>
<tr>
<th>Line No.</th>
<th>Particulars</th>
<th>Statement or Schedule Reference</th>
<th>Total Cost of Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a)</td>
<td></td>
<td>(b)</td>
<td>(c)</td>
</tr>
<tr>
<td>1</td>
<td>OPERATING EXPENSES</td>
<td>H(1)</td>
<td>$1,075,892,345</td>
</tr>
<tr>
<td>2</td>
<td>DEPRECIATION, DEPLETION AND</td>
<td>H(2)</td>
<td>34,691,196</td>
</tr>
<tr>
<td>3</td>
<td>AMORTIZATION</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>TAXES:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Federal income</td>
<td>H(3)</td>
<td>49,351,229</td>
</tr>
<tr>
<td>6</td>
<td>State income</td>
<td>H(3)</td>
<td>3,535,029</td>
</tr>
<tr>
<td>7</td>
<td>Other</td>
<td>H(4)</td>
<td>13,717,332</td>
</tr>
<tr>
<td>8</td>
<td>OTHER INCOME DEDUCTIONS - DONATIONS</td>
<td></td>
<td>166,724</td>
</tr>
<tr>
<td>9</td>
<td>RETURN AT 14.23 PERCENT</td>
<td>B</td>
<td>74,423,103</td>
</tr>
<tr>
<td>10</td>
<td>TOTAL COST OF SERVICE BEFORE</td>
<td></td>
<td>$1,251,776,958</td>
</tr>
<tr>
<td>11</td>
<td>REVENUE CREDITS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>DEDUCT - OPERATING REVENUE CREDITS:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Processing plant revenues</td>
<td>G-3</td>
<td>$21,439,789</td>
</tr>
<tr>
<td>14</td>
<td>Other operating revenues</td>
<td>G-3</td>
<td>$42,981,980</td>
</tr>
<tr>
<td>15</td>
<td></td>
<td></td>
<td>$64,421,769</td>
</tr>
<tr>
<td>16</td>
<td>NET COST OF SERVICE</td>
<td></td>
<td>$1,187,355,189</td>
</tr>
<tr>
<td>Line No.</td>
<td>Production (d)</td>
<td>Storage (e)</td>
<td>Other (f)</td>
</tr>
<tr>
<td>---------</td>
<td>----------------------</td>
<td>-------------</td>
<td>-----------</td>
</tr>
<tr>
<td>1</td>
<td>$982,914,977</td>
<td>$2,747,594</td>
<td>$4,928,541</td>
</tr>
<tr>
<td>2</td>
<td>18,577,321</td>
<td>1,150,746</td>
<td>2,854,477</td>
</tr>
<tr>
<td>3</td>
<td>16,226,684</td>
<td>1,791,449</td>
<td>10,788,179</td>
</tr>
<tr>
<td>4</td>
<td>1,162,317</td>
<td>128,322</td>
<td>772,757</td>
</tr>
<tr>
<td>5</td>
<td>8,204,651</td>
<td>318,393</td>
<td>717,141</td>
</tr>
<tr>
<td>6</td>
<td>102,802</td>
<td>4,518</td>
<td>6,502</td>
</tr>
<tr>
<td>7</td>
<td>24,472,820</td>
<td>2,700,258</td>
<td>16,267,039</td>
</tr>
<tr>
<td>8</td>
<td>$1,051,661,572</td>
<td>$8,841,280</td>
<td>$36,334,636</td>
</tr>
<tr>
<td>9</td>
<td>$21,439,789</td>
<td>$-</td>
<td>$-</td>
</tr>
<tr>
<td>10</td>
<td>17,019,600</td>
<td>1,138</td>
<td>1,635</td>
</tr>
<tr>
<td>11</td>
<td>$38,459,389</td>
<td>$1,138</td>
<td>$1,635</td>
</tr>
<tr>
<td>12</td>
<td>$1,013,202,183</td>
<td>$8,840,142</td>
<td>$36,333,001</td>
</tr>
</tbody>
</table>
Before us on exceptions is an initial decision which concludes that the Seaboard formula, which classifies the fixed costs associated with Texas Gas Transmission Corporation's (Texas Gas) investment in transmission and storage facilities equally between the demand component and the commodity component of a pipeline's rates, should be used on the Texas Gas system for the purpose of setting just and reasonable rates. Texas Gas Transmission Corp., Docket No. RP75-19 (Remand), 15 FERC ¶ 63,004 (1981). As the initial decision makes clear, this case has a lengthy history and was remanded to the Commission by the court of appeals. Columbia Gas Transmission Corp. v. FERC, 628 F.2d 578 (D. C. Cir. 1979). We affirm the initial decision but find it necessary to discuss several aspects of that decision. 

(1) As we read the initial decision, it would require the proponents of a cost classification methodology other than the Seaboard formula to first demonstrate that use of the Seaboard formula is unjust and unreasonable within the meaning of Sections 4 and 5 of the Natural Gas Act. In our view, the Commission is required only to use the Seaboard formula as a "starting point" for analysis and to provide a "reasoned explanation" for its decision to depart from the Seaboard formula. Once the Commission has provided a "reasoned explanation," the Commission need only show that the cost classification methodology it chooses results in just and reasonable rates. Permian Basin Area Rate Cases, 390 U.S. 747, 791-92, 796-98 (1968).

The court remand in Columbia Gas Transmission Corp. v. FERC, supra, does not, in our view, require that the Commission also demonstrate that the Seaboard formula results in unjust
and unreasonable rates (although the Commission may indeed reach that conclusion) before the Commission imposes an alternative cost classification methodology which yields just and reasonable rates. The only support for the narrow reading which the ALJ accorded our authority under the Natural Gas Act is found in footnote 31 of the court's opinion. 1/ As we read the court's opinion, that footnote only indicates the support which the Commission must have for purposes of judicial review if the Commission's decision is based on a finding that the Seaboard formula generates unjust and unreasonable rates. A conclusion that the Seaboard formula yields unjust and unreasonable rates is certainly a sufficient predicate, but by no means a necessary predicate, before the Commission chooses a cost classification methodology which yields just and reasonable rates. 2/

1/ That portion of the court's opinion states:

If, as it appears (see Commission Opinion at J. A. 202, 211; Commission Brief at 37-40), the Commission has decided to abandon Seaboard because the application of that formula to Texas Gas no longer generates rates that are just and reasonable within the meaning of § 4 of the Natural Gas Act, the Commission must demonstrate that its finding is supported by substantial evidence. 15 U.S.C. § 717r(b). Columbia Gas Transmission Corp. v. FERC, 628 F.2d at 586, n.31.

2/ Our conclusion on this matter is consistent with precedent discussing the Columbia Gas Transmission Corp. v. FERC case. In New Orleans Public Service, Inc. v. FERC, 659 F.2d 509 (5th Cir. 1981), the court stated:

On the contrary, in order for the Commission to have departed from the 25-75 method, which had become the established methodology and was supported by the pipeline, the Commission would have had to explain the departure or found use of the 25-75 method unjust and unreasonable. New Orleans Public Service, Inc. v. FERC, 659 F.2d at 521 (emphasis added).

This discussion stresses that alternative analytical paths are available to the Commission if it wishes to modify or abandon an existing cost classification, allocation, and rate design methodology.
In this case, the initial decision concludes, and we agree, that the record before us cannot provide a reasoned explanation to support a departure from a Seaboard formula and that the Seaboard methodology yields just and reasonable rates. There is, thus, no error based on the initial decision's analysis of Columbia Gas Transmission Corp. v. FERC, supra. Our discussion of that case is intended solely to emphasize the judgmental nature of the determinations which we make in cost classification, allocation, and rate design decisions. The Commission may, in the exercise of its discretion, choose one methodology out of several alternative cost classification methodologies, all of which may generate just and reasonable rates under a substantial evidence standard. FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944); FPC v. Natural Gas Pipeline Co., 315 U.S. 575 (1942); Permian Basin Area Rate Cases, supra; Compare, Fuels Research Council, Inc. v. FPC, 374 F.2d 842 (7th Cir. 1967) (Commission methodology which classifies almost all fixed costs to the demand component is approved) with Alabama-Tennessee Natural Gas Co. v. FPC, 203 F.2d 494 (3rd Cir. 1952) (Commission methodology which classifies all fixed costs to the commodity component is approved). The Commission need not, however, necessarily first find a potential element of a pipeline rate determination, the preexisting cost classification methodology, unjust and unreasonable and, thus, ceremoniously inter it. To read that requirement into our decisions would tend to ossify the cost classification, allocation, and rate design process at a time when flexibility, judgment, and innovative solutions to rapidly changing conditions and costs in the natural gas industry are particularly important. See, United Gas Pipe Line Co. v. FERC, 649 F.2d 1110 (5th Cir. 1981).

(2) The initial decision takes the position that a departure from the Seaboard formula cannot be justified. It focuses primarily on peak period deliveries in determining that the Texas Gas system was not underutilized and that the demand component of rates had not declined in importance relative to the commodity component. In the ALJ's view, pipeline capacity, not gas supply, was a limiting factor on peak days 3/; and, thus, the demand function reservation of capacity for delivery

3/ The initial decision correctly concludes that the Texas Gas system is not underutilized on days of maximum natural gas deliveries to the extent that would justify shifting a greater percentage of fixed costs from the demand commodity to the commodity component. Compare, Opinion No. 671, infra (peak day underutilization of 17 percent). The initial decision noted that the discrepancy between peak day deliveries and aggregate contract demands was explained by the fact that the maximum demands of Texas Gas' customers were non-coincident, that "worst case" contract demands were

(Footnote continued on next page.)
of a maximum firm quantity of natural gas) was equal in importance to the commodity function (actual deliveries of natural gas volumes) in determining how the fixed costs should be classified.

In focusing on peak day deliveries and utilization of the system, the initial decision places greater emphasis on this factor than we believe is warranted and tends to assume that the absence of peak day curtailment, standing alone, precludes

3/ (Footnote continued from previous page.)

submitted by many of Texas Gas' customers, and that the ratcheted billing demand provisions of Texas Gas' tariff created an incentive for customers to keep peak demand at or below 95 percent of contract demand. None of these factors indicate an erosion of the demand component. These factors all reflect the existence of reserved capacity (i.e., capacity which is reserved by the customers but which is released or not demanded by the customers on days of maximum gas deliveries). Reserved capacity is consistent with the Seaboard formula and with a viable demand charge.

While no peak day underutilization has been shown which would support a shift from the Seaboard formula, we cannot agree with the initial decision that "general economic conditions" and "gas conservation" are also events which reflect "reserved capacity" and which support the Seaboard formula. As the record shows, there is an elusive, but critical distinction between "excess capacity" (capacity which is reserved but which cannot be used by the customers) and "reserved capacity" (Tr. R-304, R-308-09). In the words of Opinion No. 671, infra, "general economic conditions" and "gas conservation" may be events which, like peak day gas supply curtailment, indicate "unanticipated unused" capacity (i.e., excess capacity).

On this record, the "reserved capacity," which definitely exists, cannot be separated from the "excess capacity," if any. More importantly, there is no basis for concluding that the impact of "general economic conditions" and "gas conservation" supports or refutes, and to what extent, a finding of "excess capacity" and the continued validity of the Seaboard formula. See, n.14, infra.
a Commission decision departing from the Seaboard formula. The court of appeals' opinion indicates that the absence of peak day curtailment and underutilization, while extremely important, is not necessarily determinative and that a methodology, other than the Seaboard formula, might still be proper when other facts are considered. Additional discussion of this issue is, thus, required.

This discussion is particularly important because of differences between the United system and the Texas Gas system. In the United case 4/, the Commission classified 25 percent of the fixed costs to the demand component. (Use of the United methodology has its proponents in this proceeding. Indeed, an earlier Commission adopted United in this case. Texas Gas Transmission Corp., Opinion No. 792, Docket No. RP75-19, 58 F.P.C. 165 (1977).) The Commission focused on both peak day and annual curtailment in assessing the continued vitality of the demand component, in part, because costs classified to the demand component were then allocated among customers on two separable bases. First, demand costs were allocated between jurisdictional, sale for resale customers and non-jurisdictional, direct sale customers on the basis of peak period sales. Second, demand costs were allocated among jurisdictional, sale for resale customers on the basis of contract demands. On the Texas Gas system, the virtual absence of non-jurisdictional, direct sale customers (which are allocated demand costs on the basis of peak period sales) requires a more selective analysis, an analysis which recognizes that the absence of peak day curtailment may not be as significant where virtually all customers are jurisdictional, sale for resale customers whose allocation of demand costs is governed by contract demands. 5/ Thus, the argument that the absence of peak day curtailment is not dispositive is properly grounded on a factual difference between the United system and the Texas Gas system.

On exceptions Memphis Light, Gas & Water Division (Memphis) argues that the United methodology is proper, notwithstanding the absence of both peak day curtailment and peak day underutilization. As Memphis points out, the contract demands of


5/ This potentially significant difference was recognized by the court of appeals in this proceeding. Columbia Gas Transmission Corp. v. FERC, 628 F.2d at 586, n.35.
Texas Gas' customers represent the right to take up to a maximum quantity of natural gas -- each and every day of the year -- subject only to system design limitations on an annual basis. According to Memphis, annual and seasonal curtailment on the Texas Gas system has virtually destroyed the value of the demand component of rates by limiting the number of days when a customer can take full contract demand quantities. Underutilization of the system on an annual basis, because of curtailment, is the single most important factor indicating the erosion of the demand component of rates.

Under Memphis' analysis the current absence of annual curtailment becomes an event of little or no significance. Past curtailment has resulted in a system which is delivering reduced volumes of natural gas compared to precurtailment levels; and the fact that the market is no longer supply constrained, which is all that the absence of annual or seasonal curtailment indicates, does not alter the fact that many years of curtailment have left a system which is underutilized on an annual basis.

We can agree with most, if not all, of this analysis, as far as it goes; but, when the analysis is tempered by other factors, we cannot conclude that a case for departing from the Seaboard formula has been made. True it is that a customer's contract demand was important each and every day of the year, prior to the advent of curtailment, and that annual curtailment was the result of Texas Gas' inability to assure delivery of that quantity of natural gas each and every day of the year within system design limitations. However, during the 1970's, the effect of Texas Gas' end use curtailment plan was to shift increasingly greater deliveries from off-peak periods to peak periods (when pipeline capacity, not gas supply, remained a limiting factor) and to encourage the expansion of storage fields by Texas Gas. 6/ Cost classification is designed to

6/ Memphis and, to a lesser extent, Commission staff argue that the expansion of storage allowed the shift of declining natural gas supplies on an annual basis from off-peak to peak periods and eliminated the peak day curtailment which otherwise would have occurred. The Texas Gas system, under this analysis, becomes indistinguishable from the United system because peak day curtailment would have occurred if the storage fields of Texas Gas had not been expanded.

(Footnote continued on next page.)
resolve the issue of the relative importance of the demand component (reservation of capacity for service up to a maximum specified quantity of natural gas) and the commodity component (actual deliveries over a specified period) for purposes of assessing fixed cost responsibility. Curtailment obviously affected both the demand component and the commodity component. Notwithstanding this impact on both the demand and commodity components, Texas Gas' customers did retain the right to call for up to the contract demand quantity of natural gas at all times during curtailment, albeit within seasonal and annual delivery limitations; and Texas Gas was able to meet those demands. Moreover, end use curtailment plans shifted deliveries from off-peak to peak periods, a shift which reinforced the continued relative importance of the demand component of pipeline rates. For these reasons, we cannot conclude that the demand component has declined in significance so as to justify shifting more than 50 percent of the fixed costs to the commodity component.

Nor can we agree with the related argument that the current annual underutilization of Texas Gas' system, as measured by annual sales compared to pre-curtailment levels, is a factor which, standing alone, would support a conclusion that the demand component has lost its significance. Nothing in the Commission's decisions suggest that the vitality of the Seaboard formula should be or was constantly reassessed in light of fluctuations in annual sales, which reflected changing levels of utilization by customers of contract demand. Even if the reduction in annual sales alone, compared to pre-curtailment levels, were significant, the continued relative importance of the demand component, compared to the commodity component, should be emphasized and could outweigh this factor.

6/ (Footnote continued from previous page.)

It is precisely because storage fields were expanded, deliveries were shifted to winter periods, and peak day curtailment did not occur that this argument fails. The curtailment plan dictated that temperature sensitive and high priority requirements, traditionally associated with peak period deliveries, would be served and that Texas Gas' customers would be allowed to obtain full contract quantities within seasonal and annual delivery limitations. Texas Gas took steps to assure that these commitments could be met. These considerations hardly support an analogy to the United System or a conclusion that the Seaboard methodology is inappropriate. Compare, Consolidated Gas Supply Corp. v. FPC, 520 F.2d at 1186-87, n.61.

7/ Columbia Gas Transmission Corp. v. FERC, 628 F.2d at 590.
In any event, the absence of annual or seasonal curtailment, or any other limitation on the customers' right to demand volumes of natural gas up to the contract demand quantity, is a key consideration which supports a determination that the conditions which dictated the use of the Seaboard formula for over 20 years on the Texas Gas system are present on this record. The Commission's response to a market which is not constrained by gas supply has been different than its response to a market which is so constrained. Compare, Fuels Research Council, Inc. v. FPC, supra, with Consolidated Gas Supply Corp. v. FPC, supra. Thus, while the annual underutilization of the system which resulted from past curtailment reflects an erosion of the demand charge, the absence of curtailment at present is at least as significant. Texas Gas should be allowed to increase the utilization of its system. The Seaboard formula facilitates increased utilization on an annual basis of a pipeline's system.

(3) The initial decision rejected Commission staff's argument that the pattern and nature of capital expenditures for plant additions on the Texas Gas system in recent years supports the conclusion that greater emphasis should be placed on the commodity component of pipeline rates. That decision is correct.

Even if Commission staff's analysis were proper, it would only provide a solution to the problem of how to classify the fixed costs associated with the additions to Texas Gas' plant. No conclusion could be drawn concerning whether that same cost classification would be proper for Texas Gas' remaining transmission and storage plant or whether the proper cost classification for the remaining transmission and storage plant would result in a cost classification for all transmission and storage plant which would be any different than the Seaboard cost classification methodology. Commission staff's analysis, thus, also fails because it is incomplete, and as such cannot provide the substantial evidence needed to adopt the analysis of Commission staff.

For this reason and because the initial decision concludes that the fixed costs of Texas Gas' plant additions should be classified equally to the demand component and the commodity component of rates, we affirm the initial decision's analysis of this issue.

I-33
(4) The initial decision also rejected Commission staff's analysis that a change from the Seaboard formula to the United formula was required because parts of the pipeline system were underutilized on a peak day. Once again an analysis which focuses on part of an integrated system is insufficient. It is the utilization of the entire system in support of deliveries to a pipeline's customers which determines the extent to which the fixed costs should be classified to the demand component or to the commodity component. Deliveries, and the pattern of deliveries, to customers on a peak day, seasonal, or annual basis are the key considerations in determining how costs should be recovered from the pipeline's customers. As discussed above, the utilization of the Texas Gas system supports the conclusion that, based on the record before us, the Seaboard formula continues to properly reflect the relative importance of the demand component and the commodity component for purposes of classifying the fixed costs of transmission and storage facilities.

(5) The initial decision concludes, and we agree, that a change from the Seaboard formula to the United formula cannot be supported for the period in question by any of three suggested grounds: (1) the change would discourage industrial use and sales, (2) the change would encourage more efficient use of scarce natural gas supplies, or (3) the change is consistent with economic principles and marginal cost pricing concepts.

8/ We begin with a discussion of economic and marginal cost pricing principles which present the most significant issues.

8/ In addressing these grounds, the initial decision states that systemwide average or unit rates (all costs in the cost of service divided by total volumes) on the Texas Gas system would not be affected by a change from Seaboard to United. Cost classification, allocation and rate design does not change the total cost of service.

Our concern with the emphasis on systemwide average or unit rates in the initial decision is that that analysis ultimately cannot be squared with Commission precedent. Changes in the percentage of fixed costs classified to the commodity component of rates affect the level of the commodity charge. The Commission and the courts have uniformly recognized the importance of the commodity charge, at the margin, on pipeline natural gas sales. Consolidated Gas Supply Corp. v. FPC, 520 F.2d at 1180-81, 1186.
As this record indicates, the application of marginal cost (or incremental cost) pricing to the Texas Gas system would require an analysis of the cost of providing an additional unit or units of output or the cost savings realized by producing one less unit of output. 9/ Marginal cost pricing is designed to maximize consumer well-being and optimize use of society's limited resources. A marginal cost analysis for a pipeline would require the derivation of marginal capacity costs and marginal commodity costs, since it is recognized that a pipeline provides two goods (a service and the ability to deliver the service); and these marginal costs would have to be derived for peak and off-peak periods. 10/ Properly viewed, marginal

9/ Problems with the application of marginal cost pricing include the specification of the period of time (long run or short run, off-peak or peak), the specification of the incremental block of output, and the identification of marginal costs where a large percentage of costs are common to different groups of users (Tr. R-80). The peak/off-peak problem and the analysis of common costs are the most significant problems with the application of marginal cost pricing principles; and it is these problems which are also present under average cost ratemaking and which are the essence of the cost classification, allocation, and rate design process. Marginal cost pricing, thus, does not eliminate the need to address the issues presented in this case.

10/ The discussion of the economic literature in the record suggests that peak period users should pay all capacity costs (marginal capacity costs) because the same amount of capacity would have been constructed, even if the off-peak demand were eliminated (Tr. R-123-24). Peak users "caused" the costs to be incurred and, thus, should be "responsible" for the costs. The allocation of fixed costs classified to the demand charge, based on the maximum amount of capacity reserved by customers, accomplishes precisely that result (albeit on an average or an accounting cost basis) but only for that percentage of the fixed costs which are so classified.

We believe, however, that it can also be argued that, if the peak demand were eliminated, off-peak users would be required to pay all the costs of the capacity required
cost pricing is an alternative to ratemaking on the basis of average or accounting costs, FPC v. Hope Natural Gas Co., supra; Permian Basin Area Rate Cases, 390 U.S. 747 (1967); or a guideline against which to measure the propriety and the incentive and disincentive signals of ratemaking on the basis of average costs.

No marginal cost analysis has been performed for the Texas Gas system. Moreover, total revenues derived from marginal cost rates will be different than the total revenue requirement or cost of service which would be recovered under average cost ratemaking. As this record indicates, you cannot use a revenue requirement which is different than the level generated by marginal cost rates and derive marginal cost rates (Tr. R-325-26). 11/

Insofar as this record does support a result based on the application of economic and marginal cost pricing principles, within the context of traditional demand and commodity rates, that result is Seaboard. Capacity is a limiting factor; and costs are incurred to maintain existing capacity (Tr. R-86). 12/

10/ (Footnote continued from previous page.)

to meet that off-peak demand (see, Tr. R-88). They "caused" that amount of capacity to be built. A capacity charge would be derived on a marginal cost basis; and amounts would be billed on the basis of the customers' reservation of that off-peak demand.

This discussion only highlights problems with marginal cost principles and economic theory which are noted above. See n.9, supra. It is these problems which Seaboard implicitly deals with, however imprecisely, in the limiting context of demand and commodity charges. It is these problems which are at the core of the decision to classify fixed costs to a charge which is not predicated on the maximum amount of capacity reserved by a pipeline's customers.

11/ This consideration is obviously a caveat to the use of marginal cost pricing principles, not a bar to the use of these principles.

12/ Even if capacity were not a limiting factor, the greater capacity costs associated with serving customers in the winter, when compared to the summer, would still support rates, based on marginal cost principles, which contain seasonal (peak/off-peak) differentials and a demand charge (Tr. R-88, R-347-48).
Thus, both marginal capacity costs and marginal commodity costs are being incurred; and rates should not be based only on a commodity charge (Tr. R-280). The existence of storage also indicates a seasonal differential in capacity costs and in marginal capacity costs which should be reflected in rates. The Seaboard cost classification methodology is more consistent with the existence of seasonal differentials in capacity costs (Tr. R-329-30).

We also cannot justify a change from the Seaboard methodology to the United methodology in order to encourage more efficient use of scarce natural gas supplies or to discourage industrial use and sales. These policy grounds are simply insufficient in the abstract to support a change given our conclusion that the Seaboard formula is fair and is supported by an analysis of the supply situation and the role of industrial utilization of the Texas Gas system and by an analysis of the relative importance of the demand component and the commodity component of rates.

We would note that the emphasis which has traditionally been placed on the fixed costs of transmission and storage facilities for purposes of achieving these goals is no longer warranted for the relevant period. In our view, the record before us demonstrates increased emphasis should be placed on the far more significant purchased gas and other costs incurred by pipelines. The relationship between purchased gas costs and pipeline sales has become critically important and would appear to be a better vehicle for assuring efficient use of natural gas supplies consistent with marginal cost pricing principles and economic theory. Both Congress, in Title II of the NGPA, and the courts have recognized the need for additional analysis in this area. United Gas Pipeline Co. v. FERC, supra.

(6) While we affirm the initial decision's conclusion that the Seaboard formula is appropriate and yields just and reasonable rates for the reasons set forth here and in the initial decision 13/, several additional comments are in order. The Commission and the courts have emphasized that cost classification is only one aspect of a larger, fundamentally indivisible process -- cost classification, allocation, and rate

13/ Of the other factors discussed in the initial decision, the better match between cost incurrence and cost responsibility within a demand/commodity framework which is provided by the Seaboard formula, compared to the United formula, is the most significant, n.10, supra; Columbia Gas Transmission Corp. v. FERC, 628 F.2d at 590, 591, n.60.

Yet, the only issue before us is whether the percentage of fixed costs associated with the investment in transmission and storage facilities should be classified to the demand component in accordance with the Seaboard formula or in accordance with the United formula. No issue has been raised concerning the basis for allocating the demand or commodity costs among Texas Gas' customers or for designing rates on Texas Gas' system. No issue has been raised concerning purchased gas costs or production and gathering costs. Indeed, the interplay of these broader issues in the context of Texas Gas' system has recently been set for hearing. 19 FERC ¶ 61,205.

Our discussion here concerning conditions on the Texas Gas system should not be uncritically applied in the future to other cost classification, allocation, and rate design issues. For example, many of the concerns which have been raised with the demand charge may be more precisely and fairly addressed by modifying the basis for allocating and billing demand costs among Texas Gas' customers, modifications which would be consistent with system design limitations on the annual use by a customer of its contract demand and which have received favorable comment by the court. Consolidated Gas Supply Corp. v. FPC, 520 F.2d at 1189. Our decision not to modify the percentage of fixed costs classified to the demand component should not be read to support the conclusion that conditions on the Texas Gas system require no changes in cost classification, allocation, and rate design on that system. In a more comprehensive rate inquiry, subsequent changes in the system's overall rate design could dictate revisiting the result reached today.

Our decision should also not be read to support the conclusion that underutilization of a pipeline's system is a fact of little or no importance in cost classification, allocation, and rate design. A system which is underutilized because there is an inadequate demand for natural gas as a result of natural gas prices is, in many respects, indistinguishable in the reality of its operation though not necessarily in its customer impact, from a pipeline system which is underutilized because there is an inadequate supply of natural gas as a result of curtailment (Tr. R-290). Of particular concern would be reductions in annual sales levels, reductions in
peak period sales, or the failure by customers to demand full contract demand quantities. 14/ In this regard Commission decisions which apply the Seaboard formula or the "tilted" Seaboard formula 15/ should not be viewed as talismans, to be routinely invoked in the 1980's. Changing conditions in the natural gas market may well compel the conclusion that another formula is a superior methodology for assuring that natural gas rates are just and reasonable.

We conclude today only that the Seaboard methodology properly classifies fixed costs associated with the investment in transmission and storage facilities between the demand and the commodity components and results in just and reasonable rates. No reasoned explanation has been provided in this record which would support a wholesale departure from the Seaboard methodology.

The Commission orders:

(A) To the extent not inconsistent herewith, the initial decision is affirmed and adopted as the decision of the Commission.

(B) All exceptions to the initial decision are denied.

By the Commission.

(SEAL)

Kenneth F. Plumb, Secretary.

14/ The initial decision places great weight on the fact that no customer has requested a reduction in its contract demand. In our view this factor has less weight in measuring the continued vitality of the demand charge for three reasons. First, this consideration which was also present in the original United case provided no justification for the retention of the Seaboard formula in that case. Second, Texas Gas' tariff imposes significant constraints on a customer wishing to reduce its contract demand. FERC Gas Tariff, 3rd Rev. Vol. No. 1, Orig. Sheet No. 96. Third, as this case demonstrates, a customer should not be precluded from arguing the reduced relevance of the demand component of rates, as measured by the contract demand quantity, where full contract demand quantities are not often demanded.

15/ Fuels Research Council, Inc. v. FPC, supra.
# Impact of Alternative Cost Classification Methodologies on Jurisdictional Cost of Service and Revenue Requirements

## Functionalized Cost

<table>
<thead>
<tr>
<th>Item</th>
<th>Functionalized Cost</th>
<th>Total</th>
<th>Demand</th>
<th>Commodity</th>
<th>Total</th>
<th>Demand</th>
<th>Commodity</th>
<th>Total</th>
<th>Demand</th>
<th>Commodity</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Production</td>
<td>$1,000</td>
<td>$900</td>
<td>$1,000</td>
<td>$900</td>
<td>$1,000</td>
<td>$900</td>
<td>$1,000</td>
<td>$900</td>
<td>$1,000</td>
<td>$900</td>
</tr>
<tr>
<td>2</td>
<td>Purchased Gas-Demand</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
<td>1,000</td>
</tr>
<tr>
<td>3</td>
<td>Purchased Gas-Commodity</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
</tr>
<tr>
<td>Transmissions</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td>700</td>
<td></td>
</tr>
</tbody>
</table>

## Allocation of Total Cost of Service to Classes of Customers

| Jurisdictional Cost of Service | $4,790 | $3,795 | $2,665 | $2,013 | $1,402 | $1,070 | $7,310 | $5,971 | $4,790 |
| Non-Jurisdictional Cost of Service | 320 | 270  | 2,222 | 1,850 | 1,433 | 1,189 | 3,550 | 2,939 | 1,850 |
| Total Cost of Service | $5,110 | $4,065 | $4,885 | $3,843 | $2,835 | $2,259 | $8,860 | $7,910 | $6,640 |

## Peak Period Service

<table>
<thead>
<tr>
<th>Allocation Factor</th>
<th>M/Lf</th>
<th>Allocation Factor</th>
<th>M/Lf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jurisdictional</td>
<td>28,000</td>
<td>90%</td>
<td>3,009,000</td>
</tr>
<tr>
<td>Non-Jurisdictional</td>
<td>2,717</td>
<td>10%</td>
<td>282,350</td>
</tr>
<tr>
<td>Total</td>
<td>30,717</td>
<td>100%</td>
<td>3,291,350</td>
</tr>
</tbody>
</table>

---

Reference: Gas Rate Fundamentals, American Gas Association, Third Edition (1978); Table 16, page 239.
Gentlemen:

On September 21, 1982, Michigan Wisconsin Pipe Line Company (Mich Wisc) filed a request for a temporary certificate to commence service under a new rate schedule designated Rate Schedule DF-1. The new service would be available to existing customers purchasing natural gas under Rate Schedules CD-1, LVS-1, and SGS-1, and would not increase their daily and annual entitlements under those rate schedules. Mich Wisc alleges that effective November 1, 1982, when its increased rates under Docket Nos. RP82-80 and TA83-1-48-000 become effective, certain of its customers will experience losses in sales amounting to several billion cubic feet annually. Mich Wisc represents that its sales will have decreased by 22% over the three-year period ending in 1982 due primarily to the severe economic recession, competition by available alternate fuels and increased conservation.

Rate Schedule DF-1 will be available to distributors only for resale to gas users with annual requirements of 100,000 cubic feet, which use gas for feedstock or process purposes, or have existing capacity to use No. 5 or No. 6 fuel oil or liquefied petroleum gas. When such users request a reduced price from their distributor, so as to move the distributor to seek gas under Rate Schedule DF-1, the users must demonstrate that their current economic conditions, and/or alternate fuel prices, are such as to require such service if they are to avoid substantial reduction in, or discontinuance of, gas use, or are to be able to begin to resume gas use.

The rates for service under Rate Schedule DF-1 are proposed to differ depending upon whether the end user is exempt from incremental pricing. For exempt end users, the rate would be that rate necessary to enable the end user to purchase the gas, but the rate would be no lower than the then effective price for Section 102 natural gas nor no higher than the then effective rate for service under the LVS-1 rate schedule. For a non-exempt end user, the rate would be equal to 90% of the incremental ceiling prices published for the FERC (prices published by The Energy Information Administration) for the area where the end user is located. Mich Wisc proposes to credit to Account No. 191 any revenues received in excess of the "cost of gas purchased for such service."
Based upon its rate change filings to become effective on November 1, 1982, Mich Wisc's commodity charge will be approximately $4.20 per dth, which includes purchased gas costs of $3.39 plus $.007 attributable to the GRI surcharge. Mich Wisc represents that the price of No. 6 residual fuel oil in its market area approximates $3.80 per dth. Consequently, its distributor customers will be unable to compete with residual fuel oil and still recover their variable costs associated with the commodity charge. Mich Wisc proposes the DF-1 rate schedule to enable its customers to compete, but in no event would the rate charged be less than the "average acquisition cost of natural gas included in Seller's (Mich Wisc) resale rates."

The Section 102 price for the month of November, 1982, is $3.249 per MMbtu as compared with Mich Wisc's current cost of gas of $3.17 per dth beginning November 1, 1982. The current cost of gas excludes the surcharge of 22.73¢ to recoup under-collections recorded in Account No. 191. Ninety percent of the incremental ceiling prices for the major markets served by Mich Wisc would range from $3.13 to $3.18 per MMbtu for the month of November 1982. Consequently, it appears that the current cost of purchased gas closely approximates the minimum rates under the DF-1 rate schedule.

We are satisfied that Mich Wisc and its distributor customers should be able to compete with alternate fuels so long as the rates charged by Mich Wisc are compensatory. At a minimum the rates should recover the cost of gas plus any other out-of-pocket costs associated with making the sales. They should also recover any fixed costs necessary to assure that other customers or classes of customers do not suffer undue adverse impact as the result of the sales. Our review of prior PGA filings reveals that, Mich Wisc has typically experienced positive balances in its Account No. 191 which means that its actual costs of purchased gas have exceeded the costs included in its rates. To be compensatory, any DF-1 rates must recover the actual cost of purchased gas. Based upon this analysis, it appears that the current cost of gas included in rates would not be compensatory and that the 22.73¢ per dth surcharge should be added to the current cost of gas. Moreover, we have found that a .72¢ surcharge should be added to Mich Wisc's rates to fund GRI’s research effort. For Mich Wisc's DF-1 rates to recover the cost of gas, they must equal $3.40 per dth. We will permit Mich Wisc to charge a rate between the cost of gas and the price of residual fuel provided it files the rate within 10 days of the date of this letter. We expect the appropriate rate or rates for DF-1 service to be determined in the Docket No. RP82-80 proceeding and Mich Wisc is hereby advised that it may not be able to collect any differential between the rate charged under the DF-1 rate schedule and the rate found appropriate in Docket No. RP82-80.
We are mindful of Mich Wisc's allegations that all of its customers will benefit to the extent that take-or-pay costs and storage costs can be avoided if the sales can be made. However, we are concerned that the DF-1 rates for exempt end users would be individually negotiated rates which is inconsistent with Section 154.38(d) of the Commission's regulations. Moreover, we are concerned that the special DF-1 rate schedule may not be the best way for Mich Wisc and its customers to respond to current market conditions. Consequently, we will grant temporary authority for a term of six months for Mich Wisc to render service under the DF-1 rate schedule for sales to those end users that would otherwise use residual fuel oil. We intend to act promptly upon the permanent certificate in this docket and this temporary authority is without prejudice to any final action on the permanent certificate.

By direction of the Commission.

Kenneth F. Plumb
Secretary

cc: Brackett & Collins, P.C.
1899 L Street, N.W.
Suite 501
Washington, D.C. 20036

I-43
ORDER REJECTING COMPLIANCE FILING WITHOUT PREJUDICE AND CLARIFYING PRIOR ORDER

(Issued November 5, 1982)


BACKGROUND

On September 21, 1982, Michigan Wisconsin Pipeline Company (Mich Wisc) filed with the Commission a request for a temporary certificate in this docket. The filing proposed to allow Mich Wisc to provide new service under a rate schedule designated as "DF-1". According to Mich Wisc, this new rate schedule would not increase certain customers' daily and annual entitlements under existing rate schedules CD-1, LVS-1 and SGS-1.

To support its request for the temporary certificate, Mich Wisc stated that without such a certificate, its customers might experience severe load loss. Specifically, the company observed that its sales of natural gas over a three year period, ending in 1982, will have decreased by 22%. It stated that this decrease was attributable to the severe economic depression, the competitive advantage of available alternate fuels and increased customer conservation in their purchases and use of natural gas.

On October 29, 1982, the Commission issued a letter order which granted Mich Wisc's request for a temporary certificate subject to several conditions. The letter order provided for an effective date of November 1, 1982.
The letter order indicated that the Commission did not per se oppose the concept of designing rates to permit Mich Wisc's distributor customers to compete with alternative fuels "... so long as the rates charged by Mich Wisc are compensatory (letter order, p. 2)". In defining this term further, the Commission stated the following:

At a minimum the rates should recover the cost of gas plus any other out-of-pocket costs associated with making the sales. They should also recover any fixed costs necessary to assure that other customers or classes of customers do not suffer undue adverse impact as the result of the sales.

The Commission noted further that Mich Wisc's cost of gas as of November 1, 1982, equalled $3.40 per dth which was the sum of (1) $3.17 per dth which is the current cost of gas plus (2) 2.73¢ per dth which is the Account No. 191 surcharge plus (3) .72 per dth to fund GRI's research effort. The Commission then stated that it would permit Mich Wisc to charge a rate under Rate Schedule DF-1 "between the cost of gas and the price of residual fuel (oil) provided it files the rate within 10 days of the date of this letter." 1/ However, the Commission specifically noted that there were rate conditions to the appropriateness of a finally determined DF-1 rate, including a condition that the rate should be fully compensatory and recover an appropriate level of fixed costs. Additionally, the Commission noted that the appropriate rate or rates for DF-1 service would be determined in Docket No. RP82-80, Mich Wisc's ongoing general Section 4 rate proceeding, wherein the suspended rates, as modified, became effective subject to refund on November 1, 1982. 2/ The Commission also expressly advised Mich Wisc that it may not be able to "collect any differential between the rate charged under the DF-1 rate schedule and the rate found appropriate in Docket No. RP82-80." In other words, while Mich Wisc was granted temporary authority to enter into special arrangements with DF-1 customers, it was expressly advised, and we continue to emphasize, that its shareholders assumed the risk of undercollection in the event the finally approved rate in RP82-80 was established at a level higher than that charged by Mich Wisc to its DF-1 customers consistent with its temporary authority. By virtue of the fact that any such service would be

1/ In the letter order, the Commission noted that Mich Wisc had represented that the price of No. 6 residual fuel oil in its market area is approximately $3.80 per dth.

performed under temporary authority, any final rate determination would relate back to the date of initial service.

Finally, the Commission stated the following:

We are mindful of Mich Wisc's allegations that all of its customers will benefit to the extent that take-or-pay costs and storage costs can be avoided if the sales can be made. However, we are concerned that the DF-1 rates for exempt end users would be individually negotiated rates which is inconsistent with Section 154.38(d) of the Commission's regulations. Moreover, we are concerned that the special DF-1 rate schedule may not be the best way for Mich Wisc and its customers to respond to current market conditions. Consequently, we will grant temporary authority for a term of six months for Mich Wisc to render service under the DF-1 rate schedule for sales to those end users that would otherwise use residual fuel oil. We intend to act promptly upon the permanent certificate in this docket and this temporary authority is without prejudice to any final action on the permanent certificate (emphasis added).

COMPLIANCE FILING

On November 3, 1982, Mich Wisc made its compliance filing with the Commission. Therein, Mich Wisc proposed a rate of $3.45 per 6th and indicated that "consistent with the DF-1 Rate Schedule initially filed herein", Mich Wisc "is proposing to make the rate schedule available to those end-users who otherwise qualify under the DF-1 Rate Schedule and who use gas for feedstock and process purposes or have existing capability to use No. 5 or No. 6 fuel oil or liquefied petroleum gas."

We find that the availability provision reflected in Mich Wisc's compliance filing is inconsistent with the Commission's October 29, 1982 letter order. That order expressly provided that the temporary certificate authorization granted to Mich Wisc under the Rate Schedule DF-1 rate was limited to "sales to those end users that would otherwise use residual fuel oil." Clearly, end users who use gas for feedstock or process purposes "do not fall within that category because those users cannot use residual fuel oil as an alternate fuel. Accordingly, we shall
reject Mich Wisc's compliance filing without prejudice to Mich Wisc's right to file revised tariff sheets for Rate Schedule DF-1 which limit its availability to end users who would otherwise use residual fuel oil and which reflect the discussion below.

Further, we disagree with Mich Wisc's explanation of its proposed $3.45 per dth rate for Rate Schedule DF-1. Mich Wisc states that only $3.17 of that rate should be considered purchased gas cost and that the 22.73¢ per Mcf Account No. 191 PGA surcharge and the .72¢ per dth surcharge should not be considered gas cost. Mich Wisc states that this is true because "the PGA surcharge represents costs which will not vary if the subject DF-1 sales are or are not made, since the surcharge represents costs incurred in the past, which must be recovered."

Mich Wisc's assertions are clearly inconsistent with the October 29, 1982, letter order. The letter order noted (p. 2) that Mich Wisc has typically experienced positive balances in its unrecovered purchased gas cost account (Account No. 191) and that it was therefore appropriate that in order for the rate to be fully compensatory that the cost of gas component of Rate Schedule DF-1 reflect the 22.73¢ per dth. The Commission also found that volumes sold under Rate Schedule DF-1 should also include the GRI surcharge of .72¢ per dth to fund GRI's research effort. Accordingly, any new compliance filing made by Mich Wisc should reflect a rate that reflects the foregoing discussion, i.e., that $3.40 per dth is the cost of gas plus GRI surcharge.

There are also statements made by Mich Wisc in its transmittal letter that require a response. Mich Wisc argues that volumes sold under Rate Schedule DF-1 are volumes that would not otherwise be sold under Mich Wisc's Rate Schedules CD-1, LVS-1 and SG-1. Therefore, Mich Wisc argues that the Rate Schedule DF-1 rate should not recover any "fixed" costs or "out of pocket costs" because all sales made under Rate Schedule DF-1 will be to Mich Wisc's existing customers using existing facilities and therefore these sales will "create no 'out of pocket' costs or 'fixed' costs." As we stated in our October 29, 1982, letter order, the issue of the proper rate level for Rate Schedule DF-1 will be resolved in Docket No. KP82-80 where the suspended rates became effective, subject to refund, as of November 1, 1982. The question as to whether the $3.45 per dth proposed by Mich Wisc (or such other rate as Mich Wisc may propose in a subsequent compliance filing), become effective as of November 1, 1982, for Rate Schedule DF-1 is fully compensatory will be determined in Docket No. KP82-80. Thus, we state again that
should it be found in Docket No. RP82-80 that Mich Wisc did not charge enough under Rate Schedule DF-1, Michigan Wisconsin's shareholders may be required to absorb the difference between the rate actually charged and the rate that should have been charged as of November 1, 1982, by Mich Wisc for Rate Schedule DF-1. Accordingly, the Commission reserves the right to assign such additional costs to Rate Schedule DF-1 as of November 1, 1982, after a hearing in Docket No. RP82-80 as may be appropriate.

One further matter requires comment. We note that our October 29, 1982, order stated that we would accept a "rate between the cost of gas and the price of residual fuel ...". Upon further review, we believe the language "the price of residual fuel" may be interpreted to be a ceiling for the initial rate to be charged by Mich Wisc under Rate Schedule DF-1, particularly since, as our October 29, 1982, letter order notes, Mich-Wisc has represented that the price of No. 6 residual fuel oil in its market area approximates $3.80 dth. We note that in its November 3, 1982, compliance filing Mich-Wisc proposed a rate of $3.45 per dth. Therefore, the question of whether or not the price of residual fuel was a ceiling for Rate Schedule DF-1 apparently was not a concern for Mich Wisc in making its compliance filing. In any event, the Commission hereby in this order expressly states that the "price of residual fuel oil" is not a price ceiling for Mich-Wisc's Rate Schedule DF-1.

This is consistent with our statements in the October 29, 1982, letter order and this order that the Commission may assign additional costs as of November 1, 1982, to Rate Schedule DF-1 if the record developed in Docket No. RP82-80 justifies this action.

The Commission orders:

Mich Wisc's November 3, 1982, compliance filing is rejected without prejudice as discussed in the body of the order.

By the Commission.

( SEAL )

Kenneth F. Plumb, Secretary.
I. INTRODUCTION

On September 21, 1982, Michigan Wisconsin Pipe Line Company (Mich Wisc) filed under Section 7(c) of the Natural Gas Act an application for a limited term certificate of public convenience and necessity authorizing Mich Wisc to provide a new service under a rate schedule designated DF-1 which would make available to eligible customers certain quantities of natural gas at a price which would enable its customers to retain or regain consumers who possess the capability of utilizing alternate fuels priced lower than natural gas. Mich Wisc also sought, and on October 29, 1982, was granted temporary authorization to provide the service for a period of six months. 1/

The temporary certificate set forth criteria for the interim rate to be charged and referred the question of an appropriate final rate to Mich Wisc's general rate proceeding in Docket No. RP82-80. The temporary certificate requires Mich Wisc to recover in its interim DF-1 rate the cost of gas and the GRI surcharge, plus any other out-of-pocket costs associated with the sale. In addition, Mich Wisc was advised that for the final rate to be compensatory it must recover any fixed costs necessary to assure that other customers or classes of customers do not suffer undue adverse impact as a result of these sales. The Commission permitted Mich Wisc to charge an interim rate which would be competitive with residual fuel oil but would be no less than $3.40 per dth. Mich Wisc's shareholders are required to assume the risk of undercollection in the event the finally approved DF-1 rate is established at a level higher than that charged by Mich Wisc in the interim. 1/

1/ 21 FERC ¶ 61,055.
On November 3, 1982, Mich Wisc tendered for filing tariff sheets in purported compliance with the temporary certificate. The filing was rejected by order issued November 5, 1982, without prejudice to refiling because Mich Wisc's tariff sheets stated that Mich Wisc would provide DF-1 service not only to consumers who would otherwise use residual fuel oil as authorized, but also to feedstock and process gas consumers. Moreover, we rejected Mich Wisc's assertion that only $3.17 of its DF-1 rate should be considered purchased gas costs, rather than at least $3.40 (or the full $3.45 rate actually proposed by Mich Wisc) as conditioned by the temporary certificate. On November 10, 1982, Mich Wisc's revised tariff sheets were accepted as being in compliance with the temporary authorization.

II. DISCUSSION

The proposed DF-1 rate raises both short-term and long-term policy concerns. We are concerned first of all that the proposed rate be compensatory in an immediate and short-term sense. The rate would not be based on differences in the cost of serving customers but on differences in customers' demand for gas. Such a rate may be justified if, but only if, non-discount customers would be better off with approval of the rate than otherwise. Mich Wisc asserts that non-discount customers will in fact benefit from the rate, through the crediting of excess revenues and reduction of the pipeline's exposure to prepayments under its take-or-pay obligations. However, they will receive this benefit only if the discount rate recovers an amount in excess of the costs that would be avoided by not making the special discount sales. These avoided costs may not necessarily relate to the pipeline's weighted average cost of gas. If the pipeline would be required to purchase additional supplies in order to serve the discount customers, the avoided cost in general would reflect the price of those supplies. On the other hand, if the pipeline would instead increase its takes under existing contracts, the avoided cost might depend upon the price of gas under those contracts and any costs that the pipeline would incur even if it did not take the gas. It must be recognized that avoided costs apply to more than purchased gas costs. The discount rates may have the effect of shifting costs among customers with those customers unable to take advantage of the lower rates being required to assume a greater share of the capacity costs.

The excess of the proposed rate over Mich Wisc's avoided costs must be large enough to make a reasonable contribution to fixed costs. In addition, although the rate is directed at customers who would not otherwise purchase gas, it may be difficult to identify such customers precisely. It may be found that some gas is likely to be purchased under the discount rate by
customers who otherwise would have purchased under Mich Wisc's regular rate schedule. Although this diversion of sales from regular to discount rates may be difficult to measure, the possibility that it will occur may suggest that a rate that closely approximates avoided costs would not sufficiently benefit short-term non-discount customers.

We are, in addition, concerned that the proposed rate be beneficial in a longer-term sense. It is possible that Mich Wisc's avoided costs are low, possibly even lower than its weighted average cost of gas. However, we do not believe that the long-term interests of Mich Wisc's customers are best served by encouraging sales at such a low rate. Such sales convey an unrealistic picture of the market for natural gas and thus fail to encourage the restructuring of the contractual relationships between pipelines and producers that must eventually occur. Even if a rate below Mich Wisc's weighted average cost of gas would leave its non-discount customers better off in the short term, we do not believe that such a rate would benefit them in the long run.

As we stated in the order granting Mich Wisc temporary authorization to provide DF-1 service, we are satisfied that Mich Wisc and its customers should be in a position to compete with alternate fuels so long the rate charged by Mich Wisc is consistent with the above criteria, and we will only approve a final rate for DF-1 service that is shown to benefit the customers in both the short and long-term sense. 2/ To be compensatory, any final special sales incentive rate must recover the actual cost of purchased gas attributable to the sales. In addition, the rate must recover the current Gas Research Institute (GRI) surcharge plus any other out-of-pocket costs associated with making the sales. It must also recover any fixed costs necessary to assure that other customers or classes of customers do not suffer undue adverse impact as the result of the sales. Any final rate charged by Mich Wisc under Rate Schedule SSI must meet these criteria. The interim rate we permitted in the temporary certificate was required to recover at least (1) the current cost of purchased gas including the current Account No. 191 surcharge, (2) the current GRI surcharge, plus (3) any out-of-pocket costs associated with making the sales. As stated in the temporary certificate, we will require that a final determination

2/ Nothing said herein or in the order granting the temporary certificate is intended to relieve Mich Wisc or its customers from the requirements of Title II of the Natural Gas Policy Act or Part 282 of the Commission's Regulations.
of the appropriate DF-1 rate be made in Docket No. RP82-80, Mich Wisc's ongoing Section 4 general rate proceeding.

We again expressly advise Mich Wisc that it may not be able to collect any differential between the rate found appropriate in Docket No. RP82-80 and the rate charged under the temporary certificate. In other words, while Mich Wisc was granted temporary authority to charge an interim rate to its customers, it was expressly advised, and we emphasize, that its shareholders will assume the risk of undercollection in the event the finally approved rate in Docket No. RP82-80 is established at a level higher than that charged by Mich Wisc to its DF-1 customers consistent with its temporary authority. By virtue of the fact that any service will be performed under temporary authority, any final rate determination will relate back to the date of initial service. 3/ We are mindful of Mich Wisc's allegations that all of its customers will benefit to the extent that take-or-pay costs and storage costs can be avoided if these sales can be made. However, we are concerned that the special DF-1 rate schedule may not be the best way for Mich Wisc and its customers to respond to current market conditions. We are unable to resolve these issues on the basis of the present record.

Consequently, we will set the matter of Mich Wisc's permanent certificate for formal hearing in order to resolve these, as well as other, issues of material fact, law, and policy such as:

(1) Whether Mich Wisc's customers will derive a benefit from this service;

(2) In particular, whether the rates to customers who are not eligible for DF-1 service will be lower;

(3) The long-term effect of this service on Mich Wisc's system;

(4) Whether service under the DF-1 rate schedule is unduly discriminatory;

(5) The impact of these sales on Mich Wisc's overall rate design;

(6) How Mich Wisc will comply with Title II of the Natural Gas Policy Act of 1978 (NGPA) in the administration of these sales;

(7) To what extent have Mich Wisc's gas acquisition practices contributed to the need to make these sales;

(8) Whether the DF-1 rate contains sufficient safeguards to protect Mich Wisc's other customers;

(9) The effect of the DF-1 service on market forces in the gas industry;

(10) The effect of the DF-1 service on Mich Wisc's future gas acquisition practices;

(11) The proper apportionment of revenues derived from the DF-1 service;

(12) Whether the DF-1 rate was calculated properly; and

(13) Whether the DF-1 rate promotes unfair competition between eligible consumers and those similarly situated elsewhere who are not afforded such service.

III. INTERVENTIONS

Notice of Mich Wisc's application was published in the Federal Register on October 15, 1982 (47 Fed Reg. 46129). Eighteen persons identified in the Appendix filed timely motions to intervene. Great River Gas Company (Great River) and Michigan Gas Utilities (MGU) filed motions to intervene out of time. Great River avers that its motion to intervene was filed out of time due to its President and Chief Operating Officer being on travel status during the shortened notice period. MGU avers that its motion to intervene was filed out of time because it became aware of the magnitude of Mich Wisc's projected load loss under current rate schedules at a late date.

The Commission finds:

(1) Mich Wisc's proposal herein raises material issues of fact.

---

4/ Timely interventions are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure.
(2) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that the application in Docket No. CP82-542 be set for formal hearing on the matters involved and the issues presented in this proceeding as hereinbefore described.

(3) Good cause exists to permit the late intervention by Great River and MGU.

The Commission orders:

(A) Pursuant to Sections 7 and 15 of the Natural Gas Act, Mich Wisc's application in Docket No. CP82-542 is set for hearing.

(B) An Administrative Law Judge to be designated by the Chief Administrative Law Judge (18 CFR § 375.304) shall preside at a prehearing conference and subsequent hearing in this proceeding, with authority to establish and change all procedural dates and to rule on all motions, as provided by the Commission's Rules of Practice and Procedure.

(C) Great River and MGU are permitted to intervene, subject to the rules and regulations of the Commission; provided, however, that the participation of such intervenors shall be limited to matters affecting asserted rights and interests as specifically set forth in their motions to intervene; and provided, further, that the admission of these intervenors shall not be construed as recognition by the Commission that they might be aggrieved because of any order of the Commission entered in this proceeding.

By the Commission.

(SEAL)

Kenneth F. Plumb,
Secretary.
North Central Public Service Company,
   Division of Donovan Companies, Inc.
Iowa Electric Light and Power Company
Illinois Power Company
Wisconsin Fuel and Light Company
City Gas Company
Wisconsin Power and Light Company
Wisconsin Natural Gas Company
Wisconsin Gas Company
Wisconsin Public Service Corporation
Michigan Power Company
Madison Gas & Electric Company
Chevron Chemical Company
Iowa State Commerce Commission
Ohio Valley Gas Corporation
Michigan Consolidated Gas Company
Association of Businesses Advocating Tariff Equity
First Miss, Inc.
The Public Service Commission of Wisconsin
ORDER DENYING REQUESTS FOR REHEARING

(Issued February 22, 1983)

Introduction

On September 21, 1982, Michigan Wisconsin Pipe Line Company (Mich Wis) filed, under Section 7(c) of the Natural Gas Act, an application for a limited term certificate of public convenience and necessity authorizing Mich Wis to provide a new service under a rate schedule designated DF-1, which would make available to eligible customers certain quantities of natural gas at a price that would enable its customers to retain or regain consumers who possess the capability of utilizing alternate fuels priced lower than natural gas. Mich Wis also sought, and on October 29, 1982 (21 FERC ¶ 61,063) was granted, temporary authorization to provide the service for a period of six months.

On November 3, 1982, Mich Wis tendered for filing tariff sheets in purported compliance with the temporary certificate. The filing was rejected by order issued November 5, 1982 (21 FERC ¶ 61,062), without prejudice to refiling, because Mich Wis's tariff sheets stated that Mich Wis would provide DF-1 service not only to consumers who would otherwise use residential fuel oil as authorized, but also to feedstock and process gas consumers. Moreover, we rejected Mich Wis's assertion that only $3.17 of its DF-1 rate should be considered purchased gas costs, rather than at least $3.40 (or the full $3.45 rate actually proposed by Mich Wis) as required by the temporary certificate. On November 10, 1982, Mich Wis's revised tariff sheets were accepted as being in compliance with the temporary authorization.
Both the October 29, 1982 1/ and the November 5, 1982, orders made clear our intent that in the event the finally approved rate was established at a higher level than that charged by Mich Wisc to its DF-1 customers, Mich Wisc's shareholders would be required to absorb any difference between the rate actually charged and the rate that should have been charged as of November 1, 1982, by Mich Wisc for Rate Schedule DF-1. (21 FERC at 61,230).

On December 22, 1982, the Commission, repeating its concern that the Special DF-1 rate schedule may not be the best way for Michigan Wisconsin and its customers to respond to market conditions, ordered Mich Wisc's Section 7(c) application set for hearing. This hearing order addressed, inter alia, the appropriate rate treatment to be accorded sales consummated under Mich Wisc's temporary authority.

Discussion

On January 20, 1983, Mich Wisc filed for a rehearing and/or clarification of the Commission's December 22, 1982, order. Mich Wisc alleges that aspects of that order could be read to have changed substantially the terms of the temporary authorization granted by Commission letter order of October 29, 1982.

Likewise, a joint petition for reconsideration and rehearing was filed on January 20, 1982, by Wisconsin Natural Gas Company, Wisconsin Power & Light Company, Wisconsin Gas Company, Madison Gas & Electric Company, Wisconsin Bulb and Light Company, City Gas Company and Wisconsin Public Service Corporation (the Wisconsin Distributors Group), Michigan Gas Utilities Company, Michigan Power Company and North Central Public Service Company (all collectively hereinafter referred to as joint petitioners). The joint petitioners, customers of Mich Wisc, allege that the December 22, 1982, order places Mich Wisc at considerably more risk than the October 29 order, if the final rate is ultimately determined to be more than the $3.45 per dth rate at which the gas is presently being sold. Joint petitioners fear this interpretation of the December 22, 1982, order will cause Mich Wisc to cease sales to the detriment of joint petitioners.

1/ We stated on October 29, 1982, "Mich Wisc is hereby advised that it may not be able to collect any differential between the rate charged under the DF-1 rate Schedule and the rate found appropriate in Docket No. RP82-80" (21 FERC at 61,231).
The Commission finds that Mich Wis's claim that the order of December 22, 1982, changed the conditions imposed upon Mich Wis under the temporary authority granted October 29, and reiterated by order of November 5, 1982, is totally without merit. Mich Wis was expressly told in both the October 29, 1982 and the November 5 order that it and not its ratepayers would be at risk for any underrecovery in the event the Commission should ultimately determine that the appropriate DF-1 rate should be higher than that charged by Mich Wis under the temporary certificate. We find nothing in the petitions to cause us to modify the December 22, 1982 order.

Past Gas Acquisition Practices

As to the issues listed for hearing at pages 4 and 5 of December 22 order, Mich Wis challenges the relevancy of issue number seven, i.e., the prudency of Mich Wis's past gas acquisition practices.

Mich Wis asserts that questions of prudency may be raised more appropriately in Mich Wis's related rate proceeding (Docket No. RP82-80), and that such questions have been raised in certain PGA protest cases.

We note that Mich Wis, on January 6, 1982, filed a motion 2/ with the Chief Administrative Law Judge requesting joint hearings before Judge Gordon (assigned to Docket No. RP82-80) relative to the special Rate Schedule DF-1 issues which are germane to both the certificate proceeding (CP82-542-004) and the rate proceeding.

By order of January 10, 1983, 3/ the Chief Administrative Law Judge transferred to Judge Gordon for joint hearing the DF-1 special rate issues in Docket No. CP82-542-004.

---


The Commission is thus assured that the relevant issue of the prudency of past gas acquisition practices will be fully developed in that joint hearing while preserving administrative efficiency.

In sum, the rates collected under the temporary certificate shall remain subject to refund pending a determination in Docket No. RP82-80, and the merits of Mich Wise's requested permanent certificate authorization remain to be considered in the Docket No. CP82-542 proceeding.

The Commission finds:

(1) The Commission finds no new facts or points of law in the arguments raised by Mich Wise or the joint petitioners, respectively, to warrant modification of the December 22, 1982, order setting for hearing Mich Wise's September 21, 1982, application.

(2) As has been clearly stated in our earlier orders, Mich Wise's shareholders must bear the risk of underrecovery during the period of temporary authorization.

(3) The appropriate DF-1 rate will be determined in Docket No. RP82-80.

The Commission orders:

(A) Rate treatment for any sales completed prior to this rescission will be governed by the rationale set out in the October 29, 1982, order as further clarified by our orders of November 5, 1982, and December 22, 1982, in this docket.

(B) Petitioners' requests for modification of the December 22, 1982, order are denied.

By the Commission. Commissioner Sheldon abstained.

( S E A L )

Kenneth F. Plumb
Secretary.