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Stuart I. Silverman

ENCOURAGING CONSERVATION OF NATURAL GAS THROUGH THE PRICE MECHANISM

STUART I. SILVERMAN*

I.

As the nation continues to grapple with its seemingly intractable energy problems, the natural gas industry is certain to play a significant role in meeting the country's energy needs. Natural gas is a premium resource due to its clean burning characteristics and low cost relative to the market price of substitute fuels. It is, however, an irreplaceable resource and its supply is dwindling. A rational energy policy must take account of the wasting nature of the country's natural gas reserves by encouraging more efficient uses of remaining supplies.

Conservation has received increased attention of late as a means of effectuating a balance of supply and demand in energy markets. Numerous proposals have been enacted by state legislatures and the Congress providing for special tax incentives, mandatory building codes, and thermostat controls to encourage more thoughtful uses of all energy forms. While the effectiveness of these measures is not to be minimized, the most promising means of achieving more optimum natural gas utilization is through its market price.

Obviously, reliance upon the price mechanism depends to a large extent upon the degree to which the demand for natural gas is price responsive. Although there may be need for more analysis of demand elasticity[1] for various specific end uses, there is little doubt that the price elasticity of demand for natural gas is significant for residential, commercial, and industrial consumer categories.[2] Given the degree of price elasticity for natural gas, more optimum allocations are possible if rates charged by pipelines and local distributors accurately reflect the true value of gas service to consumers.

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* B.S., 1972, Drexel University; J.D., 1975, Temple University School of Law. Member, Pennsylvania and District of Columbia Bars. Member, American Bar Association: Section of Natural Resources Law; Natural Gas, Overseas Mineral Resources, and Electric Power Committees.

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1. Elasticity of demand is a measure of the responsiveness or sensitivity in quantity of goods or services demanded or consumed to changes in price. Elasticity is the percentage change in quantity demanded caused by a one percent change in price or the percentage change in quantity demanded over the percentage change in price. *See* E. BERLIN, C. CICCHETTI, & W. GILLEN, PERSPECTIVE ON POWER 117 (1974).

2. Although difficult to precisely measure, it has been estimated that the long run elasticity of demand for residential/commercial and industrial users is -.721 and -.392, respectively. FEDERAL ENERGY ADMINISTRATION, 1976 NATIONAL ENERGY OUTLOOK C-7, C-10 (1976).

The concept of functional pricing in the natural gas industry is not an outgrowth of the nation's current energy ills. Thirty-six years ago, Justice Jackson, in his dissent in *FPC v. Hope Natural Gas Co.*,[3] advocated reliance upon the price mechanism as a means of ensuring more socially desirable end uses of natural gas. A majority of the Supreme Court, however, viewed the ratemaking powers of the Federal Power Commission[4] under sections 4 and 5 of the Natural Gas Act as more circumscribed, that is, strictly limited to traditional concerns of meeting gas utility revenue requirements, including return on investment, at just and reasonable rates.[5]

Governed by these conventional approaches to natural gas ratemaking, federal regulators of interstate pipelines have favored accounting methods which, in recent years, have failed to afford natural gas consumers accurate pricing signals by which to gauge their incremental purchases. Likewise, practices adopted by state utility commissions vested with ratemaking authority over natural gas distributors have had similar unfavorable results. Major reforms of federal and state ratemaking practices are needed before more efficient end uses of natural gas by consumers can be realized.

II.

Ensuring that gas transmission and distribution rates are sufficient to satisfy utility revenue requirements necessarily involves the identification of the various costs incurred as an incidence of serving consumers. Once fixed and variable costs of the pipeline or distribution company are determined, these costs are apportioned among different customer classes, and rates are set at levels guaranteeing recovery of utility revenue requirements including a reasonable rate of return to investors.

The opportunity for utility regulators to influence conservation of natural gas exists at this juncture of the ratemaking process. Fundamental economic theory suggests that in an economy of finite resources, most optimum allocations of these resources occur when market prices reflect marginal costs.[6] Simply stated, marginal cost is the cost of providing one more unit of

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3. 320 U.S. 591 (1944).

4. In August 1977, the Federal Power Commission's authority to regulate natural gas rates was transferred to the Federal Energy Regulatory Commission under § 402 of the Department of Energy Organization Act, 42 U.S.C. § 7172(a) (Supp. II 1978). Throughout the remaining portion of this article, the Federal Power Commission and the Federal Energy Regulatory Commission will be referred to as the "Commission."

5. The Court in *Hope* specifically held that the Commission was without statutory authority to discourage certain end uses of natural gas in fulfilling its ratemaking responsibilities under §§ 4 and 5 of the Natural Gas Act (NGA), 15 U.S.C. §§ 717c, d (1976). 320 U.S at 616.

The Commission's ratemaking authority under §§ 4 and 5 of NGA extends to any "natural gas company," specifically defined in § 2(6) of NGA, 15 U.S.C. § 717a(6) (1976), as an individual or corporation "engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale." The scope of this article as it relates to federal regulation of natural gas rates concerns the Commission's exercise of its statutory authority over natural gas rates charged by interstate pipelines. However, as a result of the Supreme Court's decisions in Interstate Natural Gas Co. v. FPC, 331 U.S. 682 (1947) and Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954), the Commission's ratemaking powers under §§ 4 and 5 of NGA are considerably broader, extending to wellhead prices charged by natural gas producers engaged in the sale of natural gas in interstate commerce for resale.

6. *See* 1 A. KAHN, THE ECONOMICS OF REGULATION, 65 (1970).

a good or service.[7]

Identifying these individual marginal costs is an essential first step in the application of marginal costing theory to the establishment of natural gas rates. The most significant marginal cost of providing natural gas service under current market supply conditions is the cost of natural gas, otherwise known as energy costs, to pipelines and local distribution companies.[8] Once marginal energy costs are accurately measured, their allocation to end users is dependent upon the rate tariff or design utilized for particular customer classes of a gas utility. The rate tariff most commonly suggested by proponents of marginal costing is the inverted rate structure which imposes higher per unit rates for gas service as the level of gas usage increases toward the last consumption block of the rate design. The per unit price at the outer block of an inverted rate tariff represents the actual marginal cost of natural gas at that level of consumption.[9] Excess utility revenues, generated as a result of setting gas rates at marginal costs while utility revenue requirements are based upon average costs, may best be avoided by downward adjustments of gas rates in the initial consumption blocks of the inverted rate tariff.[10]

Setting the price of natural gas service equal to the marginal cost of providing such service for various customer classes would ensure greater economic efficiencies and conservation by confronting consumers with the true costs of additional consumption. Cognizant of these costs, consumers would be better able to judge whether to forego further purchases of natural gas either for substitute fuels, or for reliance upon energy saving measures such as cogeneration, insulation, or improvements in boiler combustion efficiencies.

Acceptance of marginal costing principles in the natural gas industry has thus far been resisted by federal and most state regulatory authorities.[11]

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7. *Id.*

8. The inclusion of capital expenditures, as a marginal cost of providing gas service, for increased utility plant capacity to service either the demands of new gas customers or higher peak demands by existing end users seems unwarranted given the unlikely incurrence of such costs in the future. Notwithstanding the current surplus of gas in the interstate market, intermediate and long term supply forecasts indicate a shortage of natural gas and underutilization of most gas utility systems.

The costs of natural gas are also commonly referred to as "commodity costs" whereas expenditures for plant expansion are often known as "demand costs."

9. This method of apportioning the marginal cost of natural gas has often been referred to as "marginal cost pricing" whereby the cost of an infinitesimally small additional unit of production is imposed only at the last consumption block of the inverted rate tariff.

The term "marginal cost pricing" and "incremental cost pricing" are often incorrectly used synonymously. The latter term properly refers to an alternative marginal costing method in which the average cost of an additional large, finite unit of production is imposed in toto on a particular customer class. See text accompanying notes 17-27 *infra.*

These definitional distinctions are noted only for purposes of clarification. The thrust of this article is to focus attention on the need to adopt marginal costing principles in the establishment of natural gas rates rather than an endorsement of a particular rate design or method of allocating the marginal cost of natural gas service.

10. Proposed in varying contexts and deserving of further consideration, taxation of excess profits and consumer rebates are two alternative means of contending with excess utility revenues resulting from the adoption of marginal cost concepts in the establishment of natural gas rates.

11. Wisconsin and California are two of the few states which have, in the past few years, begun to incorporate marginal cost concepts in the structuring of natural gas rate tariffs. *See,*

However, its adoption is long overdue. Largely as a result of changing cost relationships, the accounting methods most favored by regulators for arriving at the value of the energy and capacity cost components of gas rates have grossly distorted the market price of natural gas service. Traditionally, the wellhead costs of vintaged, older gas have been averaged or rolled in with the costs of more expensive, newly discovered reserves and imported supplemental gas supplies. Similarly, expenditures for increased plant capacity of pipeline or distribution companies to meet peak demands have been averaged with historical book values of the utility's rate base. Under prevailing economic conditions, where marginal costs far exceed average costs, these regulatory practices have tended to understate the true economic value of natural gas as delivered to the customer.

In conjunction with these cost accounting deficiencies, rate designs most commonly used by gas transmission and distribution companies have generally failed to properly allocate the fixed costs of providing necessary peak demand capacity to those end users most responsible for the peak demands. The declining block rate design, prevalent in gas sales by local distributors to residential and small commercial users, allocates a major portion of the distributor's fixed capacity costs in the initial consumption blocks of the rate tariff. As the volume of gas consumption increases toward the tail blocks, the per unit charge for gas consumed typically decreases, ultimately representing only energy costs incurred.[12] Additionally, following its adoption of the *Seaboard* formula[13] for apportioning fixed pipeline capacity costs, the Commission has consistently assigned a portion of fixed capacity costs to the commodity component of the demand-commodity rate design which governs gas sales by interstate pipelines to local distributors.[14] Allocating the fixed costs in this manner has had the effect of shifting away from peak service

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e.g., *In re* Application of Southern California Gas Co., Decision No. 90822 (Cal. Pub. Util. Comm'n, Sept. 12, 1979); Action on Motion of the Commission to Determine Revenue Requirement and Design Gas Rates for Wisconsin Southern Gas Co., Case No. 6710-GR-5 (Wis. Pub. Serv. Comm'n, Dec. 11, 1979); Application of Superior Water, Light & Power Co., Case No. 5820-UR-4 (Wis. Pub. Serv. Comm'n, Sept. 28, 1979); Application of Wisconsin Fuel & Light Co., Case No. 6640-GR-4 (Wis. Pub. Serv. Comm'n, Aug. 23, 1979); Application of Wisconsin Power & Light Co., Case No. 6680-GR-3 (Wis. Pub. Serv. Comm'n, Oct. 26, 1978). Generally, however, the utility commissions in both states have favored defining the marginal cost of gas equal to the equivalent price of alternative fuel rather than the accurately measured true cost of additional gas.

12. The predominance of capacity costs in the initial consumption blocks has produced discount rates in the tail end of the declining block rate form, thereby encouraging more gas usage and, ultimately, expansions to the utility's physical plant. While apportioning fixed capacity costs in this manner may have accurately reflected resulting economies of scale during a time when the marginal costs of providing additional plant capacity were less than average costs, it is arguable that such economies have, for the most part, been greatly diminished if not exhausted. However, the problem of allocating future expenditures for increased plant capacity is purely academic and no longer of great concern given foreseeable gas supply conditions. See note 8 *supra*.

13. *Re* Atlantic Seaboard Corp., 94 Pub. U. Rep. (n.s.) 235 (FPC 1952).

14. The rate tariff which governs gas sales by interstate pipelines to local distributors imposes a charge based upon demand and commodity components of a two part rate design. The demand charge primarily represents the fixed costs associated with providing the necessary utility plant capacity to meet peak demands in accordance with contractual entitlements. The commodity charge of the rate design embodies the variable costs, principally energy costs, incurred during a discrete billing period.

users the cost responsibility of maintaining sufficient pipeline capacity to serve their peak demands. The *Seaboard* formula of assigning 50% of the fixed capacity costs to the demand component and 50% of such costs to the commodity component has generally predominated. Federal regulators have occasionally tilted the *Seaboard* formula by assigning a greater share of pipeline fixed costs to the demand component; however, this practice has been motivated more from a desire to influence improvements in pipeline load factors, to encourage construction of storage and peak-shaving facilities, or to ensure the competitive standing of natural gas in relation to other fuels rather than from a commitment to properly assign fixed capacity costs to those users who demand service at the system peak.[15]

As a consequence of these ratemaking practices by both federal and state regulatory commissions, natural gas consumers have been given inaccurate pricing signals by which to judge their incremental purchases, thereby resulting in costly plant expansions and less than optimum allocations of natural gas supplies. The regulatory induced misallocations of the country's natural gas reserves has contributed substantially to the gas shortages experienced in the past decade. The Commission's response to these natural gas shortfalls has resulted in further regulation of market forces by the imposition of curtailment plans purportedly designed to allocate available gas supplies of jurisdictional pipeline companies according to predetermined priority end use categories. While these curtailment plans represent an honest effort at managing an otherwise complex energy shortage problem, substitution of an administratively imposed curtailment program for the market ordering potential of the price mechanism necessarily ensures other than most optimum uses of scarce natural gas supplies.[16]

III.

On two separate occasions, the Commission has attempted, unsuccessfully, to depart from the conventional practice of rolling in the costs of addi-

15. *E.g.*, Fuels Research Council, Inc., 34 F.P.C. 973 (1965), *aff'd sub nom.*, Fuels Research Council, Inc. v. FPC, 374 F.2d 842 (7th Cir. 1967); United Fuel Gas Co., 31 F.P.C. 1342 (1964); Natural Gas Pipeline Co., 28 F.P.C. 731 (1962).

16. The remand by the United States Court of Appeals for the District of Columbia Circuit in North Carolina v. FERC, 584 F.2d 1003 (D.C. Cir. 1978) surfaces a major shortcoming in the natural gas curtailment program. The court noted that prior to the Commission's issuance of an order prescribing a permanent curtailment plan for Transcontinental Gas Pipe Line Corporation (Transco), it had not made the requisite findings as to the actual impact Transco's curtailment plan would have on ultimate consumers. As with many existing curtailment plans of other jurisdictional pipelines, the Transco plan was based upon stale end use consumer profiles. In view of this fact, the Court expressed skepticism that the Transco plan allocated natural gas on a basis which reasonably ensured protection of high priority users.

Natural gas shortages in the early 1970s led the Commission to consider an alternate rate tariff technique in a proposed rulemaking. 40 Fed. Reg. 8,571 (1975). Terming the demand-commodity rate tariff ineffective in discouraging industrial consumption, otherwise viewed as an inferior end use, the Commission proposed end use rate schedules designed to impose the higher price of newer gas on industrial users. By removing economic incentives for continued gas purchases in lieu of higher priced substitute fuels, the Commission contemplated a decline in gas usage by industrial concerns and conservation of this resource for higher priority residential and commercial end use categories. Due to overwhelming opposition, the concept of separate rate schedules for various categories of use as proposed by the Commission was short-lived.

tional gas supplies by pricing imports of Algerian liquified natural gas (LNG) on an incremental cost pricing basis.[17] In both rate cases, incremental pricing was initially thought to be the appropriate means of apportioning the cost of the LNG imports to avoid creating false markets for the supplemental gas supply. Averaging, or rolling in the price of the LNG would have effectively disguised the true cost of what was considered expensive gas supplements. However, subsequent conditions in the natural gas market and an apparent reluctance to renounce rolled-in pricing led to a return, in both cases, to the longstanding practice of averaging gas costs.

On June 28, 1972, the Commission issued Opinion No. 622 in Re *Columbia LNG Corp.*[18] granting applications filed by three jurisdictional pipeline companies to import for sale in interstate commerce approximately 1,000,000 Mcf per day of Algerian LNG to service the pipeline applicants' existing low priority industrial customers.[19] The Commission conditioned its approval of the LNG project by requiring that the imported gas be sold on a curtailable basis under separate incrementally priced rate schedules at both the pipeline and distributor levels.

Considerable opposition to Opinion No. 622 ensued which threatened the financial viability of the Algerian gas import project. Distributor customers of the three jurisdictional pipelines asserted that the Commission exceeded its statutory authority by requiring that the imported LNG be sold at the burner tip under separate incrementally priced rate schedules. Additionally, low priority industrial customers and distributors who served a high proportion of such customers contended Opinion No. 622 was inequitable; under the Commission's order, low priority users were to absorb the higher incremental cost of the imported supplemental gas supplies yet faced the prospect of curtailment under pipeline curtailment plans during periods of gas shortages. Absent a willingness on the part of low priority industrial customers and distributors to enter into long term contracts for the LNG, lenders were reluctant to commit financial resources to fund the LNG project.

To ensure financial backing for what was considered badly needed supplemental gas, the Commission, following rehearing, issued Opinion No. 622-A[20] in which it modified its previous order. The Commission declared the Algerian LNG subject to contract on a firm basis and ineligible for curtailment. While the Commission declined to concede lack of jurisdiction to require incremental pricing at the burner tip, it recognized the regulatory obstacles in administering such a far reaching pricing scheme. It therefore

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17. See note 9 *supra*.

18. 95 Pub. U. Rep.3d 145 (FPC 1972), *rev'd in part*, 96 Pub. Util. Rep. 3d 389 (FPC 1972), *rev'd*, UTIL. L. REP. (CCH) ¶ 11,894 (FPC 1977).

19. The approved initial per unit price of the imported LNG was approximately 40% greater than the pipeline applicants' averaged per unit cost of their respective gas system supplies. This estimate is exclusive of construction costs for required receiving terminals and pipeline extensions which were properly included as capital expenditures by the Commission in the approved price of the LNG.

20. *Re* Columbia LNG Corp., 96 Pub. U. Rep.3d 389 (FPC 1972), *rev'd*, UTIL. L. REP. (CCH) ¶ 11,894 (FPC 1977).

imposed incremental pricing for the imported LNG solely at the pipeline level.

Notwithstanding the modifications to Opinion No. 622, the Commission's departure from the traditional cost allocation method of rolled-in pricing led to judicial review by the Fifth Circuit in *Columbia LNG Corp. v. FPC.*[21] Noting that the Commission's substitution of incremental for rolled-in pricing was unsupported by substantial evidence, the Fifth Circuit reversed and remanded for further proceedings that portion of Opinion No. 622-A pertaining to pipeline pricing of the LNG. Ultimately, the Commission reembraced rolled-in pricing coupled with pipeline curtailment as the means of allocating the costs of the Algerian LNG imports. Following its reconsideration in light of the Fifth Circuit remand, on January 21, 1977, the Commission issued Opinion No. 786[22] in which it cited two developments in the natural gas market influencing its decision to withdraw its earlier endorsement for incremental pricing. At the time of Opinion No. 786, the approved per unit price of the Algerian LNG was roughly equivalent to the existing national rate for new domestic gas delivered to the interstate market. Consequently, the Commission no longer viewed the Algerian LNG as an exotic, expensive supplemental gas supply. Moreover, domestic supplies of natural gas had appreciably deteriorated since Opinion No. 622 was issued in 1972 to an extent which made it likely that the Algerian LNG, at one time earmarked exclusively for low priority industrial users, would substantially contribute to meeting the basic gas needs of high priority residential and small commercial users. The Commission believed rolling in the price of the LNG would ensure that those high priority end users benefiting from the supplemental supply also bore the attendant costs.[23]

Three months following its repudiation of incremental cost pricing in *Columbia LNG Corp.*, the Commission returned to this method of cost allocation in *Trunkline LNG Co.*[24] by granting an application in Opinion No. 796, issued April 29, 1977, for the importation and subsequent sale in interstate commerce of approximately 168,000,000 Mcf per year of Algerian LNG. Like the gas supply forecasts in *Columbia LNG Corp.*, indications were that the supplemental gas supplies in this second LNG import case were to service the basic requirments of the pipeline applicant's high priority residential and small commercial customers. The Commission distinguished its earlier decision in *Columbia LNG Corp.* in which it ultimately rejected incremental pricing by stressing the wide price differential in *Trunkline LNG Co.* between the imported LNG and the national rate for new domestic gas.[25] Given the

21. 491 F.2d 651 (5th Cir. 1974).

22. Columbia LNG Corp., UTIL. L. REP. (CCH) ¶ 11,894 (FPC 1977).

23. Although in January 1977, the price of Algerian LNG was comparable with the national rate for new domestic gas, the Commission's decision to roll in the cost of the LNG actually resulted in an averaging of the price of the imported gas supplement with the infra marginal costs of older, less expensive domestic gas, thereby concealing from the end user the true cost of the imported gas supplement.

24. UTIL. L. REP. (CCH) ¶ 11,942, *rev'd in part*, UTIL. L. REP. (CCH) § 11,970 (FPC 1977).

25. In 1980, the year in which importation of the Algerian LNG would commence, the national rate for new domestic gas was estimated at approximately $1.60 per Mcf, compared with an estimated cost of $3.37 per Mcf for the regasified LNG, delivered to the pipeline appli-

substantial cost difference, the Commission held that incremental pricing of the Algerian LNG would confirm whether or not the supplemental gas project was economically justifiable. The Commission stated that "[u]se of the incremental method discourages the inefficient use of the gas because the LNG will be subject to the market test of whether its users value the LNG enough to pay the true cost of supplying them with this expensive gas."[26] The requirement that the LNG be incrementally priced was imposed solely for pipeline sales of the imported gas to distributors. The Commission, however, explicitly encouraged state utility commissions to adopt incremental pricing of the LNG for sales by distributors to ultimate end users so that the full weight of market forces could properly determine the economic soundness of the Algerian import venture.

An apparent lack of sufficient demand for the Algerian LNG under separate incrementally priced rate schedules threatened financial support for the supplemental gas project. The Commission noted gas supply projections which indicated the LNG project, if successful, would be a major source of needed gas supply in the mid-1980s for residential, commercial, and essential industrial end uses of the pipeline applicant's system. Unwilling to allow market forces to determine the fate of the Algerian LNG project, the Commission, in Opinion No. 796-A[27] reversed its previous decision and ordered the LNG priced on a rolled-in basis, thereby guaranteeing the financial success and viability of the venture.

IV.

Reversal of existing maladjustments in the allocation of natural gas may best be accomplished by remedial legislation at the national level in the context of a comprehensive national energy policy.[28] The Ninety-fifth Congress did enact legislation which will have a direct bearing on natural gas pricing. Under Title II of the Natural Gas Policy Act of 1978 (NGPA),[29] interstate pipelines and their local distributors are required to pass through to certain industrial facilities, in the form of a surcharge, most of the costs of acquiring natural gas above a specified pricing level[30] until the cost to these end users equals the Btu equivalent price of alternative fuel.[31] The conference report

cant's transportation system. The approximate cost of the regasified LNG includes capital expenditures for required receiving terminal, regasification plant, storage, and pipeline extensions. These expenditures were properly included by the Commission in the approved initial per unit price of the imported LNG.

26. 12 F.P.S. 5-33, 5-54 (FPC 1977).

27. Trunkline LNG Co., UTIL. L. REP. (CCH) ¶ 11,970 (FPC 1977).

28. Consideration by federal lawmakers of legislative measures for more effective gas pricing techniques appears warranted given the national scope of the problem and the serious questions regarding limitations on the Commission's current authority to influence more efficacious gas uses pursuant to its ratemaking powers under the Natural Gas Act. See note 5 *supra*.

29. 15 U.S.C. §§ 3341-3348 (Supp. II 1978).

30. The specified pricing level for most natural gas categories subject to the pass through provisions of Title II is known as the incremental pricing threshold, established under Section 203 of NGPA, 15 U.S.C. § 3343 (Supp. II 1978), at $1.48 per MMBtu as of March, 1978; for succeeding months, the threshold escalates by application of an inflation adjustment factor as defined by the Act. The pricing level for remaining natural gas categories subject to Title II is set by statutory formula under NGPA.

31. Pursuant to § 201 of NGPA, 15 U.S.C. § 3341 (Supp. II 1978), the Commission has

indicates that once the cost of natural gas to affected industrial facilities reaches this equivalent price, interstate pipelines and affiliated distributors may allocate remaining energy costs by the traditional means of averaging or rolling in the price of additional gas supplies.[32] The conferees explicitly admonish state regulatory commissions against mitigating incremental surcharges passed through to industrial facilities by adjustments in basic cost of service charges or other components comprising a particular industrial rate tariff.[33]

The price mechanism under Title II is certain to reverse the traditional practice at both the federal and state level of pricing natural gas sales to industrial consumers well below the market price of alternative fuels. The obvious purpose of NGPA's incremental pricing scheme is to protect high priority residential and commercial customers from initial increases in wellhead rates mandated by Title I of NGPA. The Congress intended low priority industrial users to absorb as much of these wellhead price increases as possible without precipitating loss of industrial load and concomitant increases in gas prices for high priority residential and commercial users.

The full import of Title II is not strictly limited to impacts on gas rates at the burner tip for certain end use categories. Title II must also be viewed in conjunction with substantial changes in federal regulation of wellhead prices imposed by Title I of NGPA. One of the major issues which dominated congressional debate regarding natural gas policy concerned an appropriate substitute for the much criticized dual market system of interstate and intrastate gas pricing.[34] The House bill[35] extended federal control of wellhead prices to the intrastate market while the Senate bill[36] provided for gradual decontrol of wellhead rates of new gas in the interstate market.

Title I of NGPA reconciles these two fundamentally divergent approaches. For the first time in the history of federal regulation of the natural gas industry, federal control of all wellhead prices of natural gas is extended to the intrastate market. Wellhead rates in both intrastate and interstate markets are established by a statutorily based formula which provides for gradual price escalations for various gas categories. Further, Title I man-

adopted a three-tier approach for the establishment of the alternative fuel price ceiling for large industrial boiler facilities subject to the pass through provisions of Title II. Dependent upon the facility's legal authority and installed capability to burn certain fuels, the appropriate regional price will be set at either the price of No. 2, No. 6 low sulfur, or No. 6 high sulfur fuel oil. The three-tier system will be fully implemented by November 1, 1980. In the interim, the appropriate regional price of No. 6 high sulfur fuel oil will act as the sole alternative fuel ceiling price. 44 Fed. Reg. 57,754, 57,778 (1979); 45 Fed. Reg. 1,872 (1980) (to be codified in 18 C.F.R. § 282).

Under § 202 of NGPA, 15 U.S.C. § 3342 (Supp. II 1978), the Commission is directed to adopt a rule, within 18 months of the Act's enactment, which would expand the applicability of the incremental pricing provisions of Title II to a larger category of industrial natural gas users. Pursuant to § 202(c) of NGPA, 15 U.S.C. § 3342(c) (Supp. II 1978), the rule promulgated by the Commission will become effective if not vetoed by either house of the Congress.

32. H.R. REP. NO. 95-1752, 95th Cong., 2d Sess. 99 (1978).

33. *Id.* at 100.

34. The existence of two distinct markets often resulted in higher intrastate wellhead rates and conscious withholding by producers of gas from the federally controlled interstate market for higher priced intrastate sales.

35. H.R. 8444, 95th Cong., 1st Sess., Part 4 (1977).

36. H.R. 5289, 95th Cong., 1st Sess. (1977).

dates the deregulation, in 1985, of the wellhead price of new gas sold in both interstate and intrastate markets.

Economic analyses, however, have forecasted a supply-demand imbalance in the interstate market in the mid-1980s, the time deregulation is to occur. To ensure adequate supplies for their low priority industrial customers in the face of natural gas shortfalls, interstate pipelines would ordinarily be induced to bid extremely high prices for deregulated gas which are far above long run marginal costs of production. Little incentive would exist for pipelines to moderate their bidding practices out of fear of pricing themselves out of the market and thereby losing industrial customers. By averaging or rolling in demand-driven prices of deregulated gas with the cost of cheaper, price controlled gas comprising the major portion of a pipeline's overall gas supply, transmission companies would effectively pass through the higher costs of deregulated gas to all their customers.

Legislative history suggests that the Congress intended the incremental pricing provisions of Title II to serve the additional function of preparing the interstate natural gas market for wellhead price deregulation.[37] By enacting Title II, the Congress sought an orderly transition to a deregulated market absent disruptive, excessive price increases for deregulated new gas and accompanying large, excessive income transfers to gas producers. It was thought that setting the price of natural gas for large industrial users equal to the market price of alternative fuels would cause these end users to encourage interstate pipelines to exercise restraint in bidding for new gas in a deregulated market.

V.

Title II of NGPA clearly falls short of the kind of legislative reforms required to encourage more optimum uses of natural gas through the price mechanism. The need for gas utility rate reform is even more imperative as the market prices of natural gas substitutes such as oil and electrical power continue to approach the marginal cost of production.[38] Absent needed

37. *See* HOUSE SUBCOMM. ON ENERGY AND POWER, 95TH. CONG., 2D SESS., ECONOMIC ANALYSIS OF NATURAL GAS POLICY ALTERNATIVES 11-12 (Comm. Print No. 95-31, 1978); HOUSE SUBCOMM. ON ENERGY AND POWER, 95TH. CONG., 2D SESS., ECONOMIC ANALYSIS OF H.R. 5289, NATURAL GAS POLICY ACT OF 1978, 3-5 (Comm. Print No. 95-62, 1978). *See also* H.R. REP. NO. 95-543, 95th Cong., 1st Sess., REPORT OF THE AD HOC COMMITTEE ON ENERGY, U.S. HOUSE OF REPRESENTATIVES ON H.R. 8444, Vol. II at 394-416 (1977).

38. The market price of oil has been nearing marginal cost as a result of growing dependence on imported foreign oil and certain regulatory measures adopted by the Economic Regulatory Administration (ERA). In the past five years, the percentage of foreign oil consumed in the country at world market prices has increased appreciably while that of domestically produced, price controlled oil has diminished. Further, in preparation for total price decontrol of domestic crude oil, mandated by the Energy Policy and Conservation Act of 1975 to occur on September 30, 1981, 42 U.S.C. § 6201 (1976), a number of steps have been taken administratively by the ERA to gradually phase out existing price controls.

With regard to the electric utility industry, approximately twelve states have already adopted marginal costing concepts in the establishment of electrical rates. (Arkansas, California, Illinois, Maine, Michigan, Montana, New York, Ohio, Oregon, South Dakota, Vermont and Wisconsin). This trend is likely to continue given the mandatory duty imposed under Title I of the Public Utility Regulatory Policies Act of 1978, 92 Stat. 3120 (codified in scattered sections of 15, 16, 42 U.S.C.), requiring state regulatory authorities to determine in writing, changes in natural gas ratemaking practices to ensure gas prices more nearly reflect the marginal costs of providing service, consumers of oil and electrical power and potential new users of these energy forms will find it economically beneficial to rely upon natural gas as the cheaper fuel.[39] Such fuel switching will hasten depletion of the nation's remaining gas reserves and add to the already existing suboptimal end uses of this resource.

Federal legislation has been enacted which could materially limit, by the imposition of certain regulatory prohibitions, fuel switching from oil to natural gas by electric powerplants[40] and other end use categories. Except as provided therein, Title II of the Powerplant and Industrial Fuel Use Act of 1978[41] (FUA) precludes the use of natural gas by new electric powerplants and fuel-burning installations, as specifically defined. Additionally, section 301(a)(1) of Title III of FUA prohibits the use of natural gas as a primary energy source by an existing electric powerplant on and after January 1, 1990.[42] In the interim, sections 301(a)(2) and (3) of FUA[43] permit the use of natural gas, in specified limited quantities, as a primary energy source by an existing electric powerplant provided the subject plant used natural gas as a primary energy source during the calendar year 1977.[44]

Notwithstanding regulatory measures implemented by the Economic Regulatory Administration under FUA which impose limits on current and future gas usage, achieving more efficient natural gas utilization can best be accomplished by the market ordering potential of the price mechanism, a

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based upon evidence introduced at a public hearing, whether or not implementation of certain specified rate concepts related to marginal cost principles are appropriate for each electric utility for which they have ratemaking authority. Each determination made by a state regulatory authority is reviewable in the appropriate state court. 16 U.S.C. §§ 2611-2613, 2621-2625 (Supp. II 1978).

39. It has been estimated that, for the year 1978, the average price of gas to end users was $2.18 per MMBtu while that for oil was $3.66 per MMBtu. AMERICAN GAS ASS'N, GAS FACTS 115 (1978). For the same year, in the home heating market alone, there were approximately 135,000 conversions of heating units (singly metered homes and multifamily units) from oil to natural gas, representing an increase of approximately 61% from the previous year. AMERICAN GAS ASS'N, GAS HOUSEHEATING SURVEY 11 (1978).

Substantial benefits will be derived from the application of marginal cost principles even if the per unit cost of natural gas at the margin is lower than the equivalent per unit cost of substitute fuels. While still the cheaper fuel, end users of natural gas will be given an incentive to adopt more thoughtful and conservative consumption habits when confronted with the true replacement value of the product.

40. The preference for natural gas rather than for oil by new and existing electric utilities is certain to exist given that these end users are exempt from incremental pricing surcharges imposed under Title II of NGPA. The price of gas to these users would be substantially below the cost of substitute fuel oil and thus economically desirable.

41. 42 U.S.C. §§ 8311-8312, 8321-8324 (Supp. II 1978).

42. *Id.* at § 8341(a)(1).

43. *Id.* at § 8341(a)(2), (3).

44. However, in response to what it perceived as a need for "immediate action" to reduce the country's dependence on foreign oil, the Economic Regulatory Administration promulgated a special rule setting forth criteria and procedures by which owners and operators of electric powerplants subject to §§ 301(a)(2) and (3) may petition for a special public interest exemption for a two year period, subject to further extensions of up to a total of five years, if, among other things, such allowance would result in the substitution of natural gas for middle distillates and residual fuel oils as boiler fuels. 44 Fed. Reg. 21,230 (1979) (to be codified in 10 C.F.R. § 508). Reducing the country's reliance on foreign oil should undoubtedly be one of several predominate objectives of a comprehensive national energy policy. Of no less import, however, is the conservation of remaining domestic natural gas reserves.

concept which may be gaining increasing acceptance of late by both federal regulators and legislators. Recently, the Commission published a "study proposal,"[45] known as industrial end use deregulation, which relies upon market forces to assist in the implementation of its pipeline curtailment program as well as the incremental pricing provisions under Title II of NGPA. Premised upon the concept that market price is "the best mechanism for allocating natural gas among low-priority users," the Commission proposed a bidding or auction type program whereby low-priority industrial end users subject to incremental pricing under NGPA would select a price no lower than No. 6 fuel oil to serve the dual purpose of establishing their curtailment status during periods of gas shortages and as an alternative fuel price ceiling for the surcharge pass through provisions of Title II.[46] Although the Commission suspended, at least temporarily, active consideration of industrial end use deregulation in the wake of adverse comments received in response to the proposal,[47] the concept of introducing market forces to the allocation of natural gas supplies is an encouraging sign perhaps indicative of emerging attitudes on the part of federal regulators.

Apparently, the Ninety-fifth Congress was not unmindful of the need to consider ratemaking reforms designed to influence more efficient end uses of natural gas. In accordance with Title III of the Public Utility Regulatory Policies Act of 1978 (PURPA), the Secretary of the Department of Energy is required to undertake a study of various rate reform measures, including marginal cost pricing and incremental cost pricing, and to submit to the Congress, within twenty-four months of PURPA's enactment, proposals, together with legislative recommendations, to improve gas utility rate design and promote conservation of natural gas.[48] Undoubtedly, further inquiry is required to determine the means by which marginal cost principles may best be applied in conjunction with longstanding ratemaking objectives of equitable treatment among customer classes, maximization of utility revenue stability, and efficient use of existing gas utility systems. Of equal importance are the questions of appropriate rate tariff designs and the most effective means of dealing with excess utility revenues generated as a result of setting gas rates at marginal costs while utility revenue requirements are based upon average costs.

The need for more optimum natural gas use can perhaps best be illus-

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45. 44 Fed. Reg. 38,857 (1979).

46. By pegging an industrial user's curtailment status to yearly, self-designated market values, the Commission was attempting to overcome a major problem with most curtailment plans of predicating a user's curtailment status on stale end use data. See note 16 *supra*.

Further, the Commission perceived its industrial end use deregulation proposal as a means of lightening administrative burdens imposed by NGPA's incremental pricing program as well as a way of removing the incentive for installations of No. 6 fuel oil burning equipment by industrial users for the sole purpose of escaping higher incremental pricing surcharges imposed upon users of No. 2 fuel oil. The Commission viewed the latter result as unjustified economic waste and circumvention of Congressional purposes underlying enactment of Title II.

47. One of the most often cited objections filed in response to the study proposal concerned the perceived lack of statutory authority of the Commission to impose its auction or bidding type program. *See* Regulations Implementing the Second Stage Incremental Pricing Provisions of the Natural Gas Policy Act of 1978, FERC Docket No. RM79-56 (1979).

48. 42 U.S.C. §§ 8341-8343 (Supp. II 1978).

trated by current estimates which indicate a decline by approximately 30% in the past ten years in the level of proved natural gas reserves in the United States. The country can ill afford a national energy policy which fails to ensure the conservative uses of one of its most valued and diminishing resources.