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Natural Gas Regulation and Market Disorder

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NATURAL GAS REGULATION AND MARKET DISORDER*

I. INTRODUCTION

The increasingly tumultuous natural gas markets are presenting problems to both the natural gas industry and those who depend upon it. One need not search far to find the problems' symptoms. Within the past year, interstate pipelines have paid more than ten dollars per million British thermal unit (MMBtu)[1] for natural gas, a record price which is more than five times the average price existing prior to the passage of the Natural Gas Policy Act of 1978 (NGPA).[2] Yet many of these pipelines have seen their markets in the industrial North evaporate suddenly because of the deep national recession and unexpectedly strong competition from residual fuel oil.[3] Moreover, they have found it increasingly difficult to persuade distributors and state regulatory commissions that residential and commercial consumers should accept additional price increases.[4] In at least one instance, a gas distributor notified its pipeline suppliers that it will no longer honor the minimum bill provisions of their tariffs.[5]

Faced with declining demand, the interstate pipelines have turned toward markets in Texas, Louisiana, Oklahoma, and elsewhere which

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1. DIVISION OF ENERGY DEREGULATION, OFFICE OF POLICY, PLANNING AND ANALYSIS, U.S. DEP'T OF ENERGY, A STUDY OF ALTERNATIVES TO THE NATURAL GAS POLICY ACT OF 1978 3 (1981) [hereinafter cited as NGPA ALTERNATIVES].

2. Sections 2 to 602, 15 U.S.C. §§ 3301-3432 (Supp. V 1981).

3. *See, e.g.*, Foster Nat. Gas Rep., Dec. 29, 1982, at 9 (No. 1395); Foster Nat. Gas Rep., Aug. 12, 1982, at 1 (No. 1376) (summary of testimony of United Distribution Companies). Inside F.E.R.C., Apr. 19, 1982, at 3. Montana-Dakota Utilities Co. provided a dramatic example of this trend when it informed the Federal Energy Regulatory Commission (FERC) that it had lost two-thirds of its jurisdictional sales. Foster Nat. Gas Rep., Dec. 16, 1982, at 19 (No. 1394).

4. Last fall, voters in several industrial states—most notably Michigan—approved referenda authorizing state public service commissions to combat escalating gas prices. *See State Regulators Take Up Battle Against Rising Natural Gas Prices*, Wall St. J., Jan. 21, 1983, at 25, col. 4; Foster Nat. Gas Rep., Dec. 16, 1982, at 1 (No. 1394).

5. Inside F.E.R.C., Oct. 25, 1982, at 1 (repudiation by Columbia Gas Transmission of minimum bill provisions in suppliers' tariffs). A minimum bill provision in a tariff requires a distributor to make a minimum monthly payment to its supplier, regardless of the amount of gas which is actually delivered.

have traditionally been served by intrastate pipelines. Not surprisingly, the intrastate pipelines have denounced these attempts as "market raiding," claiming that the NGPA gives interstate pipelines unfair advantages in obtaining new supplies and competing for industrial markets.[6] Producers have also suffered since both interstate and intrastate pipelines have stopped purchasing gas and have been increasingly reluctant to honor contractual take-or-pay commitments.[7] These contracts were made during the 1970's when consumers had a seemingly boundless appetite for new gas supplies.[8]

The wellhead price deregulation of approximately sixty percent of the nation's natural gas supplies, which is now scheduled to occur January 1, 1985,[9] will further disrupt natural gas markets. Because of lower aggregate demand for energy, the prospects for a sharp increase of natural gas prices upon deregulation, commonly referred to as a "fly-up," have substantially declined. However, the world market for energy is dynamic, changing abruptly in response to disruptions of supply and shifts in demand. Accordingly, there is no assurance that prices will remain stable over the next two years. Even if prices were to remain stable, indefinite escalation clauses and favored nations clauses in gas sales contracts could still create a fly-up upon deregulation.[10]

The crisis in the gas markets has not gone unnoticed in Washington. The Federal Energy Regulatory Commission (FERC)[11] issued a notice of inquiry last spring to "investigate allegations that serious economic distortions may be evolving in the nation's natural gas markets."[12] Dozens of bills addressing aspects of the market disorder problems are already before Congress, and the current session will undoubtedly bring the introduction of dozens more. Proposals currently under consideration range from the extremes of total wellhead price decontrol to price freezes and even rollbacks.[13] The consensus on natu-

6. *See* Inside F.E.R.C., Oct. 18, 1982, at 1.

7. Under a take-or-pay gas purchase contract, the buyer may refuse to take his agreed quantity, but will still be required to pay a percentage of its cost. *See infra* notes 45-48 and accompanying text.

8. *See* M. SANDERS, THE REGULATION OF NATURAL GAS 125 (1981).

9. NGPA § 121.

10. NGPA ALTERNATIVES, *supra* note 1, at 65.

11. FERC was created in 1977 by the Department of Energy Organization Act (DOE Act), Pub. L. No. 95-91, 91 Stat. 565 (codified at 42 U.S.C. §§ 7101-7352 (Supp. V 1981)). FERC is in essence the successor of the now defunct Federal Power Commission (FPC). *See* 42 U.S.C. § 7172 (Supp. V 1981) (transferring functions and personnel from the FPC to the FERC). In this Article, the term "Commission" shall be used when referring to both entities.

12. Notice of Inquiry, 47 Fed. Reg. 19,157 (1982).

13. *See infra* text accompanying notes 124-60.

ral gas policy is that there is no consensus.

This Article will argue that the turmoil in the natural gas markets is primarily a result of federal policy. Natural gas policy is now poised between the comprehensive price control scheme of previous law and the strange new world of deregulation, towards which the industry has been hesitantly moving for the past decade. In essence, all areas of the law contain elements of both freedom and restraint and the natural gas industry is not exempt from that principle. Yet the current hodgepodge of freedom and restraint that characterizes federal energy policy cannot long endure.

If federal energy policy is in crisis, then opportunities will be presented as well as dangers. Federal controls on wellhead prices have had a destabilizing effect on the nation's industries and residences for more than forty years. Accordingly, the current gas glut presents an ideal opportunity for the deregulation of wellhead natural gas prices and the introduction of reforms designed to bring economic rationality to gas markets. Previous experience with price decontrol of crude oil and refined petroleum products suggests that gas decontrol could occur without the danger of any price fly-up. Only relatively minor regulatory adjustments would be necessary to provide for an orderly transition to a completely deregulated market.[14] A tax on the "windfall," if any, accruing to producers upon deregulation could serve no useful purpose and should be resisted.[15] Though deregulation of wellhead prices would be helpful, additional measures are necessary to restore order to gas markets. Federal policy should encourage pipelines to obtain gas supplies at the lowest possible cost. Moreover, serious consideration should be given to imposing common carrier status on pipelines, with a view to simulating if not actually establishing a spot market for natural gas. Such a course may lead to administrative complexity and additional regulatory burdens in the short run, but these problems may merely be the price of progress.

Beginning with a general discussion on the market for natural gas and the structure of the industry, this Article will review the history of natural gas regulation under both the Natural Gas Act of 1938 (NGA)[16] and the NGPA. After demonstrating that federal regulation has been largely responsible for the disorder in the natural gas markets,

14. *See infra* text accompanying notes 161-62.
15. *See infra* text accompanying notes 117-22.
16. 15 U.S.C. §§ 717-717w (1976).

this Article will conclude with an examination and evaluation of the most important solutions.

II. An Overview of the Natural Gas Industry

A. *The Natural Gas Markets*

Natural gas provides approximately one-fourth of all energy consumed in the United States, ranking second only to oil as an energy source.[17] Although natural gas is used in a number of ways, its primary use is in residential and commercial furnaces and industrial boilers.[18] The leading residential fuel in most regions of the country except the Northeast, where oil is dominant, and the Pacific Northwest, where hydroelectric power is dominant, natural gas heats over fifty-five percent of the nation's houses and a substantial number of its businesses.[19] Electricity has recently gained a greater share of the residential heating market largely because of the lower installation costs and the moratorium on natural gas hookups which state utility commissions imposed after the severe natural gas shortages of the 1970's.[20]

Industrial uses of natural gas fall into three broad categories: feedstock, process uses, and boiler fuel. Use of natural gas as feedstock means that it is used as a raw material rather than as fuel.[21] Process uses refer to the use of natural gas heat in the processing of some product and may vary widely. Many who use gas in processing depend upon it as a fuel because of its clear, direct flame of precisely controllable temperature with immediate warm-up and cool-down.[22] In boilers, natural gas is burned to produce steam for mechanical or processing purposes or for the generation of electricity.[23]

Electric utilities, particularly those located in Texas, Louisiana, California, Oklahoma, and Kansas, are the largest industrial users of natural gas, using eighteen percent of the total production in 1978.[24]

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17. Economic Regulatory Admin., U.S. Dep't of Energy, Natural Gas Rate Design Study 3 (1980) [hereinafter cited as ERA Study].

18. *Id.* at 7.

19. *Id.* at 9.

20. *Id.*

21. *Id.* at 10. Examples of products made with natural gas are ammonia and carbon black. *Id.*

22. *Id.* For such industrial uses as food processing, glass and ceramic manufacturing, and textiles drying, natural gas is superior to other fuels. *Id.*

23. *Id.* The use of natural gas as boiler fuel constitutes "the largest portion of natural gas in the industrial sector." *Id.*

24. *Id.*

Together, the chemical industry, iron and steel manufacturers, food and fertilizer producers, metal products fabricators, and petroleum refiners consumed another forty percent of the total.[25] The installation costs of facilities which can use alternate fuels, primarily residual fuel oil, are relatively low for industrial consumers; thus they are extremely sensitive to price differentials among competing fuels,[26] and could be expected to shift fuels if fly-up were to occur. Overall, approximately twenty-eight percent of the natural gas produced in 1978 was ultimately consumed by residential users while thirteen percent was consumed commercially.[27]

B. *The Structure of the Industry*

The natural gas industry consists of three segments: production, transmission, and distribution.[28] Gas is produced at the wellhead, transmitted through pipelines, and distributed to customers. Each of these activities is discussed in greater detail below.

1. Production

Natural gas is brought to market from wells drilled to gas-bearing strata which may be far beneath the earth's surface.[29] While the primary component of natural gas is methane, it is not uncommon for it to contain other hydrocarbons such as ethane, propane, butane, and pentane. These "natural gas liquids," which are valuable chemical feedstock and have a number of other commercial uses, are gaseous while under high pressure in the reservoir but condense to liquid form upon reaching the surface and passing through separators.[30]

The costs of natural gas production are high, including lease acquisition, geological analysis of prospects, seismic exploration, and drilling. It is not rare for the costs of a single well to exceed one million dollars, and wells drilled to extraordinary depths or under difficult circumstances, such as those drilled in offshore Alaskan waters, may cost

25. *Id.*
26. *Id.*
27. *Id.* at 9.
28. *See* CONGRESSIONAL RESEARCH SERV. AND NAT'L REGULATORY RESEARCH INST., 97TH CONG., 2D SESS., NATURAL GAS REGULATION STUDY 17 (Comm. Print 1982) (prepared for the Subcomm. on Fossil and Synthetic Fuels of the House Comm. on Energy and Commerce) [hereinafter cited as NATURAL GAS REGULATION STUDY].
29. Wells drilled to depths of 20,000 feet or more are not uncommon. *See id.* at 96.
30. *Id.* at 96-70.

over eight million dollars.[31] Moreover, a large number of wells are unsuccessful; while a producer may use sophisticated exploration techniques to reduce risks, there is never assurance of finding additional reserves.

Natural gas is found in many states. However, six states—Texas, Louisiana, Oklahoma, Arkansas, Kansas, and California—account for more than two-thirds of United States production.[32] The largest natural gas producers are the major integrated oil companies; the twenty largest natural gas producers account for about half of all sales at the wellhead.[33] However, thousands of small, independent gas producers compete with the majors in the search for new reserves.[34]

2. Transmission

Pipeline companies transport natural gas from the field to urban distribution companies at the "city gate" or, in some cases, directly to industrial consumers.[35] Natural gas transmission is extremely expensive, requiring networks of seamless steel pipe and compressor stations that must be constructed under difficult circumstances across inhospitable terrain.[36] The transmission segment of the industry has elements of both monopoly and monopsony; a city may be served by only one interstate pipeline, which may, in turn, be the sole gas purchaser from several fields.[37] It is therefore generally believed that the transmission segment of the industry displays most of the characteristics of a natural monopoly, although some commentators have vociferously disagreed with this conclusion.[38]

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31. OIL & GAS J., Mar. 16, 1981, at 43.

32. ERA STUDY, *supra* note 17, at 7.

33. NATURAL GAS REGULATION STUDY, *supra* note 28, at 19.

34. *Id.*

35. Prior to being transported, the gas is usually treated for impurities such as sulfur, carbon dioxide, and water vapor, and processed for removal of natural gas liquids. *See* NATURAL GAS REGULATION STUDY, *supra* note 28, at 97-98.

36. Pipeline construction costs of $1 million per mile are not uncommon, and are much higher for pipelines of larger diameters (i.e., 32 inches or more) and offshore pipelines. *See* OIL & GAS J., Nov. 22, 1982, at 73, 78 (annual pipeline issue).

37. For a discussion of the monopolistic tendencies of natural gas transmission, see M. SANDERS, *supra* note 8, at 17-45.

38. The conventional wisdom on natural gas pipelines may be found in *id. See also* NATURAL GAS REGULATION STUDY, *supra* note 28, at 132-38, 166-71. The dissenting viewpoint may be found in Tussing & Barlow, *The Rise and Fall of Regulation In the Natural Gas Industry*, PUB. UTIL. FORT., Mar. 4, 1982, at 15-23. For a more scholarly and less tendentious discussion of the subject, see 2 A. KAHN, THE ECONOMICS OF REGULATION 152-71 (1971).

3. Distribution

Distributors transport natural gas from the city gate and deliver it to the burner tip for consumption by residential, commercial, and industrial users. Many of these customers purchase gas under interruptible service contracts, subject to tariffs established either by municipal ordinance or state utility commission order.[39] Distribution companies are generally considered to be natural monopolies, since economies of scale make it inefficient for more than one such company to operate within a given city.[40]

C. *Market Structure*

To an extent unmatched by other markets, the structure of the natural gas market is determined by the nature of the commodity itself.[41] Unlike oil, natural gas is extremely difficult to store and, unless liquefied at great cost, can be transported to market only by pipeline. This latter characteristic is particularly important because the demand for natural gas is subject to sharp seasonal fluctuations, with peak demand occurring from October through March.[42]

Long-term purchase contracts have made the marketing of gas possible by assuring the revenues necessary to recover the initial investment in pipeline facilities. Contract terms of ten to twenty years are now the most common, although in earlier times contracts frequently lasted for the length of the producer's leases.[43] Because of their long duration, gas contracts include a number of special provisions designed to provide both purchaser and seller with the flexibility to meet changing market conditions, while maintaining a stable framework of predictable rights and duties. The most important of these provisions will be discussed below.[44]

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39. NATURAL GAS REGULATION STUDY, *supra* note 28, at 34-35.

40. *Id.* at 132-38; *see* 2 A. KAHN, *supra* note 38, at 152-71.

41. An early oil and gas decision eloquently summarized the peculiar characteristics of natural gas.

> Water and oil, and still more strongly gas, may be classed by themselves, . . . as minerals *ferae naturae*. In common with animals, and unlike other minerals, they have the power and the tendency to escape without the volition of the owner. Their "fugitive and wandering existence within the limits of a particular tract was uncertain," . . . .

Westmoreland & Cambria Natural Gas Co. v. DeWitt, 130 Pa. 235, 236, 18 A. 724, 725 (1889) (quoting Brown v. Vandergrift, 80 Pa. 142, 147-48 (1875)).

42. NATURAL GAS REGULATION STUDY, *supra* note 28, at 18.

43. For a general discussion of this point, see Pierce, *Natural Gas Regulation, Deregulation, and Contracts*, 68 VA. L. REV. 63 (1982).

44. The ensuing discussion, *infra* text accompanying notes 45-57, is heavily indebted to Pierce, *supra* note 43, at 78-82.

1. Take-or-Pay Clauses

In general, a "take-or-pay" clause requires the purchaser to pay for a specified minimum percentage of the quantity of gas which the seller's wells can physically produce, regardless of whether the purchaser actually buys ("takes") the gas.[45] That minimum is usually between seventy and eighty percent,[46] although it may be as high as ninety percent for offshore wells. Also, pipelines generally agree to take all of a producer's "casinghead" or "oil well" gas, which would otherwise have to be flared in violation of state conservation laws.

The take-or-pay clause is beneficial to a producer because it assures his cash flow, thereby reducing his risk and facilitating the financing of further exploration. The take-or-pay clause is also beneficial to pipelines because it permits them to curtail their takes without incurring contractual liability or jeopardizing their continued access to the producer's reserves.[47] In the absence of such a clause, the pipeline would be liable to the producer for an amount equal to the excess of the contract price over the market price for gas contracted for but not taken.[48]

2. Price-Escalation Clauses

During the early days of the gas industry, inflation rates were low and gas was seen as little more than a byproduct of oil production. Markets were stable, oil was relatively inexpensive, and many fields had only one pipeline outlet. These circumstances led producers to sign long-term fixed price contracts under which gas was sold for only pennies per MMBtu.[49]

During the 1960's, however, rising inflation and the increasing scarcity of natural gas allowed producers to include price-escalation clauses in their contracts.[50] There are two general types of such clauses: fixed escalation clauses and indefinite escalation clauses. Fixed clauses establish a base price and a predetermined yearly escalation rate,[51] while indefinite escalation clauses tie the contract price to

45. *Id.* at 78.
46. *Id.*
47. *Id.* at 78-79.
48. *Id.* Pierce notes that § 2-708 of the Uniform Commercial Code sets the measure of damages as "the difference between the market price at the time and place for tender and the unpaid contract price." *Id.* at 79 n.63.
49. *Id.* at 79-80.
50. *See id.* at 80-81.
51. *Id.*

the price of some other product outside of the contract itself. Common indefinite escalation clauses are two- and three-party "favored nations" clauses,[52] "area rate" or "NGPA" clauses,[53] and "oil equivalency" clauses.[54] Both take-or-pay and indefinite escalator clauses permit the adaptation of long-term contracts to changing markets, whereas a fixed-escalation clause simply adjusts the price according to the future market conditions which the parties expected when the contract was made. However, even take-or-pay and indefinite escalator clauses may in some instances freeze arrangements that no longer reflect market conditions.[55]

3. Other Contractual Provisions

Two additional types of clauses are worthy of mention. The first, known as a "market-out" clause, gives the purchaser the right to reduce the price which it currently pays for gas to one at which it believes the gas can be marketed. The seller then has the option of accepting the new offer or terminating the contract and seeking a new purchaser.[56] The circumstances under which the purchaser may exercise its market-out rights depend upon the terms of the contract. Some of these contracts may give the purchaser broad discretion, while others specify objective market conditions, such as the price of competing fuels, under which the market-out provision may be invoked. Market-out clauses are a relatively recent development, thus many current gas purchase contracts are without them.[57]

"Price redetermination" clauses have also appeared in gas

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52. A two-party favored nations clause . . . provides that if the buyer purchases gas in the same field or area at a higher price than is paid under the contract in question, it must thereafter pay to seller the same price it is paying to other sellers. A third-party favored nations clause provides that the buyer will pay seller a price equal to the highest price paid by any buyer to any seller in the same field or area.

8 H. WILLIAMS & C. MEYERS, OIL & GAS LAW 439 (1982).

53. "Area rate" and "NGPA" clauses provide that the seller shall receive a contract price equal to the maximum legal selling price prescribed by law. Area rate clauses were used when the FPC established maximum legal prices under the NGA with reference to producers' rates of return on regionally averaged investment costs. *See id.* at 39; *infra* notes 72-88 and accompanying text. NGPA clauses replaced area rate clauses after the passage of the NGPA.

54. An "oil equivalency" clause establishes the price for gas with reference to either No. 2 fuel oil or No. 6 fuel oil, which compete with natural gas for a share of the industrial energy market. *See* 8 H. WILLIAMS & C. MEYERS, OIL & GAS LAW 27 (Supp. Nov. 1982).

55. *See infra* text accompanying notes 120, 129-30.

56. Several interstate pipelines have already invoked market-out clauses, thereby running the risk of losing reserves in an effort to meet the competition for the industrial market provided by No. 2 and No. 6 fuel oils. *See* Inside F.E.R.C., June 14, 1982, at 1 (Michigan-Wisconsin exercising market-out option and offering new price of $6/MMBtu).

57. For further discussion of market-out clauses, *see infra* text accompanying note 129.

purchase contracts with increasing frequency. Such clauses provide that in the event of deregulation the price will be renegotiated. The new price may be established with reference to the local gas market, but is not bound by that factor. Moreover, the producer may have the option of selling his gas to another purchaser, subject to the original buyer's right of first refusal. Since these clauses are appearing in gas purchase contracts with greater frequency, it is not inconceivable that immediate deregulation would lead to lower prices negotiated on the basis of current market conditions, rather than those existing at the time the original contract was made.

III. Federal Regulation of Natural Gas Markets

This section will examine federal regulation of both producers and pipelines in order to determine the effect of regulation on natural gas markets. A discussion of current regulations will begin after a brief examination of the origins of federal regulation. The section will then conclude with an analysis of some of the inefficiencies which the present regulatory scheme appears to have caused.

A. *The History of Natural Gas Regulation*

During the late nineteenth century, natural gas was considered a waste product of oil production, and was usually flared at the well site.[58] However, it was not long before entrepreneurs in the oil producing communities realized the value of natural gas as a source of heating and lighting. These distribution companies soon became subject to regulation by state commissions as legal monopolies.

As technology advanced, pipeline companies were able to extend their markets beyond oil-producing regions to communities nationwide.[59] However, this transmission of gas from one state to another was deemed by the Supreme Court to be interstate commerce which could not be regulated by the individual states.[60] Therefore, prompted in 1938 by the disruptions inherent to an incompletely regulated industry, Congress instituted federal regulation by passing the Natural Gas Act.[61]

58. *See* M. SANDERS, *supra* note 8, at 24-25; Connole, *General Considerations: A Nation's Natural-Gas Pains*, 44 GEO. L.J. 555, 555-57 (1956).

59. *See* M. SANDERS, *supra* note 8, at 25.

60. Missouri *ex rel.* Barrett v. Kansas Natural Gas Co., 265 U.S. 298 (1924).

61. For a detailed technical discussion of the NGA's legislative history, see Note, *Legislative History of the Natural Gas Act*, 44 GEO. L.J. 695 (1956).

The NGA gave broad power to the Federal Power Commission (FPC) over a number of transactions, although the grant of jurisdiction was not extended to the limits of Congress' powers under the commerce clause, even as those powers were construed in the 1930's.[62] Under the NGA, a "natural-gas company"[63] is allowed to charge no more than is "just and reasonable," which means rates must be cost-based. Furthermore, gas companies were required to obtain certificates of public convenience and necessity before beginning sales involving interstate commerce, and could only abandon such sales after having first obtained the Commission's consent.[64]

While the NGA imposed a pervasive scheme of federal regulation on natural gas pipelines, the regulatory status of independent producers was ambiguous and remained so until 1954.[65] Natural gas distributors were generally exempt from the Commission's NGA jurisdiction because they were believed to be adequately regulated by state utility commissions. While in recent years distributors have become more subject to indirect regulation, a discussion of such regulation is beyond the scope of this Article.[66]

B. *Pipeline Regulation Under the NGA*

The FPC has adopted a cost-of-service approach which permits interstate pipelines to charge rates to recover taxes, depreciation, operating expenses, energy and other costs, as well as an acceptable return on the net investment.[67] Pipeline customer rates are allocated between a "demand charge" and a "commodity charge." The demand charge is a payment for the right to purchase gas from the pipeline and the com-

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62. Under the NGA, the FPC's jurisdiction extends to:

> the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas to the facilities used for such distribution or to the production or gathering of natural gas.

NGA § 1(b).

63. The NGA defines "natural-gas company" as "a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale." NGA § 2(7).

64. NGA § 4 (rates and charges); NGA § 7 (certification of convenience and necessity and abandonment of service).

65. *See infra* notes 72-73 and accompanying text.

66. For a detailed discussion of the regulation of distribution companies, see NATURAL GAS REGULATION STUDY, *supra* note 28, at 195-297.

67. *See generally* 1 A. KAHN, *supra* note 38, at 20-57 (1970) (discussing factors considered in setting prices for public utility services based on costs of service).

modity charge is simply a payment for the amount of gas actually purchased.[68] Both charges are set at a level sufficient to recover the pipeline's costs over the quantity of gas which it expects to sell.[69]

This rate design has led to serious distortions in the burner-tip price of gas[70] by generally permitting pipelines to operate in what is essentially a cost-plus environment. In return for having a relatively low ceiling placed on profits, pipelines are virtually assured of passing all service costs on to ratepayers.[71] Pipelines, therefore, have little incentive to minimize these costs, particularly since purchased gas adjustment clauses in their tariffs ensure that increased energy costs will be promptly picked up by consumers.

C. *Regulation of Producers*

1. Regulation Under the NGA

During the 1940's, the Supreme Court dispelled any doubt concerning the NGA's applicability to wellhead prices charged by producers affiliated with interstate pipelines.[72] However, in 1954 the Court concluded in effect that the NGA also required the FPC to regulate wellhead natural gas prices charged by independent producers.[73]

The FPC, somewhat reluctantly thrust into uncharted waters by the Court's decision, attempted to set rates for hundreds of producers on an individual basis, using traditional cost-based rate-making criteria.[74] Overwhelmed by the staggering administrative burdens imposed by this method, the FPC abandoned it in favor of "area rate" regulation.[75] Under this method, the FPC based the producers' rate of return

68. Pierce, *supra* note 43, at 83.

69. *Id.* Fixed costs are primarily allocated to the commodity charge, while variable costs are done so exclusively. *Id.* The use of energy comprises the largest component of variable costs and its costs are determined by calculating a weighted average of the pipeline's gas purchase prices. *Id.*

70. *See infra* notes 109-11 and accompanying text.

71. *See supra* note 67 and accompanying text.

72. *See* Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 597-604 (1945) (FPC may consider production properties and gathering facilities of natural gas companies in setting rates under the NGA).

73. Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 682-85 (1954) (FPC may regulate prices of independent gas producers that sell to interstate pipelines).

74. *See* Note, *Legislative History of the Natural Gas Policy Act: Title I*, 59 TEX. L. REV. 101, 108 (1980). *See generally id.* at 107-12 (describing FPC's various pricing strategies under the NGA).

75. Statement of General Policy No. 61-1, 24 F.P.C. 818 (1960) (codified at 18 C.F.R. § 2.56 (1982)). When the FPC initiated area rate proceedings in 1960, it was estimated that there were 4500 natural gas producers in business. C. HAWKINS, THE FIELD REGULATION OF NATURAL GAS 37 (1969). To the surprise of no one, the FPC estimated that it would not achieve current status in

on industry-wide production and regionally averaged investment costs, thereby avoiding the burdensome task of setting prices for individual producer sales.[76] The FPC also initiated a two-tier pricing system designed to stimulate production without permitting a "windfall" to producers of already-flowing gas.[77] Accordingly, the higher ceiling covered "new" gas from gas wells, and the lower ceiling applied to both "old" gas from gas wells and to "associated gas," meaning all gas from oil wells.[78] While upholding both the area rate and two-tier ceiling methodologies in the *Permian Basin Area Rate Cases*,[79] the Supreme Court made the following observation: "Producers of natural gas cannot usefully be classed as public utilities. . . . The value to the public of the services they perform is measured by the quantity and character of the natural gas they produce, and not by the resources they have expended in its search . . . ."[80]

Shortly after the *Permian Basin* decision, the FPC began to investigate the possibilities of establishing a unified national price for producer sales of natural gas.[81] This investigation culminated in 1974 when the FPC set a national ceiling price of $.42 per thousand cubic feet (Mcf) for gas from wells commenced on or after January 1, 1973.[82] The FPC's action, intended as an incentive for the production of new gas, was consistent with the policies underlying the two-tier pricing system.[83] After having established this "national rate," the FPC set two other national rates for new gas: $.50 per Mcf in December 1974 and $1.42 per Mcf in 1977. The FPC also experimented with regulatory

its independent producer case load until the year 2043. Phillips Petroleum Co., 24 F.P.C. 537, 546 (1960), *aff'd sub nom.* Wisconsin v. FPC, 303 F.2d 380, *aff'd*, 373 U.S. 294 (1963).

76. Area Rate Proceeding for Permian Basin, 34 F.P.C. 159, 189-208 (1965), *aff'd in part and rev'd in part sub nom.* Skelly Oil Co. v. FPC, 375 F.2d 6 (10th Cir. 1967), *aff'd in part and rev'd in part sub nom.* Permian Basin Area Rate Cases, 390 U.S. 747, 755 (1968) (approving FPC decision in its entirety). For a detailed discussion of area ratemaking, see Breyer & MacAvoy, *The Natural Gas Shortage and the Regulation of Natural Gas Producers*, 86 HARV. L. REV. 941, 958-65 (1973).

77. *See* Note, *supra* note 74, at 109. For a discussion of the economic theory underlying the two-tier system, see Breyer & MacAvoy, *supra* note 76, at 948-52.

78. *See* Breyer & MacAvoy, *supra* note 76, at 959.

79. 390 U.S. 747 (1968).

80. 390 U.S. at 756-57. Similarly, the FPC had suggested abandonment of cost-based utility ratemaking principles in establishing maximum permissible producer prices as early as 1956. [1956] F.P.C. ANN. REP. 19.

81. *See* Initial Rates for Future Sales of Natural Gas, 35 Fed. Reg. 11,638 (1970). The FPC's decision to abandon area ratemaking was dictated in part by the conceptual problems inherent in the scheme. *See* Breyer & MacAvoy, *supra* note 76, at 958-65.

82. Opinion No. 699, 51 F.P.C. 2212, 2215, 2281-82 (1974).

83. *See* [1971] F.P.C. ANN. REP. 36 (justifying price incentives offered to producers by the FPC on the basis of developing greater gas supplies to meet additional demand); Note, *supra* note 74, at 110.

approaches that were less restrictive than those sanctioned under traditional utility ratemaking procedures.[84]

Unfortunately, these approaches were insufficient to correct the problems inherent in regulating producer prices under the NGA. The cost-based ratemaking methodology which the NGA mandates and its corollary emphasis on consumer protection led the FPC to fix ceiling prices for natural gas far below market-clearing levels.[85] At such prices, the demand for natural gas greatly exceeded the available interstate supply and thus caused severe shortages and pipeline curtailments.[86] Moreover, the FPC's jurisdiction extended only to sales of natural gas in the interstate market.[87] Not even upper-tier FPC ceiling prices were sufficient to attract the necessary supplies away from the unregulated intrastate market.[88] This arbitrary regulatory distinction only worsened the already acute shortage of gas in the interstate market.

2. Regulation Under the NGPA

The NGA's failure to assure adequate gas supplies at reasonable prices for the interstate market led to the adoption of the NGPA.[89] Title I[90] of the NGPA establishes statutory maximum prices for both interstate and intrastate "first sales" of natural gas.[91] These prices are determined with reference to eight major categories and numerous sub-

84. *See* Note, *supra* note 74, at 111. For example, the FPC began to accept the discounted cash flow (DCF) pricing method in determining producer costs. This method attempted to simulate the free market by imitating the economic behavior of gas producers. For a detailed explanation of DCF analysis in oil and gas production, see S. MCDONALD, PETROLEUM CONSERVATION IN THE UNITED STATES: AN ECONOMIC ANALYSIS 76-82 (1971); W. LOVEJOY & P. HOMAN, ECONOMIC ASPECTS OF OIL CONSERVATION REGULATION 90-93 (1967).

85. *See* Note, *supra* note 74, at 112; Breyer & MacAvoy, *supra* note 76, at 968-76.

86. H.R. REP. NO. 496, pt. 4, 95th Cong., 1st Sess. 90, *reprinted in* 1978 U.S. CODE CONG. & AD. NEWS 8454, 8534; *see also* North Carolina v. FERC, 584 F.2d 1003 (1978) (curtailment levels of 40%). For a discussion of the economic theory underlying the relationship between shortages and insufficiently high prices, see Note, *Production Bounties for New Natural Gas in Times of Shortage*, 58 TEX. L. REV. 197, 203-05 (1979).

87. NGA § 1(b) (quoted at *supra* note 62).

88. *See supra* note 86.

89. *See* Note, *supra* note 74. For a discussion of the legislative maneuvering that led to the NGPA's adoption, see Hollis & Strohl, *Squaring the Circle: Implementing the Agricultural Use Exemption From Incremental Pricing Under the Natural Gas Policy Act*, 15 NAT. RESOURCES LAW. 419, 419 n.3 (1982).

90. NGPA §§ 101-123.

91. *Id.* §§ 101-109. *Id.* § 2(21) defines "first sale" as follows:

(A) General rule

The term "first sale" means any sale of any volume of natural gas—

categories of natural gas production.[92] A volume of gas is categorized according to the rate at which it is produced,[93] the geological formation from which it is produced,[94] and a number of other factors.[95] In essence, however, "first sales" fall into two classes: those which require a jurisdictional agency to determine whether the subject gas qualifies for collection of the statutorily-prescribed maximum price and those for which no such determination is necessary.[96] These categories can be

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(i) to any interstate pipeline or intrastate pipeline;
(ii) to any local distribution company;
(iii) to any person for use by such person;
(iv) which precedes any sale described in clauses (i), (ii), or (iii); and
(v) which precedes or follows any sale described in clauses (i), (ii), (iii), or (iv) and is defined by the Commission as a first sale in order to prevent circumvention of any maximum lawful price established under this chapter.

(B) Certain sales not included
Clauses (i), (ii), (iii), or (iv) of subparagraph (A) shall not include the sale of any volume of natural gas by any interstate pipeline, intrastate pipeline, or local distribution company, or any affiliate thereof, unless such sale is attributable to volumes of natural gas produced by such interstate pipeline, intrastate pipeline, or local distribution company, or any affiliate thereof.

There can be numerous first sales of the same volume of gas under this definition. For example, when a producer sells to a gatherer who in turn sells to a processor who eventually sells to a pipeline, there may be three first sales of the same gas. *See* 18 C.F.R. § 270.202(a) (1981); Letter Opinion to Pronto Compression Co. (Mar. 12, 1980), [FERC Actions] NGPA INF. SERV. (FPAS) ¶ 4361; *see also* Hollis, *Title I and Related Producer Matters Under the NGPA*, 2 ENERGY L. SERV. (CALLAGHAN) § 4D.02 at 2 (Apr. 1981) (outlining first sale rule). Under certain circumstances, a producer's maximum legal selling prices in first sales may be increased to permit recovery of certain production related costs and state severance taxes. NGPA § 110(a).

92. *See* NGPA §§ 102-109.

93. *E.g.*, *id.* § 108(b)(1)(A) (establishing category for stripper well gas, produced at rate not in excess of 60 Mcf per day and subject to certain limitations).

94. For example, "high-cost" natural gas is defined as follows:

(c) Definition of high-cost natural gas
For purposes of this section, the term "high-cost natural gas" means natural gas determined in accordance with section 3413 of this title [NGPA § 503] to be—
(1) produced from any well the surface drilling of which began on or after February 19, 1977, if such production is from a completion location which is located at a depth of more than 15,000 feet;
(2) produced from geopressured brine;
(3) occluded natural gas produced from coal seams;
(4) produced from Devonian shale, and
(5) produced under such other conditions as the Commission determines to present extraordinary risks or costs.

Id. § 107(c).

95. *See, e.g.*, *id.* § 103 (gas produced from a reservoir from which there was no production in commercial quantities before Apr. 20, 1977); *id.* § 104 (gas committed or dedicated to interstate commerce prior to enactment of NGPA and subject to rates established under the NGA); *id.* § 105 (gas sold under intrastate contracts on NGPA enactment date). Congress, in its wisdom, even devised a category for gas that did not qualify for any other NGPA category. *See id.* § 109. For a general discussion of the title I pricing scheme, see Hollis, *supra* note 91.

96. The categories in the first class are: (1) new natural gas, NGPA § 102(c)(1)(A)-(C); (2) certain natural gas produced from the Outer Continental Shelf, *id.* § 102(d); (3) new, onshore production wells, *id.* § 103; (4) high cost natural gas, *id.* § 107; (5) stripper well natural gas, *id.* § 108. The categories in the second class are (1) gas dedicated to interstate commerce, *id.* § 104;

seen as a complicated variation of the old NGA two-tier pricing scheme.[97] The first class corresponds to the upper tier which was eligible for incentive prices, and the second class corresponds to the lower tier of "old" and low-cost gas.[98] Thus, the NGPA discarded the NGA's distinction between interstate and intrastate sales as well as its cost-based ratemaking methodology, but continued to give favorable price treatment to new and high-cost gas as a spur to greater production.

Title I of the NGPA also provides for an eventual partial deregulation of wellhead prices. Gas falling within the four categories outlined in NGPA section 107(a)-(d) has been exempt from price ceilings since November 9, 1979.[99] Moreover, section 121(a) of the NGPA provides for the removal of title I price ceilings for gas in three additional categories beginning January 1, 1985.[100] However, NGPA sections 121 and 122 provide that after six months either the President or Congress may reimpose controls of these three categories for a period of eighteen months, to begin not later than June 30, 1987.[101] Already flowing gas, which falls into the various categories set forth in sections 104-106 and 109 of the NGPA, will remain regulated indefinitely, with certain exceptions.[102] Nevertheless, it is estimated that as of 1985, or 1987 if title I is extended pursuant to NGPA section 122, fifty to sixty percent of domestic gas production will be exempt from NGPA price controls.[103]

D. *The Regulatory Origins of Market Disorder*

Close examination of the turmoil in the natural gas markets

(2) sales under existing intrastate contracts, *id.* § 105; (3) sales under rollover contracts, *id.* § 106; (4) other categories of natural gas, *id.* § 109. *See* Hollis, *supra* note 91, § 4D.06 at 7.

97. *See supra* notes 77-80 and accompanying text.

98. All the categories in the second class are eligible only for the monthly inflation adjustment prescribed by NGPA § 101(a), whereas those in the first class are also adjusted by real growth factors to provide additional incentives for exploration and development, and to phase in their eventual exemption from title I price ceilings. *See infra* notes 100-102 and accompanying text.

99. NGPA § 121(b).

100. Those categories are new natural gas, (as defined by NGPA § 102(c)), natural gas sold for more than one dollar per million Btu's under intrastate contracts, and gas from new, onshore production wells (as defined by NGPA § 103(c)).

101. *See id.* §§ 121, 122. Gas from new, onshore production wells will be deregulated on Jan. 1, 1985 only if it "is produced from a completion location which is located at a depth of more than 5,000 feet. *Id.* § 121(a)(2)(B). Shallower production from such wells will not be deregulated until either July 1, 1987, or at the expiration of price controls reinstated under NGPA § 122(c), whichever date is later. *Id.* § 121(c).

102. Natural gas priced under NGPA § 105 or NGPA § 106 will be deregulated on Jan. 1, 1985 if its price exceeds one dollar per million Btu's and it was not committed to interstate commerce before enactment of the NGPA. *Id.* § 121(a)(3).

103. NGPA ALTERNATIVES, *supra* note 1, at 3.

reveals that it is in fact several distinct but interrelated problems. The following section outlines several aspects of the turmoil and traces its roots to the regulatory system to which gas markets are presently subject.

1. Fly-Up

When the NGPA was enacted, Congress prescribed ceiling prices for natural gas on the assumption that world crude oil prices would be no more than eighteen dollars per barrel.[104] Although there has been some softening in world crude oil prices, there is a substantial likelihood that, under current policy, crude oil prices will be at least thirty dollars per barrel in 1985.[105] As a consequence, many observers fear that when partial decontrol takes place, gas prices will rise sharply to the approximate level of oil prices on a Btu-equivalent basis.[106]

A fly-up in gas prices seems less likely now than it has in recent years. As of this writing, there is some possibility that the Organization of Petroleum Exporting Countries (OPEC) may collapse, plunging prices toward the levels envisioned by the authors of the NGPA.[107] However, such a collapse, while possible, is not considered likely by some observers.[108] Fly-up therefore remains a possibility of which policymakers must be aware.

2. Bidding Disparities Between Interstate and Intrastate Pipelines

Pipelines usually purchase gas from a number of sources at a wide range of prices. When a pipeline resells gas, the price which the customer pays generally reflects the pipeline's weighted average cost of gas. Accordingly, this "rolled-in" pricing[109] allows a pipeline with a lower weighted average cost of gas to outbid its competitors for new supplies. Under title I of the NGPA, there are approximately twenty-seven price categories of gas, ranging from as low as $.27/MMBtu to as high as $10/MMBtu for some deregulated gas. Pipelines having access to old gas, which is subject to controls established under the NGA,

104. *See* Pannill, *Reform of the Natural Gas Policy Act of 1978*, 17 TULSA L.J. 54, 66 (1981).
105. NGPA ALTERNATIVES, *supra* note 1, at 9, table 1.
106. *Id.* at 12-18.
107. *See* OIL & GAS J., Dec. 27, 1982, at 39.
108. *See* Wall St. J., Jan. 21, 1983, at 3, col. 2.
109. "Rolled-in" pricing averages gas acquisition costs for purposes of calculating the unit rates to be paid by pipeline customers and ultimate consumers of the gas. 8 H. WILLIAMS & C. MEYERS, *supra* note 52, at 653.

enjoy a "gas cushion" which will permit them to bid the prices of new gas above market-clearing levels, since the more expensive gas can be rolled in with less expensive gas and sold to consumers at a competitive burner-tip price.[110]

As a result of the gas cushion, interstate pipelines who have greater access to old gas are able to bid extremely high prices for new supplies of natural gas, to the detriment of intrastate pipelines. This trend favors producers of new gas, who can obtain prices in excess of what would otherwise be market-clearing levels. Moreover, intrastate pipelines will eventually be forced to curtail deliveries to their customers if they fail to obtain new supplies of gas before their current supplies are exhausted. Finally, through "off-system sales," interstate pipelines can sell surplus supplies to customers who had previously been served by intrastate pipelines.[111] Thus, the NGPA has not eliminated the artificial distinction between interstate and intrastate sales created by the NGA, but has merely reversed its negative consequences.

3. Allocation Inefficiencies

As noted in the preceding section, rolled-in pricing and the wide range of maximum permissible prices for gas under the NGPA encourage pipelines with access to low-cost gas to bid prices above market-clearing levels for deregulated gas or gas which qualifies for incentive pricing. This tendency is enhanced by pipeline rate design. Prices which pipelines charge are designed to cover costs and to provide a reasonable return on the estimated quantity of gas to be delivered.[112] Because a pipeline's fixed costs are allocated both to the demand and the commodity charges, gas sold up to the original estimate will recover a portion of fixed costs. The commodity charge is not reduced after fixed costs have been recovered, thus, sales in excess of the estimated quantity enhance profits.[113] Moreover, if low-cost supplies are insufficient to meet demand, pipelines will maximize profits by purchasing additional supplies at a relatively high cost if no other low-

110. For a thorough discussion of the effect of rolled-in pricing on burner tip rates, see Pierce, *Natural Gas Rate Design: A Neglected Issue*, 31 VAND. L. REV. 1089, 1094-110 (1978).

111. An "off-system sale" is a sale of gas produced by a pipeline company to another pipeline company. In an "on-system" sale, the producing pipeline transports the gas to the purchaser. City of Chicago v. Federal Power Comm'n, 458 F.2d 731, 733-34 n.3 (D.C. Cir. 1971), *cert. denied*, 405 U.S. 1074 (1972).

112. *See* Pierce, *supra* note 43, at 83.

113. *See id.* at 84.

cost supplies are available.[114]

It is an axiom of microeconomics that the price of a commodity should equal its marginal cost.[115] Yet, from the examples given above, it is apparent that gas consumers pay prices *below* marginal cost because the price of new supplies is rolled in with that of old supplies. Consequently, gas consumption is encouraged since the time and cost of bringing new supplies to market are understated. If the cost of new supplies of gas is the weighted average cost rather than the marginal cost, economic resources have been inefficiently allocated.[116]

4. Apparent Unresponsiveness of Gas Prices to Market Forces

There is little doubt that there is now a "gas glut" in that more gas can be delivered to purchasers than they are willing to buy at currently prevailing prices.[117] Under such circumstances, one would expect the price of gas to decline until supply and demand were in equilibrium. However, most available evidence indicates that consumers still face rapidly escalating gas costs.[118] Consequently, many industrial consumers are switching from natural gas to fuel oil, thereby forcing pipelines and distributors to recover the high fixed costs by further increasing prices charged to those residential and commercial customers who cannot readily shift to alternate energy sources.[119]

To a certain extent, this phenomenon may simply be due to the long lag period during which gas markets respond to price signals, and to the fact that gas prices are still being set in accordance with escalation provisions that were drafted during the gas shortages of the 1970's. Also, take-or-pay provisions in long-term contracts may be forcing pipelines to purchase more expensive supplies from large producers

114. *See id.*

115. Marginal cost is the avoidable cost that is incurred to produce one more unit of a good or service. 1 A. KAHN, *supra* note 67, at 65.

116. The following hypothetical, adapted from one given by Professor Pierce, demonstrates this point in greater detail. Suppose that a distributor purchases 100,000 MMBtu of price-controlled gas at $.80/MMBtu when the market price for such gas is actually $2/MMBtu. To meet the excess demand, it would be rational for the distributor to purchase 20,000 MMBtu of liquefied natural gas (LNG) at $4.50/MMBtu, since the weighted average cost of all supplies to consumers would be only $1.43/MMBtu—far below the market level given in the hypothetical. However, the purchase of the LNG would be rational from society's viewpoint only if consumers would be willing to pay $4.50/MMBtu in order to increase their consumption of energy by one-fifth. Otherwise, the consumers would maximize their satisfaction by placing the $90,000 spent on the LNG into the purchase of other goods and services. *See* Pierce, *supra* note 110, at 1098-99.

117. *See supra* note 3 and accompanying text.

118. Wall St. J., Jan. 21, 1983, at 3, col. 2.

119. *See* Foster Nat. Gas Rep., Dec. 29, 1982, at 1 (No. 1395) (summarizing petition filed by Citizen/Labor Energy Coalition).

while shutting in less expensive gas from smaller producers.[120] Such a situation works a hardship not only on consumers but on the shut-in producers as well. The leases of these producers may expire if production is not quickly restored.[121] Furthermore, the reservoirs under their leases may be drained by another pipeline taking gas from a different producer in the same reservoir. Faced with a desperate situation, many producers are invoking the aid of state common purchaser statutes.[122]

In addition to these explanations, it is also possible that pipeline rate design and producer price regulations are partly responsible for the peculiar behavior of the natural gas market. Multiple gas pricing categories, unequal pipeline access to low-cost gas, and rolled-in pricing are all factors which encourage pipelines to pay above-market prices for new gas. As a result, their incentive to purchase new, higher-priced gas is even stronger than it otherwise would be. Moreover, gas pipelines have little incentive to purchase less expensive supplies since a dollar-for-dollar passthrough of their costs is virtually guaranteed by law.[123]

IV. Proposed Means of Achieving Order

Since the disorder in the natural gas markets is actually several distinct yet interrelated problems, it should come as no surprise to learn that a number of solutions to these problems have been proposed.[124] The following section will discuss the most frequently mentioned of these solutions, categorizing them as being directed primarily either to

120. *Id.*

121. Once gas is discovered, the lessee has a duty to use due diligence to market the product. "Satisfaction of the implied marketing obligation through continuing efforts to market the product will not satisfy the habendum clause indefinitely. At some point, even though there has been no breach of the covenant [to market], the lease will expire if there is no production." 5 H. Williams & C. Meyers, *supra* note 52, at 397. *But see* Bristol v. Colorado Oil & Gas Corp., 225 F.2d 894 (10th Cir. 1955) (lease preserved although no gas had been marketed for seven and two-thirds years after primary term and nine and a half years from completion date of well; under circumstances, lessee had used due diligence to market gas and unreasonable time had not yet elapsed).

122. State common purchaser statutes generally require purchasers to take oil or gas without discrimination among producers or fields. *See, e.g.*, Tex. Nat. Res. Code Ann. §§ 111.083-.086 (Vernon 1978). However, it would appear that such statutes are pre-empted by the NGA and hence do not apply to interstate pipelines. Northern Natural Gas Co v. State Corp. Comm'n, 372 U.S. 84, 91 (1963).

123. *See supra* notes 67-69 and accompanying text.

124. The Reagan Administration has drafted a bill designed to alleviate many of the existing problems in the natural gas markets. S. 615, 98th Cong., 1st Sess. (1983). The basic provisions are: (1) deregulation of contracts signed after enactment, with the new price forming a "gas cap" price until total deregulation in 1986; (2) modification of take-or-pay clauses; (3) an option for either party to "market-out" or cancel the take-or-pay contracts; (4) limitations on passthrough of increased gas costs. *Id.*; *see* Foster Nat. Gas Rep., Mar. 3, 1983, at 1 (No. 1404).

producers or to pipelines. Following discussion of these solutions, they will be evaluated in a brief concluding section.

A. *Proposals Affecting Producers*

1. Continuation of Wellhead Price Controls

Maintaining price controls on gas is an obvious response to the disorder in the natural gas markets. Groups claiming to represent residential and commercial gas consumers have contended that the NGPA's phased, partial decontrol is the source of the ailment afflicting the market, pointing to the substantial price increases of the past five years.[125] Arguments may also be made that the recontrol of gas prices would end many of the alleged abuses in the purchasing practices of interstate pipelines by limiting the maximum prices which can be paid for new supplies.[126]

As has been shown, however, higher prices are a relatively minor symptom of the gas market's sickness.[127] Moreover, the consumer advocates have forgotten all too readily the painful lessons of curtailment, bureaucracy, and chaos which were taught in the 1970's. While price controls on essential commodities such as natural gas may be an acceptable evil in times of emergency, they are generally futile and indeed counterproductive for two reasons. First, price controls inevitably lead to the inefficient allocation of resources and to consumer dissatisfaction.[128] Second, price controls impose heavy administrative costs on industry and the public. Government personnel must be assigned to interpret, administer, and enforce restrictions. Companies must spend considerable money and time complying with the law, thereby depriving them of the use of assets that would otherwise be available for producing goods and services. Accordingly, the continuation of price controls offers no significant solution to the problems of the natural gas markets.

2. Contractual Solutions

The last half of 1982 saw the introduction of many proposals addressing the so-called "contracts" aspect of the market-ordering problem. Some of these proposals would merely require all gas purchase

125. Foster Nat. Gas Rep., Dec. 29, 1982, at 1 (No. 1395).
126. *Id.* at 1-2.
127. For a more detailed discussion of this point, see Pierce, *supra* note 43, at 71-72.
128. *Id.* at 72.

contracts to contain "market-out" clauses while others would modify or even eliminate take-or-pay and indefinite price escalation provisions in natural gas contracts.[129] Both types of provisions are seen as having led to unnecessary consumer price increases. Take-or-pay provisions have been attacked because they encourage pipelines either to take high-priced gas or pay up to ninety percent of daily deliverability without receiving any gas whatsoever. In times of excess demand, the gas wells of smaller producers with less favorable take-or-pay arrangements, or none at all, would then be shut-in, even if it were less expensive. Indefinite price escalation provisions, on the other hand, provide for steady increases in gas prices over time, without regard to the ultimate marketability of the gas at any particular time. Thus, even when demand declines, the prices which pipelines pay will continue to rise, ultimately to be passed through to consumers.

As previously shown,[130] both take-or-pay clauses and indefinite price escalation provisions are essential to insure the financial integrity of those who produce and explore for natural gas. Moreover, as is true with respect to other issues in gas policy, there appears to be little reliable data on the effect that these provisions might have on consumers. In any event, a better approach would appear to be the encouragement of pipelines and producers alike to renegotiate contracts that no longer reflect market realities. Finally, there is no reason to believe that legislative tinkering with contractual provisions would resolve problems attributable to natural gas rate design and to the multi-tiered pricing system which the NGPA mandates.

Incorporating market-out clauses in gas contracts is an attractive way of protecting consumers from ratchet-like increases in gas prices, while continuing to afford producers the protection which take-or-pay and indefinite price escalator clauses may afford. However, the difficulty arises in drafting a suitable market-out provision. In order to protect producers, the provision must provide reasonable, objective criteria for determining whether gas is marketable and yet must provide pipelines with some flexibility in making such a determination. Each pipeline and distributor operates in different local markets which are subject to different competitive restraints. It would seem virtually impossible to design uniform, national standards for market-out provi-

129. *See, e.g.*, Foster Nat. Gas Rep., Dec. 29, 1982, at 2 (No. 1395) (suggesting that all existing contracts be construed to contain market-out clauses); Notice of Inquiry, 47 Fed. Reg. 19,157, 19,161-62 (1982) (discussing various proposals made to the Commission).

130. *See supra* notes 53-55 and accompanying text.

sions, let alone an actual provision, that could accommodate the wide range of situations confronting those companies ultimately responsible for marketing natural gas. Accordingly, market-out provisions can provide no panacea for gas markets in general.

3. Decontrol of Natural Gas Wellhead Prices

An obvious solution to the problems caused by regulation is simply to eliminate regulation altogether. Many of the economic inefficiencies associated with price controls would be eliminated if wellhead prices were allowed to respond to market conditions. In particular, the bidding disparities between interstate and intrastate pipelines would be eliminated; overconsumption of gas would be prevented because consumers could compare the costs of new natural gas supplies with those of alternate sources of energy; and the administrative costs of administering and enforcing price controls could be eliminated.

However, the decontrol of wellhead prices, despite its attractiveness, would create additional problems if not supplemented by other approaches. First, it is possible that there would be a fly-up in gas prices upon decontrol, due in part to indefinite price escalation clauses.[131] Although it is difficult to determine precisely how great the fly-up would be, consumers would undoubtedly be affected, particularly those who had benefited from access to supplies still subject to "old gas" ceilings. A fly-up would, of course, transfer wealth from consumers to producers and impose heavy burdens on industries which depend upon natural gas for fuel. Second, deregulation would probably result in rents, or "windfall profits," to producers of gas previously subject to price controls. Third, deregulation of wellhead prices would not necessarily give pipelines any greater incentive to acquire the least expensive gas supplies; accordingly, the temptation would still be great for pipelines to obtain new reserves by bidding high prices for them and then passing the prices through to distributors and ultimately to consumers.[132]

Notwithstanding these objections to immediate decontrol, a possible remedy may be a gradual, phased decontrol coupled with reforms in other areas of natural gas regulation and taxation.

131. *See supra* notes 49-50 and accompanying text.
132. *See supra* notes 67-69 and accompanying text.

4. Deregulation of Wellhead Prices and Windfall Profit Tax

Immediate deregulation of natural gas prices might result in a windfall for natural gas producers equal to the difference between the unregulated price and the price ceiling which had existed prior to deregulation, particularly for those who produce "old gas." The most obvious way to relieve a producer of such a windfall is to tax it, a path which Congress chose when it decontrolled crude oil.[133] While no legislation implementing a windfall tax on natural gas has yet been introduced, one might assume that the structure of such legislation would be similar to that of the Crude Oil Windfall Profit Tax of 1980.[134] A tax on windfall profits is attractive because it would raise much needed revenue for the federal government while preventing a redistribution of wealth. A windfall profits tax might also reduce the administrative burdens associated with a full-fledged price control scheme.

However, although a windfall profits tax would eliminate producer rents, it would not resolve problems associated with decontrol.[135] Moreover, the extremely large number of pricing categories would make the administration of a windfall tax for gas even more complicated than the windfall tax on crude oil and would lead to the imposition upon sellers of certification procedures which in many instances might be far more burdensome than current regulation under the NGPA.[136] Finally, it is open to dispute that windfalls are an evil which must somehow be taxed away. The revenues which producers would receive upon decontrol would presumably be used for financing energy production, rather than for purchasing personal luxury items. Indeed, windfall profits serve two important economic functions. First, they provide the capital necessary for further exploration and development of energy resources. Second, they allow producers to defray the currently high costs of replacing reserves which were discovered before the 1970's and which are now nearing exhaustion.[137]

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133. *See* 26 U.S.C. §§ 4986-4998 (Supp. V 1981).

134. *Id.*

135. For a discussion of this evidence, see NATURAL GAS REGULATION STUDY, *supra* note 28, at 147-49.

136. The economic theory underlying the concept of rents is discussed at some length in Pierce, *supra* note 110, at 1099 n.33.

137. For a more detailed discussion of these points, see Eck, *Future U.S. Exploration—The Key Is Economics*, OIL & GAS J., Aug. 16, 1982, at 114.

B. *Proposals Affecting Pipelines*

1. Encouraging Prudence in Pipeline Gas Acquisitions

A fundamental and recurring problem affecting gas markets is that under the current regulatory scheme pipelines have little or no incentive to acquire the least expensive gas available. As a result, burner-tip gas prices have been slow to respond to market forces.

It is at least arguable that FERC has the statutory authority to encourage pipelines to acquire less expensive sources of gas. Section 601(c)(2) of the NGPA prohibits the passthrough of gas acquisition costs incurred as a result of "fraud, abuse, or similar grounds."[138] To date, FERC has taken a very narrow view of its authority under this section, stating that it may only disallow costs incurred as a result of common law fraud.[139]

Moreover, FERC appears to have authority under sections 4 and 5 of the NGPA to prohibit the passthrough of gas acquisition costs if doing so would result in rates which are not "just and reasonable."[140] Indeed, there have been recent indications that FERC will adopt this course. In *Tennessee Gas Pipeline Co.*,[141] the Commission announced its intention to deny passthrough of pipeline gas acquisition costs if it resulted in a load loss of a pipeline's system, which would occur if customers shifted to low-priced alternative fuels. Some pipelines have taken corrective action on their own initiative and obtained the Commission's consent to reduce their rates to levels necessary to avoid industrial load loss.[142]

A slightly different approach has been advocated by those who argue for allowing pipelines to earn an "incentive rate of return" as a reward for prudent purchasing practices. Under such a scheme, the pipeline's return on equity would be "adjusted upward or downward depending on whether its deregulated gas purchases were below or above the market-clearing price."[143]

While pipelines should be encouraged to keep gas acquisition costs as low as possible, there is a significant possibility that the Commission

138. NGPA § 601(c)(2).

139. Statement of Policy, 47 Fed. Reg. 6253 (1982).

140. NGPA §§ 4, 5.

141. [21 FERC, Oct.-Dec. 1982 Transfer Binder] FED. ENERGY REG. COMM'N REP. (CCH) ¶ 61,004, at 61,009 (Oct. 1, 1982).

142. *See* Foster Nat. Gas Rep., Dec. 29, 1982, at 9 (No. 1395) (discussing the applications of three pipelines).

143. Notice of Inquiry, 47 Fed. Reg. 19,157, 19,164 (1982) (discussion of the proposal).

will substitute its own notions of prudence for those of the pipeline companies' management. This is particularly true since it is difficult to determine when a pipeline's gas acquisition costs may result in rates above theoretical market-clearing levels. A miscalculation on the part of the Commission could lead it to set rates too low, making it impossible for a pipeline to obtain the reserves necessary to maintain service on its system. One suspects that it would be better to scrap the entire elaborate ratemaking apparatus of the NGPA and substitute for it the discipline of the marketplace itself.

2. Encouraging Marginal Cost Pricing

As previously noted, present natural gas rate designs lead to burner-tip prices that do not properly reflect the higher marginal cost of obtaining new supplies.[144] Various proposals for implementing marginal cost pricing have been made, one of which is the incremental pricing program established by title II of the NGPA. This program is designed to shift to industrial facilities the cost of acquiring newer, more expensive supplies of gas.[145] By so doing, the incremental pricing program is intended primarily to shield residential and commercial consumers from wellhead price increases and to discourage a fly-up in the price of high-cost supplies.[146]

In theory, incremental pricing is essentially identical to marginal cost pricing. However, the NGPA program is not a true marginal cost pricing mechanism because it confronts only industrial consumers with the variable costs of purchasing an additional unit of gas and not residential and commercial consumers.[147] Also, the NGPA's incremental pricing program requires that industrial consumers pay a rate which reflects the average cost of transporting, storing, and distributing a unit of gas, as well as its marginal cost. Such a requirement is inconsistent with marginal cost pricing since the fixed costs of transportation and distribution cannot be avoided by deciding not to produce or not to purchase the last unit of output.[148]

Professor Pierce has identified three possible methods of bringing natural gas rate design into accord with the principles of marginal cost

144. *See supra* notes 109-10 and accompanying text.
145. Moody & Garten, *The Natural Gas Policy Act of 1978: Analysis & Overview*, 25 ROCKY MTN. MIN. L. INST. 2-1, 2-41 to -42 (1979).
146. *Id.*
147. Pierce, *supra* note 110, at 1120.
148. *Id.* at 1122.

pricing.[149] However, he recognizes that each method suffers from analytical and institutional defects which, while perhaps not insurmountable, are nonetheless formidable.[150] Like many good theories, marginal cost pricing presents far too many difficulties in application to be hailed as a panacea for ailing gas markets.

3. Imposing Common Carrier Duties Upon Pipelines

A proposal which has been considered more carefully is to eliminate utility regulation of pipelines in favor of common carrier regulation. At common law, common carriers had a duty to carry goods for all persons at non-discriminatory rates.[151] Oil pipelines have traditionally been regulated as common carriers and so it would not be unprecedented to treat gas pipelines in that manner.[152]

As applied to the natural gas industry, gas would be transported by pipelines for a fee, its services available to all wishing to avail themselves of the service. Pipelines could move gas from producers to distributors or, like many oil pipelines, they could ship their own gas to distributors and serve other producers on a space available basis.[153]

Some have observed that common carrier regulation could increase competition and facilitate the more rapid movement of gas in response to market conditions.[154] On the other hand, such regulation would also raise questions about access,[155] pipeline revenue stability,[156] and rate discrimination, particularly in connection with transportation of a pipeline's own production.[157] Also, producers might be reluctant to deal with small distributors except at very high prices because of the minor gas volumes involved.[158] Moreover, the serpentine history of the oil pipeline industry suggests that common carrier regulation of gas pipelines, however attractive it may be in principle, would be as troub-

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149. *Id.* at 1138-47. These methods are: (1) inclining block rates; (2) marginal cost pricing with consumer rebates; and (3) marginal cost pricing with an excess profits tax. *Id.*

150. *Id.* at 1147-62.

151. *See* Cincinnati, N.O. & Tex. Ry. v. Interstate Commerce Comm'n, 162 U.S. 184, 197 (1896).

152. *See* United States v. Ohio Oil Co., 234 U.S. 548, 560 (1914); 4 W. SUMMERS, THE LAW OF OIL & GAS 321-25 (1962).

153. *See* NATURAL GAS REGULATION STUDY, *supra* note 28, at 158.

154. *Id.* at 161.

155. *Id.*

156. *Id.* at 159-61.

157. For instance, the issue would arise whether a pipeline could give its own gas priority during periods of "pipeline shortages." If pipelines do have that right, then questions of whether a pipeline owns the gas produced by a subsidiary become important.

158. *See* NATURAL GAS REGULATION STUDY, *supra* note 28, at 160-61.

lesome as it would be beneficial for gas markets.[159]

Furthermore, the transition from utility to common carrier regulation would be extraordinarily complex. Commitments under present long-term gas purchase contracts would have to be limited or abrogated altogether—raising fifth amendment issues of taking property—in order to free available pipeline capacity. Procedures for obtaining access to existing pipeline capacity and for constructing new capacity would have to be devised and the question of divesting pipelines of producing properties requiring transportation through their lines would have to be considered closely.[160] The means by which the transition from utility to common carrier regulation is made must be carefully designed if gas markets are not to be thrown into complete confusion.

C. *Some Tentative Suggestions for Reform*

It would be naive to imagine that economic problems are ever solved as one would solve an equation or a puzzle. Moreover, it would be impossible within the confines of this Article to set forth a comprehensive solution to the disorder in the natural gas markets. Construing lengthy statutes on a daily basis produces a healthy skepticism about the possibility of working out the details of any major proposal in a few short pages. Moreover, the difficulty of obtaining data about gas markets and in making empirical determinations about conditions in them make any proposals other than the most general extremely hazardous. With these caveats in mind, it is suggested that deregulation of wellhead prices and a revision of FERC's role would be substantial progress towards rationality in the natural gas markets.

1. Deregulation of Wellhead Prices

A key cause of the disorder in the natural gas markets is the regulation of wellhead prices. As demonstrated previously in this Article, such regulation distorts market demand and is economically inefficient.[161] The dangers of a fly-up in natural gas prices upon decontrol, while not negligible, have lessened considerably over recent months.[162] Any danger of such a fly-up could be eliminated by legislation that would freeze natural gas prices and suspend the operation of indefinite

159. *See* 4 W. SUMMERS, *supra* note 152, at 321-25.
160. NATURAL GAS REGULATION STUDY, *supra* note 28, at 163.
161. *See supra* notes 109-11 and accompanying text.
162. *See supra* notes 104-08 and accompanying text.

price escalation clauses for a 90 or 120 day period pending market stabilization. Current market conditions would likely encourage a general reduction in prices that would be in the best interests of consumers while ensuring rationality in gas markets.

2. Pipeline Regulation

The time has come to rethink the fundamental premises underlying pipeline regulation. For some time, it has been evident that pipelines are not pure natural monopolies, largely because the alternative fuel capabilities of large industrial consumers effectively limit the prices which they can be charged. Moreover, the current regulatory scheme does little to encourage pipelines to acquire the least expensive supplies of gas. Accordingly, it may be time to consider whether pipelines should be deregulated altogether.

Such a course would afford pipelines the flexibility they will need in responding to the pricing instability that wellhead decontrol may bring. Pipeline deregulation would also remove artificial ceilings currently in effect on transportation fees, thereby encouraging pipelines to carry gas for producers without the necessity of implementing a complicated common carrier arrangement. Finally, deregulation would allow successful pipelines to reap the rewards of good service while punishing poorly managed pipelines for their improvidence.

There are dangers in such a course. Pipelines might avoid markets with a heavy residential load, since the cost of serving them would be too great when compared with the demand. Also, pipelines might subsidize industrial customers with low rates while charging their fixed costs to commercial and residential consumers, who lack alternative fuel capability.

A feasible solution to the problem might be to redefine FERC's role from rate-setter to referee. Pipelines could be allowed to charge what the market would bear for their services, provided that their rates were not unduly discriminatory and that they maintained service to their customers without curtailment. The details of such an arrangement would be most difficult to work out, yet the effort might be worthwhile.

V. Conclusion

It would be easy to conclude by restating the obvious: that the problems in the natural gas market are complex, that gas markets are inscrutable in their complexity, and that, even to the wisest, no clear-cut answers are available. Such observations are neither controversial nor satisfying, and would convey no sense of the importance of the crisis that is upon us or of how critical it is that some attempt be made to improve a situation that has impaired the welfare of millions, whether they were aware of it or not. This Article has attempted to state the problem and to outline some possible solutions. The important part—working out the provisions of a practicable solution—lies in the province of the statesman, not the scholar.