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GAS INVENTORY CHARGES: EVOLVING MECHANISMS FOR ALLOCATING THE RISKS AND RECOVERING THE COSTS OF MAINTAINING GAS SUPPLY

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I. INTRODUCTION

Historically, the allocation of risks and the recovery of costs associated with maintaining adequate natural gas supplies was governed by a series of parallel contractual relationships between producers, pipelines, and distributors. These basic contractual relationships remained relatively stable for many years. However, beginning in the late 1970s, a series of economic and regulatory developments undermined traditional contractual relationships. The industry experienced a period of severe market disorder which culminated in massive pipeline take-or-pay liability. The natural gas industry and the Federal Energy Regulatory Commission (Commission or FERC) have undertaken several actions to ameliorate the take-or-pay crisis and to reestablish a rational economic equilibrium with regard to gas supply responsibility. The development of gas inventory charges (GICs) is currently at the forefront of this effort.

This article first briefly reviews the events and circumstances that have given rise to the current situation relative to gas supply responsibility. Next, it sets forth certain general principles of GIC design, as propounded by the

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Commission and as developed in individual pipeline proposals. The article then addresses certain important issues and problems that remain to be resolved as the Commission and the industry continue their efforts to fashion a reasonable and workable GIC policy. Finally, the article offers some observations regarding the potential impact of GICs upon various segments of the industry.

II. Breakdown of Traditional Gas Supply Risk Allocation

A. *Historical Contractual Relationships Governing the Allocation of Gas Supply Costs and Risks*

Until very recently, the contractual relationships between natural gas producers, pipelines and local distributors generally followed a fixed pattern. Producers sold gas to pipelines under long-term contracts. The contracts specified that the producer would commit all production from identified wells or properties to the pipeline. The contracts further specified an initial fixed price for the gas and generally provided for escalation or redetermination of the price over time.

Pipelines undertook a commitment to pay for a specified amount of gas under these contracts, regardless of whether they actually took delivery of that amount.[1] This commitment became known as a take-or-pay obligation.[2] Generally, the take-or-pay obligation was stated as a percentage of the annual deliverability under the contract, as determined by testing. Pipeline take-or-pay obligations ranged from seventy to ninety-five percent of deliverability.[3]

Take-or-pay clauses compensated producers for the exclusive commitment of reserves to a particular gas sales contract. Take-or-pay clauses also served a risk allocation function. As the United States Court of Appeals for the Fifth Circuit stated:

> The purpose of take-or-pay clauses is to apportion the risks of natural gas production and sales between the buyer and seller. The seller bears the risks of production. To compensate seller for that risk, buyer agrees to take, or pay for if not taken, a minimum quantity of gas. The buyer bears the risk of market demand. The take-or-pay clause insures that if the demand for gas goes down, seller will still receive the price for the contract quantity delivered each year.[4]

Interstate pipelines sell gas to local distribution companies under pipeline tariffs[5] which generally establish two-part rates. The demand charge recovers a portion of the pipeline's fixed facility and operating costs and reflects the

1. The pipeline often retained the right to "make up" volumes of gas paid for but not taken during a specified period of time.

2. Some contracts required the pipeline to *both* take *and* pay for a specified quantity of gas. These contracts were known as take-or-pay contracts.

3. Statement of Policy, *Take or Pay Provisions in Gas Purchase Contracts,* [1982-1985 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,410, at 30,311 (1982); General Accounting Office, *Natural Gas Price Increases: A Preliminary Analysis,* GAO/RCED-83-76, Dec. 9, 1982, at 18-19.

4. Diamond Shamrock Exploration Co. v. Hodel, 853 F.2d 1159, 1167 (5th Cir. 1988) (quoting Universal Resources Corp. v. Panhandle E. Pipeline Co., 813 F.2d 77, 80 (5th Cir. 1987)).

5. Interstate pipeline tariffs are regulated by the Commission under the Natural Gas Act (NGA). 15 U.S.C. §§ 717-717w (1982 & Supp. V 1987).

contractual obligations of the pipeline and the distributor respectively to provide and pay for gas. The demand charge is paid each month regardless of the quantity of gas purchased during that month.[6] The commodity charge is assessed on each unit of gas sold and includes whatever fixed costs are not included in the demand charge, as well as the pipeline's variable costs, including all purchased gas costs.[7]

Until recently, most pipeline tariffs also incorporated a "minimum commodity bill" which required the customer to pay the full commodity charge for a specified percentage of its contract entitlement, regardless of whether the customer actually took that quantity of gas.[8] The minimum purchase obligation ranged from sixty-six and two thirds to ninety percent of the customer's specified contract entitlement. The pipeline, on the other hand, obligated itself to deliver the customer's full contract entitlement, absent an event of *force majeure.*[9]

Minimum commodity bills were intended, at least in part, to protect the pipeline and its other customers from take-or-pay exposure by discouraging partial requirements customers from "swinging" or purchasing gas from other sources, including less expensive sources.[10] Through the minimum commodity bill, the risk allocated to a pipeline under a take-or-pay contract was transferred, in part, to the pipeline's distributor customers. Until the early 1980s, however, the degree of risk associated with take-or-pay contracts was minimal because interstate pipelines were taking practically all of the gas they had contracted to buy.[11]

B. Economic Disorder in the Natural Gas Market

Beginning in the late 1970s, the natural gas market began to experience a period of disorder characterized by three interrelated problems. First, the price of natural gas increased sharply.[12] Second, the demand for natural gas

6. Panhandle E. Pipe Line Co. v. FERC, 890 F.2d 435, 437 (D.C. Cir. 1989). Order No. 380, *Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions,* [1982-1985 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,571, at 30,958 (1984) [hereinafter Order No. 380].

7. Order No. 380, *supra* note 6, at 30,958. Variable costs are those costs that vary depending on the volume of gas delivered through the pipeline. *Id.* at 30,977 n.3.

8. *Id.* at 30,958-59.

9. Notice of Proposed Rulemaking, *Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions,* [1982-1987 Proposed Regs.] F.E.R.C. Stats. & Regs. ¶ 32,334, at 32,668 (1983).

10. Order No. 380, *supra* note 6, at 30,960.

11. *Id.* at 30,969; *see also* Stanfield, *Paying for Nothing,* 19 NAT'L J. 812 (1987).

12. From 1978 to 1982, wellhead prices and prices for gas sold to consumers increased rapidly, largely in response to the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. §§ 3301-3432 (1982). *See* Notice of Proposed Rulemaking, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* [1982-1987 Proposed Regs.] F.E.R.C. Stats. & Regs. ¶ 32,408, at 33,105 (1985) [hereinafter *Transportation NOPR*] (establishing incentive maximum lawful prices for several categories of natural gas production). For the most part, pipelines were willing to pay the maximum lawful prices in new contracts in order to avoid a recurrence of the gas supply shortages of the 1970s. In addition, the Commission ruled that area rate clauses, common in many pre-NGPA contracts, provided contractual authority for producers to collect the applicable NGPA ceiling prices, including the escalation adjustment. Order No. 23, *Final Regulations Amending and Clarifying Regulations Under the Natural Gas Policy Act and the Natural Gas Act,* [1977-

softened considerably.[13] Third, a gas surplus developed.[14] This triad of market problems contributed to the accrual of substantial take-or-pay liability under producer-pipeline contracts.

C. *Commission Order No. 380*

At the time that the natural gas market was experiencing serious disorder, the Commission began to reconsider the regulatory structure supporting the traditional contractual relationships in the industry. In May 1984, the Commission adopted Order No. 380,[15] a rule which eliminated variable costs, including all purchased gas costs, from the minimum commodity charge portion of pipeline sales tariffs. The Commission grounded Order No. 380 on a finding that the use of minimum commodity bills to recover variable costs is anti-competitive and can result in unjust and unreasonable charges.[16]

With the elimination of pipeline minimum commodity bills, pipelines were deprived of an important mechanism for mitigating take-or-pay exposure. Pipelines retained both their take-or-pay obligations to producers and their obligations to supply their customers up to the level of the customers' contract entitlements. Pipelines' customers, however, no longer had any concomitant obligation to take or pay for any portion of their contract entitle-

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1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,040 (1979); Order No. 23-A, *Regulated Sales of Natural Gas; General Rules and Definitions*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,058 (1979), *aff'd in relevant part*, Pennzoil Co. v. FERC, 645 F.2d 260 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982); Order NO. 23-B, *Order Adopting Final Regulations Establishing Protest Procedures Regarding Blanket Affidavit Filings and Interim and Retroactive Collection Filings*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,065 (1979). Furthermore, so-called favored nations clauses, which tied the contract price to prices being paid under other contracts, acted to raise prices to NGPA ceiling levels.

13. The American Gas Association (AGA) reported that United States industrial gas demand declined an estimated fourteen percent in 1982, compared with an average annual decline of 1.1 percent during the period 1978-1981. AMERICAN GAS ASSOCIATION, HISTORICAL AND PROJECTED U.S. NATURAL GAS DEMAND FOR MINING MANUFACTURING AND AGRICULTURAL INDUSTRIES, at 1 (Feb. 4, 1983). The decline in industrial demand was attributed to the economic recession, which reduced output in most industries, energy conservation, and fuel switching from natural gas to other fuels owing to the availability of fuel oil at stable or declining prices at a time of rising gas prices. *Id.*; *see also* Notice of Proposed Rulemaking, *Elimination of Variable Costs from Natural Gas Pipeline Minimum Commodity Bills*, *supra* note 9, at 32,671. Overall, natural gas consumption declined from approximately 19.8 Tcf per year in the 1975-1980 period to 17.5 Tcf in 1984. *Transportation NOPR*, *supra* note 12, at 33,105 (citing U.S. ENERGY INFORMATION ADMINISTRATION, NATURAL GAS MONTHLY, at 12 n.5 (Table 3) (Feb. 1985 (DOE/EIA 0130) (85/02)).

14. The AGA estimated that there was between 1.9 and 2.7 Tcf of unused gas production capability in 1982, excluding 1 Tcf of Canadian gas under contract and not taken. AMERICAN GAS ASSOCIATION, NATURAL GAS PRODUCTION CAPABILITY 1982, (Dec. 24, 1982). The General Accounting Office estimated that supplies available for a normal winter in 1982-83 were about ten percent higher than actual supplies used in 1981-82 and about fifteen percent higher than a plausible projection of actual supplies to be used in 1982-83. GENERAL ACCOUNTING OFFICE, NATURAL GAS PRICE INCREASES: A PRELIMINARY ANALYSIS, at 27 (Dec. 9, 1982 (GAO/RCED-83-76)).

15. Order No. 380, *supra* note 6.

16. *Id.* at 30,958. The Commission expressed concern that the presence of variable costs in a minimum commodity bill might operate to recover costs that a pipeline is not actually incurring and might serve as a barrier to competition. *Id.* at 30,959.

ments.[17] The traditional allocation of the risk associated with maintaining gas supply, therefore, was tilted substantially in the pipelines' direction.

D. *Trend Toward Increased Transportation*

Additional pressure was brought to bear on the ability of pipelines to sell gas by the development of Commission policy favoring "unbundled" transportation service. Unbundled transportation permits producers, distributors and end users to enter into direct sales agreements, utilizing the pipeline solely as a transporter. These transactions can displace sales that would otherwise have been made by the transporting pipeline.

Prior to 1985, the Commission had established several regulatory programs of limited scope authorizing interstate transportation under both the NGA and the NGPA.[18] Under those programs, interstate pipeline transportation for others increased substantially.[19] Then, on October 9, 1985, the Com-

17. Pipeline customers, of course, did remain responsible for paying demand charges which were tied to the level of customer entitlements, as well as the fixed cost portion of minimum bills.

18. Order No. 27, *Certification of Pipeline Transportation for Certain High Priority Users*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,049 (1979) (codified at 18 C.F.R. pt. 157 subpt. E (§§ 157.100-157.105) (1987)) (facilitating interstate transportation to certain non-industrial end users including those using gas for essential agricultural users, or in schools, hospitals, or similar institutions); Order No. 30, *Transportation Certificates for Natural Gas for the Displacement of Fuel Oil*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,054, *amended on reh'g*, Order No. 30-A, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,084 (1979) (facilitating interstate transportation by both interstate and intrastate pipelines to individual end users under section 311 of the NGPA to displace fuel oil); Order No. 60, *Interstate Pipeline Transportation on Behalf of Other Interstate Pipelines*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,107 (1979) (adopting blanket certificate program allowing interstate pipelines to transport gas on behalf of other interstate pipelines on self implementing basis); Order No. 46, *Sales and Transportation of Natural Gas*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,081 (1979) (adopting permanent regulations authorizing transportation under NGPA section 311); Order No. 63, *Certain Transportation, Sales and Assignments by Pipeline Companies Not Subject to Commission Jurisdiction Under Section 1(c) of the Natural Gas Act*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,118 (1980) (permitting Hinshaw pipelines to transport gas in interstate commerce on the same terms and conditions applicable to intrastate pipelines under NGPA section 311); Order No. 52, *In the Matter of Fuel Oil Displacement by Process or Feedstock Users*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,088 (1979) (codified at 18 C.F.R. § 2.79(k)-(n) (1987)) (removing end use restrictions on transportation of gas for high priority customers and allowing them to have gas transported to displace fuel oil); Order No. 92, *Statement of Policy on Distributor Access to Outer Continental Shelf Gas*, [1977-1981 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,173 (1980) (outlined criteria for Commission authorization of transportation of natural gas produced from Outer Continental Shelf leases owned by distributors to their service areas); Order No. 319, *Sales and Transportation by Interstate Pipelines and Distributors*, [1982-1985 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,477 (1983), *reh'g granted in part and denied in part*, Order No. 319-A, 25 F.E.R.C. ¶ 61,194 (1983) (codified at 18 C.F.R. §§ 157.209 and 157.202(a)(13), (14) (1987)) (authorizing interstate pipeline transportation for various high priority end users); Order No. 234-B, *Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors*, [1982-1985 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,476 (1983) (codified at 18 C.F.R. § 157.209(e)) (designating all end users eligible for blanket certificate transportation for limited period ending June 30, 1985); Maryland People's Counsel v. FERC, 761 F.2d 780 (D.C. Cir. 1985) (vacating Order Nos. 234-B, 319 and 319-A to the extent that such orders permitted lower-priced transportation service to fuel-switchable end users without requiring pipelines to provide same service to LDCs and captive customers).

19. Interstate pipeline transportation on behalf of distributors and intrastate pipelines had increased from 74,000 Mcf in 1978 to approximately 1.6 Tcf in 1983. Notice of Inquiry, *Interstate Transportation of*

mission issued Order No. 436,[20] which implemented a blanket certificate transportation program under NGA section 7 and NGPA section 311, subject to the condition that pipelines offer such transportation on a non-discriminatory "open access" basis. Generally, Order No. 436 provided traditional pipeline sales customers much greater latitude to arrange for alternative sources of gas supply and to utilize pipelines as transporters. This reduced customer reliance on the pipelines' merchant function and placed new pressure on pipelines' ability to sell volumes of gas sufficient to avoid incurring take-or-pay liability under their producer contracts.[21]

E. *Accrual of Take-or-Pay Liability*

Pipeline take-or-pay exposure rapidly mounted in the 1980s. Although actual pipeline liability is difficult to determine, it is clear that total potential exposure assumed extraordinary levels. According to FERC Forms No. 2 filed by interstate pipelines, Account No. 165[22] balances, which reflect pipeline prepayments to producers, totaled approximately $1 billion as of December 31, 1983.[23] The Commission further acknowledged that, according to published industry trade association estimates, potential liability under take-or-pay provisions was substantially greater.[24]

In 1987, the Commission noted that pipeline Form 10-K and 10-Q filings with the Securities and Exchange Commission showed total potential take-or-pay liability of $2.88 billion at year-end 1984; $5.85 billion at year-end 1985;

Gas for Others, IV F.E.R.C. Stats. & Regs. ¶ 35,516, at 35,605 (1984) [hereinafter *Notice of Inquiry*] (citing U.S. ENERGY INFORMATION ADMINISTRATION, NATURAL GAS MONTHLY, at 40 (Sept. 1984 (DOE/EIA 0130 (84/08))). Moreover, volumes transported during the first nine months of Order Nos. 319 and 234-B exceeded 120 Bcf. *Notice of Inquiry*, at 35,605.

20. Order No. 436, Final Rule and Statement of Policy, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [1982-1985 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,665 (1985), *modified*, Order No. 436-A, [1982-1985 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,675 (1985), *modified further*, Order No. 436-B, F.E.R.C. Stats. & Regs. ¶ 30,688 (1986), *reh'g denied*, Order No. 436-C, 34 F.E.R.C. ¶ 61,404 (1986), *reh'g denied*, Order No. 436-D, 34 F.E.R.C. ¶ 61,405 (1986), *reconsideration denied*, Order No. 436-E, 34 F.E.R.C. ¶ 61,403 (1986), *vacated and remanded*, Associated Gas Distribs. v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 108 S. Ct. 1468 (1988).

21. The D.C. Circuit, on review of Order No. 436, specifically remanded to the Commission, for want of reasoned decisionmaking, its choice not to take any affirmative action to solve the problems posed by uneconomic pipeline-producer contracts. *See Associated Gas Distribs.*, 824 F.2d at 1030. The court required the Commission to address more convincingly the magnitude of the problem and the adverse consequences likely to result from non-discriminatory access and contract demand adjustment. *Id.* at 1044. The Commission purported to address the take-or-pay problem in Order No. 500. *See infra* notes 54-77 and accompanying text. The D.C. Circuit subsequently found that Order No. 500 failed to comply with the mandate in *Associated Gas Distributors* and remanded the record to the Commission, requiring the issuance, in 60 days, of a rule that satisfied the *Associated Gas Distributors* mandate. American Gas Ass'n v. FERC, 888 F.2d 136, 153 (D.C. Cir. 1989). The Commission subsequently issued Order No. 500-H, in response to the court's mandate. *See infra* note 27.

22. 18 C.F.R. § 201 (1989).

23. Statement of Policy and Interpretative Rule, *Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations*, [1982-1985 Regulations Preambles] F.E.R.C. Stats. & Regs. ¶ 30,637, at 31,301 (1985).

24. *Id.* (citing INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA, THE GAS CONTRACTS PROBLEM: RESULTS OF AN INGAA SURVEY (May, 1983); NATURAL GAS SUPPLY ASSOCIATION, ANALYSIS OF THE TAKE-OR-PAY PROBLEM, prepared by Foster Associates, Inc. (March, 1984)).

and $7.85 billion at September 30, 1986.[25] More recently, the former Chairman of the Commission stated that approximately $9 billion has been paid out by pipeline companies to buyout or buydown take-or-pay liability under producer contracts.[26] In its recent Order No. 500-H,[27] the Commission stated that responses to its 1987 take-or-pay data request indicate that pipelines had incurred take-or-pay exposure of $24 billion or more during the period 1983 through 1987, while making take-or-pay payments of approximately $700 million.[28]

F. Regulatory Responses to Take-or-Pay Problem

As take-or-pay liability mounted, the Commission adopted a series of regulatory initiatives designed to address the problem. In 1982, the Commission issued a Statement of Policy[29] regarding prepayments for gas pursuant to take-or-pay provisions in gas purchase contracts. The Commission found that high take-or-pay obligations could be expected to aggravate counter-market behavior by influencing pipelines to take and sell high cost gas while cutting back on purchases of lower cost gas.[30] Accordingly, the Commission established a rebuttable presumption in pipeline general rate cases that prepayments to producers will not be given rate base treatment if the prepayments are made pursuant to take-or-pay requirements which exceed seventy-five percent of annual deliverability.[31]

In 1985, the Commission issued a Statement of Policy[32] regarding the regulatory treatment to be accorded to payments made by pipelines to producers for the purpose of waiving or revising purchase obligations under natural gas sales contracts. The Commission determined that those expenditures are not purchased gas costs, nor do they constitute payments made for gas in a first sale for purposes of section 504(a) of the NGPA.[33] The Commission found that a pipeline making such non-recoupable "buyout" or "buydown" payments may file to recover them in any non-Purchased Gas Adjustment rate filing under section 4(e) of the NGA.[34] The Commission further held that issues relating to how the pipeline can recover such costs and how such costs should be allocated among customers would be addressed in the context of individual rate case filings.[35] Customers were accorded their full rights to

25. Notice of Issuance of Proposed Policy Statement and Opportunity for Public Comment, *Recovery of Take-or-Pay Buy-Out and Buy-Down Costs by Interstate Natural Gas Pipelines*, 38 F.E.R.C. ¶ 61,230, at 61,730 n.7 (1987).

26. Remarks of Chairman Martha Hesse before Institute of Gas Technology Conference, Arlington, Virginia (April 10, 1989).

27. Order No. 500-H, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, No. RM87-34-000 (F.E.R.C. issued December 13, 1989).

28. *Id.* slip op. at 24.

29. Statement of Policy, *Take-or-Pay Provisions in Gas Purchase Contracts, supra* note 3.

30. *Id.*

31. 18 C.F.R. § 2.103 (1987).

32. Statement of Policy and Interpretative Rule, *Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations, supra* note 23.

33. *Id.* at 31,300.

34. *Id.*

35. *Id.*

challenge the prudence of such costs and the apportionment of costs among customers.[36]

In 1987, the Commission issued a Proposed Policy Statement[37] designed to address the equitable allocation of pipeline take-or-pay buyout and buydown costs. The Commission stated two basic policy objectives for dealing with the take-or-pay problem: (1) to encourage pipelines and their customers to adjust contractual relationships so that pipelines can balance gas purchase obligations with future service obligations; and (2) to provide for the apportionment of costs associated with extinguishing accrued take-or-pay obligations and reforming or terminating current gas supply contracts to reflect the pipelines' future service obligations.[38]

The Commission observed that, in pipeline rate cases decided subsequent to its 1985 Policy Statement, it had required that take-or-pay buyout and buydown costs be recovered through pipeline commodity sales rates.[39] The Commission, however, recognized the pipelines' claim that they were unable to recover such costs in their commodity rates because inclusion in the rates rendered gas unmarketable vis-a-vis available lower cost alternative supplies.[40] While noting that recovery of take-or-pay costs through a pipeline's demand charge was inconsistent with the transmission of accurate price signals, the Commission found the accumulation of take-or-pay costs to be a function of the transition period toward market-based pricing mandated by the NGPA.[41] Accordingly, the Commission determined that where a pipeline agreed to absorb an equitable share of its take-or-pay buyout and buydown costs, the Commission would permit the pipeline to recover an equivalent share of these costs through its demand rates.[42]

In addressing the equitable apportionment of take-or-pay costs, the Commission found "no reasonable basis to ascribe culpability for the current take-or-pay problem solely to a particular segment of the industry."[43] Finding no basis for assigning a proportionately greater share of take-or-pay costs to pipelines or their customers, the Commission held, as a matter of judgment, that

36. *Id.* at 31,301.

37. Notice of Issuance of Proposed Policy Statement and Opportunity for Public Comment, *Recovery of Take-or-Pay Buy-Out and Buy-Down Costs by Interstate Natural Gas Pipelines, supra* note 25.

38. *Id.* at 61,726.

39. *See, e.g.,* Transcontinental Gas Pipe Line Corp., 37 F.E.R.C. ¶ 61,089 (1986), *reh'g granted in part and denied in part,* 40 F.E.R.C. ¶ 61,065 (1987), *reh'g denied,* 42 F.E.R.C. ¶ 61,354 (1988); Trunkline Gas Co., 37 F.E.R.C. ¶ 61,201 (1986), *aff'd,* 42 F.E.R.C. ¶ 61,201 (1988).

40. Notice of Issuance of Proposed Policy Statement and Opportunity for Public Comment, *Recovery of Take-or-Pay Buy-Out and Buy-Down Costs by Interstate Natural Gas Pipelines, supra* note 25, at 61,725.

41. *Id.*

42. *Id.*

43. *Id.* More specifically, the Commission stated its belief that "some pipelines unwisely and even imprudently entered into contracts incorporating both high prices and high take-or-pay levels." *Id.* On the other hand, the Commission opined that many pipeline purchases were based on the anticipated demands of customers and reflected terms that producers were able to obtain under prevailing market conditions. *Id.* at 61,727. Furthermore, the Commission observed that "[i]n many instances pipeline take-or-pay obligations mounted because of reduced purchases by their customers due to purchases from alternative suppliers, fuel switching by industrial users due to lower fuel oil prices, reduced levels of economic activity and conservation." *Id.*

the fifty-fifty cost sharing approach was reasonable in relation to the objective of providing a fair and equitable apportionment of costs.[44]

The Proposed Policy Statement established general principles to govern the allocation among customers of take-or-pay buyout and buydown costs to be recovered through demand surcharges. The Commission determined that a reasonable method of allocating such costs would be to base each customer's demand surcharge on its cumulative deficiency of purchases in recent years measured in relationship to that customer's purchases during a representative prior period during which take-or-pay liabilities were not incurred.[45] The Commission permitted pipelines to select a reasonable amortization period for buyout and buydown costs to be recovered through the demand surcharge and to collect carrying charges on unamortized amounts.[46]

In June 1987, the Commission issued Order No. 500,[47] which attempted to respond to the concerns expressed by the United States Court of Appeals for the D.C. Circuit when the court vacated Order No. 436 for failure to adequately address pipeline take-or-pay problems.[48] Order No. 500 implemented three interrelated regulatory initiatives designed to mitigate the effects of open access transportation on pipeline take-or-pay problems and to provide relief from take-or-pay problems not related to, or aggravated by, the Commission's transportation regulations.[49]

First, Order No. 500 instituted a crediting mechanism intended to permit pipelines to reduce the incurrence of take-or-pay liability caused by open access transportation. Order No. 500 required a producer seeking to have gas transported under those regulations to offer credits against the transporting pipeline's take-or-pay liability.[50] The crediting mechanism treated volumes of gas transported as though they were volumes of the producer's gas purchased by the pipeline under pre-June 23, 1987 take-or-pay contracts, with certain exceptions. Pipelines were permitted to apply the credits as though the

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44. *Id.*

45. *Id.*

46. *Id.* The Commission also attempted to avoid lengthy hearings regarding the ascribing of blame for take-or-pay liability by establishing a presumption of prudence. The Commission stated that a pipeline's agreement to assume an equitable share of take-or-pay costs would be sufficient to take account of any imprudence on the part of the pipeline. *Id.* at 61,728. The Commission stated that it would examine the issue of prudence if raised by a party, but added its belief that "the sharing of responsibility for take-or-pay costs provided for under the policy statement will make a showing of further imprudence difficult." *Id.*

47. Order No. 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, III F.E.R.C. Stats. & Regs. ¶ 30,761 (1987) [hereinafter Order No. 500]; Order No. 500-A, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, III FERC Stats. & Regs. ¶ 30,770, *modified in part*, Order No. 500-B, III F.E.R.C. Stats. & Regs. ¶ 30,772 (1987), *modified further*, III F.E.R.C. Stats. & Regs. ¶ 30,786 (1987), *modified further*, III F.E.R.C. Stats. & Regs. ¶ 30,800 (1988), *modified further*, Order No. 500-F, III F.E.R.C. ¶ 30,841 (1988), *remanded*, *American Gas Ass'n*, 888 F.2d 136 (D.C. Cir. 1989), *order on remand*, Order No. 500-H, No. RM87-34-000 (issued Dec. 13, 1989).

48. Associated Gas Distribs. v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 108 S. Ct. 1468 (1988).

49. Order No. 500 *supra* note 47, at 30,779. In Order No. 500, the Commission declined to exercise its powers under NGA section 5 to modify or abrogate take-or-pay provisions in producer-pipeline contracts. *Id.* at 30,784. In Order No. 500-H, the Commission again declined to exercise its section 5 powers.

50. *Id.* at 30,779-84 (codified at 18 C.F.R. §§ 284.8(f), 284.9(f) (1987)).

volumes were purchased in the contract year in which the gas was transported, or in any previous year commencing on or after January 1, 1986, in which the pipeline transported gas under the open access regulations.[51]

Second, the Commission adopted certain pass-through mechanisms that pipelines could use to recover take-or-pay buyout or buydown costs under existing contracts.[52] The basic mechanism, available to all pipelines, permitted the recovery of all take-or-pay costs in pipeline sales commodity charges. For pipelines agreeing to provide open access transportation, the Commission reaffirmed its position that there should be an equitable sharing of take-or-pay costs among all segments of the industry.[53] Recognizing that the fifty-fifty split required by the Proposed Policy Statement might not provide sufficient flexibility, the Commission gave pipelines the discretion to assume anywhere from twenty-five to fifty percent of their take-or-pay buyout and buydown costs and to recoup, through a fixed charge, an equivalent amount. The Commission also allowed pipelines to seek to recover any amounts not absorbed or assigned to a fixed charge, at their option, through a sales commodity rate surcharge or a volumetric surcharge on total pipeline throughput.[54]

The equitable sharing mechanism of Order No. 500 was not intended to be a permanent solution to the problem of allocating the costs associated with maintaining gas inventories.[55] The device allowed "costs [to] be charged to customers who did nothing to cause the problem."[56] Moreover, under the equitable sharing mechanism, charges were passed through to customers long after purchasing decisions were made.[57] Customers were, therefore, unable to consider their liability for gas supply charges as a factor in choosing among various supply alternatives at the time these decisions were made.[58] It is the third Order No. 500 initiative—the gas inventory charge—that is designed to

51. Order No. 500-H terminates the take-or-pay crediting mechanism as of December 31, 1990. Order No. 500-H also terminates, effective December 13, 1989, the exemption from the application of take-or-pay credits established in Order No. 500 for casinghead gas.

52. *See* Order No. 500, *supra* note 47, at 30,784-92 (codified at 18 C.F.R. § 2.104 (1987)).

53. *Id.* at 30,786.

54. *Id.* at 30,787. In Order No. 500, the Commission continued its effort to discourage litigation of prudence relative to pipeline take-or-pay costs. The Commission restated the presumption of prudence applicable to claimed take-or-pay costs, where a pipeline agrees to absorb a portion of such costs. *Id.* If challenged, the pipeline must demonstrate the prudence of incurring those costs. In the absence of a challenge, the costs will be deemed prudent. *Id.* at 30,788. The Commission indicated that it would approve contested settlements regarding pipeline recovery of take-or-pay buyout/buydown costs, either as to all consenting parties, or on their merits if supported by substantial evidence. *Id.* Moreover, the Commission stated that, where hearings are held, pipelines will be permitted to seek to recover from litigating parties their proportionate shares of all take-or-pay costs found to be prudent, "even if the amount allowed is greater than the amounts originally claimed by the pipeline." *Id.*

55. In Order No. 500-C, the Commission set a deadline of December 31, 1988 for pipeline filings to recover take-or-pay buyout and buydown costs. Order No. 500-C, III F.E.R.C. Stats. & Regs. ¶ 30,786, at 30,962 (1987). In Order No. 500-F, the commission extended that "sunset" date until March 31, 1989. Order No. 500-F, III F.E.R.C. Stats. & Regs. ¶ 30,841, at 31,268 (1988). On remand from the D.C. Circuit, the Commission, in Order No. 500-H, extended the sunset date until December 31, 1990.

56. Order No. 500, *supra* note 47, at 30,793.

57. *Id.*

58. *Id.*

establish a more rational, forward-looking approach to gas supply responsibility.

III. Forward Looking Gas Supply Risk and Cost Allocation Mechanisms Under Order No. 500

In Order No. 500, the Commission outlined mechanisms which would permit pipelines to allocate the risks and costs associated with maintaining gas inventory to those customers actually deriving benefit from the maintenance of that inventory. At the same time, the Commission proposed not to restrict unduly the operation of the gas commodity market:

> The Commission is aware of a need for transition between the operation of the take-or-pay buyout or buydown passthrough policies (which deal with *past* take-or-pay costs and uneconomic contracts) . . . and the principles embodied in the new rate design which is intended to be forward-looking, and deal with *future* take-or-pay costs. The new rate design is intended as a future-looking mechanism to recover the costs of contractually committing gas service that has been tailored to meet the customer's nominations whenever fewer than nominated volumes (or a reasonable percentage of nominated volumes) are taken by a customer, who is fully aware that such charges would be *currently* assessed on a monthly basis, based on its own service nomination. In brief, the Commission is seeking to establish a rational, efficient pricing structure for the pipeline merchant function with emphasis on reciprocity and consideration of service obligations under the increased options available to a pipeline's sales customers.[59]

Order No. 500 promulgated specific principles of rate design intended to achieve the Commission's stated policy objectives:

> (1) An interstate natural gas pipeline that transports under Part 284 of the Commission's regulations may include in its tariff a charge, not related to facilities, for standing ready to supply gas to sales customers.
>
> (2) The pipeline may not recover take-or-pay or similar charges from suppliers by any other means.
>
> (3) The pipeline must allow its sales customers to nominate levels of service freely within their firm sales entitlements or otherwise employ a mechanism for the renegotiation of levels of service at regular intervals.
>
> (4) The pipeline must announce prior to nominations by the customers a firm price or pricing formula for the service, and hold that price or pricing formula firm during the interval arranged in number (3) above.
>
> (5) By nominating new levels of service lower than its current level, a customer would be consenting to any abandonment sought by the pipeline commensurate with the difference between the current level of service and the nominated level.[60]

These rate design principles were intended to compensate pipelines, on a current basis, for contracting for gas supply to meet customers' requirements.[61] The principles allocate risks associated with maintaining gas inventory between purchasers and suppliers. The Commission apparently intended

59. *Id.* at 30,793-94 (emphasis in original).
60. *Id.* at 30,792.
61. *Id.* at 30,793.

to assign short-term market risks to pipelines while apportioning certain long-term risks to pipeline customers.

Subparagraphs (a) through (c) serve to protect the integrity of the decision-making process by which customers choose among supply alternatives in the short-term gas market,[62] and shift much of the risk of short-term market fluctuations to pipelines. The pipeline assumes the risk associated with maintaining gas inventory during each nomination cycle. If the pipeline nominates too low a price for the period during which nominations will apply or misestimates customer demand, it will be required to absorb any unrecovered costs.

Subparagraph (d) is apparently intended to be the *quid pro quo* for the pipeline's assumption of short-term market risks. Because it allows the pipeline to abandon firm sales down to a lower renominated level, the pipeline may shed supplies to bring supply and demand on its system into balance.[63] Much of the risk associated with maintaining supplies on a long-term basis is, therefore, shifted to the pipeline's customers.[64] To the extent that a customer leaves the pipeline system for an alternate supply source, the pipeline is relieved of its duty to supply that customer. The onus is placed on customers to decide the appropriate level of gas supply inventory that the pipeline should maintain on their behalf.

On a more specific level, Order No. 500 described two types of GIC mechanisms which employ the stated principles. The first mechanism is the "forward supply service charge."[65] A pipeline implementing this rate design commits itself to sell specific quantities of gas at a posted price for some period in the future. The buyer nominates purchase volumes on the terms offered by the pipeline up to its firm sales entitlement. The buyer's obligation is reciprocal to that of the supplier: a firm obligation to purchase the nominated volume level at the full posted price. The mechanism may also include make-up rights whereby a purchaser would be entitled to take delivery of volumes paid for but not taken in a past period. Under this arrangement, the pipeline assumes the risk of a price rise by its underlying supply sources during the

62. Specifically, the rate design requirements of subparagraph (a) assure that a customer who has made an economic purchase decision based on a pipeline's current charges will not have unanticipated additional costs associated with gas supply responsibility assigned to it in the future. Subparagraph (b) is designed to protect pipeline customers from being assigned gas supply cost responsibility based on outdated requirements for pipeline sales service or from being locked into long-term contractual arrangements which would restrict their ability to purchase gas elsewhere. Subparagraph (c) ensures that the pipeline's charges will be known before a purchasing decision is made.

63. This assumes that the pipeline has a contractual right to terminate its supply contracts or that such contracts are expiring. Of course, the pipeline can also buy out a firm sales or take-or-pay contract. Pipelines may find it more difficult, however, to obtain producers' agreement to cents-on-the-dollar settlements than was previously the case. Past settlements were premised, at least in part, on producers' perceptions that pipelines would be limited in their abilities to recover accrued take-or-pay liability from their downstream customers due to the Commission's policies. The fact that a pipeline will now have in place a GIC which is designed specifically to recover such costs may be a disincentive to the producer to settle for less than the full value of its contract rights.

64. Note that not all the risk is shifted. The pipeline must still maintain sufficient deliverability to meet its customer's nominated levels.

65. Order No. 500, *supra* note 47, at 30,802.

forward supply period. Should it be unable to recover its gas inventory costs through the posted price, it would have to absorb them.

The second mechanism described in Order No. 500 is the "option service charge."[66] A pipeline implementing a charge of this nature would collect a two-part rate: a gas inventory or reservation charge and a gas commodity charge. The first part of the rate operates as an option to purchase gas at a specific price during a specified period. This rate component must be paid on all volumes of gas nominated for firm sales service. The second part of the rate, the gas commodity charge, is incurred only if the customer exercises the option. The commodity charge should start to converge with the monthly spot market price at the date of delivery.

The pipeline must propose the amount of the reservation charge and the maximum gas commodity charge in advance of the customer's nominations. The pipeline again assumes the risks of a rising gas market price because it cannot adjust the commodity price to a level in excess of the stated maximum amount.[67]

IV. Implementation of Order No. 500 GIC Policy

Subsequent to the issuance of Order No. 500, a number of pipelines filed with the Commission for authorization to implement GICs. Other GIC proposals have been presented to the Commission in the form of settlements. Most pipeline proposals have varied to some extent from the guidelines set forth in Order No. 500. The GICs proposed can be categorized loosely as either "deficiency-based" or "market-based."

A. Deficiency-Based GICs

One basic form of GIC which varies greatly from the Order No. 500 guidelines is the so-called deficiency-based GIC.[68] Generally, deficiency-based GICs require customers to nominate a gas supply entitlement covering a fixed period. The nominated amount constitutes the limit of the pipeline's gas supply obligation to the customer and the pipeline may abandon its service obligation down to the nominated level of service. GIC charges are then assessed on any deficiency that a customer fails to purchase below a certain threshold percentage of its nominated entitlement.[69]

The GIC unit charge may be a percentage of the pipeline's weighted average cost of gas (WACOG) or some other more arbitrary amount. The charge is intended to cover all of the pipeline's gas inventory costs, which may include: take-or-pay costs, take-or-pay buyout or buydown costs, contract reformation or termination costs, nonrecoupable prepayments, upstream pipeline

66. *Id.* at 30,803.

67. The pipeline may, however, propose the duration of the period for which it will be bound.

68. *See, e.g.,* Columbia Gas Transmission Corp., 49 F.E.R.C. ¶ 61,071 (1989); Northwest Pipeline Corp., 46 F.E.R.C. ¶ 63,006 (1989); Texas E. Transmission Corp., 44 F.E.R.C. ¶ 61,413 (1988), *reh'g denied*, 47 F.E.R.C. ¶ 61,100 (1989); Transwestern Pipeline Co., 43 F.E.R.C. ¶ 61,240, *reh'g denied*, 44 F.E.R.C. ¶ 61,164 (1988).

69. Customers may also be required to take a certain percentage of their nomination in the summer months or incur an additional deficiency. *Columbia*, 49 F.E.R.C. at 61,280.

GIC charges,[70] the value of transportation rate discounts given in lieu of inventory costs, carrying charges on take-or-pay prepayments, and royalty indemnification payments.[71]

Generally, GIC charges are retained by the pipeline for a period of years and may be applied to inventory costs incurred during that period.[72] Typically, any GIC revenues retained after the specified period are returned through a "true-up" mechanism whereby overcollected GIC revenues, including reserved and purchased gas costs, are returned to customers after a period of time.[73]

B. *Market-Based GICs*

Other GICs have been proposed which would permit a pipeline to recover from its customers, on a current basis, the costs associated with maintaining gas supply. These proposals involve demand GIC charges, commodity GIC charges or some combination of the two.[74] Generally, these GICs bear a relationship to spot market gas prices, plus some additional charge to reflect the cost of holding gas in inventory.

A demand-type GIC charge may simply take the pipeline's forecasted or estimated inventory charges over a fixed period and recover those costs from customers each month, based on each customer's inventory billing determinants. Daily firm contract demand, total annual entitlements or some other nominated level may be utilized to establish customer inventory determinants.

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70. See *infra* notes 165-172 and accompanying text for a discussion of the recovery of upstream pipeline GIC charges.

71. *See Columbia*, 49 F.E.R.C. at 61,280.

72. Columbia's GIC also contains a "Comparability Test" whereunder the pipeline forfeits its right to collect any GIC revenues otherwise due for any contract year (November through October) in which Columbia's "Comparability Test Gas Cost" exceeds a "Comparable Average" derived from the Comparability Test Gas Costs of selected competing pipelines. The Comparability Test Gas Costs of Columbia and the selected pipelines take into account: the gas cost component of the pipelines' commodity rates, certain producer demand charges, pipeline demand GIC charges, upstream pipeline demand GIC charges flowed through on an as-billed basis, Account No. 191 direct billings, and deficiency-based upstream pipeline GIC charges flowed through on a demand basis. *Id.*

73. Deficiency-based GICs to a certain extent reallocate the assignment of risks contemplated under Order No. 500. Under Order No. 500, customers were to make their long-term supply decisions at the beginning of a nominations period. During the nominations period, Order No. 500 contemplates the customer will choose freely between the gas reserved from the pipeline and alternate supplies available from sources such as the spot market. The deficiency mechanism deviates from this scheme by creating a second decisional point. At this point the customer must decide whether to incur the GIC since the GIC may be avoided entirely by always purchasing at or above the deficiency level. In effect, the decision whether to incur the premium associated with maintaining long-term supply, *i.e.* the GIC, is shifted into the current market when the customer runs the risk of falling below the threshold. The apparent trade-off for the customer's assumption of this additional short-term market risk is the pipeline's assumption of the entire risk and cost of maintaining gas inventory on a long-term basis for customer purchases above the threshold level. In contrast, the forward supply GICs and option GICs discussed in Order No. 500 assign less market risk to the pipeline at the same customer purchase levels since the GIC amount under those mechanisms is assessed on *all* of the customers' nominated volumes.

74. *See, e.g.*, National Fuel Gas Supply Corp., 49 F.E.R.C. ¶ 61,011 (1989); Natural Gas Pipeline Co., 49 F.E.R.C. ¶ 61,137 (1989); Northern Natural Gas Co., 49 F.E.R.C. ¶ 61,027 (1989); Tennessee Gas Pipeline Co., 47 F.E.R.C. ¶ 61,245 (1989); El Paso Natural Gas Co., 48 F.E.R.C. ¶ 61,202 (1989); Transcontinental Gas Pipe Line Corp., 48 F.E.R.C. ¶ 61,399 (1989).

Alternatively, the GIC charge could directly reflect some percentage of the spot market price of gas, to be recovered over nominated determinants.

Generally, before a demand GIC takes effect, the GIC charge is made known and customers have the right to freely nominate whatever determinants are being used to assess GIC charge responsibility. Pipelines, however, may seek to impose some limit on the degree to which aggregate customer entitlements may be reduced as a result of these nominations.[75] Moreover, there is generally some right to adjust nomination levels, within limits, at reasonable intervals or if the pipeline modifies the pricing formula.

A demand GIC charge is frequently coupled with a commodity charge derived from some approximation of the price of gas to the pipeline in the spot market. Often, this market-based commodity charge substitutes for the pipeline's purchased gas adjustment mechanism. Additionally, a demand GIC may feature a reconciliation or true-up provision.

A commodity-type GIC may seek to recover inventory costs through a premium over spot market price levels charged on each unit of gas actually purchased. The commodity charge may be coupled with charges tied to a customer's reservation of the right to nominate certain volumes, and charges tied to volumes actually nominated for purchase.

V. Problem Areas in the Development of GIC Policy

Important practical, legal and policy issues have arisen in the development and implementation of GIC policy. These issues reflect the difficulty inherent in fashioning a mechanism which fundamentally restructures existing business relationships.

A. *The Need for Rapid Implementation of GICs*

Although pipelines are currently incurring inventory costs, including take-or-pay related courts, few GICs have been placed in operation to date. There is widespread agreement that GICs must be implemented quickly in order to avoid a second wave of take-or-pay liability and to permit pipelines and customers to engage in rational gas supply planning. Several issues arise out of this need for the expeditious implementation of GICs.

1. The Debate Regarding Implementation Under NGA Section 4 or Section 7

One of the more fundamental legal issues relative to the implementation of GICs is whether such proposals should be filed and processed under section 4 or section 7 of the NGA. Whether GIC proposals are processed under section 4 or section 7 determines the speed with which a pipeline may place a GIC into effect. In view of the recognized need for GICs to become operational as quickly as possible, this issue has assumed vital significance.

When a pipeline proceeds under section 4(e) of the NGA,[76] the GIC

75. *See, e.g.,* Transcontinental Gas Pipe Line Corp., 46 F.E.R.C. ¶ 61,364, at 62,133-34 (1989).
76. 15 U.S.C. § 717c(e) (1988).

becomes effective, subject to refund, after the expiration of the maximum five month suspension period.[77] Thus, a pipeline is able to quickly put a GIC proposal into place, pending the outcome of a hearing to determine the justness and reasonableness of the GIC. By contrast, if characterized as a certificate filing under NGA section 7(c),[78] a proposed GIC may only become effective prospectively after the Commission holds a hearing and formally approves the proposal.[79] Consequently, under section 7(c), a pipeline foregoes the benefit of collecting GIC charges prior to Commission approval of its proposal.

Initially, pipelines utilized the former approach, and GIC proposals were submitted as rate and tariff change filings under section 4(e).[80] In reviewing these proposals, however, the Commission asserted that because GIC proposals may fundamentally and irreparably alter service and supply arrangements between pipelines and customers, they constitute "a change in service that should be handled as an application for a certificate amendment under section 7(c) of the NGA rather than as a rate and tariff change under section 4(e) of the Act."[81]

The Commission has conceded that the dividing line between a change in service that can be effected through the section 4(e) suspension procedure and a change in service that requires prior authorization under section 7(c) "is not

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77. Section 4(e) provides in pertinent part:

> Whenever any . . . new [rate] schedule is filed the Commission shall have authority . . . to enter upon a hearing concerning the lawfulness of such rate . . . and, pending such hearing and the decision thereon, the Commission . . . may suspend the operation of such schedule . . . but not for a longer period than five months beyond the time when it would otherwise go into effect . . . . If the proceeding has not been concluded and an order made at the expiration of the suspension period, on motion of the natural-gas company making the filing, the proposed change of rate . . . or service shall go into effect.

78. 15 U.S.C. § 717f(c) (1988).

79. It should be noted, however, that the hearing required for Commission approval of a GIC under section 7 need not be an extensive, trial-type hearing as contemplated by the Administrative Procedure Act. The Commission has established so-called "paper hearings" in numerous proceedings to address the issue whether a pipeline's market is sufficiently competitive to justify implementing a GIC. *See* Natural Gas Pipeline Co., F.E.R.C. No. CP89-1281-000 (Nov. 1, 1989) at 5-6; Southern Natural Gas Co., F.E.R.C. No. CP89-1721-000 (Nov. 1, 1989) at 6-7; El Paso Natural Gas Co., 47 F.E.R.C. ¶ 61,108, at 61,306, *reh'g denied*, 48 F.E.R.C. ¶ 61,202 (1989); Transcontinental Gas Pipe Line Corp., 46 F.E.R.C. ¶ 61,364, at 62,135, *reh'g granted in part and denied in part*, 47 F.E.R.C. ¶ 61,244, *reh'g denied*, 48 F.E.R.C. ¶ 61,199 (1989); Tennessee Gas Pipeline Co., 47 F.E.R.C. ¶ 61,245, at 61,855, *reh'g denied*, 48 F.E.R.C. ¶ 61,198 (1989) [hereinafter *Paper Hearings Proceedings*]. Under the paper hearing format, the pipeline submits pertinent information in written form and other interested parties are then given the opportunity to respond in writing within 30 days. *See, e.g., El Paso*, 47 F.E.R.C. at 61,306. Moreover, in the absence of opposition to a proposal, the Commission could conduct a pro forma hearing on the application, without invoking any formal proceedings.

80. *See, e.g.,* El Paso Natural Gas Co., 42 F.E.R.C. ¶ 61,092 (1988); Texas E. Transmission Corp., 41 F.E.R.C. ¶ 61,373 (1987); Transwestern Pipeline Co., 41 F.E.R.C. ¶ 61,371 (1987); Natural Gas Pipeline Co., 41 F.E.R.C. ¶ 61,119 (1987).

81. *Natural Gas Pipeline Co.*, 41 F.E.R.C. at 61,972. *See also* El Paso Natural Gas Co., 43 F.E.R.C. ¶ 61,327, at 61,913 (1988); Natural Gas Pipeline Co., 43 F.E.R.C. ¶ 61,068, at 61,214 (1988); Transwestern Pipeline Co., 42 F.E.R.C. ¶ 61,370, at 62,083 (1988); Texas E. Transmission Corp., 41 F.E.R.C. ¶ 61,373, at 62,018-19 (1987).

always clearly defined."[82] To bolster its choice of the section 7(c) approach, the Commission expressed that if a customer nominates a gas supply entitlement under the GIC mechanism which is less than its contract demand level, the pipeline is authorized to abandon its firm obligation to supply the customer above such nominated level.[83] To the extent that the customer's demand may subsequently exceed its nominated level, the customer will likely buy the additional quantities elsewhere. Thus, the pipeline's abandonment of its sales obligation and the customer's concomitant purchases from other suppliers combine to effectuate a significant change in the pipeline-customer service relationship thereby meriting section 7(c) treatment.[84]

Following the Commission's transformation of pipelines' section 4(e) GIC proposals into section 7(c) applications, several pipelines sought to circumvent the Commission's decision either by filing new GIC proposals purportedly not requiring abandonment or by arguing on rehearing that abandonment was not required within the context of their particular GIC proposal. According to the pipelines, the absence of an abandonment feature rendered section 7(c) treatment unnecessary.[85]

The Commission, however, rejected the pipelines' contentions for two reasons. First, the Commission declined to elevate form over substance, preferring to examine the effect of a pipeline's GIC on its customers rather than the specific wording of a particular GIC proposal.[86] Second, the Commission found Order No. 500 to mandate that a properly structured GIC have an abandonment feature.[87]

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82. *Natural Gas Pipeline Co.*, 43 F.E.R.C. at 61,214.

83. *Id.* at 61,212-13.

84. *Id.* It should be noted that if the pipeline's abandonment took place within the context of a section 4(e) proceeding, and the Commission thereafter found a pipeline's GIC deficient under NGA standards, it would be difficult to return the customer to the position it would have occupied had the GIC not been implemented. Thus, the traditional section 4(e) refund remedy would not be adequate in this circumstance. *See Natural Gas Pipeline Co.*, 41 F.E.R.C. at 61,973 (lack of effective refund remedy and fact pattern's resemblance to situations such as the institution of sales incentive programs, discount sales programs and seasonal service rates where certificate amendment was required, dictated proceeding under section 7(c) rather than section 4(e)).

85. *See, e.g., El Paso Natural Gas Co.*, 43 F.E.R.C. at 61,913 (El Paso stating that its GIC proposal, in and of itself, did not reduce or otherwise alter El Paso's existing sales obligation); *Natural Gas Pipeline Co.*, 43 F.E.R.C. at 61,212 (Natural withdrawing its original GIC (inventory holding charge (IHC)) and instead filing and proposing a gas supply charge "not result[ing] in abandonment of service"); *Transwestern Pipeline Co.*, 42 F.E.R.C. at 62,083 (Transwestern arguing that implementation of GIC would in no way result in abandonment of certificated services).

86. *Transwestern Pipeline Co.*, 42 F.E.R.C. at 62,083. *See also Natural Gas Pipeline Co.*, 43 F.E.R.C. at 61,212 ("[F]irst, and most generally, the Commission is vested with discretion to docket and schedule matters before it, notwithstanding an applicant's differing view of how it would prefer the matter to be docketed and treated.").

87. *See Natural Gas Pipeline Co.*, 43 F.E.R.C. at 61,212-13, where the Commission stated:

> [S]ection 2.105(d) promulgated by Order No. 500 states as a required principle of any gas supply charge that by nominating a new level of service lower than its current level, a customer has consented to any abandonment sought by the pipeline commensurate with the difference between the current level of service and the nominated level. The Commission reiterates that this customer consent to abandonment is a significant aspect of Natural's [GIC] proposal, and of any properly structured gas inventory charge under the Order No. 500 principles . . . . The ability to obtain abandonment is integral to implementation of a gas inventory charge, since bringing a pipeline's

Subsequently, however, the Commission has cast some doubt on whether it will continue to insist that GICs be processed under section 7. A Notice of Proposed Policy Statement regarding interim GICs,[88] issued May 30, 1989, suggests that the goal of expediency may have assumed primary importance and that the Commission may be reevaluating its position regarding the processing of GIC proposals. The Commission emphasized that "it is in the public interest for interstate gas pipelines to implement GIC mechanisms as soon as possible in order to prevent reoccurrence of the take-or-pay problems of the past."[89] The Commission expressly noted the possibility of a return to section 4 review.[90]

Additionally, Commissioner Trabandt, in a concurring opinion, placed blame for the delay in GIC implementation squarely on the FERC's "lamentable decision" to shift from section 4 ratemaking to section 7 certification procedures.[91] Trabandt added that the lack of the section 4 five-month suspension procedure has created turmoil. Procedural opportunities for expediting the processing of GICs, including a return to the section 4 approach, should appropriately be viewed as a supplement, if not a complete alternative, to interim GICs.[92] Thus, it is possible that the Commission's heightened concern with the need for more rapid implementation of GICs may precipitate a return to the use of section 4 in processing GIC proposals.

> service obligations in line with its customers' requests for service is at the heart of any future gas supply charge filing under § 2.105.

Id.

88. Notice of Proposed Policy Statement, *Interim Gas Supply Charges and Interim Gas Inventory Charges*, 47 F.E.R.C. ¶ 61,294 (1989) [hereinafter *Proposed Policy Statement*]. *See infra* notes 93-102 and accompanying text for discussion of the Proposed Policy Statement.

89. *Id.* at 62,027. The Commission stated that its intent:

> is to avoid the reoccurrence of significant amounts of unfunded pipeline take-or-pay costs. A pipeline must maintain adequate gas supplies to meet its entire service obligation. The Commission recognizes that if a mechanism does not exist to compensate a pipeline for maintaining these gas supplies, it will have a negative impact on the ability of the pipeline to serve as merchant. For this reason, the Commission recognizes that action is needed in the near term to allow pipelines to put in place an interim GIC.

Id.

90. The Commission stated:

> On[e] alternative to the two methods proposed in this Notice would be to allow any pipeline to file tariffs immediately, pursuant to Section 4 of the Natural Gas Act, to implement an interim GIC of 35 cents per MMBTU, for deficiencies below 80% of the volumes nominated, subject to refund. The amounts paid would be added to the PGA. The case would go to hearing on an expedited basis to determine the just and reasonable rate for a permanent GIC. Would this method work? Would it be preferable to the other two methods? Would consumers be protected under this proposal?

Id. at 62,036.

91. *Id.* at 62,042.

92. *Id.* Trabandt's sentiments have been echoed by the president of the Interstate Natural Gas Association of America, who, in a letter to former Commission Chairman Martha Hesse, advocated the use of section 4 filings so that pipeline customers are protected by refund provisions while pipelines are permitted to send appropriate price signals to the market without undue delay. Letter from Jerald V. Halvorsen to Martha Hesse (April 19, 1989). *See also* FOSTER NAT. GAS REP. NO. 1733, at 2 (July 27, 1989) (in public comments to Proposed Policy Statement, pipeline interests arguing that interim, as well as permanent, GICs should be implemented using section 4 procedures, subject to refund).

The Commission, however, should avoid the temptation to utilize section 4(e) procedures. Once a GIC is placed in operation and a pipeline abandons customer entitlements below freely nominated levels, a return to the status quo after a hearing may be a practical impossibility. There is no guarantee that the pipeline will be able to reacquire supplies adequate to serve reinstated entitlements or that supplies may be reacquired on equally favorable terms. Moreover, abandonment and the shedding of gas supply which might have to be reacquired will send inaccurate signals to producers. On the other hand, if a pipeline maintains supply pending the outcome of its GIC hearing, while customers are paying GIC charges based on lower nominated entitlements, the pipeline may be forced to absorb substantial take-or-pay costs. The "subject to refund" condition of section 4(e) simply provides inadequate protection in the context of a GIC proceeding. Accordingly, the Commission should continue to review GICs under section 7(c) and apply all available resources to permit their implementation as quickly as possible.

2. The Interim GIC Strategy

When the Commission issued its Proposed Policy Statement, the interim GIC suddenly emerged as a high-profile, quick-fix strategy designed to combat the delay that has characterized the implementation of GICs. In fact, however, many of the same criticisms and difficulties that have plagued permanent GICs have also attended the processing of interim GICs. Moreover, the Commission has not yet issued a final policy statement regarding interim GICs. Nor has it shown an inclination to act quickly to approve interim GICs.

The Commission proposed the interim GIC mechanism as a stop-gap measure intended to effectuate a smooth transition between the equitable sharing direct billing mechanism of Order No. 500 and the establishment of permanent GICs throughout the industry.[93] The Commission determined that the need to promote and stabilize pipelines' merchant functions, and to send accurate pricing signals to the market, mandated the rapid implementation of interim GICs until permanent mechanisms could be put into place.[94]

In the Proposed Policy Statement, the Commission offered guidance as to the characteristics of acceptable interim GICs but declined to adopt a "cookie cutter" approach. The Commission detailed two potential types of interim GICs, while stressing that pipelines were not precluded from deviating from the models.

The "competitive price method" replaces the pipeline's purchased gas

93. *Proposed Policy Statement, supra* note 88, at 62,027.

94. Much of the urgency supporting the need for interim GICs resulted from the existence of the Order No. 500 "sunset" provision which established a deadline of March 31, 1989 for pipeline filings to recover take-or-pay costs through the equitable sharing mechanism. Order No. 500, *supra* note 47, at 30,792. The D.C. Circuit, however, recently struck down the sunset provision as arbitrary and capricious because the imposition of that deadline placed undue pressure upon pipelines to enter into settlements which were potentially detrimental to their interests. American Gas Ass'n v. FERC, 888 F.2d 136, 151 (D.C. Cir. 1989). In Order No. 500-H, discussed, *supra*, at note 27, the Commission extended the sunset date for Order No. 500 take-or-pay recovery filings until December 31, 1990. It is unclear whether the extension of the sunset provision will dampen the Commission's sense of urgency relative to the implementation of interim GICs.

adjustment (PGA) mechanism with a two-part interim gas supply charge. One part is the gas commodity charge and the other is the interim GIC. The GIC amount would be the product of three factors:[95] (1) the monthly average price of competitive market purchases;[96] (2) the pipeline's approved overall pre-tax rate of return;[97] and (3) an assumed overall take-or-pay requirement of seventy-five percent.[98] Thus, the inventory charge is derived by focusing upon the aggregated value of the pipeline's inventory of gas supply contracts. The value of that inventory of contracts is determined based upon the expected value for which the pipeline could sell the gas in the competitive market.[99]

In the deficiency-charge method, the interim gas supply charge would consist of the pipeline's commodity charge based on the PGA mechanism, subject to a cap, plus an interim GIC. The interim GIC charge would equal twenty percent of the pipeline's currently-effective WACOG, and would be imposed upon customer deficiencies below sixty percent of nominated volumes.[100]

The Proposed Policy Statement also contains a reconciliation mechanism that would require a pipeline to file a comparison of actual GIC revenues and actual inventory costs. Any excess GIC revenues accrued by the pipeline would eventually be refunded to customers in proportion to their nominations or deficiencies.[101] The Proposed Policy Statement further requires that a pipeline have an application for a permanent GIC pending before the Commission when an interim GIC filing is made; that a pipeline must allow firm sales customers to convert up to 100% of their entitlement to firm transportation service; and that the term of an interim GIC certificate be limited to two years.[102]

The interim GIC concept raises several concerns. While interim GICs

95. *Proposed Policy Statement, supra* note 88, at 62,031.

96. The Proposed Policy Statement sets forth a four-step method for computing a pipeline's monthly average price. *Id.* at 62,039-40. First, the pipeline would look to four sources of spot market prices for the month, specifically those listed in INSIDE FERC, NATURAL GAS WEEK, NATURAL GAS INTELLIGENCE, and GAS DAILY. Second, the pipeline would extract price information from the relevant geographic area where it obtains natural gas supplies. *Id.* Third, prices from this area would be used to construct an average price for each source of data, and, finally, a composite price for the month would be computed by averaging the four reporting services. *Id.* Pipelines using the competitive price method are required to submit quarterly filings detailing the competitive prices used to compute the interim GIC. *Id.*

97. *Id.* at 62,029. The concept of imputing a value to the pipeline's gas supply contracts by applying the pipeline's rate of return can be analogized to the application of the return to items in the pipeline's rate base in deriving non-gas rates.

98. *Id.* at 62,028. The use of the seventy-five percent factor limits the pipeline to earning a return on that portion of the gas available under its contracts for which the pipeline is at risk. The seventy-five percent inferred take level is drawn from 18 C.F.R. § 2.103, which established the level above which no presumption of prudence would apply for new contracts. *Id.* at 62,030.

99. *Id.* at 62,029.

100. *Id.* at 62,030-31. The percentages used in the Proposed Policy Statement are illustrative only. *Id.* at 62,031.

101. *Id.* at 62,032.

102. *Id.* at 62,033-34. It should be noted that Commissioner Trabandt expressed concern about the Commission's flexible attitude toward the form of interim GIC chosen and implemented by the pipeline. He feared the proliferation of "unlimited variations" of GICs and would have preferred the enunciation of a single, deficiency-based type of interim GIC. *Id.* at 62,042.

were proposed as an expedient transitional device, there is concern that the mechanism might undermine the effort to implement permanent GICs in a timely manner. For example, certain local distribution companies asserted, during the public comment period following the announcement of the Proposed Policy Statement, that an interim GIC might serve to hinder the adoption of permanent GICs by lessening some of the pressure on the pipeline to negotiate with its customers.[103] Similarly, during the deliberations of the Senate Energy Committee's Subcommittee on Mineral Resources Development and Production, held prior to the FERC's issuance of its Proposed Policy Statement, producers and marketers stated a preference for a comprehensive solution imposed on a permanent basis.[104] In addition, various members of the Commission have also expressed reservations about the interim GIC approach.[105] On the other hand, however, pipelines have expressed concern that the Commission has been too slow in approving interim GICs.[106]

In view of the Commission's inability to act quickly in response to interim GIC proposals and the strong potential that the interim GIC alternative may undermine progress in implementing permanent GICs, the Commission may be best advised to revoke the Proposed Policy Statement and focus its energies on expedited consideration of permanent GIC proposals. Elimination of the interim GIC concept is particularly appropriate now that the sunset date for Order No. 500 take-or-pay recovery filings has been extended. The goal of establishing rational, long-term gas supply arrangements is not forwarded by expending effort and resources on stop-gap measures. Continued focus on interim GICs may be counterproductive.

B. The Need to Demonstrate Competitive Markets

In addressing GIC proposals, the Commission has required a showing of competition in a pipeline's markets. Specifically, a pipeline must show that the relevant markets in which it operates are sufficiently competitive to insure that rates charged by the pipeline remain at a reasonable level.

The Commission first articulated the competitiveness requirement in

103. FOSTER NAT. GAS REP. No. 1733, at 7-10 (July 27, 1989).

104. FOSTER NAT. GAS REP. No. 1740, at 4 (Sept. 14, 1989).

105. Commissioner Moler generally believes that the interim GIC mechanism is "worth exploring." FOSTER NAT. GAS REP. No. 1726, at 3 (June 8, 1989). Moler has speculated, however, that former FERC Chairman Martha Hesse formulated an interim GIC proposal out of frustration over the Commission's failure to achieve implementation of permanent GICs. *Id.* Former Commissioner Stalon at one point stated that there was no need for interim GICs and Commissioner Langdon has noted a fundamental inconsistency between the idea of an interim GIC and the objective of reserving a natural gas supply on a long-term basis. FOSTER NAT. GAS REP. No. 1740 at 4B-5 (Sept. 15, 1989).

106. Natural Gas Pipeline Company of America recently alleged that the Commission's inaction regarding Natural's offer of settlement, supported by almost all of its sales customers, which included an interim GIC, constituted an emergency. Emergency Motion By Natural Gas Pipeline Company of America for Expedited Approval of Interim Settlement, Natural Gas Pipeline Co., F.E.R.C. No. CP89-1281-000 (Nov. 1, 1989) (motion filed Nov. 16, 1989). Natural alleged that without a GIC in place it cannot risk a significant increase in take-or-pay exposure by entering into firm supply commitments, despite the onset of the winter heating season. *Id.* at 4. Delay in implementing an interim GIC also hampers efforts to renegotiate service agreements and to resolve the permanent GIC proceeding, according to Natural. *Id.* at 2.

reviewing the GIC proposed by Transwestern Pipeline Company (Transwestern). Under Transwestern's proposal,[107] applicable only to its largest customer, Southern California Gas Company (SoCal), the customer was assessed a GIC on shortfalls below 100% of its nominations up to 157,500 Dth per day, known as "forward supply service." Quantities nominated above 157,500 Dth per day would be "option service" and a GIC would be assessed on shortfalls below eighty-five percent of SoCal's daily nominations.[108]

SoCal objected to the forward supply service as a noncompetitive market structuring mechanism, one that deprived the LDC of flexibility in satisfying its supply needs.[109] The California Public Utilities Commission asserted that the competitive benefit of SoCal's access to transportation capacity on the pipeline's system might be undermined by the lack of long-term supply availability in Transwestern's producing area.[110]

The Commission responded that Congress, through the enactment of the NGPA, sought to establish competitive markets for natural gas. To assure the fulfillment of this objective with regard to GICs, the Commission required a showing of substantial evidence that competition in relevant markets would operate to constrain Transwestern's exercise of market power.[111] The Commission further found that, for three reasons, Transwestern had made such a showing. First, SoCal had access to substantial sales and transportation capacity in several pipelines other than Transwestern. Thus, the customer could make arrangements to completely replace Transwestern as a merchant supplier should the circumstances warrant.[112] Second, Transwestern did not process significant market power in the southern California market. Finally, SoCal was a sophisticated gas purchaser with significant experience in negotiating service contracts.[113] Thus, the Commission determined that sufficient competitiveness existed to satisfy the NGPA's statutory mandate.[114]

Subsequently, the Commission has required that competitiveness be addressed in the paper hearing proceedings.[115] In addressing the competitiveness issue in a paper hearing, the Commission seeks evidence regarding: the ability of the pipeline's customers to purchase sufficient amounts of natural gas elsewhere, the amount of divertible gas supply available to firm sales customers who may choose to convert to firm transportation service, the extent to which the pipeline will guarantee customers converting to firm transportation

107. Transwestern's proposal provided that the pipeline would post price levels for its commodity charges and GICs thirty days prior to their effective date. Transwestern Pipeline Co., 43 F.E.R.C. ¶ 61,240, at 61,648, *reh'g denied in part and granted in part,* 44 F.E.R.C. ¶ 61,164 (1988). Its customer, SoCal, would then nominate its desired level of sales service up to its current certificated CD quantity. *Transwestern,* 43 F.E.R.C. at 61,648. The pipeline would be permitted to abandon its service obligation to the extent that the nomination level represented less than existing CD quantity. *Id.*

108. *Transwestern,* 43 F.E.R.C. at 61,648.

109. *Id.* at 61,649.

110. *Id.*

111. *Id.* at 61,650.

112. *Id.* at 61,651.

113. *Id.*

114. *Transwestern,* 44 F.E.R.C. at 61,533.

115. *See Paper Hearings Proceedings, supra* note 79 and accompanying text.

under the proposed GIC that they will be able to contract for such service as long as they desire, and the nature of the pipeline's affiliated production and transportation transactions.[116]

The Commission has recently completed its first paper hearing, with regard to El Paso Natural Gas Company's proposed market-based GIC, and has issued an order authorizing the GIC, subject to the pipeline's satisfaction of certain enumerated conditions.[117] El Paso's market-based GIC provides that each nonexempt customer, and any electing exempt customer, is entitled to freely nominate any maximum daily quantity of gas that it wishes the pipeline to hold in inventory, with the amount of the charge for holding such gas to either be negotiated between the parties or to be based upon a composite spot pricing mechanism.[118] The amount nominated may range from its currently authorized certificated sales levels to zero. El Paso will guarantee, subject to *force majeure*, the availability of the nominated amount. A customer's election to nominate a quantity less than its current sales entitlement will constitute consent to an abandonment of El Paso's firm sales obligation for the difference, and, subject to the customer's underlying service agreement with El Paso, the amount of abandoned sales service will be converted into firm transportation service.[119]

In approving El Paso's GIC proposal, the Commission found that the pipeline had satisfied the Commission's high standard for demonstrating the competitiveness of its markets, and had proven that sufficient divertible supplies existed to meet the customers' requirements should GIC prices become noncompetitive.[120] With regard to the divertibility issue, the FERC asked three questions: (1) What quantity of gas must be divertible so as to preclude El Paso from exercising undue market power? (2) Is actual divertible supply competitively available to El Paso's customers? (3) How much gas will be divertible and available in the future?[121] The Commission first found that the gas dedicated to the pipeline under long-term contracts, together with affiliates' volumes, represented the correct measure of the amount of divertible gas needed to prevent El Paso from exercising significant market power. Next, the Commission determined, after failing to find any attempt on El Paso's part to coordinate a withholding of gas supply with other suppliers, that divertible supplies were presently available to El Paso's customers and would be so in the future.[122] A factor helpful to El Paso's assertion of divertibility was the pipeline's stated willingness to release gas should the Commission conclude in

116. *See, e.g.*, Natural Gas Pipeline Co., F.E.R.C. No CP89-1281-000 (Nov. 1, 1989) at Appendix B; Transcontinental Gas Pipe Line Corp., 46 F.E.R.C. ¶ 61,364, at 62,136 (1989), *reh'g granted in part and denied in part*, 47 F.E.R.C. ¶ 61,244, *reh'g denied*, 48 F.E.R.C. ¶ 61,198 (1989).

117. Opinion No. 336, El Paso Natural Gas Co., 49 F.E.R.C. ¶ 61,262 (1989).

118. *Id.* at 61,900. In addition to paying the charge for holding gas supplies in inventory, a customer must also pay a commodity charge for volumes actually purchased. *Id.*

119. *Id.*

120. *Id.* at 61,909.

121. *Id.* at 61,912.

122. *Id.* at 61,916.

the future that present divertible gas supplies are inadequate.[123]

Also critical to the Commission's approval of the GIC was its finding that transportation "comparability" existed, as El Paso's firm sales customers had the right to convert up to 100% of their firm sales to firm transportation comparable to the transportation available under the firm sales contracts.[124] While offering no specific methodology regarding conversion rights, El Paso proposed that customers obtain access to facilities on an "actual needs" daily basis.[125] If capacity constraints were to develop, capacity would be allocated pro rata based upon the lesser amount of requested capacity or confirmed supply on the day the constraint occurs.[126] The Commission accepted the proposal, subject to the condition that should an actual capacity constraint take place, a report must be filed by El Paso within five days, explaining in detail the circumstances which gave rise to the constraint and the steps that will be taken to prevent a recurrence.[127] El Paso was required to file (1) a new rate case within ninety days of accepting the certificate in which sales costs and transportation costs will be unbundled, (2) new tariff sheets detailing an appropriate procedure for the allocation of capacity at constraint points, and (3) revised gas supply curtailment procedures.[128]

Thus, it appears that a finding of competitiveness, whether made within the framework of a formal Commission hearing or a paper hearing, will turn upon three important factors. These factors are the customers' access to alternate sources of supply, the existence of transportation comparability on the pipeline system, and the pipeline's degree of market power within the pertinent geographical area.

C. *Cost Based Considerations Under NGA Sections 4 and 5*

Section 4 of the NGA requires that "[a]ll rates and charges . . . received by any natural-gas company for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the Commission . . . shall be just and reasonable."[129] Section 5 of the NGA similarly empowers the Commission to prescribe a just and reasonable rate if it finds an existing rate to be unjust or unreasonable.[130] Because GICs are rates, they must meet the just and reasonable standard.[131] This could limit the Commission's ability to implement market based GICs.

The calculation of just and reasonable rates has traditionally been based

123. *Id.* at 61,920. The Commission did, however, request further details as to how a release plan would operate. *Id.*

124. *Id.* at 61,923.

125. *Id.* at 61,925-26.

126. *Id.*

127. *Id.* at 61,930. As an additional matter, various El Paso customers urged the Commission to require capacity brokering as a condition for approval of the GIC. The Commission refused to impose such a requirement, while at the same time noting that it expects El Paso to fully address this issue when filing its next rate case. *Id.* at 61,930-31.

128. *Id.* at 61,938.

129. 15 U.S.C. § 717c (1988).

130. 15 U.S.C. § 717d (1988).

131. *See* Atlantic Ref. Co. v. Public Serv. Comm'n, 360 U.S. 378, 388 (1959).

upon the pipeline's projected costs. From the standpoint of a regulated company, the rate should be sufficiently high to offer a return on the company's capital expenditures which will allow the business to maintain its credit rating and to attract additional capital.[132] From the standpoint of consumers, the rate should be sufficiently low so as to prevent exploitation.[133] "The [resulting] 'zone of reasonableness' is [thus] delineated by striking a fair balance between the financial interests of the regulated company and 'the relevant public interests both existing and foreseeable.' "[134]

The NGA gives the Commission considerable leeway to formulate methods of arriving at just and reasonable rates.[135] In this regard, case law clearly upholds the Commission's right to consider non-cost criteria in a rate setting proceeding.[136] For example, courts have repeatedly upheld the Commission's right to set rates for regulated producers designed to stimulate investment in gas exploration and development.[137] There is even authority supporting the Commission's use of market prices as one factor in setting producer rates.[138] These cases, however, involve instances where reliance on non-cost criteria was only supplemental to the analysis of costs.

The Commission's authority to set rates based *solely* on market prices is extremely doubtful. In *FPC v. Texaco*,[139] the Supreme Court considered an order of the Federal Power Commission that established a blanket certificate procedure eliminating direct review of small producer rates. The FPC maintained that it could ensure compliance with the just and reasonable standard indirectly through review of the purchased gas costs of pipelines and large producers to which the small producers sold their gas.[140] As the FPC envisioned this procedure, purchasers would be allowed to pass through price increases by small producers only if the increases were reasonable in comparison with regulated large producer sales and the prevailing price in the intrastate market. In the Court's view, the procedure "impli[ed] . . . that reasonableness would be judged by the standard of the marketplace."[141]

The Court upheld the FPC's assertion that a regime of indirect regulation could comply with the just and reasonable standard.[142] It found, however, that the proposed standard for reviewing rates was fatally ambiguous. Moreover, for the purpose of guiding the FPC's efforts on remand, the Court

132. City of Chicago v. FPC, 458 F.2d 731, 750 (D.C. Cir. 1971).

133. *Id.* at 751.

134. Farmers Union Cent. Exch. v. FERC, 734 F.2d 1486, 1502 (D.C. Cir. 1984) (quoting *In re* Permian Basin Area Rate Cases, 390 U.S. 747, 792 (1968)). *See also* FERC v. Pennzoil Producing Co., 439 U.S. 508, 519 (1979); *In re* Trans Alaska Pipeline Rate Cases, 436 U.S. 631, 653 (1978).

135. Wisconsin v. FPC, 373 U.S. 294, 309 (1963).

136. *Farmers Union*, 734 F.2d at 1503 ("We recognize, of course, that 'non-cost' factors may play a legitimate role in the setting of just and reasonable rates." *Id.*).

137. *See* Consumers Union v. FPC, 510 F.2d 656, 660 (D.C. Cir. 1974).

138. *See* Permian Basin Area Rate Cases, 390 U.S. at 793-95; Southern Louisiana Area Rate Cases v. FPC, 428 F.2d 407, 441 (5th Cir.), *cert. denied sub nom.* Associated Gas Distribs. v. Austral Oil Co., 400 U.S. 950 (1970).

139. FPC v. Texaco, Inc., 417 U.S. 380 (1974).

140. *Id.* at 382.

141. *Id.* at 396.

142. *Id.* at 390.

stressed that "the prevailing price in the marketplace cannot be the final measure of 'just and reasonable' rates mandated by the [Natural Gas] Act."[143]

Notwithstanding the *El Paso* decision, the Commission's power to allow the implementation of GICs based entirely on the operation of the market is questionable. Compliance with the just and reasonable standard appears to require a mechanism for setting rates which utilizes cost criteria or perhaps other criteria which are independent of the market's operation in order to ensure that market prices remain within the zone of reasonableness.

In analyzing the operation of market-based GICs against this standard, it is necessary to distinguish between GIC mechanisms which utilize a true-up or reconciliation provision and those which do not. *Transwestern Pipeline Company (Transwestern)*[144] states the Commission's position with respect to market-based GICs which lack a true-up or reconciliation device. In *Transwestern*, the pipeline proposed a GIC mechanism whereby both the commodity charge and the GIC charge would be functions of the spot market price for gas. Faced with the objection that Transwestern's proposed charge failed to meet the just and reasonable standard because it was not cost-based, the Commission appeared to agree that a rate based entirely upon the operation of market forces would be deficient. The Commission stated that it "must . . . establish that the market-oriented pricing mechanism, subject to a cost-based cap or other constraint, will produce rates that invariably fall within a zone of reasonableness so that market forces will not be the exclusive means through which to arrive at just and reasonable rates."[145] The Commission then found that the ability of Transwestern's customer to purchase gas from alternate supply sources provided such a mechanism:

> Either [Transwestern's customer] can purchase supplies from other pipeline sources at regulated rates or, more significantly, it can purchase directly from producers at prices that Congress has deemed to be just and reasonable in NGPA section 601(b), plus the cost of transportation at Commission-regulated rates.
>
> Thus, the availability of these alternate supplies, at just and reasonable rates, will serve as a check on Transwestern's gas inventory charge because Transwestern must keep its charge at or below these alternatives in order to retain [its] customer.[146]

It is not at all clear, however, that the Commission's reasoning clears the hurdles posed by *Texaco*.[147] In *Texaco*, the Commission proposed to regulate small producer sales rates by comparing them to the rates charged in other producer sales. Although some of the rates to be used in the comparison were unregulated, the Court's decision did not turn on that fact. Rather, the Court

143. *Id.* at 397. *See also* Mobil Oil Corp. v. FPC, 417 U.S. 283, 308 (1974) (commenting that consideration of non-cost factors had been allowed where "[e]ach deviation from cost-based pricing was found not to be unreasonable and to be consistent with the Commission's [statutory] responsibility"); *Farmers Union*, 734 F.2d at 1509 (proposed rate-making procedure for oil pipelines which allowed rates to vary up to ceilings exceeding the "zone of reasonableness" unless competition drove them down failed to meet the requirements of just and reasonable standard because "nothing in the regulatory scheme itself acts as a monitor to see if this occurs or to check rates if it does not.").

144. *Transwestern*, 43 F.E.R.C. at 61,648.

145. *Id.* at 61,650.

146. *Id.* at 61,652-53 (footnote omitted).

147. *Texaco*, 417 U.S. at 124.

considered the market to consist of both regulated and unregulated sales. Thus, the comparison which the Commission expects the customers to undertake under its analysis in *Transwestern* appears to be virtually indistinguishable from the comparison the Commission proposed to undertake in *Texaco*.

The Commission's reasoning in *Transwestern* also appears to be flawed for an even more fundamental reason. In *Transwestern*, the Commission stressed that Transwestern's customer would be able to purchase gas directly from producers at prices deemed to be just and reasonable under NGPA section 601(b).[148] While it is true that, under NGPA section 601(b), amounts paid by pipelines to producers consistent with NGPA pricing provisions are deemed to be just and reasonable for the purposes of sections 4 and 5 of the Natural Gas Act, this finding is limited to first sales of gas as defined in section 2(21) of the NGPA.[149] Because sales by an interstate pipeline do not qualify as first sales, section 601(b) does not appear to provide an appropriate standard of comparison. Most wellhead sales of gas are no longer subject to price ceilings and those ceilings which remain will be removed by January 1, 1993. Thus, it is largely true now and will soon be true in all cases that there are no limitations other than competitive pressures to keep prices within the zone of reasonableness.[150] *Transwestern* does not appear to provide a defensible basis for market-based GICs in light of the just and reasonable standard of the NGA.[151]

A different result should obtain, however, where a market-based GIC incorporates a true-up or reconciliation mechanism. As discussed above, this device measures the pipeline's actual gas inventory costs against the cumulative GIC revenues collected from customers during a given billing period. If the amount collected for maintaining gas inventory exceeds the expenses incurred for that function, the overcollected amounts are refunded during a subsequent billing period. Under the mechanisms proposed to date, however, any undercollections of gas inventory costs must be borne by the pipeline.[152]

The addition of a reconciliation mechanism should supply the element missing from the rate setting procedure struck down in *Texaco*. The device takes cognizance of actual costs, and assures that, over time, the pipeline cannot collect revenues in excess of its actual expenditures incurred to provide the service. It places a cost-based cap on rates which should keep them from ever exceeding the upper limit of the zone of reasonableness. Also, although the mechanism does not ensure the pipeline's ability to recover its costs, the risk of underrecovery should not render the rate confiscatory. Because the pipeline

148. 15 U.S.C. § 3431(b) (1988).

149. 15 U.S.C. § 3301(21) (1988).

150. In most cases, current market prices are also well below the applicable ceilings. The effect which price ceilings have on the operation of the market as a whole at the present time is probably negligible. *See* H.R. Rep. No. 101-29, 101st Cong., 1st Sess. 4-5 (1989).

151. The relationship between NGPA rates and compliance with the just and reasonable standard under the NGA, as applied to interstate pipelines, is governed by NGPA section 601(c), 15 U.S.C. § 3431(c) (1988), which guarantees passthrough of such amounts.

152. *See National Fuel Gas Supply Corp.*, 48 F.E.R.C. ¶ 61,128 (1989); *Transcontinental Gas Pipe Line Corp.*, 46 F.E.R.C. ¶ 61,364 (1989). The market-based interim GIC proposed in the Commission's Notice of Proposed Policy Statement also includes a reconciliation mechanism of this type.

controls its own purchasing practices, the *opportunity* it is afforded to recover its gas inventory expenses should be sufficient to meet the statutory just and reasonable standard.[153] This is particularly true since the pipeline's acceptance of a GIC certificate and rate is voluntary.[154]

D. *Deficiency Based GICs and Minimum Bills*

Since the issuance of Order No. 380, Commission policy has strongly disfavored the use of minimum bills in pipeline rate design.[155] The basis of this policy is the alleged distorting effect a minimum bill may have upon the effective price of gas for customers subject to the charge. According to the Commission, for gas purchases below the minimum bill threshold level, a customer choosing between its pipeline supplier and an alternate supply source will rationally choose the alternate supplier only if the price offered by the supplier is sufficiently low to offset the minimum bill amount. The Commission claims, therefore, that minimum bills distort the accuracy of price signals sent to the downstream gas market and prevent customers from pursuing a least cost gas purchasing policy.

Independent marketers and others have made precisely these claims with respect to the deficiency-based GIC charge. They discern no difference between the effects of a gas inventory charge triggered by purchases below a threshold and the market effects of a minimum bill charge subject to the same type of mechanism.[156]

In responding to these allegations, the Commission has taken great pains to distinguish deficiency-based GICs from minimum bills, identifying three purported distinguishing factors. First, the Commission has stated that a defi-

153. *See* FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 590 (1942) ("[R]egulation does not ensure that the business shall produce net profits"); Transwestern Pipeline Co. v. FERC, 820 F.2d 733, 742 (5th Cir. 1987) (Change in rate design which did not deny pipeline "reasonable opportunity" to earn a sufficient return upheld.); Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176, 1188 (D.C. Cir. 1975) (FERC's denial of pipeline's objection to rate it claimed deprived it of "reasonable opportunity" to recover . . . cost" was denied where change in rate design would not "necessarily produce a confiscatory result.").

154. *Cf.* FPC v. Tennessee Gas Transmission Co., 371 U.S. 145, 153 (1962) ("The company having initially filed the rates and . . . failed to collect a sufficient [rate of return] . . . must, under the theory of the [Natural Gas] Act, shoulder the hazards incident to its action including . . . its losses where its filed rate is found to be inadequate").

155. Order No. 380 was directed against the inclusion of variable costs, *i.e.* gas costs, in pipeline minimum bills. *See supra* notes 15-17 and accompanying text. Thereafter, in a series of orders concerning individual pipelines, the Commission also ruled against the inclusion of pipeline minimum bills involving only the recovery of fixed costs. *See, e.g.,* Transwestern Pipeline Co., 36 F.E.R.C. ¶ 61,175 (1986). The rationale in both Order No. 380 and the individual decisions concerns the effect on competition in the gas commodity market.

156. *See, e.g.,* Tejas Power Corp. v. FERC, No. 89-1267 (D.C. Cir. filed April 24, 1989). Hadson Gas Sys., Inc. v. FERC, No. 89-1294 (D.C. Cir. filed May 5, 1989); Citizens Gas Supply Corp. v. FERC, No. 89-1310 (D.C. Cir. filed May 12, 1989). In a May 12, 1989 "Emergency Motion for Stay Pending Review" filed concurrently in each of these cases, the petitioners, independent gas marketers, strenuously argued that the deficiency-based GIC proposed by Texas Eastern Transmission Corp. would foreclose from competition ninety-two percent of Texas Eastern's past year's sales to its major customers. *Emergency Motion* at 4. As the petitioners stated, "Texas Eastern's deficiency charge and a minimum bill are identical; each of the pipeline's sales customers is required to pay a deficiency charge to the pipeline on the difference between the minimum quantity and its actual purchases." *Id.* at 8.

ciency based GIC differs from a minimum bill in that it allows gas inventory charges to be recognized on a current basis. According to the Commission, "an inventory charge generally facilitates rational market activity by providing both suppliers and purchasers with clear price signals . . . ."[157] Second, the Commission has maintained that GIC charges are designed solely to compensate for the pipeline's obligation to stand ready to supply gas.[158] In comparison, there is no direct linkage between minimum bill liability and the pipeline's incurrence of gas inventory costs.[159] Also, minimum bills did not provide for refunds in the event the amount collected exceeded the cost of maintaining gas inventories.[160] Third, the Commission has stated that the charges are distinguishable because of differences in the regulatory environment.[161] At the time the Commission first eliminated variable cost minimum bills under Order No. 380, competitive forces in the gas marketplace were stifled. According to the Commission, there are now multiple supply alternatives available to customers, including gas transportation service by the very pipelines proposing GICs. Firm sales service subject to a GIC is merely one of a "menu" of options.[162]

Thus, the Commission's thesis in distinguishing deficiency-based GICs from minimum bills is that GICs are actually *pro-competitive*, especially when placed in the context of the Commission's other initiatives to promote the operation of the gas commodity market. The validity of this conclusion would appear to depend upon the particular terms of the pipeline's deficiency-based mechanism and the particular markets in which the pipeline operates. Nonetheless, even if a deficiency-based GIC could be anti-competitive in some

157. *See* Texas E. Transmission Corp., 47 F.E.R.C. ¶ 61,100, at 61,280 (1989).

158. *Id.*

159. In fact, revenues received under pipeline minimum bills were used to enhance the pipeline's return, while the pipeline filed separately to recover take-or-pay prepayments or buyout/buydown costs through its rates or directly under an equitable sharing filing.

160. *Texas Eastern,* 47 F.E.R.C. at 61,280.

161. *Id.*

162. *Id.* In approving a deficiency-based GIC over objections that the charge functions in the manner of a minimum bill, the Commission has also relied on the fact of the pipeline's and its customer's agreement to structure the charge in this manner. *Id.* at 61,281 ("When a pipeline and its customers reach a consensus . . . other types of gas inventory charges can result and the Commission will not superimpose its judgment on the consensus reached."). This is not per se a distinguishing factor between deficiency-based GICs and minimum bills although it may help justify adoption of a deficiency-based GIC in a specific case.

The Commission has also attempted to distinguish future gas supply charges, as proposed in Order No. 500, from minimum commodity bills:

> Minimum commodity bills bundled transportation and sales costs. They were tied to CD levels and to long-term city-gate sales. In addition, the minimum commodity bills tied the take levels and non-take levels together. In contrast, these new services would not be bundled or tied to CD levels and would allow more frequent adjustments of sales levels. . . .
>
> Minimum commodity bills were imposed only on partial requirement customers, were not optional, and generally had no make-up provisions. These new services would be for all customers, would be optional, and could have make-up provisions. In addition, the minimum commodity bills collected costs not incurred whereas the new services would keep accounts current with refunds if costs were not incurred. Finally, minimum commodity bills inhibited competition. In contrast, these new services would stimulate competition with the advance notice of prices that are held firm and the alternative services available because the pipeline would be an open-access transporter.

Order No. 500, *supra* note 47, at 30,804.

cases, such a GIC would appear to be defensible under general principles of antitrust law and, in particular, under the Commission's interpretation of antitrust law in the context of pipeline minimum bills.

It is well settled under antitrust law that not all restraints on competition are unreasonable. Under the "rule of reason" as recognized by the Commission:

> [A] contract is an unreasonable restraint of trade only if it is more restrictive than is necessary to meet an objective under the antitrust laws as the statutes [which the Commission] administers. What this means in concrete terms is that before we may find a contract's term to be an unreasonable restraint of trade, we must carefully balance the competitive harm the term causes against the term's objective in light of the alternatives available for achieving those objectives. Only if on balance the term causes more harm than is warranted in light of the term's objectives and the available alternatives, can we find the term to be an unreasonable restraint on trade. (footnotes omitted).[163]

Application of this balancing test suggests that a deficiency-based GIC may be upheld notwithstanding any potential anti-competitive effects. For example, while the Commission has struck down the use of minimum bills generally, it has recognized that, under the rule-of-reason analysis, pipelines may justify minimum bills in their rate design in order to achieve other policy goals. One such recognized goal is to remedy problems of cost recovery posed by the "minimum take-or-pay obligation which a pipeline has to its suppliers."[164] The premise of this exception is that customers whose decreased purchase levels are responsible for the pipeline incurring minimum take-or-pay obligations may be fairly charged with the pipeline's increased costs. The Commission has, however, consistently rejected minimum bills proffered on this ground because "there is no connection between the minimum bill payments the customers would make . . . and the . . . costs associated with take-or-pay liabilities . . . ."[165]

A deficiency-based GIC charge may, however, meet the requirements of a rule-of-reason analysis in achieving the goal of assigning gas inventory costs to responsible customers. As the Commission has stressed, a GIC charge is specifically designed to recover the costs of maintaining gas inventory. If properly implemented, a deficiency-based GIC will allow the pipeline to retain only sufficient amounts to reimburse it for actual gas inventory expenditures. Even assuming the charge has some anti-competitive effects, calculating the charge on the basis of cost or market forces, allowing periodic renomination rights and including a true-up mechanism should minimize such effects and more accurately target responsible customers. A charge designed in this manner would be the least intrusive competitive alternative and would still accomplish the goal of assigning gas inventory expenses to customers responsible for their incurrence.[166]

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163. Transwestern Pipeline Co., 36 F.E.R.C. ¶ 61,175, at 61,439 (1986).

164. *Id.* at 61,446 (citing Atlantic Seaboard Corp., 38 F.P.C. 91 (1967), *aff'd*, 404 F.2d 1268 (D.C. Cir. 1968)).

165. *Transwestern*, 36 F.E.R.C. at 61,446.

166. In addition, the element of causation between a particular customer's reduction in takes and the pipeline's liability to producers is much more likely to be demonstrable now than was the case in the past.

E. Flowthrough of Upstream Pipeline GIC Charges

As GICs become more prevalent in the industry, the GIC assumes an additional function—the recovery of GIC charges assessed downstream pipelines by upstream pipelines. Recently, Carnegie Natural Gas Company (Carnegie), filed a revised tariff sheet with the Commission in which it proposed procedures for the recovery of GIC costs incurred from its upstream supplier, Texas Eastern Transmission Corporation (Texas Eastern).[167] Carnegie's stated objective was to ensure that any GIC billed by Texas Eastern to Carnegie would be paid by those customers who had triggered Texas Eastern's deficiency-based GIC by taking below their supply entitlements.[168] Similarly, any amounts refunded to Carnegie by Texas Eastern pursuant to the latter's reconciliation provisions would be channeled to those of Carnegie's customers who had paid a GIC bill to Carnegie during the pertinent contract year.[169] In addition, Carnegie reserved the right to flowthrough in its purchased gas adjustment provisions any payments made to Texas Eastern that were not incurred as the result of a customer's failure to reach its entitlement level, so long as such payments were made to benefit Carnegie's customers.[170]

The Commission approved of Carnegie's general goal of matching cost responsibility with cost incurrence, although it rejected the specific proposal as "incomplete and not fully thought out."[171] The Commission found that Carnegie had not adequately explained how the PGA flowthrough mechanism would operate, *i.e.*, which costs would be flowed through and how such costs would be determined. In addition, it was unclear to the Commission what would transpire in the event that none of Carnegie's customers were responsible for the deficiency but GIC charges were still incurred by Carnegie, or if only one customer was deficient or if the deficiency was caused by a nonjurisdictional customer.[172] More fundamentally, the Commission was not sure whether Carnegie's plan should properly be characterized as a GIC since the proposal intended to utilize the PGA mechanism and intended to bill costs to individual customer's.[173] Clearly, however, future proposals to recover upstream pipeline GIC charges should be designed to assess customer cost responsibility in proportion to the customer's responsibility for the incurrence

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As the Commission has noted, there is a new regulatory environment. Because significant restructuring has occurred in the natural gas industry, supply and demand on most interstate pipeline systems is being brought more closely into balance than was the case in the past when pipelines commonly were committed to buy more gas than they could sell. A reduction in a given customer's purchases is, therefore, more likely to be the cause of a pipeline's incurrence of gas inventory costs.

167. Carnegie Natural Gas Co., 49 F.E.R.C. ¶ 61,122, at 61,516 (1989).

168. *Id.* at 61,518.

169. *Id.*

170. *Id.*

171. *Id.*

172. *Id.* at 61,519.

173. *Id.* at 61,518. The Commission had previously granted Carnegie permission to flow Texas Eastern's gas supply inventory charges through its PGA mechanism, but had emphasized that if Carnegie decided to implement its *own* GIC on its system, any charges incurred vis-a-vis Texas Eastern would have to be recovered by imposing a GIC on its customers. *See* Carnegie Natural Gas Co., 45 F.E.R.C. ¶ 61,355, at 62,134 (1988).

of GIC charges by the downstream pipeline.[174]

F. Gas Supply Development

A serious concern exists with respect to the interplay between GICs and gas supply development. A number of the demand-type GICs which have been proposed tie the unit GIC charge to spot market prices. Proponents of such devices claim that the connection will provide incentives for the pipeline to maintain competitive rates. It is not at all clear, however, that the overall result would be beneficial. At the very least, the risks presented by this approach must be recognized.

First, creating a nexus between a GIC and spot market prices would appear to shift additional short-term market risks to customers. Spot market prices have remained consistently below long-term market prices for the past several years. This fact reflects the present deliverability surplus, a condition which is not likely to persist indefinitely and which is contrary to the observed pattern in other commodity markets. As supply and demand reach equilibrium, higher spot market prices can be expected, particularly during the winter season. A severe winter could result in sharp price spikes in the spot market causing excessive GIC charge levels.

The rate design principles applicable to GICs, which were announced in Order No. 500, generally assign short-term market risk to pipelines as a *quid pro quo* for assigning a share of long-term market risks to customers. When the pipeline ties the demand charge portion of its option-type GIC to the spot market, it relieves itself of some of this responsibility. To the extent that the pipeline relies on the spot market as a source of supply, it is no longer subject to as much risk from an unanticipated rise in short-term market prices.[175]

Second, and perhaps more important, is the effect that spot market-based GICs may have on pipeline purchasing strategies and the related effects on gas supply development. Where the gas inventory charge is a function of spot market prices, the pipeline could avoid market risk by purchasing only short-term supplies. A pipeline following this course of action should be able to recover its inventory costs in a rising or falling spot market. A risk-adverse pipeline with a spot market-based GIC might avoid long term contractual arrangements, because such arrangements would pose the risk that the pipeline would be unable to recover inventory costs in the following short term market. Such purchasing practices could, in turn, also affect gas supply development. Producers (and financial institutions) may be unwilling to make the large up-front expenditures necessary for major gas exploration and development projects if they cannot obtain assurances that there will be a future income stream sufficient to allow recovery of their investments. One possible result could be that gas exploration and production activities will be carried on at less than economically optimal levels.

174. Columbia's GIC includes upstream pipeline GIC charges incurred on a deficiency basis within the definition of "inventory costs" to be funded by GIC revenues. Upstream pipeline demand GIC charges are flowed through Columbia's PGA on an as-billed basis. *See* Columbia Gas Transmission Corp., 49 F.E.R.C. ¶ 61,071, at 61,280 (1989).

175. On the other hand, the pipeline loses the opportunity to overrecover its gas purchase charges.

Third, the potential negative impact of spot-based GICs on exploration and production efforts may reduce the reliability of pipeline supply. The assumption of gas supply responsibility by pipelines up to customer nominated levels may afford customers only an illusory protection if adequate long-term reserves are not maintained and carefully monitored. Because the FERC has refused to require pipelines to make a showing that supply is available as an element in GIC implementation,[176] the safeguards built into the pipeline's tariff are of paramount importance to customers. A critical consideration in this connection will be the development of *force majeure* language that provides customers with meaningful assurances that gas supply will be forthcoming when it is demanded.[177] Properly structured curtailment plans also assume increased significance and some GICs have included provisions for GIC credits if deliveries are not made.[178] Finally, the Commission has also indicated that it believes state law damage claims would be available to compensate customers who do not receive contracted volumes.[179]

The goal of long-term supply arrangements in the natural gas industry, or indeed any industry, has always been to smooth out the volatility which can be expected in a short-term market. The Commission should carefully consider the likely result of promoting a device which may overemphasize the importance of short-term gas sales in the natural gas industry.

VI. GICs and Gas Purchasing Strategies

A. *Interstate Pipelines*

Under the rate design principles of section 2.105, the GIC will be the sole mechanism available to pipelines for the recovery of take-or-pay and other costs of maintaining gas inventory. For many pipelines which continue to purchase gas under traditional take-or-pay contracts, the incurrence of inventory costs will be a function of the pipeline's actual sales. In those cases, the presumed sales volume level used by the pipeline to calculate its GIC unit charge will be critical. A pipeline is faced with the risk, on one hand, of presuming a sales level higher than it can achieve, thereby fixing its unit charge at too low a level and potentially underrecovering its gas inventory costs. On the other hand, assuming too low a sales level, will fix the pipeline's unit charge at too high a level and potentially drive some customers from its system.

Pipelines should, therefore, seek to coordinate the GIC mechanisms that they employ with their gas purchasing practices. If the pipeline's GIC mechanism is subject to the same market influences as the underlying producer contracts, there will be more margin for error in projecting sales volume levels.

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176. *See, e.g.,* Natural Gas Pipeline Co., 49 F.E.R.C. ¶ 61,137, at 61,586 (1989); Tennessee Gas Pipeline Co., 47 F.E.R.C. ¶ 61,245, at 61,861, *reh'g denied*, 48 F.E.R.C. ¶ 61,198 (1989).

177. *See* El Paso Natural Gas Co., 49 F.E.R.C. ¶ 61,262, at 61,900 (1989); Transwestern Pipeline Co., 43 F.E.R.C. ¶ 61,240, at 61,653-54, *reh'g denied*, 44 F.E.R.C. ¶ 61,164 (1988).

178. *See El Paso*, 49 F.E.R.C. at 61,900-01; *Transwestern*, 43 F.E.R.C. at 61,653-54.

179. *See Transwestern*, 43 F.E.R.C. at 61,654 (existence of GIC crediting mechanism "should not be construed as limiting other contractual remedies [that the customer] may have if Transwestern fails to deliver").

Perhaps the clearest strategy along these lines concerns the relationship between producer take-or-pay contracts and the "forward charge" or deficiency-based GIC. All three arrangements employ a mechanism whereby charges are triggered by purchases below a threshold level. Because of this shared characteristic, pipelines using a forward charge or deficiency-based GIC will probably seek traditional take-or-pay arrangements.

A second relationship involves an emerging type of producer/pipeline contract which employs both fixed and variable charges. Under this arrangement the pipeline agrees to pay a specified unit amount for all gas volumes covered by the contract and an additional charge per unit volume of gas actually purchased. The commodity charge is generally based on an index of spot market prices.

Such a pricing mechanism appears to coordinate well with an option-type GIC. If a pipeline can achieve compatibility between GIC demand levels and demand obligations under its producer contracts, it could significantly reduce its exposure to an unanticipated loss of sales volumes.

B. Producers

Although producer attitudes toward the current gas market conditions are diverse, it is safe to assume that producers harbor some doubts concerning the value of long-term contractual arrangements. Many producers were forced to abide by long-term contracts providing for below-market prices for many years. Yet, when producers did successfully negotiate terms which they viewed as favorable to their interests, such as indefinite price escalation clauses and high take-or-pay requirements, many pipelines claimed *force majeure* or otherwise sought relief from their contractual obligations. The end result was often a cents-on-the-dollar settlement which did not provide the producer with the full value of its bargain.

The implementation of GICs may change this attitude. If producers perceive GICs as workable devices by which pipelines can assure themselves of a revenue stream dedicated expressly to maintaining gas inventory, producers should be reassured with respect to the pipelines' ability to perform under long-term arrangements. This would particularly be true where the type of GIC implemented by the pipeline matches the gas contract pricing mechanism. In such a situation, the producer is likely to perceive that the pipeline will be able to recover gas inventory costs under the same market conditions in which such costs can be expected to accrue under the contract.

C. Local Distribution Companies

In the period between Order No. 380 and the institution of GICs, local distribution companies (LDCs) were largely shielded from the costs associated with maintaining gas inventory. With the implementation of GICs by their interstate pipeline suppliers, this will no longer be the case. LDCs will bear a share of gas inventory expenses on a current basis. This new cost responsibility should provide an impetus for LDCs to reevaluate their gas purchasing practices.

The effects of GICs on LDCs will be intensified by the characteristic load factor profile found on many LDC systems. Because LDCs typically serve the residential and commercial markets, which are highly sensitive to temperature, LDCs are generally low load factor customers. An LDC's peak day sendout of gas may well be significantly greater than the LDC's volumes on an average day. The load factor profiles of many LDCs are such that peak reliance on a pipeline is required for only a few days under design weather conditions. These incremental peak day requirements nonetheless require the nomination of entitlement levels sufficient to satisfy peak demand. Such nominations increase the likelihood of incurring GIC charges under deficiency-based GICs and increase the magnitude of such charges under demand-based GICS. An LDC which can devise an alternative supply source to meet such needle peaks could, therefore, avoid a significant amount of GIC costs.

The relationship between GIC payments and peaking requirements for most LDCs thus enhances the economics of alternate peaking sources such as propane-air, peak-shaving, underground storage or liquified natural gas facilities. Many LDCs may find that, although such facilities did not appear to be economically feasible in the past, they may become desirable upon the implementation of GICs.

LDCs which are able to reduce reliance upon pipelines for peaking requirements would also experience the benefit of increased supply flexibility. Assume, for example, that an LDC customer purchases gas from an interstate pipeline that employs a deficiency-based GIC set at a level equal to sixty percent of the customer's yearly nominations. Assume also that the LDC's current load is right at the sixty percent level. Under these circumstances, the LDC will be unable to avoid paying a GIC unless it purchases its entire requirements from the pipeline. If, however, the LDC is able to reduce its peak requirements even by a relatively small amount, say fifteen percent, it will then have additional flexibility to purchase gas from alternative supply sources. Maintaining this ability could be very important in the event of market volatility.

VII. Conclusion

The Commission has significantly restructured the natural gas industry, both with respect to the operation of the gas commodity market and the availability and type of transportation service now available. One result of this undertaking, in conjunction with evolving market forces, has been the reallocation of the costs and risks of maintaining long-term gas supplies. The assignment of additional gas supply risks to interstate pipelines has contributed to the high levels of take-or-pay liability experienced by pipeline systems during the 1980s. While the Order No. 500 "equitable sharing" mechanism addressed cost responsibility for these accumulated amounts, the mechanism's inherent limitations render it unworkable as a device to recover future costs.

In the future, all segments of the industry would benefit from an appropriate allocation of the costs and risks of maintaining long-term gas supplies. The GIC represents the Commission's attempt to fashion a fair balance between a pipeline's duty to serve and the responsibility for the costs of its service. Successful implementation of GICs is of vital importance. The Commission should act quickly to implement GICs in order to avoid a new build up of take-or-pay liability and to foster rational long-term supply planning, while ensuring that its actions rest on sound legal footing. Moreover, all segments of the industry should carefully consider how individual pipeline GICs will influence their own operations and business strategies.