DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 154, 161, 250, and 284

[Docket Nos. RM98–10–000 & RM98–12–000; Order No. 637]

Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services

Issued February 9, 2000.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations in response to the growing development of more competitive markets for natural gas and the transportation of natural gas. In this rule, the Commission is revising its current regulatory framework to improve the efficiency of the market and provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity while continuing to protect against the exercise of market power. The rule revises Commission pricing policy to enhance the efficiency of the market by waiving price ceilings for short-term released capacity for a two year period and permitting pipelines to file for peak/off-peak and term differentiated rate structures. It effects changes in regulations relating to scheduling procedures, capacity segmentation and pipeline penalties to improve the competitiveness and efficiency of the interstate pipeline grid. It narrows the right of first refusal to remove economic biases in the current rule, while still protecting captive customers' ability to resubscribe to long-term capacity. And, it improves the Commission's reporting requirements to provide more transparent pricing information and permit more effective monitoring of the market.

DATES: The rule will become effective March 27, 2000, with the exception of the removal of paragraph (c)(6) of redesignated § 284.10, which will be effective on September 1, 2000. *Pro forma* tariff filings to comply with certain requirements of the rule are due by May 1, 2000. Changes to reporting requirements are to be implemented by September 1, 2000.

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SUPPLEMENTARY INFORMATION:

Regulation of Short-Term Natural Gas Transportation Services

Docket No. RM98–10–000

Regulation of Interstate Natural Gas Transportation Services

Docket No. RM98–12–000

Order No. 637

Final Rule

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The Federal Energy Regulatory Commission (Commission) is amending Part 284 of its open access regulations in response to the growing development of more competitive markets for natural gas and the transportation of natural gas. In this rule, the Commission is revising its current regulatory framework to improve the efficiency of the market and to provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity while continuing to protect against the exercise of market power. To this end, the final rule makes the following changes in the Commission's current regulatory model:

• The rule grants a waiver for a limited period of the price ceiling for short-term released capacity to enhance the efficiency of the market while continuing regulation of pipeline rates and services to provide protection against the exercise of market power.

• The rule revises the Commission's regulatory approach to pipeline pricing by permitting pipelines to propose peak/off-peak and term differentiated rate structures. Peak/off-peak rates can better accommodate rate regulation to the seasonal demands of the market, while term differentiated rates can be used to better allocate the underlying risk of contracting to both shippers and pipelines.

• The rule adds regulations to improve the competitiveness and efficiency of the interstate pipeline grid by making changes in regulations relating to scheduling procedures, capacity segmentation and pipeline penalties.

• The rule narrows the right of first refusal to remove economic biases in the current rule, while still protecting captive customers' ability to resubscribe to long-term capacity.

• The rule improves reporting requirements to provide more transparent pricing information and to permit more effective monitoring for the exercise of market power and undue discrimination.

While the regulatory revisions adopted in this rule primarily affect the regulation of short-term transportation options, the changing nature of the natural gas market also poses significant challenges to the Commission's current model for regulating long-term transportation capacity. Changing the Commission's fundamental regulatory model goes beyond the scope of this proceeding. However, the Commission is beginning a new effort to monitor the changes taking place in the market so that, after this rulemaking terminates, the Commission can be prepared to reexamine its regulatory framework in light of the challenges posed by the growing competitive market.

The changes in the gas market since wellhead decontrol and Order Nos. 436 and 636 have created a better functioning and more reliable gas market. But the very growth of a more efficient market for natural gas and transportation capacity poses significant challenges to the Commission's regulatory model which was developed when the market was not competitive or efficient. The Commission discusses below the growth that has occurred in the market since Order No. 636, the current trends and their regulatory implications. The Commission then discusses its regulatory objectives and why the Commission is instituting a new process, independent of this proceeding, to examine whether fundamental changes to its current regulatory framework are needed to respond to the changed structure of the natural gas market. In Parts II through VII, the Commission discusses the adjustments to its current regulatory model that it is making in this rule.

I. Introduction

A. The Changing Natural Gas Market

1. Prologue to Competition

Prior to Order Nos. 436 and 636, and the implementation of the Wellhead Decontrol Act, all aspects of the natural gas market were regulated. The Commission, pursuant to the dictates of the Natural Gas Act (NGA) [1] and then the Natural Gas Policy Act (NGPA) established the prices for natural gas. Interstate pipelines purchased gas at the wellhead and delivered that gas at regulated rates to local distribution companies (LDCs). The LDCs, in turn, distributed gas to industrial, commercial, and residential consumers at rates regulated by the states, which permitted passthrough of the interstate pipeline costs. There was little choice in the market for natural gas or the market for transportation capacity. The market distortions and inefficiencies created by this regulatory regime are well known. The regulation of natural gas prices created economic incentives for producers to divert interstate gas to the unregulated intrastate market where they could obtain higher prices. The regulated prices dampened the incentive to invest in the production of natural gas, which led to the gas shortages in the 1970's.[2]

The passage of the Natural Gas Policy Act (NGPA) [3] in 1978 began to alleviate the problems caused by regulation of the gas commodity by regulating both interstate and intrastate gas prices in an effort to limit the incentives for diversion of gas, seeking to break down the artificial barriers between interstate and intrastate gas markets, and gradually providing for deregulation of natural gas prices. In 1985, in response to the changed market conditions created by the NGPA, the Commission adopted Order No. 436 [4] which established rules for pipelines to offer open access transportation service independent of pipelines' sales service. In 1989, Congress passed the Wellhead Decontrol Act [5] which removed all regulation from the gas commodity by 1993. In passing the Wellhead Decontrol Act, Congress assigned to the Commission the task of regulating interstate pipeline capacity in a way that would ''maximize the benefits of [wellhead] decontrol.'' [6]

In Order No. 636,[7] the Commission found that the pipelines' provision of a bundled gas and transportation service had anticompetitive effects that limited the benefits of open access service and wellhead decontrol. The Commission, therefore, required pipelines to separate their sales of gas from their transportation service and to provide comparable transportation service to all shippers whether they purchase gas from the pipeline or another gas seller. The Commission further adopted initiatives to increase competition for pipeline capacity in order to reduce the prices paid for transportation and ultimately the overall price consumers pay for gas. The Commission allowed firm holders of pipeline capacity to resell or release their capacity to other shippers and required pipelines to permit shippers to use flexible receipt and delivery points. Enabling firm shippers to resell their capacity created competitive alternatives to purchasing pipeline services. The ability to use flexible receipt or delivery points also expanded the capacity alternatives available to buyers of capacity because it meant that buyers were not restricted to using the primary points in the releasing shipper's contract. Capacity buyers could seek capacity from any number of firm capacity holders and use flexible point authority to inject and deliver gas at the points the purchasing shipper chose to use.

The combination of wellhead decontrol, open access transportation, and the unbundling of pipeline gas sales from the pipelines' transportation function created an opportunity for increased efficiency and competition both in the gas commodity market and the transportation market. The Commission's initiatives were supplemented by the actions of state regulators who too saw the need to begin to open local distribution systems by allowing large industrial and commercial customers to purchase their own gas and transport that gas both on the interstate pipeline and on the LDC's facilities.

As a result of the Commission and state open access and unbundling efforts, the stage was set for more efficient and competitive markets to develop that would reduce overall gas prices to consumers. LDCs began to contract for gas supplies in the production area and separately for transportation service from pipelines. Large industrial customers began to do the same, contracting for interstate pipeline capacity and transportation service on LDCs. Market centers began to develop to facilitate the buying and selling of natural gas and, in 1990, NYMEX established a futures market using the Henry Hub as the market exchange center.[8] Shippers and marketers began to use the capacity release mechanism as an alternative to obtaining transportation service from the pipeline, particularly for short-term service.[9]

2. Trends in the Gas Market Today

Today's natural gas market is again in the process of change, and is substantially different operationally and economically from the market in 1993. Upstream and downstream wholesale markets are maturing. As part of this process, both upstream and downstream market centers and gas trading points are increasing, providing shippers with greater gas and capacity choices. The financial marketplace has developed a variety of options and futures contracts that better enable participants to hedge against price risk. Electronic commerce (eCommerce) has grown rapidly

[1] Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954) (mandating Commission regulation of the gas commodity).

[2] *See* Transcontinental Gas Pipe Line Corporation v. State Oil & Gas Board, 474 U.S. 409 (1986) (NGA's artificial pricing scheme major cause of imbalance between supply and demand); Public Service Commission of New York v. Mid-Louisiana Gas Co., 463 U.S. 319, 30–31 (1983) (interstate natural gas prices could not compete with intrastate prices).

[3] 15 U.S.C. 3301–3432 (1978).

[4] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol. Order No. 436, 50 FR 42408 (Oct. 18, 1985), FERC Stats. & Regs. Regulations Preambles [1982–1985] ¶ 30,665, at 31,472–74 (Oct. 9, 1985).

[5] Pub. L. 101–60 (1989); 15 U.S.C. 3431 (b)(1)(A) (as of Jan. 1, 1993, any amount paid for a first sales of natural gas is just and reasonable).

[6] Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101–29, 101st Cong., 1st Sess., at 6 (1989).

[7] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,939 (Apr. 8, 1992).

[8] NYMEX, Henry Hub Natural Gas, *http://www.nymex.com* (November 17, 1999) (futures contract began in 1990).

[9] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560, Natural Gas 1998 Issues and Trends, 26 (June 1999) (growth of capacity release from 1993 to the present).

providing greater liquidity in commodity markets and with the promise of providing such liquidity in the transportation market as well. The industry is relying more on self-regulation to develop standards for business and electronic processes that create greater efficiency in moving gas across the integrated pipeline grid. There is greater integration between the natural gas and the electric generation market, with gas usage for power generation expected to grow substantially in the near future. Residential unbundling at the state level is underway which may provide the opportunity for small commercial firms and residential consumers to purchase their gas supplies in a competitive market. These trends are in various stages of development, with the growth of wholesale markets firmly established while residential retail unbundling is still in its infancy. These trends, and the challenges they present the Commission in its regulation of the natural gas industry, are discussed below.

a. *Wholesale Markets.* The wholesale market, composed of both the natural gas commodity market and the transportation market, has grown with new participants with the unbundling of transportation and sales service at the LDC level. Since 1984, large numbers of industrial customers, electric generators, and end use customers have been buying gas from parties other than the pipelines or LDCs, as shown in Figure 1.[10]

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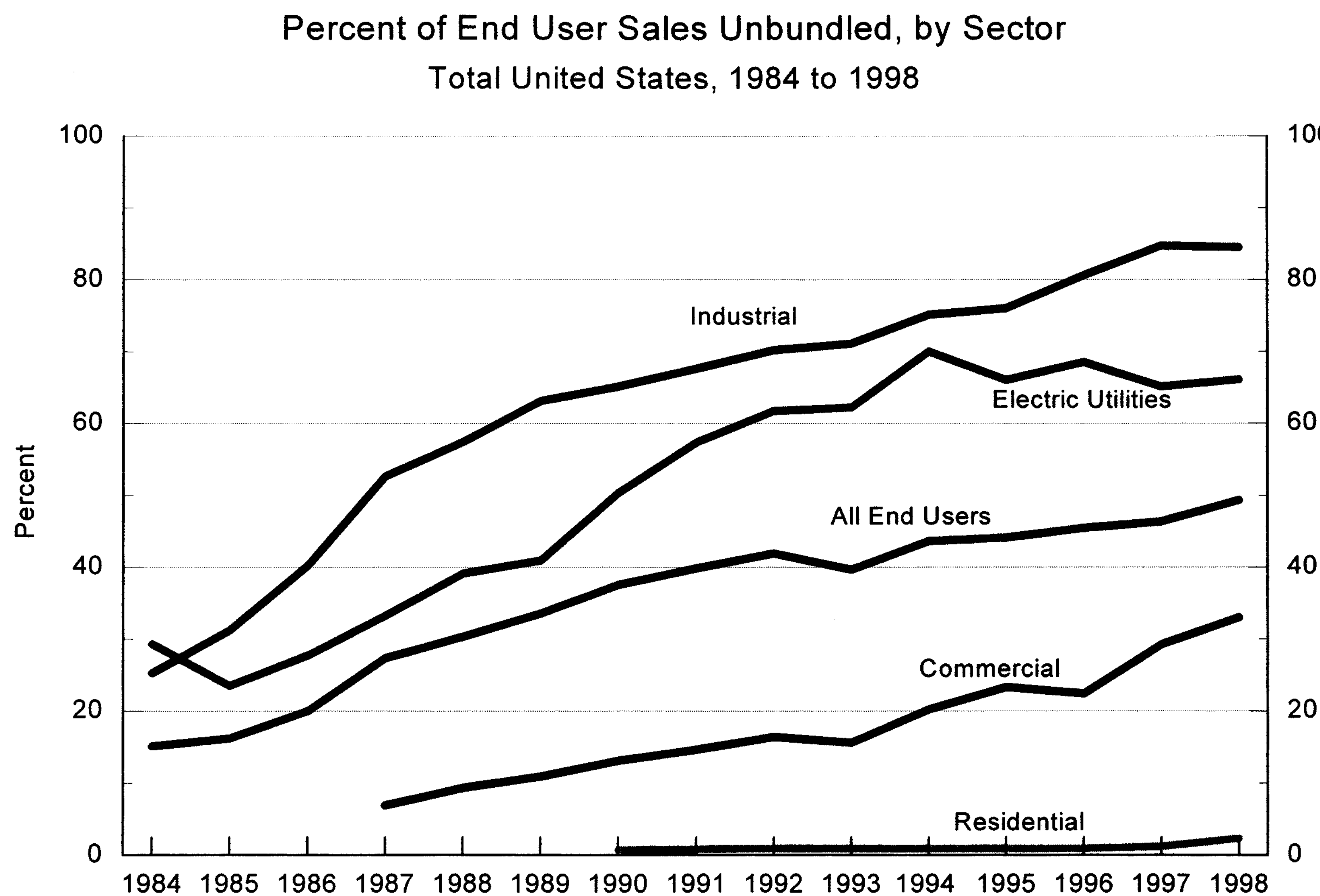
[10] As of 1998, the percentage of customers unbundled at the retail level were: industrials—84.5%, electric utilities—66.1%, other end users—49.3%, commercial customers—33%, residential consumers—2.3%. Energy Information Administration, Natural Gas Annual 1998, at 35–37, 39, 41 (Oct. 1999).

Figure 1 -- Retail Unbundling by End User Segment



Source: Energy Information Administration, *Natural Gas Annual 1998,* October 1999, pp. 35-37, 39, 41.
Note: The Energy Inrormation Administration believes there may be some double counting in the the number of residential customers for 1998.

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While industrial customers consume the largest amount of gas of any sector, the use of gas for electric generation shows the greatest recent growth, estimated for the first 11 months of 1998 at 11% greater than in 1997.[11]

Since Order No. 636, the industry has witnessed a dramatic growth in the use of marketers to provide gas, arrange transportation, or provide both services to LDCs, industrials, end users, and electric generators. Marketing is still relatively unconcentrated, with the shares of the top 4 marketers actually declining by one-third from 1992–1997.[12] At the same time, marketing sales volume has increased sharply, with the sales volume of the top twenty marketers tripling to 40 trillion cubic feet from 1992 to 1997.[13] Marketers currently hold over 20% of pipeline firm capacity.[14] Gas customers use marketers in a variety of ways. LDCs, which hold firm transportation on a single pipeline, can use the marketer to obtain and deliver gas to an interconnect point on that pipeline and the LDC can use its firm transportation service to deliver that gas to its citygate delivery point. Other customers, such as industrials, may employ a marketer to acquire gas and interstate transportation service to deliver the gas to the industrial's citygate delivery point. Increasingly, marketers are offering additional services to customers such as asset management services where the marketer manages capacity for LDCs as well as price hedging and risk management services, including the provision of financing options.[15]

Market centers: In order for producers and marketers to serve LDCs and other customers, active wholesale markets have developed upstream (in production areas) and they are growing in downstream markets as well. Gas customers have the choice of entering into long-term gas contracts to assure supply or price or they can rely upon monthly and daily spot markets to obtain their gas supplies. Customers further have the option of buying gas at upstream market centers in the production area or at market centers in downstream markets. A market center is a point of interconnection between pipelines where traders can exchange gas and shippers can obtain a variety of services, including gas trading, wheeling, parking, loaning, storage, and transfer facilities.[16]

Market centers enhance competition because buyers and sellers of gas have a greater number of alternative pipelines from which to choose in order to obtain and deliver gas supplies. The number of market centers has increased from 5 in 1992 to 38 today with additional market centers being proposed.[17] Although the initial market centers were in the upstream production areas, downstream market centers are now developing. (*See* Figure 2) [18]

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[11] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560(98), Natural Gas Issues and Trends 31–33 (1999).

[12] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560, Natural Gas 1998 Issues and Trends, 152–153 and Figure 55 (June 1999). According to one source, there are 541 electric and gas marketers as of 1998. The Energy Report, June 8, 1998.

[13] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560, Natural Gas 1998 Issues and Trends, 152–153 and Figure 55 (June 1999).

[14] *Id.* at 222, Table D12.

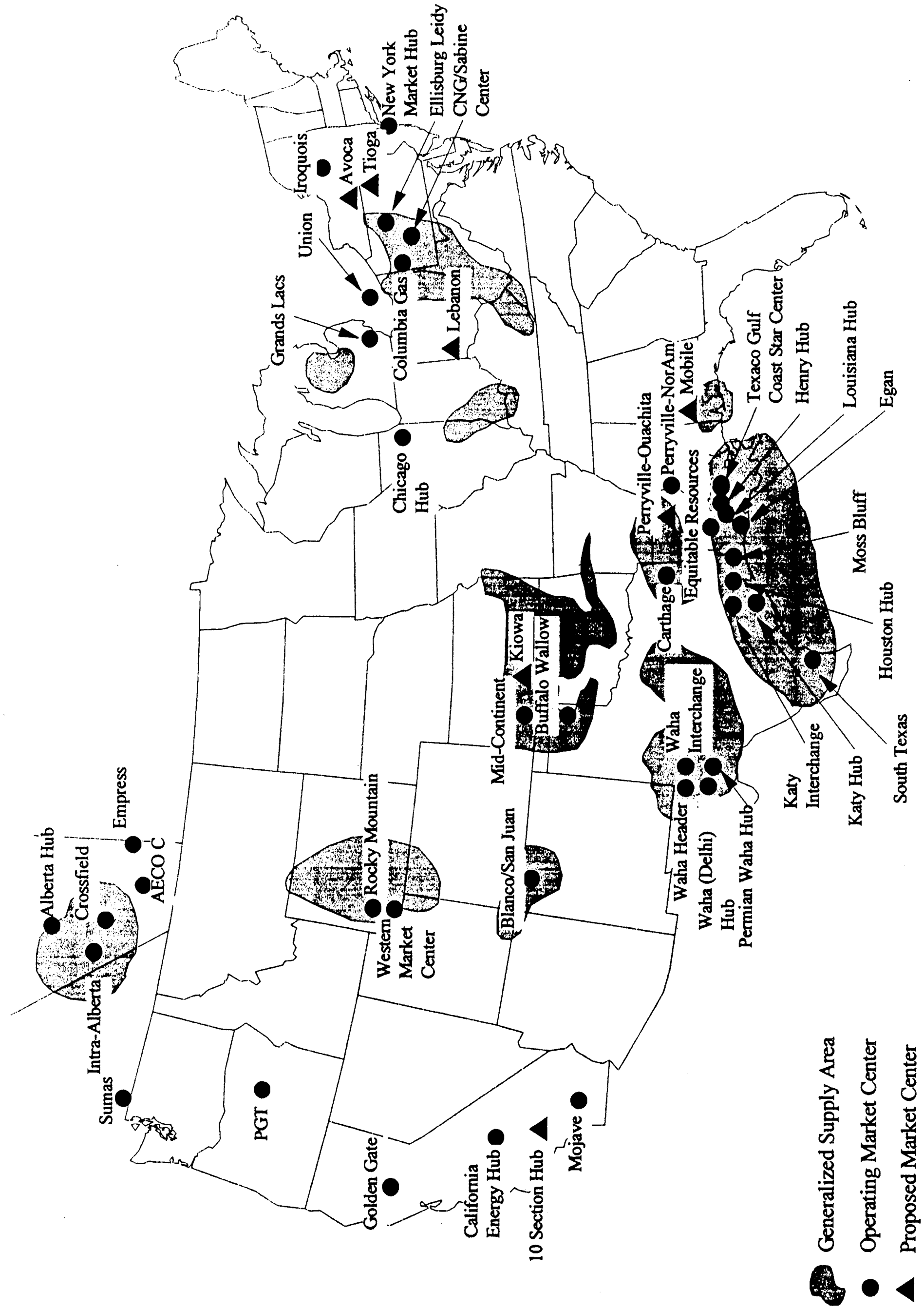
[15] *See* Comments of Dynegy (national marketer of both gas and electricity, asset manager for LDC capacity, owner of interstate pipelines and gathering systems, partner in retail gas ventures); Duke Energy Trading (provides gas and energy-related services); Enron Capital (asset management services, supplying gas for electric loads, price hedging and risk management services, provision of financing options).

[16] S. Holmes, The Development of Market Centers and Electronic Trading in Natural Gas Markets 1–2 (June 1999) (Discussion Paper 99–01, Office of Economic Policy, Federal Energy Regulatory Commission) (available from the Commission).

[17] *Id.*

[18] *Id.,* at Figure 1 and Table 1 (showing market centers in the Midwest, Northeast, and West).

Figure 2 -- Current and Proposed Market Centers as of June 1999



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The buying and selling of gas similarly has moved from the production area into downstream markets. Trade publications, for instance, report monthly prices at over 100 locations, including many downstream markets.[19]

Financial market: At the same time, an active financial market has developed on the NYMEX to enable wholesale shippers to hedge against future price risks in gas. The NYMEX futures contract has been the fastest growing instrument in its history, and in October 1992, NYMEX began offering options on natural gas futures, giving market participants additional flexibility in managing their market risk.[20]

Hedging occurs when a seller uses a financial instrument to fix the price at which it will buy or sell a commodity at some future date. By locking in a known price in the future, a buyer in the natural gas market, for example, can protect itself against future increases in the spot market price. Two financial instruments commonly used for hedging are a forward contract and a futures contract.[21]

[19] *See* Henning & Sloan, Analysis of Short-Term Natural Gas Markets, A–2 (Energy and Environmental Analysis, Inc., Nov. 1998).

[20] NYMEX, Henry Hub Natural Gas, *http://www.nymex.com* (November 17, 1999).

[21] A forward contract is a contract made now for the exchange (sale and purchase) of a physical commodity (or financial instrument) at some future date. For many forward contracts, no price is paid or received at the time the contract is entered into. The exchange contemplated in the forward contract almost always takes place. Forward contracts are usually used as a way to buy or sell the commodity.

A futures contract is a standardized contract to take or make delivery of a commodity (or financial instrument) at some future date at the prevailing price at the time they are entered into. Futures contracts differ from forward contracts in that delivery or receipt of the commodity almost never takes place. Holders of futures contracts get out of their contracts by acquiring opposite contracts for the same commodity and delivery date as their own. For example, a person who purchased a futures contract initially would sell a similar contract to get out of the initial contract prior to its delivery date. This process is known as ''offsetting'' the initial contract. After completing it, the purchaser is no longer a party to either contract.

When using futures to hedge, a seller or buyer of natural gas takes a position on the futures market that is the opposite of its position in the physical or cash market. The objective is to lock in a price (and consequently a margin) that is acceptable to the hedger. For example, a producer who wants to receive $2.00 per MMBtu for gas next month would sell a futures contract for $2.00 to deliver gas in that month. If the price on the cash market and the futures market both drop to $1.80 for the next month, the producer will obtain only $1.80 for its gas in the cash market. However, the producer can now close out its futures position by buying a similar contract (offsetting his contract) for $1.80. Since it originally sold for $2.00, it earns $0.20 on its futures position. This, added to the $1.80 received for its gas, provides the producer with the desired $2.00 price for its gas.

Transportation market: The growth of downstream markets has affected the transportation market as well. Shippers now have the choice of buying gas in upstream markets and transporting that gas to their downstream delivery points or purchasing gas in downstream markets.[22] Although not as well developed as the gas market, a more competitive transportation market also has developed with shippers able to choose between alternative means of acquiring capacity. Shippers can choose either short- or long-term services from the pipeline or acquire capacity from other shippers through the capacity release mechanism. As an example of the growth of the capacity release market, released capacity for the 12 month period ending March 1997 averaged 20 trillion Btu/day, totaling 7.4 quadrillion Btu for the year, a 22% percent increase over the previous 12 month period and almost double the level for the 12 months ending March 1995.[23] Unlike the commodity market, however, a formal forward or options market for transportation capacity has not developed, although private parties are providing price hedging and risk management services.[24]

The development of the wholesale gas market is dynamic, reflecting the ever changing supply conditions in the industry. In the past, gas supplies generally flowed north into the mid-west and Northeastern markets. But, with the development of new and increased gas supplies from Canada, gas supplies now flow south and east as well as north. Natural gas supplies from Canada have increased from less than 1 Tcf in 1985 to 3Tcf in 1998, and pipeline expansions would add approximately 3 Bcf per day of capacity to ship gas from Canada to the United States.[25] This flow creates additional market centers and trading points, such as the Chicago hub. Pipeline projects are being proposed to pick up gas at the Chicago hub and carry the gas eastward.[26] New supplies in the outer continental shelf, the production areas of Wyoming and Montana, and in Nova Scotia also create demand for new pipeline construction that will change the way in which shippers and pipelines do business and can lead to the creation of additional market centers and trading points.[27]

[22] *See* Gas Daily, September 14, 1999, at 2 (reports on citygate and pooling point prices); Natural Gas Week, November 1, 1999, at 7–8 (spot differentials between market hubs in production and consumption markets).

[23] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0618(98), Deliverability on the Interstate Natural Gas Pipeline System 83 (1998).

[24] *See* Comment of Enron Capital (providing price hedging and risk management services).

[25] *See* Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560, Natural Gas 1998 Issues and Trends, 12–13 (June 1999).

[26] *See* Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560, Natural Gas 1998 Issues and Trends, 21 (June 1999).

Changes have already occurred in the way shippers use pipelines because the growth of downstream market and trading centers has enlarged the purchasing options for gas buyers. As a result of market centers, for example, an industrial gas customer no longer needs to hold pipeline capacity upstream at the wellhead or production area. The industrial customer can hold firm capacity on the downstream pipeline that directly connects to its plant (or the LDC serving its plant) and purchase its gas from a marketer at a downstream market center. The marketer makes the arrangements for providing gas at the market center, which could include purchasing gas at the wellhead or an upstream market center in the production area and transporting the gas to the market center or simply purchasing gas from another party at the downstream market center.

The use of released capacity has made possible the development of virtual pipelines. A virtual pipeline can be created when a marketer or other shipper acquires capacity on interconnecting pipelines and can schedule gas supplies across the interconnect, creating in effect a new pipeline between receipt and delivery points that are not physically connected under a single pipeline management.[28]

Reliability and price: The changes in the wholesale market have increased efficiency and competition in the natural gas market. For example, NYMEX states ''the Commission's actions to date have promoted and produced a short-term gas market that is robust, functioning, efficient, and effective.'' [29] The increase in competition has not come at the expense of reliability, although that was a concern expressed prior to issuance of Order No. 636. For example, the first winter after implementation of Order No. 636, in February 1994, a cold spell hit the Northeast, but the market responded with prices rising to balance supply and demand, with only minor distribution outages well removed from the interstate system. Similarly, the market cleared even during severe

[27] *Id*; If You Build It, Will They Come (1999 Status Report), American Gas Association, Appendix A (summarizing new pipeline construction projects related to gas supplies in the Western Canada sedimentary basin, the deepwater Gulf of Mexico, and the Rocky Mountain states.)

[28] Comments of Dynegy and Reliant.

[29] Comments of NYMEX, at 2.

demand conditions during the winter of 1996.[30] Indeed, competition may improve reliability by enabling the market to adjust to demand conditions quickly without the need to rely on regulatory allocation or curtailment policies to determine who obtains gas.[31]

The ultimate test of any regulatory change is the impact of those changes on consumers. By this measure, wellhead decontrol and the Commission's policies have benefitted consumers by lowering the overall price they pay for natural gas. From 1983–1997, the price of natural gas to all industry sectors has fallen significantly from the peaks reached during the periods of gas price regulation and bundled sales. (See Figure 3)

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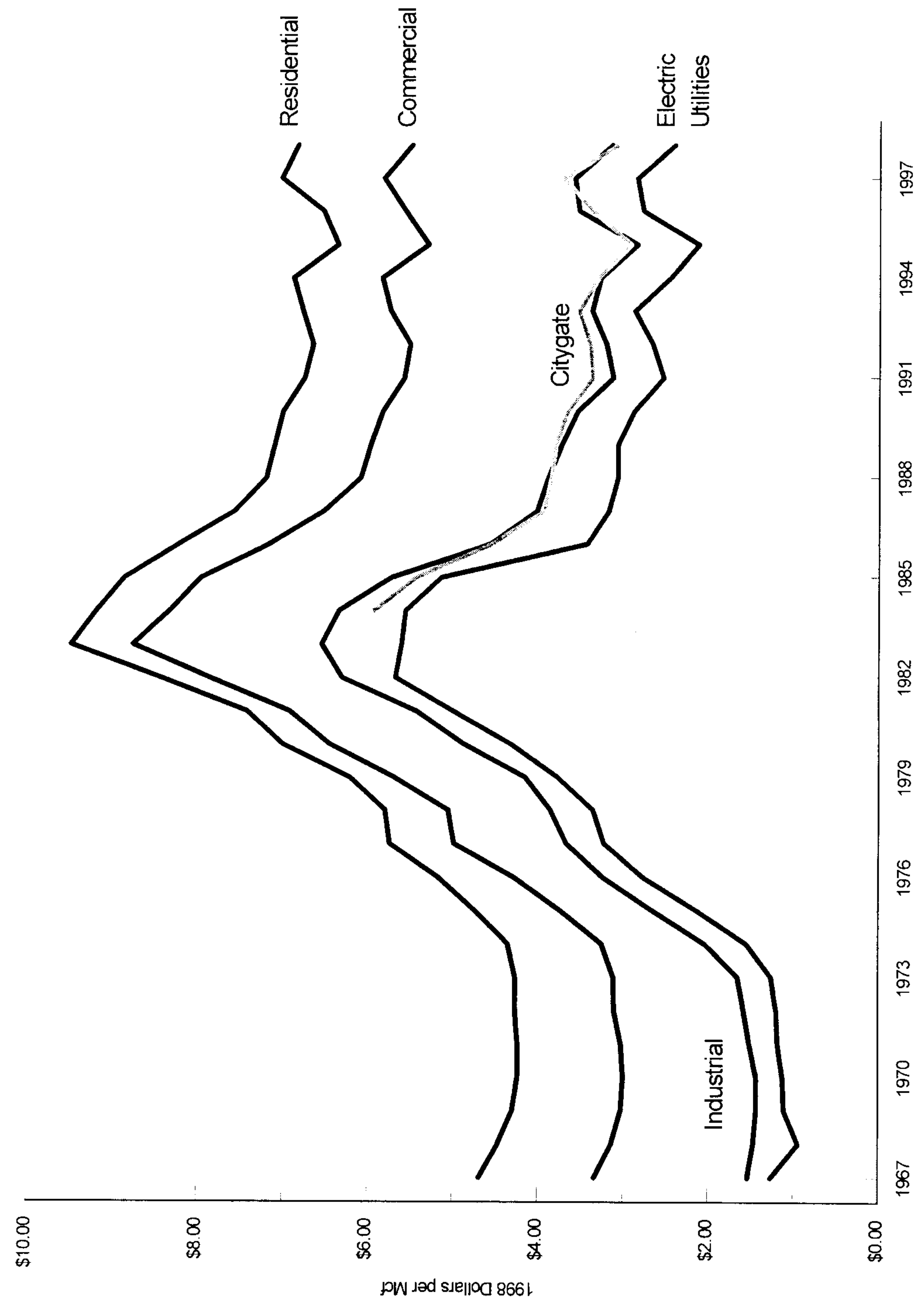
[30] *See* R. O'Neill, C. Whitmore, M. Veloso, The Governance of Energy Displacement Network Oligopolies, Discussion Paper 96–08, at 16–17 Federal Energy Regulatory Commission, Office of Economic Policy, revised May 1997) (copy available from the Federal Energy Regulatory Commission).

[31] *Id.* (concluding that the unbundled gas market has responded to severe demand conditions better than the traditionally regulated electric market).

Figure 3 -- Average Prices of Natural Gas by Industry Sector 1967-1998



Sources: Energy Information Administration, *Annual Energy Review*, 1997, and *Natural Gas Annual*, October 1999.
Note: Prices adjusted using GDP Deflator.

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eCommerce: The development of the wholesale gas market has been aided by the standardization of pipeline business practices and communication methodologies and the growth of eCommerce. As a result of Commission initiatives, the industry formed a self-governing standards development organization, the Gas Industry Standards Board (GISB), to develop standards for pipeline business and communication practices that enhance efficiency by better enabling shippers to move gas through markets centers and across interconnected pipelines.[32] GISB is a private organization which brings together all segments of the natural gas industry to develop needed standards. Its purpose is to reduce the disparities and inconsistencies in pipeline business and communication practices that have impeded the development of an integrated pipeline grid.

The Commission has encouraged the gas industry to move toward the use of eCommerce to increase efficiency. Beginning in 1993, the Commission established industry working groups to develop a set of electronic standards governing the trading of released capacity on pipeline Electronic Bulletin Boards.[33] Since then, GISB has been developing standards for conducting a wide range of business transactions over the Internet, including scheduling, transmission of flowing gas information, invoicing, and capacity release transactions.[34]

Along with the development of electronic communication between pipelines and shippers, an electronic market has developed to facilitate the buying and selling of natural gas. Electronic trading of natural gas is the furthest along of all energy markets.[35] Without electronic trading, shippers have to obtain gas by checking industry publications for a range of gas prices for the previous day, contacting potential gas suppliers using the telephone or fax machines to obtain price quotes to compare, deciding which is the best deal, and consummating the final transaction. Electronic trading creates a more efficient market by expanding the number of buyers and sellers interacting, reducing the time and resources needed to obtain price information and consummate trades, providing anonymity so traders do not have to disclose their market positions, and providing traders with more confidence in the prices they obtain.[36] One study estimates that on-line trading of natural gas in 1999 will amount to $10 billion.[37] Many of these electronic transactions occur at downstream markets. (See Figure 4 showing the electronic gas trading points for Altrade and Natural Gas Exchange).[38]

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[32] Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587, 61 FR 39053 (Jul. 26, 1996), III FERC Stats. & Regs. Regulations Preambles ¶ 31,038 (Jul. 17, 1996).

[33] Standards of Electronic Bulletin Boards Required Under Part 284 of the Commission's Regulations, 59 FR 516 (Jan. 5, 1994), FERC Stats. & Regs. Regulations Preambles (Jan. 1991–June 1996) ¶ 30,988 (Dec. 23, 1993).

[34] Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587, 61 FR 39053 (Jul. 26, 1996), III FERC Stats. & Regs. Regulations Preambles ¶ 31,038 (Jul. 17, 1996), Order No. 587–B, 62 FR 5521 (Feb. 6, 1997), III FERC Stats. & Regs. Regulations Preambles ¶ 31,046 (Jan. 30, 1997).

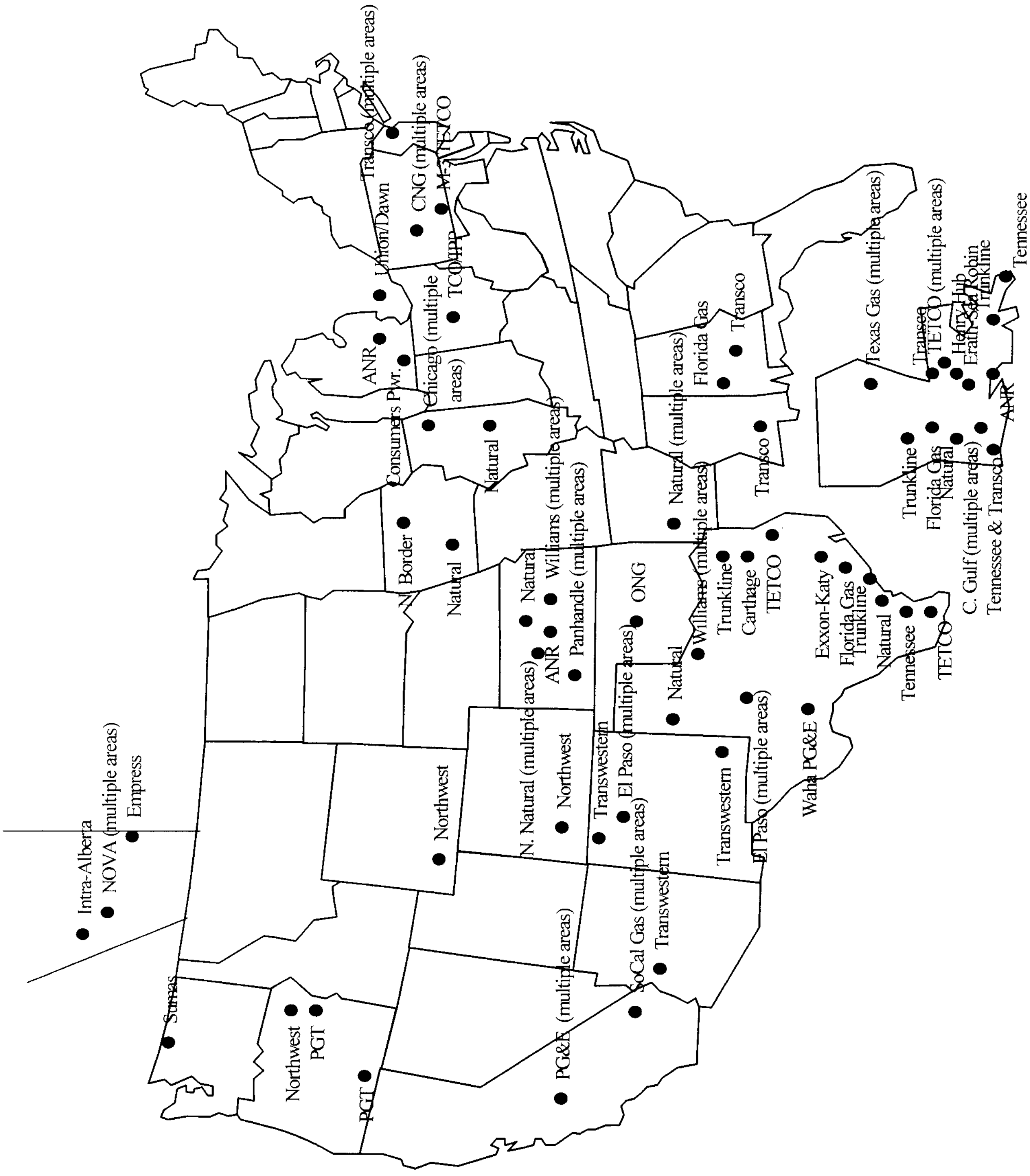
[35] V. Lief, The Surge of Online Energy, The Forrester Report, 2–3 (Sept. 1999); Comment of Altra; Enermetrix.com, *http://www.enermetrix.com.*

[36] As one interviewee in the Forrester report explained: ''before online trading, if you didn't talk to people all morning—you'd miss the market. We use it quite a bit and sometimes its the only market.'' V. Lief, The Surge of Online Energy, The Forrester Report, 2 (Sept. 1999). *See* Electronic Trading Revolution Not Over, Gas Daily, Vol. 15, No. 224, (Nov. 18, 1998) (electronic trading provides access to hundreds of potential transaction partners and price transparency).

[37] V. Lief, The Surge of Online Energy, The Forrester Report, 9 (Sept. 1999).

[38] The trading points for Altrade were provided courtesy of Ultra. The Natural Gas Exchange trading points are taken from S. Holmes, The Development of Market Centers and Electronic Trading in Natural Gas Markets 7 (June 1999) (Discussion Paper 99–01, Office of Economic Policy, Federal Energy Regulatory Commission) (available from the Commission).

Figure 4 -- Altrade and Natural Gas Exchange Trading Points



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New electronic trading companies are entering the market [39] and eCommerce for gas is expected to grow, reaching 20% of total gas business within two years.[40] The development of eCommerce can equalize the marketplace between large and small customers. As a customer quoted by Forrester Research states: ''Using online services has made us more efficient. We're a small shop so our resources are limited. The system puts us on the same page as the big guys.'' [41]

Implications for Commission regulation: Commodity and transportation markets are closely interdependent in the natural gas business with changes in one market affecting the other. This interdependence has important implications for the Commission's regulation of pipeline transportation. While the growth of a vibrant active wholesale marketplace has enhanced competition, this growth, particularly the development of downstream market centers and trading points, also creates both challenges and opportunities for Commission regulatory policy.

Many LDCs' contracts have expired, or are expiring soon, providing, in many cases, the first opportunity for these LDCs to recontract in the competitive market spawned by Order Nos. 436 and 636.[42] LDCs are considering whether to continue their current firm-to-the-wellhead capacity contracts or whether to reduce their contractual entitlements or to rely more heavily on purchasing gas from producers or gas marketers at downstream market centers or trading points. It is not clear whether marketers will choose to pick up all or some of the firm capacity relinquished by LDCs. Marketers' purchase of firm capacity, for instance, has been increasing, with their holdings increasing by 18% during the 12-months ending July 1, 1998.[43] But, unlike LDCs, marketers are not guaranteed passthrough of capacity costs and therefore are likely to subscribe to shorter term contracts than what the LDCs signed in the past.[44] Marketers, and other transportation customers, also may be less willing than LDCs to sign long-term contracts with *Memphis* [45] clauses that permit pipelines to increase prices unilaterally by filing new rate cases.

The renegotiation of contracts, both as to coverage and term, increases the risks for pipelines that may have greater difficulty reselling capacity (capacity turnback).[46] This raises issues about how to compensate pipelines for the increased risk as well as the proper way to design rates for customers remaining on the system.[47]

The growing importance of market centers suggests the need for policy development that will continue to foster the development of both upstream and downstream market centers. For instance, some urge that in order to further market center development, pipeline rate zones need to be redrawn to coincide better with market centers, rates need to be reestablished so that upstream capacity costs are not included in downstream rates, and capacity segmentation policies should be enhanced so that shippers can obtain capacity only on portions of a pipeline.[48] Reliant also suggests that the use of market centers can be encouraged by the creation of virtual pipelines in which one pipeline is able to acquire capacity on another pipeline.

The movement toward eCommerce highlights the need to create greater integration between the allocation system for pipeline and released capacity and the pipeline scheduling system. In addition, the integration of electronic trading for gas and pipeline capacity would further efficiency by permitting shippers to complete all aspects of a transaction in a single online auction. GISB has recently approved standards for title transfer tracking under which pipelines will track gas transactions between parties at pooling points using the electronic protocols for scheduling gas. Third parties also will be able to consummate gas trades at pooling points and have those trades processed by the pipeline.[49] Such title transfer services could form the basis for electronic trading that fully integrates gas and capacity trades with the pipelines' scheduling system.

b. Integration of the Gas and Electric Markets. The increasing development of wholesale markets for gas also are affected by the growing synergy between the gas and electric markets. The Commission, in Order No. 888,[50] and the states have begun to open the electric market to competitive forces in generation, a trend which is having, and is projected to have, a significant effect on gas markets. Gas for power generation is projected to grow 4.5% annually from 1997 through 2020, reaching 9.2 Tcf, a level three times the 1997 level of usage.[51] As a result of this new demand, the gas market is projected to grow from 22 Tcf per year today to 30 Tcf per year by 2010, a 27% increase over current levels.[52] Distributed power generation located near the end user may provide another vehicle for the use of natural gas, as many of these units are projected to use natural gas as an energy source.[53] Gas fired electric generators contend that their use of natural gas as a supply source would be improved by the provision of transportation service that enables them to coordinate the delivery of gas with their need to generate electricity.[54]

The increased integration of gas and electric markets is reflected in the

[39] Enron Launches Global Web-based Commodity Trading Site, *http://www4.enron.com/corp/pr/releases/1999/ene/EnronOnline.html* (Internet online trading for wholesale energy and other commodities).

[40] V. Lief, The Surge of Online Energy, The Forrester Report (Sept. 1999).

[41] *Id.* at 5. Another customer stated: ''Before we just always went to the big guys even though we were not necessarily getting the best prices. Now everyone is using the screens, everyone has the prices, and everyone has the advantage—making the net one culprit along the path towards reduced margins.''

[42] *See* Comments of Columbia.

[43] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560, Natural Gas 1998 Issues and Trends, 136 (June 1999).

[44] *Id.* at 137.

[45] United Gas Pipeline Co. v. Memphis, 358 U.S. 103 (1958).

[46] The Energy Information Agency has estimated the nationwide turnback level at 20% of the long-term contracted capacity as of July 1998, with variations by region. Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560(98), Natural Gas Issues and Trends 144 (1999).

[47] The Commission already has been faced with some of these difficulties. *See* El Paso Natural Gas Company, 83 FERC ¶ 61,286 (1998)(remarketing of turnback capacity); El Paso Natural Gas Company, 79 FERC ¶ 61,028, *reh'g denied,* 80 FERC ¶ 61,084 (1997), *remanded* Southern California Edison Company v. FERC, 162 F.3d 116 (D.C. Cir. 1999) (attempt to reach settlement on capacity turnback); Natural Gas Pipeline Company of America, 73 FERC ¶ 61,050, at 61,128–29 (1995) (recovery of turnback capacity costs).

[48] *See* Comments of Production Area Rate Design Group; Reliant.

[49] Final Actions Regarding Title Transfer Tracking, standard 1.3.64, *http://www.gisb,org/final.htm* (ratified on January 23, 1999).

[50] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 31,036 (Apr. 24, 1996).

[51] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560(98), Natural Gas Issues and Trends 33 (1999).

[52] Department of Energy/Energy Information Administration, 1999 Annual Energy Outlook (30 Tcf by 2010). *See* Gas Research Institute, Baseline Projection Data Book, at Page Sum 20 (1998 edition) (30 Tcf by 2015).

[53] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560(98), Natural Gas Issues and Trends 33. Distributed power is projected to account for 20 percent of additions to generating capacity, or 35 Gigawatts, over the next two decades. *See* Distributed Power Coalition of America, *http://www.dpc.org/faq.html* (November 17, 1999) (gas turbines most popular means of generating distributed power).

[54] See Comments of INGAA, Williams Companies, Reliant, Sithe, Sempra Energy, EEI. See *also* Reliant Energy Gas Transmission Company, 87 FERC ¶ 61,298 (1999) (hourly flexibility service designed to meet needs of power generators).

mergers between power generators and pipeline companies as well as the number of marketers that resell both gas and electricity.[55] Some marketers are operating their own generation plants.[56] For some customers, the energy markets have converged to a Btu market where the customer can purchase whatever energy source is cheapest at the time.

The pace of mergers and alliances raises questions about the future structure of the industry.[57] Mergers between pipeline corporations can increase concentration and reduce competition in markets where the merged firms previously competed. Vertical mergers between pipeline companies and gas fired power generators raise concerns about the ability of the integrated firm to injure competition by favoring its vertically integrated affiliate.[58] The increasing use of asset managers by LDCs [59] and other shippers to manage their pipeline capacity could result in the concentration of pipeline capacity in a few hands, reducing the competitiveness of the capacity resale market. The potential for increasing affiliation between pipelines and power generators also raises questions about whether changes are needed in the Commission's regulations of pipeline affiliate relationships, which are limited to pipeline marketing affiliates.[60]

c. Residential Retail Markets. The unbundling that already has taken place may be only a harbinger of the future. While unbundling for the larger industrial and end-use customers is at relatively high level,[61] unbundling for smaller commercial customers and for residential consumers has not taken place to the same extent. The growing focus in the states is on efforts to complete the unbundling process by offering unbundled services to commercial and residential consumers. According to the Energy Information Administration, as of June 1999, eleven states have active unbundling programs or are in the implementation phase, nine states and the District of Columbia have pilot programs or partial unbundling programs (with one state scheduled to begin its pilot program in November 1999), eleven states are considering action on unbundling plans, and eighteen states have taken no action. Consumer acceptance of these programs is mixed.[62] In Nebraska, 97% of eligible residential consumers have elected to choose their own supplier, while in other states participation of eligible consumers is 2% or less.[63]

The competitive dynamics of both gas and electric unbundling are generating a movement toward new ways of selling energy products to residential consumers. For instance, eCommerce is beginning to enter the consumer arena with companies offering residential customers one-stop shopping over the Internet for electric and gas service from affiliated companies as well as offering other utility services, such as long-distance telephone and Internet services.[64] There are business alliances between gas distributors and traditional consumer retailers to sell both gas and electricity to residential and commercial customers.[65]

Whether and how far residential unbundling will progress is one of the major unknowns in the current market and, even if it does occur, the implications of such a change are hard to predict. To the extent full residential unbundling occurs, LDCs would exit the interstate transportation function entirely, being replaced by producers and marketers, neither of which have the ability automatically to pass costs on to consumers. In the short-run, retail unbundling has created more uncertainty about contract duration. LDCs, which may unbundle their transportation service from gas sales, are unwilling to enter into long-term contracts for interstate capacity until the structure of unbundling in their state is determined.[66] Similarly, the marketers that may replace the LDCs are not in position yet to determine whether to sign long-term capacity contracts and for what quantities. In the long-run, however, the effect of unbundling on firm capacity holdings is less clear. Marketers still may choose to subscribe to firm capacity in order to guarantee service. In some states, regulators, concerned with ensuring reliable deliveries, are considering whether LDCs should be required to be the suppliers of last resort in case marketers default or whether marketers will be required to hold primary firm capacity as a prerequisite to participation in unbundling programs.[67]

B. The Commission's Response to the Transition in the Market

The Commission's response to the changes taking place in the market must be informed by its regulatory responsibilities and objectives.

1. The Commission's Regulatory Objectives

The Commission has the regulatory responsibility under the Natural Gas Act to ensure that pipeline rates and services are just and reasonable and not unduly discriminatory.[68] Just and reasonable rates and services need to be designed to achieve two principal objectives. They should promote competitive and efficient markets,[69] while mitigating market power and preventing undue discrimination, especially for the Commission's ''prime constituency, captive customers vulnerable to pipelines' market power''.[70] In short, the Commission's regulatory policy must seek to reconcile the objectives of fostering an efficient market that provides good alternatives

[55] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560(98), Natural Gas Issues and Trends 147–67, 231–42 (1999) (discussing the increased trend toward corporate alliances and mergers).

[56] *See* Comments of Dynegy (owner of power generation facilities).

[57] *See* Comment of Dynegy (expressing concern about the integrated corporations using transportation capacity as a marketing lever to obtain business for a generation affiliate).

[58] The Federal Trade Commission entered into a consent decree in one vertical merger between a pipeline and an LDC out of concern about the ability of the LDC to manipulate its confirmation practices to favor its pipeline affiliate. CMS Energy Corp, 64 FR 14725 (Mar. 26, 1999).

[59] *See* Comments of Dynegy, Enron Capital (providing asset management services).

[60] 18 CFR 161 (1999).

[61] See text and notes, *supra,* at Figure 1.

[62] Department of Energy/Energy Information Administration *http://www.eia.doe.gov/oil gas/natural gas/restructure/state/us.html* (2/2/00) (The eleven states that have active unbundling programs or are in the implementation phase are: New Mexico, New York, West Virginia, Georgia, Maryland, Massachusetts, New Jersey, Ohio, California, Colorado, Pennsylvania).

[63] *Id.*

[64] *See* Power Trust.com, *http://www.powertrust.com;* Essential.com, *http://essential.com.*

[65] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560(98), Natural Gas Issues and Trends 231 (1999) (alliance between Columbia Energy and Amway Corporation for door-to-door marketing of gas and electricity); *http://www.amway.com/infocenter/pressrel/pressrel49.asp* (November 18, 1999) (program expands from Georgia to Ohio); Ga. Marketers Unveil Deals, Gas Daily, November 16, 1999, at 5 (alliance between SCANA Energy and Krogers grocery stores to market natural gas services at kiosks).

[66] Comments of AGA I, PSE&G, Columbia.

[67] See Comment of ConEd.

[68] Natural Gas Act, § 4, 15 U.S.C. 717(d).

[69] Under the Wellhead Decontrol Act, for example, the Commission is obliged to structure its regulatory framework to ''improve (the) competitive structure [of the natural gas industry] in order to maximize the benefits of (Wellhead) decontrol. Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101–29, 101st Cong., 1st Sess., at 6 (1989); Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636.57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,939, at 30,932 (Apr. 8, 1992).

[70] United Distribution Companies v. FERC, 88 F.3d 1105, 1123 (D.C Cir. 1996). *See* Maryland People's Counsel v. FERC, 761 F.2d 780, 781 (D.C. Cir 1985); FPC v. Hope Natural Gas Co., 320 U.S. 591, 610 (1944); Associated Gas Distributors v. FERC, 824 F.2d 981, 995 (D.C. Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988).

to as many shippers as possible while at the same time creating a regulatory framework that is fair and protects captive customers without good alternatives.

In order to achieve these basic objectives, there are several subsidiary ends that regulatory policy should strive to achieve. Regulatory policies should seek to expand customers' alternatives and choices, which will in turn dissipate the ability to exercise market power. These policies need to create efficient market mechanisms that will enhance competitive options. They also should ensure that reliable information is available to better enable shippers to make informed choices in the market and to permit shippers and the Commission to monitor for undue discrimination and the exercise of market power. At the same time, to the extent adequate competition does not exist, regulation needs to mitigate residual market power and protect captive customers. In addition, regulation needs to be fair and administratively efficient, so that the regulation itself does not impose undue or unnecessary costs on the industry.

2. The Commission's Response to the Changing Gas Market

Since Order No. 436, the Commission has been reexamining its rate and regulatory policies to adapt those policies to changes in the competitive market and to ensure that its regulatory policies promote its goals and objectives.[71] In analyzing the interrelation between the Commission's current regulatory policy and the changing natural gas market, the Commission has concluded that its current regulatory framework does not meet the current needs of the market. In some situations, the current regulatory model inhibits the ability of the market to respond efficiently to demand conditions, limits shippers' capacity choices, and may not provide the lowest rates to captive customers.

The Commission is taking two steps to better achieve its regulatory objectives. First, in this rule, the Commission is taking an interim step to revise aspects of its current regulatory model to improve competition and efficiency, without making fundamental changes to that model. Second, the Commission is beginning an effort, outside of this proceeding, to examine more fundamental changes to its regulatory model.

a. The Changes Adopted in this Rule. The changes adopted in this rule are designed to improve the efficiency of the market and increase competition while continuing cost-of-service regulation to protect against the exercise of market power by pipelines. These changes involve modifications to the Commission's ratesetting policies to enable rates to better reflect market demand and to reduce the rate burden on captive customers, improvements to the Commission's regulation of the pipeline grid to increase competition, and revisions to the Commission's reporting requirements.

With respect to rates, the Commission is waiving the price ceiling for short-term capacity release transactions for a period of two years. This change is intended to improve shipper options and market efficiency during peak periods, when an efficient and effective market is most needed. During peak periods, the maximum rate cap on capacity release transactions inhibits the creation of an effective transportation market by preventing capacity from going to those who value it the most. The elimination of the rate ceiling will eliminate this inefficiency and enhance shipper options in the short-term market. To protect against the potential exercise of market power, the Commission is maintaining cost-of-service regulation of the pipelines as well as improving efficiency and competition across the pipeline grid along with enhanced reporting requirements that will provide more information to the market and permit better detection of market power abuses. While the changes in the natural gas industry support the removal of the rate ceiling, the Commission recognizes that this is a significant change in policy. The limited term waiver is intended to provide an opportunity for Commission review of this policy after the industry and the Commission have experience over two winters, which should be sufficient to analyze the results of this change.

The Commission further is revising its regulatory policies regarding rates for pipeline services to enable pipelines to file for peak/off-peak and term differentiated rates if a pipeline finds that such rates better reflect the demands and risks it faces. Such rates, however, would still have to satisfy the revenue and cost constraints of the traditional regulatory model. To help facilitate the trend toward eCommerce, the Commission is encouraging both pipelines and third-parties to develop voluntary auctions and is willing to consider waivers of some of its regulatory requirements that may impede the development of capacity auctions.

The removal of the rate ceiling for short-term capacity release transactions and the ability of pipelines to institute peak/off-peak and term-differentiated rates should help to reduce the cost of capacity to captive customers. The captive customers currently pay maximum rates for transportation capacity during peak and off-peak periods to support the pipeline system, while short-term shippers benefit by paying lower market prices during off-peak periods reflecting the reduced demand on the system, but do not face the market rate for capacity during peak periods as a result of the rate ceiling. The changes in ratemaking policies adopted in this rule will help to reduce the revenue responsibility of captive customers by placing on short-term shippers more of the burden of paying for peak period usage of the system. The Commission's objective is for the reduction in captive customers' revenue responsibility to be achieved through a combination of increased capacity release revenues, as well as revenue credits, reduced discount adjustments, and lower long-term rates on pipelines instituting peak/off-peak or term-differentiated rates.

To create greater substitutability between different forms of capacity and enhance competition across the pipeline grid, the Commission is revising its regulations regarding scheduling, segmentation and flexible point rights, penalties, and reporting requirements. The Commission is revising pipeline scheduling procedures so that capacity release transactions can be better coordinated with the nomination process. The Commission is further requiring pipelines to permit shippers to segment capacity wherever feasible, which increases potential capacity alternatives and helps to facilitate the development and use of market centers. The Commission's revision to penalty procedures will create appropriate incentives and will provide shippers with increased information and additional services to help them avoid the incurrence of penalties. The changes to the Commission's reporting requirements will enhance the reliability of information about capacity availability and price that shippers need to make informed decisions in a competitive market as well as improve shippers' and the Commission's ability to monitor marketplace behavior to

[71] *See* Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 FR 42408 (Oct. 18, 1985), FERC Stats. & Regs. Regulations Preambles (1982–1985) ¶ 30,665, at 31,534 (Oct. 9., 1985); 18 CFR 284.7(c); Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295 (1989) (requiring that rate methodologies must be designed to improve allocative and productivity efficiency).

detect, and remedy anticompetitive behavior.

The Commission is clarifying its policies regarding two aspects of pipeline service: the right of first refusal and negotiated rates and terms and conditions of service. The Commission is narrowing the right of first refusal (ROFR) in its regulations so that this right interferes as little as possible with the efficient allocation of pipeline capacity, while protecting captive customers against the loss of transportation service. The Commission is clarifying the operation of its policies regarding negotiated rates and negotiated terms and conditions of service in light of its decision in this rule not to adopt regulations providing pre-approval for pipelines to negotiate terms and conditions of service.

b. Process for Future Regulatory Policy Development. All of the changes in this rule remain within the Commission's current regulatory framework. As discussed earlier, many of the trends in the current market raise questions about a number of Commission regulatory policies, including the effectiveness of the current regulatory model in light of changes to long-term contracts, the effect of regulatory policies on market centers, the need to improve the effectiveness of eCommerce, and the regulation of pipeline affiliates not covered by the current affiliate regulations. It is not yet clear in what direction these trends will lead the market. The changes adopted in this rule are designed to improve the efficiency of the market and to facilitate its development, primarily toward the open and competitive marketplace that current conditions appear to support. Whether more fundamental changes are needed will depend on future market developments and especially how the industry responds to the changes adopted in this rule.

In the Notice of Proposed Rulemaking (NOPR)[72] and Notice of Inquiry (NOI),[73] the Commission sought comment on a variety of fundamental changes to its current regulatory methods to respond to issues raised by the changes in the gas market. In the NOPR, for example, the Commission sought comment on whether mandatory auctions should be used to allocate pipeline capacity and whether pipelines should receive pre-approval for negotiation of the terms and conditions of service with individual shippers. In the NOI, the Commission inquired as to whether fundamental changes in the cost-of-service rate methodology, such as indexing and incentive and performance based rates, should be implemented, whether market based rates are appropriate for turned back capacity, whether a periodic review of pipeline rates should be implemented, whether to revise the straight-fixed-variable rate design requirement, and whether options other than cost-based ratemaking would be more efficient.

Some commenters contend the Commission should make fundamental changes in its regulatory model to accommodate the changes in the market, maintaining that such changes would be consistent with the Commission's responsibilities under the Natural Gas Act. AGA and Williams, for instance, envision a market that is moving toward a structure divided between two classes of pipeline shippers: One class comprised of those customers with sufficient alternatives and options which insulate them from the exercise of market power by the pipelines; the other class comprised of those customers who are captive and have limited choices. As AGA states:

> Some LDCs are captive to pipelines' market power because they are tied to capacity contracts for many more years or because pipeline capacity is constrained into their region.* * * Other LDCs are not subject to abuse of market power by pipelines because they have been able to renegotiate their capacity contracts to better reflect their current and anticipated need for capacity and because capacity is not constrained into the region.''[74]

AGA proposes that the Commission institute two tracks for regulating pipeline transportation service, each available for any shipper to choose. One track would be for cost-based regulated tariff service and the other track for market-responsive negotiated services. The Williams Companies similarly assert that pipelines need to be able to respond to the needs of new customers, like gas fired power generators, by offering market responsive rates and contracts, while still providing cost-based rates as protections for all shippers.

Reliant contends that the development of greater competition in certain areas should lead the Commission to place greater reliance on the use of market forces to establish rates. It contends, for example, that market-based rates should be permitted for pipelines in producing regions where interstate pipelines compete with intrastate pipelines, when a pipeline is unable to sell turned back capacity, and where customers can solicit bids for services from more than one pipeline.

A number of parties support the use of auctions as creating more efficient and fairer methods of allocating capacity,[75] although many other parties are concerned about whether auctions can be designed efficiently and the ability to coordinate gas and capacity purchases in an auction limited to pipeline capacity.[76] INGAA is concerned that auctions would lower capacity prices which would threaten pipeline revenue recovery, and AGA is concerned about similar impacts on the value of released capacity.

Amoco and NGSA recommend significant changes in current regulatory policy through the adoption of an incentivized cost-of-service of service regulatory model to replace existing cost-of-service procedures. Others support periodic rate reviews or other methods of readjusting pipeline rates.[77] The Customer Coalition argues that the need to review these long-term issues requires that the Commission consider changes through a new NOPR, additional comments, or further technical conferences.

After reviewing the comments, and the current state of the industry, the Commission has determined that (1) it must approach its regulatory policymaking more strategically to determine whether it needs to examine and begin developing fundamentally new regulatory methods in anticipation of changing market conditions and (2) it must monitor market conditions on an ongoing basis to ensure that its decisions do not inhibit competition or foster inefficiency. In these proceedings, the Commission has studied improvements to its regulatory policies that would comport with current developments in the market. It must now ask whether it is effective in this dynamic environment to engage in generic policymaking without a deeper understanding of which possible regulatory model best achieves the Commission's regulatory objectives within the changing structure of the natural gas market and energy markets generally. The Commission, therefore, will be instituting a new process to undertake a continuing examination of

[72] Regulation of Short-Term Natural Gas Transportation Services, Notice of Proposed Rulemaking, 63 FR 42982 (Aug. 11, 1998), FERC Stats. & Regs. Proposed Regulations (1988–1998) ¶32,533 (July 29, 1998).

[73] Regulation of Interstate Natural Gas Transportation Services, Notice of Inquiry, 63 FR 42973, IV FERC Stats. & Regs. Notices ¶35,533 (July 29, 1998).

[74] AGA II, at 5.

[75] Comments of Amoco, Altra, Sithe, Southern Company Energy Marketing.

[76] *E.g.,* Comment of Dynegy.

[77] Comments and Supplemental Comments of the Customer Coalition.

the market and the relationship of its rules to the market. This examination will involve questions of rate design and risk allocation in light of changes to long-term contracting policies, improving market centers, creating greater integration of capacity allocation and scheduling processes with the growing trend toward eCommerce, and reexamining the methods for setting and reviewing pipeline rates.

In a nutshell, the Commission still largely applies a coherent ''model'' of regulation designed for traditional regulated monopolies. Its ratemaking tenets were not fundamentally questioned even as Order Nos. 436 and 636 were adopted. However, the current market may in fact call into question the basic underpinnings of this model and require the Commission to examine the legitimacy of alternative models. Some commenters suggest, for example, that the market is moving toward a dual market structure in which some customers want to negotiate with the pipelines, while others are still captive and need protection against the exercise of market power and undue discrimination. If that is the case, such a trend raises significant questions about the nature of the Commission's regulatory model. Designing a regulatory framework to accommodate such a trend, if that is the direction of the industry, would involve issues such as whether to permit negotiated terms and conditions of service, whether to allow market-based pricing for pipeline services (both long and short term), whether and how to support pipeline revenue requirements, and whether to change rate designs or the ratemaking process itself.

The Commission's current regulatory model is premised on the assumption that regulation of all pipeline services is necessary and that pipeline rates should be set so that the pipeline is given a reasonable opportunity to recover its prudently incurred costs. But this model would need to be changed to accommodate a two-track model of regulation in which non-captive customers would face market priced services and service flexibility and captive customers would be able to obtain service at regulated rates to protect against the exercise of market power.

A two-track regulatory model would require development of new regulatory methods developed for both the non-captive and captive customers. Customers opting for negotiated service should be subject to the risk of that choice and not be able to choose to negotiate only when it benefits them. New methods would be needed for determining just and reasonable rates and services to protect captive customers.

Captive customers should not be forced to pay for pipeline losses or additional risks in the unregulated portion of their businesses. Indeed, such an outcome may be difficult to square with the Commission's mandate under the NGA. If pipelines are given the upside potential inherent in lifting regulatory controls over prices and services, it is questionable whether they should have their revenues supported by a ratemaking regime that also guarantees the recovery of all ''prudently incurred'' costs.[78] Under a two-track regulatory model, therefore, the rates for captive customers would likely need to be established separate from the revenues from the pipelines' market-based services. One possibility would be to establish captive customer rates based on the proportion of pipeline capacity used by the captive and non-captive customers rather than as is done today on throughput and contract demand. It also might be necessary to change from rates based on a pipeline's individual cost-of-service to rates developed more on average industry costs. In addition, quality of service would need to factor into rate design so that pipelines would have an incentive to continue to improve the quality of service for captive customers.

The industry indeed may be headed in a direction that would make a two-track regulatory model appropriate. If so, these are the kinds of issues with which the Commission would need to grapple. It is not clear, however, whether this is in fact the industry's direction or whether a two-track regulatory model would be the best regulatory model to use. The market's development may reveal that other regulatory models are more desirable. It is possible that a sound regulatory approach could fall anywhere on a spectrum, from traditional utility regulation to a lighter-handed, highly market-oriented focus. Where Commission regulation should fall on that spectrum will depend on the developments in the market and the specific measures that would promote efficiency and protect captive customers at any moment in time. Simply because the industry is in transition today and these choices are therefore difficult, does not mean that the larger questions, of how to adapt the Commission's regulatory approach to changing conditions and how to move policy toward identifiable goals or models, are to be avoided.

The Commission, therefore, is still considering whether to move forward on various proposals for changes in its current regulatory framework, including the use of negotiated terms and conditions of service, changes to SFV rate design, whether to permit discount adjustments, whether to adopt rate reviews or refreshers, and whether to permit more market-based rates. But these issues are interrelated in many respects and cannot be considered separately. Rather, they must be considered within the overall context of the regulatory model that is most appropriate for the current conditions in the market and its likely future direction.

In order to better address these interrelated issues, the Commission has determined to institute a new process outside of this proceeding that will undertake a more systematic approach to evaluating the direction of future natural gas regulation than was possible in this proceeding. This process will be a flexible one and will involve Commission monitoring of the market, dialog between various industry segments, as well as participation by Commission staff in industry conferences or the establishment of new Commission docketed proceedings if needed.

Any such systematic approach to continuous improvement must do two things. First, it should not contribute greater uncertainty to commercial transactions. The Commission, therefore, needs to collaborate with the pipeline industry and its customers to advance market efficiency on a consensus basis where possible. Second, it should be based on current information. Therefore, the Commission needs to gather and analyze data on an ongoing basis to ensure that its decisions, even in individual cases, reflect the current state of the market. In order to address the comprehensive regulatory issues raised by the changing gas market, the Commission is directing its staff to develop the appropriate market monitoring capability and to begin engaging in a continuing dialog with the industry about potential regulatory improvements.

Through monitoring, the Commission staff will seek to evaluate the structure, conduct, and performance of the industry. For example, Commission staff is directed to look at issues relating to capacity availability during periods of peak and nonpeak demand, the concentration of capacity holdings

[78] Williams, for instance, recognizes that if pipelines are to be given the same potential as competitive firms to earn greater returns through market opportunities, they need to be subject to the risks of market failure just as are unregulated firms.

during peak and nonpeak periods, and the rates charged for service.

This analysis should seek to identify markets where light-handed regulation may be appropriate, as well as those markets in which competitive constraints still exist and the reasons for such constraints. This will allow an assessment of the need for negotiated terms and conditions of service. Such monitoring also will include examination of the industry's response to the changes in this rule to see the effects of these developments on the market. In this regard, the revised reporting requirements adopted in this rule will permit the Commission to examine how capacity prices respond to the lifting of the price ceiling on short-term capacity release transactions and how delivered prices and capacity prices track each other.

The staff should also monitor pipeline rates and operating and maintenance expenditures to see how well pipelines are performing both as an industry and individually compared to the rest of the industry. Such measures should provide a better measure of pipeline performance than relying on earnings or profitability based on historic investment in plant and equipment. In this regard, the staff should examine whether to change the annual reporting forms filed by pipelines to reduce the burden of supplying unnecessary information, while focusing the reports on data that will provide for a better evaluation of pipeline performance and efficiency. As part of this review, staff should consider whether performance based ratemaking should be pursued as a means to establish rates that appropriately reimburse pipelines for efficiency gains while passing on some of those gains to ratepayers through reduced rates.

In addition, the Commission will be looking at the development of the market in a number of areas, including residential unbundling, evolution of downstream gas markets, the development of eCommerce and auctions, mergers and changes in market structure, affiliate relationships and conduct, the effect of penalties on the market, and long-term investments.

But monitoring, by itself, is not sufficient to develop a full picture of the trends in the industry. It is important for all segments of the industry to engage in a dialog to consider how industry changes do or should affect Commission regulatory policy. Such a dialog will enable the Commission and state regulators to achieve a better understanding of industry trends and regulatory changes that better meet the changing character of the industry. Also, constructive dialog between all the industry segments such as was held under the auspices of the Natural Gas Council will be needed if the industry is to grow to the levels some project. This kind of industry dialog can occur independently of government regulators or it can begin initially with regularly scheduled Commission staff conferences with the industry and market participants. The frequency of these conferences and the nature of any reports or recommendations to the Commission can be determined by the participants themselves.

Some of the topics that need to be considered are:

• Whether regulatory changes would further facilitate upstream and downstream market centers, trading areas, and greater gas liquidity;
• Whether changes are needed in gas transportation policies to accommodate the increasing convergence of energy markets;
• Whether the Commission should seek to create greater standardization in terms and conditions of service across the grid;
• Whether regulatory policy with respect to pipeline affiliates and nonaffiliates, as well as asset managers and agents, should be revised to reflect the changing nature of the gas market;
• Whether auctions should be developed to coordinate the allocation and scheduling of capacity and the purchase and sale of gas;
• Whether rate design policies need to be changed to establish incentives for pipelines to enhance quality and efficiency and reward pipelines appropriately;
• Whether the Commission should fundamentally reform its current regulatory model, moving to a two track model or to performance based ratemaking; and
• Whether adjustments to reporting requirements beyond those adopted in this rule are needed to better reflect pipeline performance and efficiency.

Examination of these topics could show that changes in certain areas would be inconsistent with changes in other areas, while other changes would complement each other. Whether discussion of these topics ultimately leads to regulatory changes, and what those changes might be, will depend on the outcome of the dialog and developments in the market. The objective is to establish, as routine, an industry-wide dialog with the Commission, through its staff, to determine whether changes are needed in Commission policy and regulation to achieve the Commission's regulatory objectives.

To begin this process, staff will be scheduling technical conferences over the course of the year to discuss issues relating to: whether changes are needed to facilitate the development of upstream and downstream market centers and trading areas, including rate design changes; whether changes are needed to accommodate the convergence of electric and gas markets; whether the Commission should seek to create greater standardization of services and penalty provisions; and whether there need to be revisions to regulations relating to pipeline affiliates.

In the sections that follow, the Commission discusses the changes in its regulations and policies that are being adopted in this order.

II. Adjustments to Rate Policies to Improve Efficiency and Protect Against the Exercise of Market Power

The Commission's objective in designing rates is to establish a ratesetting framework that increases efficiency in the marketplace, while protecting against the potential exercise of market power. No regulated rate can perfectly emulate the prices found in a competitive marketplace nor protect perfectly against the exercise of market power. This is particularly true when the regulated firm is a natural monopoly [79] where the competitive price would be insufficient to permit the firm to recover its costs.[80] Thus, price regulation often permits some exercise of market power and involves tradeoffs between pricing efficiency and the regulatory control over market power. On balance, the Commission finds that the changes to regulation made in this rule—removing the rate ceiling from capacity release transactions, permitting pipelines to file for peak/off-peak and term differentiated rates, plus the improvements to scheduling, segmentation, penalties, and reporting requirements—will enhance marketplace efficiency and competition, protect captive customers, and set prices for short-term transactions that reflect demand during peak periods, while not

[79] *See* United Distribution Companies v. FERC, 88 F.3d 1105, 1122 & n.4 (D.C. Cir. 1996) (pipelines are treated as natural monopolies with enormous economies of scale producing declining average costs).

[80] The competitive price is the single price at which the marginal cost curve intersects the demand curve. Due to declining average costs at the point where demand intersects marginal cost (the competitive price), a natural monopoly charging what would be the competitive price for capacity would not cover its total investment. This creates difficult questions of devising an efficient price structure. *See* Comment of El Paso Energy, Appendix A, at 15 (no way to ensure revenue adequacy for pipelines without deviating in some way from short-run optimal prices); 1 A. Kahn, The Economics of Regulation, 130 (1970) (in decreasing cost cases, price at marginal cost insufficient to cover total costs); R. Posner, Economic Analysis of the Law, § 12.1, 251–254 (2d ed. 1977) (difficulty of devising an efficient price structure for natural monopolies).

jeopardizing protections against the exercise of market power.

In this Part, the Commission discusses the changes in rate policies for capacity release transactions as well as for pipeline services. The first section discusses generally the inefficiencies created by the current regulatory method and how the removal of the rate ceiling for short-term capacity release transactions will create a more efficient and competitive marketplace. That is followed by discussion of changes in policy with respect to pipeline service, i.e., peak/off-peak and term differential rates. Finally, the use of voluntary auctions as a means of pricing short-term services is discussed.

A. Removal of the Rate Ceiling for Short-Term Capacity Release Transactions

During peak demand periods, when capacity is at a premium, the need to provide shippers with the greatest number of potential options and the most efficient competitive marketplace is crucial. Shippers that most need capacity during periods of scarce supply need a market that can efficiently respond to their demands and provide the capacity they need. The Commission's regulatory framework also needs to protect captive customers and fairly apportion revenue responsibility between captive customers with limited alternatives and short-term shippers with greater options. At the same time, the Commission's regulatory mechanism needs to provide all shippers with as much regulatory protection against the exercise of market power as possible. The removal of the rate ceiling for capacity release transactions with continued cost-of-service regulation of pipeline services better satisfies these objectives than continuation of the current uniform maximum rate ceiling for capacity release transactions.

This section first examines the inefficiencies engendered by the current uniform maximum rate ceiling; second, it summarizes the options put forward in the NOPR and comments for dealing with these inefficiencies; third, it discusses how the removal of the rate ceiling for capacity release transactions provides for more efficient markets and protects captive customers, while maintaining cost-based regulation of pipeline services as a protection against market power; and fourth, it addresses the comments on the legal and policy basis for these regulatory changes.

1. Current Regulatory Framework

a. Description of the Current Regulatory Framework. Under section 4 of the NGA, rates are established by the pipeline filing for rate changes. The rates thus established continue in effect until the pipeline makes a subsequent rate case filing or the Commission takes action under section 5 of the NGA and determines that the existing rates are not just and reasonable.

The Commission currently develops a maximum annual transportation rate for each pipeline that, when applied to the pipeline's contract demand and throughput levels, will enable the pipeline to recover its annual cost-of-service revenue requirement. When the Commission sought to develop a maximum rate for monthly or daily interruptible or short-term firm transactions, it simply took the yearly maximum rate and divided by 12 or 365, respectively.

The principal reason for limiting pipeline rates to a level that would permit recovery of the pipeline's annual revenue requirement is to limit the ability of the pipelines to exercise market power, so that the pipeline does not charge excessive rates. Without rate regulation, pipelines would have the economic incentive to exercise market power by withholding capacity (including not building new capacity) in order to raise rates and earn greater revenue by creating scarcity. Because pipeline rates are regulated, however, there is little incentive for a pipeline to withhold capacity, because even if it creates scarcity, it cannot charge rates above those set by its cost-of-service. Since pipelines cannot increase revenues by withholding capacity, rate regulation has the added benefit of providing pipelines with a financial incentive to build new capacity when demand exists. The investment in new capacity increases a pipeline's revenue because the new investment increases the pipeline's rate base on which the pipeline earns a rate of return.[81] Thus, annual rate regulation protects against the pipeline's exercise of market power by limiting the incentive of a monopolist to withhold capacity in order to increase price as well as creates a positive incentive for a pipeline to add capacity when needed by the market.

The protection provided by rate regulation, however, is related solely to the pipeline's annual revenue requirement, not to the monthly or daily rate charged by the pipelines for capacity. The monthly or daily rate does not approximate the rates that would be charged in a competitive market, since such short-term rates do not seek to match price with the demands placed on the system. Indeed, the current regulatory model permits pipelines to exercise market power by selectively discounting their daily, monthly, and sometimes yearly rates (in effect price discriminating) at rates less than the maximum rate. Selective discounting helps the pipeline generate more annual revenue than it could receive by charging a single fixed price. The justification for permitting selective discounting is that the additional revenue benefits those shippers paying maximum cost-of-service rates by reducing, in the pipeline's rate case, the amount of the costs that otherwise would be recovered through the rates paid by those captive customers.[82]

In Order No. 636, the Commission applied the daily maximum rate to capacity release transactions. At that time, the Commission declined requests to remove the price cap for released capacity on the ground that the release market had not been shown to be sufficiently competitive.[83] When Order No. 636 was issued, most gas transactions occurred at the wellhead or upstream market centers.

Since Order No. 636, the gas market has continued to evolve with the development of spot markets in downstream markets at which customers without firm capacity or without sufficient capacity to cover their needs purchase delivered gas on a short-term basis. The price for these transactions reflects both the cost of gas and the value of transportation to the delivered market. Figure 5 shows the variances between weekly average gas prices in various upstream and downstream markets as well as the implicit price for transportation between each of the markets. The prices at each designated market represent the price of gas and the figures in parenthesis between markets represent the implicit value of transporting gas from the lower priced to the higher priced market. The prices in

[81] For instance, if a pipeline has a current rate base of $1 million and an approved overall rate of return of 10%, the pipeline earns $100,000. However, if demand justifies an expansion of the pipeline's system at a cost of $500,000, at the same rate of return, the pipeline would earn $150,000, thus creating a financial incentive to expand the pipeline's system whenever demand permits.

[82] Associated Gas Distributors v. FERC, 824 F.2d 981, 1010–1012 (D.C. Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988); Comment of El Paso Energy, Appendix A (price discrimination below the existing maximum rate helps pipelines recover cost-of-service); 1 A. Kahn, The Economics of Regulation 131–33 (1970) (price discrimination one solution to problems of natural monopoly and declining costs).

[83] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under part 284 and regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636–A, (Regs. Preambles Jan. 1991–June 1992) FERC Stats. & Regs. ¶ 30,950, at 30,569 (1992).

downstream markets, such as the Chicago Citygate, represent the price paid by shippers purchasing delivered gas at that market.[84] The implicit price for transportation represents the most any shipper purchasing delivered gas at a downstream market would pay to move gas from the lower priced market to the higher priced market. For instance, the implicit value of transportation between the Henry Hub and the Chicago Citygate market was $.07 in September 1999 (the difference between the $2.67 price for gas in Chicago and the $2.60 price at the Henry Hub).[85]

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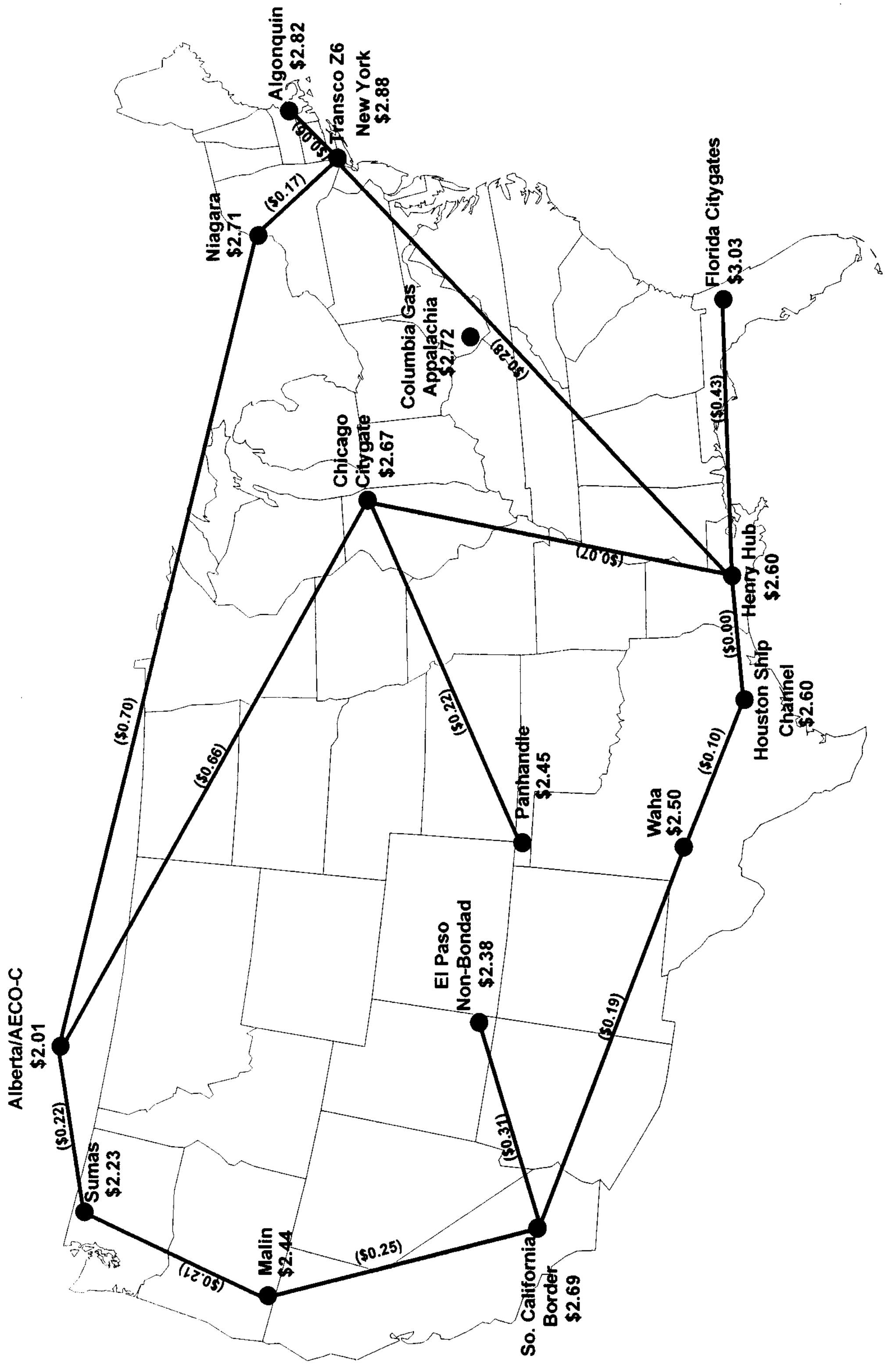
[84] The prices in downstream markeets do not represent the price firm shippers would pay. A firm shipper could purchase gas at the Henry Hub price and would pay only the low usage charge to transport gas to Chicago.

[85] A shipper would not pay more than $.07 to transport gas purchased at $2.60 at the Henry Hub to the Chicago Citygate market, because the shipper could buy gas for $2.67 at the Chicago Citygate.

Figure 5 -- Regional Natural Gas Prices and Differentials in Transportation Values
September 1999



Source: *Gas Daily*, Weekly Weighted Average Prices. Data through September 30, 1999.
Note: Prices shown on map are in dollars per MMBtu.

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The value of the transportation component of these bundled sales transactions results from the interaction of supply and demand forces and, unlike capacity release transactions, is not constrained by the maximum rate. Particularly during peak periods, shippers making bundled sales in the current market can avoid the maximum transportation rate and thereby obtain the market value for their capacity.

Figure 6 shows the increasing value of the transportation component during peak periods when demand for capacity is high. The transportation values in this chart represent the implicit amount that shippers that are unable to use firm capacity would pay for the transportation component of a bundled sales transaction. In the graph, for instance, the value of transportation rose to $6.50/MMBtu during the peak winter period of 1995–1996, to $1 during the winter of 1996–1997, and to less than $.50 during the winter of 1997–1998.

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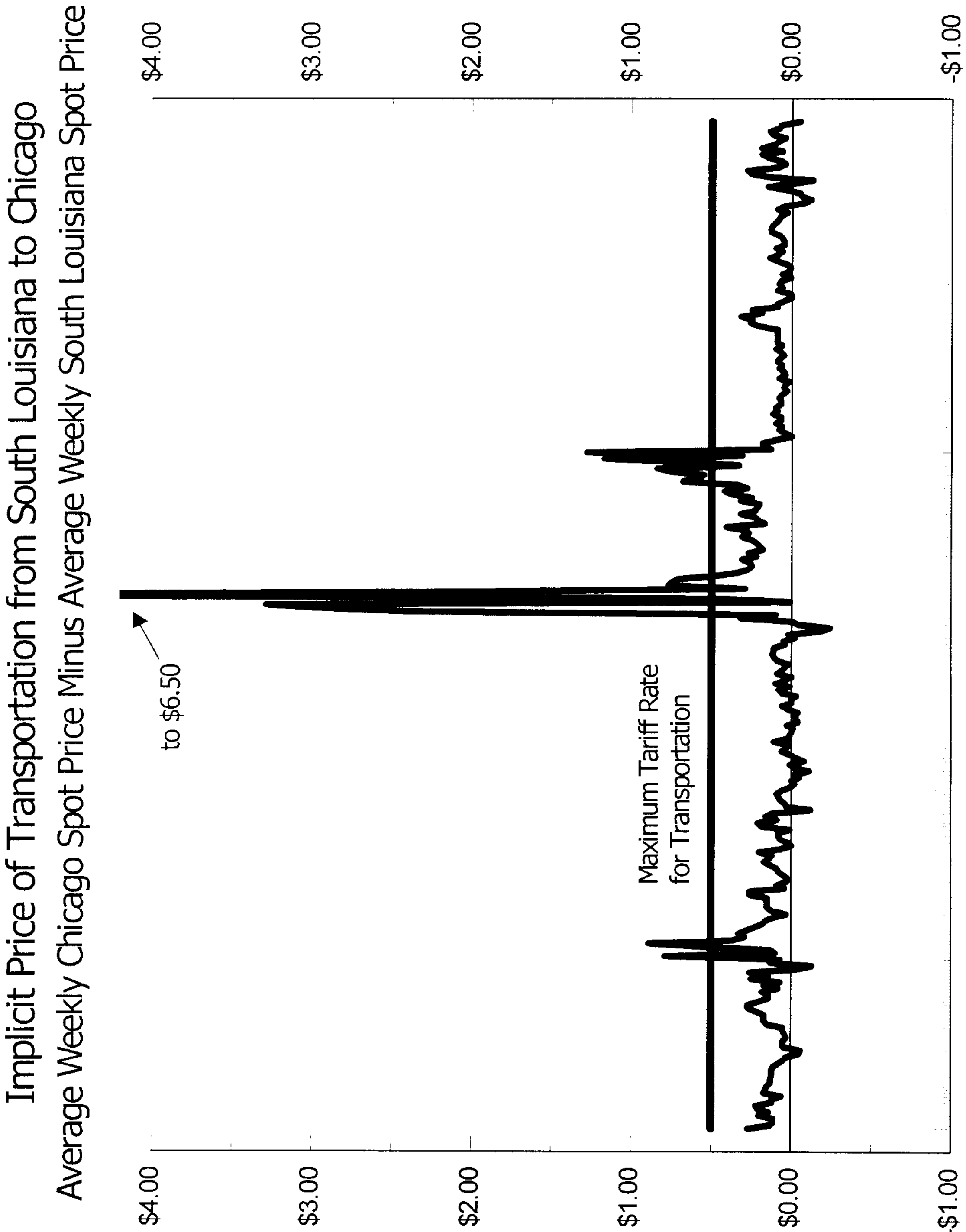
Figure 6 -- Implicit Transportation Values



Sources: *Gas Daily*, Weekly Weighted Average Prices and PI Grid. Data through December 31, 1998.
Tariff rate is the IT rate from Natural Gas Pipeline.

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Figure 7 illustrates how the value of transportation can vary on a daily basis. This graph shows the price of gas in the New York market for January 2000 compared with the price of gas in the production area. The line entitled production area price plus maximum transportation rate reflects the price that would be paid by a shipper purchasing gas in the production area and transporting that gas to New York at the maximum interruptible transportation rate on the pipeline.[86] As the chart shows, as temperatures dropped in the Northeast during January,[87] the price of buying delivered gas in New York rose to $15/MMBtu. In contrast, before the weather turned colder, the price of delivered gas in New York essentially reflected the price of gas in the production area plus the maximum transportation rate to transport that gas to New York. The difference between the price in the New York market area and the production area price represents the implicit price for (or value of) transportation paid by those shippers buying delivered gas in New York.

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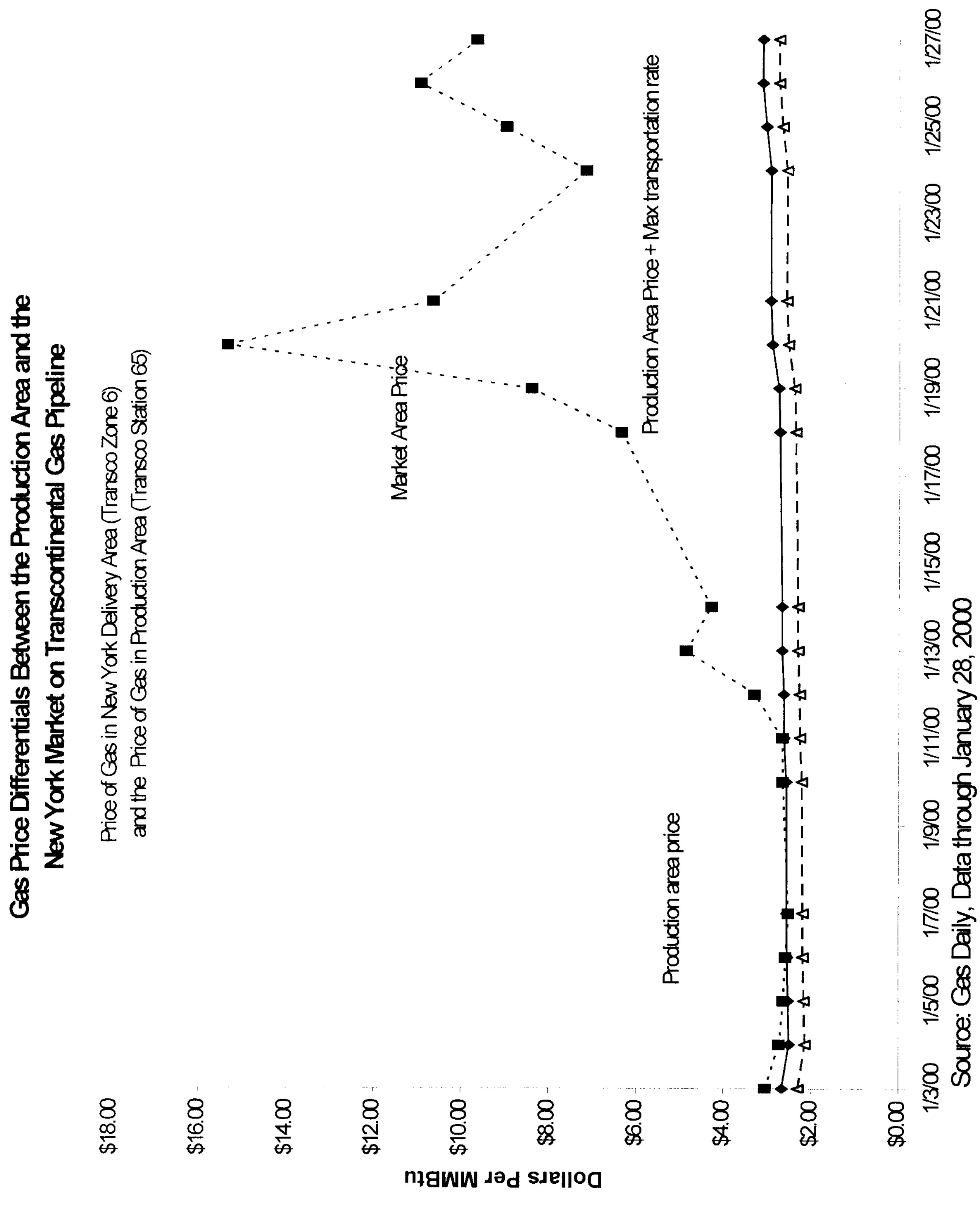
[86] Firm shippers would pay a lower rate because they would pay the production area price plus a usage charge of only $.0202 which is much lower than the maximum interruptible transportation rate of $.3147. *See* Transcontinental Gas Pipe Line Corporation FERC Gas Tariff, Third Revised Volume No. 1, Eighth Revised Sheet No. 35–A (firm usage charge zones 4–6) and Eighth Revised Sheet No. 42 (interruptible rate zones 4–6).

[87] The temperatures during this period changed from daily range in the low mid-thirties to low fifties to mid-thirties during the early part of the month to temperature ranges in the teens and low twenties during the later part of the month. The temperatures are reported at http://www.wunderground.com/US/NY/New York.html (historical data).

Figure 7 -- Price Differentials During January 2000



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Market Area Price—The market area price is the price paid by short-term customers (those without sufficient firm capacity for their needs) to obtain gas in the New York market. Shippers using firm capacity would pay the production area price plus the 2 cent usage charge to transport gas to New York.

Production Area Price—This is the price of gas purchased at the production area.

Production Area + Maximum Transportation rate—This is the price a shipper would pay if it could buy gas in the production area and ship it to New York at the pipeline's maximum IT rate.

Value of Transportation—The value of transportation is the area between the market area price and the production area price. During much of January, the value of transportation is shown to be about equal to the maximum IT rate. The value exceeds that rate only on days of peak demand.

These graphs show that the value of transportation, particularly during peak periods, is not related to the maximum tariff rates for transportation. As one commentator has stated, ''gas commodity markets now determine the economic value of pipeline transportation services in many parts of the country. Thus, even as FERC has sought to isolate pipeline services from commodity sales, it is within the commodity markets that one can see revealed the true price for gas transportation.'' [88] Because the Commission's current regulatory model permits discounting below the maximum rate, the Commission's regulation does not inhibit pipelines and shippers from adjusting transportation rates to the off-peak demand in the market. However, during peak periods, the Commission's maximum rate cap does not allow unbundled transportation prices to equilibrate with demand.

The fact that the value of transportation in the short-term bundled sales market exceeds the daily or monthly maximum rate now permitted in pipeline tariffs is not surprising, nor is it evidence that market power is being exercised. The daily or monthly rates (derived by simple division of the annual rate) were never intended to replicate prices that demand conditions would produce.[89] Particularly during peak periods, the value of transportation will rise because the transportation quantity demanded begins to exceed the quantity of capacity supplied. As a result, a higher price is needed to efficiently allocate transportation to those who most need to obtain it and are willing to pay the highest price for the bundled commodity. Such price increases would occur in any competitive market when supply becomes constrained relative to demand. This situation must be distinguished from the exercise of market power when a pipeline has power to raise prices by withholding capacity, creating greater scarcity than would occur in a competitive market. Indeed, all commenters recognize that the bundled sales market operates independently of the regulated rate governing straight-forward (unbundled) capacity transactions, but none suggest that the Commission should attempt to impose more stringent regulation on the bundled sales market.

b. The Price Constraint for Capacity Release Transactions Reduces Efficiency. Applying a ceiling to the rate for capacity release transactions does not achieve the Commission's regulatory objectives. It reduces shippers' options, decreases the efficient operation of the market, and does not adequately protect captive customers.

Particularly during peak constraint periods on pipelines, preventing transportation prices from exceeding the pipeline's maximum rate can reduce the options of shippers purchasing in the short-term market. With the maximum rate cap, a shipper, without a contract sufficient to cover its requirements on a peak day, that is seeking to acquire additional capacity has limited options. It can first try to obtain pipeline interruptible capacity at the maximum rate cap, if the capacity is available. Even if pipeline capacity is available, the shipper may be unable to obtain that capacity despite placing the highest value on the capacity. Because the pipeline cannot exceed the maximum rate, the pipeline must allocate its available capacity either on a *pro rata* basis or on the basis of a queue based on contract execution date. In either case, a shipper may not obtain the capacity or the amount of capacity it needs regardless of whether it places the highest value on the capacity.

The shipper is therefore left with only two available options: to purchase gas in a bundled transaction in the downstream market at a price reflecting the market-determined value of transportation, or to simply take the gas out of the pipeline and pay the pipeline's scheduling or overrun penalties. The shipper generally will not be able to obtain released capacity at the capped price, because holders of that capacity are unlikely to release capacity at a price less than the amount they can receive by making a bundled sales transaction. Thus, during a peak day, capping the price of released capacity does not effectively limit the price a purchaser has to pay to obtain transportation service. It only serves to limit the purchasing shipper's capacity options.

But the shipper's other options—using a bundled sales transaction or incurring overrun and scheduling penalties—may not be the most efficient choice. The purchaser may prefer not to use the bundled gas sales market when it has a natural gas contract at a less expensive price than the price of gas included in the bundled transaction and, as a result, would prefer to use its own gas. To use its own gas supplies to meet its peak day needs, the shipper would have to pay substantial penalties for overrunning its transportation contract. Shippers accumulating overruns also compromise the operational integrity of the pipeline's system, leading to a degradation of service for all shippers, including the possibility of service curtailment through operational flow orders, during peak periods when shippers most need the system to run efficiently.

Moreover, even if the maximum rate cap were more effective in limiting the prices at which firm capacity holders could resell capacity (for instance, LDCs who are unable to make bundled sales),[90] it would provide little benefit to shippers purchasing capacity during peak periods. The maximum rate cap

[88] M. Barcella, How Commodity Markets Drive Gas Pipeline Values, Public Utilities Fortnightly, Feb. 1, 1998, 24–25; *See* Henning & Sloan, Analysis of Short-Term Natural Gas Markets (Energy and Environmental Analysis, Inc., Nov. 1998) (showing how basis differentials between prices in different pipeline corridors correlate with value of capacity release transactions); B. Schlesinger, Natural Gas Industry Trends: Commoditizing Everything in Sight, *http://www.nymex.com* (November 17, 1999) (basis competition establishes the value of transportation capacity); R. O'Neill, C. Whitmore, M. Veloso, The Governance of Energy Displacement Network Oligopolies, Discussion Paper 96–08, at 41 Federal Energy Regulatory Commission, Office of Economic Policy, revised May 1997) (copy available from the Federal Energy Regulatory Commission) (the option to buy transmission rights is worth the difference in spot prices between two geographic areas, as opposed to a rate relating to embedded costs).

[89] The rationale for the commission's method of regulating the rates of pipeline transactions does not apply to capacity release transactions. As discussed earlier, by regulating pipelines' rates so they cannot recover more than their annual revenue requirement, the Commission seeks to ensure that the pipelines do not have an incentive to withhold capacity to create excess returns. But this justification for rate regulation has little applicability to capacity release transactions, since releasing shippers are not in the position to withhold long-term capacity by failing to add capacity when necessary.

[90] *See* Comment of Arkansas PSC (price ceiling is effective, if at all, only on LDC capacity releases which tend to be unbundled sales of capacity).

reduces the efficiency of the market by preventing the efficient allocation of capacity to those who most need it and are willing to pay for it. During a time of capacity constraint, there may not be sufficient capacity to serve all shippers seeking capacity at the maximum rate. It is therefore necessary to allocate or ration that capacity among the shippers desiring it. The Commission's regulations, in fact, require that one of the objectives in setting rates is to ration capacity during peak periods.[91] The appropriate method of rationing scarce capacity is to allocate the capacity to those who place the greatest value on obtaining that capacity. Maximum rate regulation prevents such allocation during constrained periods, resulting in shippers who place a lower value on capacity retaining their capacity, rather than selling the capacity to shippers placing a greater value on obtaining the capacity.

Restrictions on capacity release transactions limit the development of an efficient and viable capacity market and can skew customer capacity choices. If a customer could rely on an effective short-term market to obtain additional capacity during peak periods, it might decide that it was not necessary to reserve sufficient long-term firm transportation to cover all of its peak day needs. It could be more economic for it to purchase short-term daily capacity, even at a high price, when it needed additional capacity, as opposed to paying for long-term capacity to meet peak needs. However, if the short-term market is less reliable, and, as a result, the customer valuing the capacity the most cannot acquire as much as it needs, the customer will be more reluctant to relinquish long-term capacity and rely upon the short-term market for its peak needs.[92]

Indeed, the use of the pipeline's maximum rate as the cap for capacity release transactions, can reduce the amount of released capacity available during peak periods, precisely the period when capacity is needed most. As a result of the maximum rate, firm capacity holders may not find it sufficiently profitable to make their capacity available for release. For instance, a dual fuel industrial customer might determine that it would be more economic not to use gas, and to substitute a different fuel, if it could obtain a sufficiently high price for its released capacity. Similarly, an LDC might have a peak shaving capability (storage or liquefied natural gas (LNG)) that costs more to produce and deliver gas than purchasing the gas in upstream markets and using its transportation capacity to transport that gas to its citygate. The LDC might be willing to release its transportation capacity and use the peak shaving device instead if it could receive a price above the maximum rate for its transportation capacity so that the amount it receives for the release of its transportation capacity covers the costs of the peak shaving device.[93] By using its peak shaving device instead of transportation, the shipper would be expanding the amount of released capacity available during a peak period. But if the price cap prevents the shipper from obtaining a price higher than the cost of the peak shaving device, and the shipper cannot sell the gas on a delivered basis, the shipper will use its transportation capacity, thus depriving other shippers (without peak shaving) of the opportunity to acquire needed transportation capacity. Removal of the price cap, therefore, could make additional released capacity available during peak periods to those most needing that capacity. As more capacity enters the marketplace during peak periods, the consequence would be a lowering of transportation prices, which would be of significant benefit to all shippers needing capacity when the pipeline system is most constrained.[94]

Capping capacity release transactions during peak periods at the current maximum rate system also harms captive customers holding long-term contracts on the pipeline. These customers have to pay maximum rates for both peak and off-peak periods. During off-peak periods, when prices are generally low, they cannot recover the cost of their investment. But, when demand increases the value of capacity, captive customers cannot reap the benefits of the higher value through a straight-forward release of capacity. Instead, their only alternative in selling capacity is to seek to make bundled sales transactions, which may be more difficult for smaller customers and raise transactions costs for both parties.

2. Alternatives to the Price Cap

In the NOPR, the Commission proposed one alternative to respond to the inefficiencies created by price caps, as well as requesting comments on other approaches. The Commission proposed to eliminate the maximum rate from both short-term (less than one year) capacity release and pipeline transactions, together with a number of proposals to increase competition in the short-term market and limit the exercise of market power. Chief among the proposals was the requirement that all short-term capacity would be sold through an auction process in which daily pipeline capacity would be sold without a reserve (or minimum) price. The purpose of the no-reserve price proposal was to protect against the exercise of market power in the short-term market by ensuring that pipelines could not withhold capacity. In addition, the Commission solicited comment on other potential approaches, such as the use of seasonal rates or the application of market power analysis similar to that used in the Alternative Rate Design Policy Statement,[95] to determine whether markets are sufficiently competitive to remove regulatory rate ceilings for all services.

The comments, for the most part, do not challenge the Commission's analysis of the inefficiencies created by maximum rate regulation in the short-term market, but they take very different positions as to the possible solution. Some commenters, principally pipelines, support removal of the price cap for all services in the short-term market, contending removal would improve market efficiency, mitigate the adverse effects of the current cost-based rate designs, increase competition, and remove a major obstacle to contracting

[91] 18 CFR 284.7(b)(1), redesignated § 284.10(b)(1).

[92] The comments recognize that the Commission's current regulatory policy can result in market distortions and inefficiencies. *See* Comments of Amoco I, at 17–18 (''maximum rates can result in inefficiencies); INGAA, at 25 (graph of transportation value shows that the market value of capacity is less than its allocated cost during off-peak periods and must be discounted); AGA I, at 13 (off-peak customers receive transportation at discounted rates which cannot be recouped during peak periods); El Paso Energy, Appendix A (allocative inefficiencies exist when prices exceed maximum rate).

[93] Suppose the costs to the LDC of using the peak shaving device were $6.00/MMBtu and the costs of buying gas in the upstream market was $4.00/MMBtu with a $.10/MMBtu usage charge (under its firm contract) for transportation, If the LDC could resell its transportation capacity for more than $1.90/MMBtu (the difference between using its peak shaving device and its transportation service), it would release that capacity and use its peak shaving instead. If the release were subject to a maximum cap of less that $1.90, however, the LDC would choose not to peak shave and the capacity would not be released to others.

[94] *See* Comments of Amoco I, at 17–18 (''incremental costs due to market inefficiencies (which may be described as transaction costs) may arise during periods when the demand for capacity exceeds its supply, resulting in delivered gas prices in downstream markets that are higher than they would be in a more allocatively efficient, i.e., liquid and transparent market'').

[95] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, 61 FR 4633 (Feb. 7, 1996), FERC ¶ 61,076 (1996).

for long-term capacity.[96] Many of the comments, however, contend that the Commission should not remove rate regulation over pipelines, because pipelines continue to hold market power. They maintain that rate caps can be removed only upon a showing that market power cannot be exercised.[97] Several commenters, particularly LDCs, support removal of price caps for short-term capacity release transactions, but not for pipeline services.[98]

Some commenters support the use of auctions as a method for limiting the exercise of market power and providing a non-discriminatory method for allocating capacity, although they recognize that there may be a need to implement some mechanism to protect pipelines against cost under-recovery.[99] By far the vast majority of commenters, however, oppose the use of mandatory auctions at this time, principally out of a concern that auctions would be complex and expensive, would require more personnel to monitor the auctions on multiple pipelines, would not work as efficiently as the use of pre-arranged deals for capacity exchanges, would not permit coordination between gas and capacity purchases, could interfere with state unbundling plans by inhibiting prearranged releases, and would frustrate asset management arrangements.[100] INGAA and AGA raise concerns about the impact of mandatory no-reserve price auctions on pipelines' or firm shippers' abilities to recover their investments. Several commenters suggest the use of voluntary rather than mandatory auctions as a way to gain more experience with auctions.[101] Others suggest that while auctions may be a viable method of allocating capacity, a mandatory auction may not be the most efficient method of allocating capacity and may inhibit the development of other equally efficient approaches, in particular pre-arranged deals. They suggest that the Commission should not mandate the use of auctions, but instead consider a variety of options, including auctions that would prevent withholding of capacity.[102]

In place of mandatory auctions, INGAA, along with most pipelines, and AGA, and most of the LDCs, propose an alternative to mandatory auctions under which the Commission would remove maximum rate caps from capacity release transactions, but not pipeline transactions. INGAA and AGA argue that such an approach would eliminate inefficiencies in the marketplace while preserving pipeline capacity as a ''just and reasonable'' safe harbor or recourse service. INGAA also proposes that pipelines be permitted to institute seasonal rates to better reflect peak and off-peak demands faced by many pipelines. INGAA maintains that permitting pipelines to institute seasonal rates where demand differs throughout the year would help to ameliorate the inequities of the current ratemaking structure in which shippers purchasing short-term capacity are able to shift costs to those customers purchasing capacity on a long-term basis at maximum rates. INGAA further proposes that seasonal rates be cost-based in the sense that they be limited by the pipeline's revenue requirement. INGAA suggests a number of ways in which seasonal rates could be designed, for instance, using seasonal pipeline utilization, and others suggest other approaches.[103]

3. The Regulatory Changes Implemented in this Rule

In this rule, the Commission is revising its policies on rate regulation to improve marketplace efficiency by adopting the two-part approach suggested by commenters: removing the rate ceiling for capacity release transactions and clarifying its policy on seasonal rates to permit pipelines to file for differing peak and off-peak rates based on different demand conditions on those pipelines. The Commission is waiving the rate ceiling in its capacity release regulations[104] until September 30, 2002 for short-term releases of capacity of less than one year beginning upon the effective date of this rule. The Commission, however, is continuing its current regulations regarding the posting and bidding for capacity release transactions of greater than one month.

While the removal of the price cap is justified based on the record in this rulemaking, the Commission recognizes that this is a significant regulatory change that should be subject to ongoing review by the Commission and the industry. No matter how good the data suggesting that a regulatory change should be made, there is no substitute for reviewing the actual results of a regulatory action. The two year waiver will provide an opportunity for such a review after sufficient information is obtained to validly assess the results. Due to the variation between years in winter temperatures, the waiver will provide the Commission and the industry with two winter's worth of data with which to examine the effects of this policy change and determine whether changes or modifications may be needed prior to the expiration of the waiver.

At this point, the Commission is retaining the price cap for capacity release transactions over one year because this rule is focused on revising regulations that interfere with the efficient allocation of capacity during the short-term periods when demand pushes the value of transportation above the current maximum rate. There has been no showing made that for capacity release transactions of one year or more the value of capacity exceeds the uniform annual rate such that maximum rates impede efficiency. This policy too may be reassessed based on the results during the two year waiver period.

a. Consistency with the Commission's Regulatory Objectives. The removal of the price cap from short-term capacity release transactions better satisfies the Commission's regulatory objectives than the current system. Removal of the rate cap will expand shippers' options, create a more efficient marketplace, increase market transparency, and better protect captive customers, without changing the current regulatory environment.

[96] Comments of Consolidated Natural Gas I, IMD, Koch I, MichCon, NYMEX, Nicor, PG&E, Mercatus, Sempra Energy, TransCanada, and Williams I.

[97] Comments of Arkansas Gas Consumers, Market Hub Partners, NWIGU, Process Gas Consumers, et al., and Southern Company Services, Amoco I, IPAA, Indicated Shippers, NGSA, PanCanadian, PSC of New York I, and CPUC.

[98] Comments of AGA I, Arkansas PSC, ConEd, Enron Pipelines, Illinois Commerce Commission, INGAA, NARUC, NASUCA, Nisource, Pennsylvania/Ohio Consumer Advocates, Pennsylvania PUC, Philadelphia Gas Works, Piedmont/UGI, PSC of Wisconsin I, PUC of Ohio, and Washington Gas Light.

[99] Comments of Altra Amoco I, Florida DMS, Sithe, Southern Company Energy Marketing, and Southern Company Services. While not directly supporting removal of the maximum rate cap, Indicated Shippers and NGSA maintain that if the price cap is lifted, auctions need to be required.

[100] Comments of AEC Marketing, Allenergy Marketing, et al., AGA I, CMS Panhandle, Coastal I, Colorado Springs I, Columbia LDCs, Consolidated Natural Gas I, Cove Point, Duke Energy Trading, El Paso, Enron Pipelines, INGAA, KN, Koch I, Louisville, Mississippi Valley, et al., National Fuel Gas Supply, Nisource, NWIGU, PanCanadian, Pennsylvania PUC, Peoples Energy I, Philadelphia Gas Works, Piedmont/UGI, Process Gas Consumers, et al., Reliant, Sempra Energy, TETCO/Algonquin, TransCanada, Williston Basin, Williams I, and UGI. Other commenters, while not specifically opposing auctions, raise similar concerns about the use of auctions. APGA, Enron Capital & Trade, Entergy, Fertilizer Institute, Foothills, Illinois Commerce Commission, IMD, Market Hub Partners, NARUC, Nicor, PG&E, PNGTS, Proliance, PSC of Kentucky, PSC of New York I, PSC of Wisconsin I, CPUC, Mercatus, Shell, and Southwest Gas.

[101] Comments of Colorado Springs I, Enron Capital & Trade, Enron Pipelines, INGAA, K N, National Fuel Gas Supply, Sempra Energy, and TransCanada.

[102] Comments of Mercatus; CAPP/ADOE.

[103] Comments of Enron Pipelines, Amoco I.

[104] The waiver is contained in redesignated § 284.8(i). The existing capacity release regulations are not being revised.

Removal of the rate ceiling from short-term capacity release transactions will remove an impediment to the development of an efficient capacity market by giving purchasers an additional option for obtaining capacity during peak periods. Instead of having only the choices of purchasing a bundled sale or incurring a contract overrun, a customer needing gas can directly obtain the capacity it needs from a firm capacity holder. Removal of the rate ceiling for capacity release transactions also will enhance efficiency by ensuring that capacity is properly allocated to those placing the most value on obtaining capacity during peak periods.

By fostering a more efficient short-term market, removal of the rate ceiling on short-term capacity release transactions will help create a more reliable short-term capacity market where shippers who need short-term capacity will know they can obtain as much capacity as they need by paying the market price. The development of a more reliable short-term capacity market, in turn, will enable shippers to make better informed choices about whether to purchase long or short-term capacity depending on their circumstances. Some shippers may prefer the price stability they obtain from a long-term firm contract. On the other hand, some shippers may opt not to contract for long-term capacity if they are assured of a reliable short-term capacity market in which they could obtain transportation by offering to pay the market price for the capacity.[105] Even demand inelastic customers in Chicago might not want to subscribe to sufficient firm capacity to meet the worst-case scenario that occurred in 1996 [106] if an effective spot market exists in which they can obtain capacity when needed or hedge against the financial risk of buying in the spot market.

The more reliable the market the less shippers and regulators may be pushed toward requiring long-term capacity contracts to ensure reliability. For example, with an effective market for transportation capacity, there could be less need for states contemplating retail unbundling to require marketers or LDCs, as suppliers of last resort, to hold firm capacity on pipelines to guarantee transportation, just as long-term contracts are no longer necessary to guarantee access to the gas commodity.

Removal of the rate cap for short-term capacity release transactions also will have an added benefit of increasing market transparency. In today's market, there is little information on the price of transportation capacity during peak periods, because, due to the price caps, transactions move to the bundled sales market. Permitting transportation capacity to trade freely during peak periods will increase the number of transactions moving from the bundled sales market to the transportation market, which, given the changes in reporting requirements adopted in this rule, will increase pricing information during peak periods, when such information is most critical to the marketplace.

Removal of the rate ceiling will have limited effect on the effective prices paid by customers using short-term transportation capacity. In today's market, when the value of transportation exceeds the maximum rate, firm capacity holders have an incentive not to release capacity, but to bundle that capacity with gas so that they can obtain the full market value of the transportation capacity by selling gas in the delivery market. Thus, removal of the rate ceiling should not significantly raise transportation prices, but will instead provide shippers looking for capacity with the alternative of buying transportation capacity directly rather than obtaining that capacity indirectly through a bundled sale.

Moreover, even if some replacement shippers do end up paying higher prices for capacity during peak periods than they did with the regulated rate in effect, it is appropriate for shippers using the system only during peak periods to pay higher prices reflecting the greater demand on the system. Short-term shippers currently receive the benefit of paying reduced capacity release prices during off-peak periods, but face a cap on the market price during peak periods. Removal of the rate ceiling on capacity release prices will ensure that those shippers which receive the benefit of lower market prices during off-peak periods face the higher market prices during peak periods. Removing the price ceiling for released capacity also will benefit captive customers by eliminating the regulatory bias built into the current rate structure. Long-term shippers pay the same rate for capacity during both peak and off-peak periods. During off-peak periods, they can recover only a small portion of their capacity cost through capacity release, because the market value for released capacity is generally quite low due to the reduced demand for capacity and the increased availability of released capacity. But during peak periods, the price cap limits long-term captive customers (who cannot make bundled sales) from receiving the full market value of their capacity. Long-term shippers pay for the largest proportion of the pipeline's fixed costs through their annual reservation charges, and permitting them to receive more revenue from capacity release transactions during peak periods will help them defray those costs.

b. Protections Against the Exercise of Market Power. While removal of the rate cap for short-term capacity releases will add an additional capacity option, such removal does not significantly reduce the protection of shippers buying short-term transportation. First, the capacity release rate cap is largely ineffective in protecting short-term capacity purchasers in today's market since shippers can make bundled sales to evade the cap. Thus, removal of the rate cap will not provide releasing shippers with significant additional pricing freedom. Instead, it will improve the market for buyers by giving them an additional capacity option from which to choose.

Second, the fact that prices for transportation rise during peak periods is not evidence of the exercise of market power, but may be the appropriate market response to an increase in demand for capacity. During peak periods when there is insufficient capacity to satisfy all the demand for short-term capacity, an increase in market price would be the competitive response to a situation in which the quantity of transportation demanded increases relative to the quantity that can be supplied.

The rule also continues to provide protections against the possible exercise of market power by releasing shippers. Market power can be exercised in two ways: through withholding capacity to raise price or through price discrimination.

Firm shippers cannot successfully withhold capacity from the market to raise price above the existing maximum just and reasonable rate because, if the firm shippers do not use their capacity, the pipeline has the incentive to sell the capacity as interruptible service. Moreover, the Commission is continuing to protect against the possibility that, in an oligopolistic market structure, the pipeline and the firm shippers will have a mutual interest in withholding capacity to raise

[105] A low load factor shipper (one with greater demand during peak than off-peak) might find that paying reservation rates for a full year to hold long-term capacity sufficient to meet its peak needs is less economic than purchasing capacity only for the short time when it needs the capacity even if the rate for that short-term capacity is much higher than the yearly rate.

[106] *See* Figure 6, *supra* (showing the spike in gas price to $6.50/MMBtu during the winter of 1996).

price because the Commission is continuing cost-based regulation of pipeline transportation transactions. The pipelines will be required to sell both short-term and long-term capacity at just and reasonable cost-based rates. In the short-term, a releasing shipper's attempt to withhold capacity in order to raise price above maximum rates will be undermined because the pipeline will be required to sell that capacity as interruptible capacity to a shipper willing to pay the maximum rate. Shippers also have the option of purchasing long-term firm capacity from the pipelines at just and reasonable rates.

In addition, the ability of pipelines to build additional capacity will check the potential exercise of market power by releasing shippers. Regardless of the value of scarce capacity, pipelines' rates are capped. Thus, if a pipeline observes that the market price for capacity exceeds the pipeline's maximum rate in the short-term market, and the market prices are sufficient to cover the cost of new pipeline capacity, the pipeline can capture that revenue only by building additional capacity to serve the demand. In many cases, capacity can be added relatively quickly simply by adding compression. Thus, firm shippers have little incentive to exercise market power by withholding capacity given the pipeline's ability and incentive to dissipate that market power through new construction.

The cost-based regulation of pipeline services also limits firm shippers' ability to price discriminate, since a purchaser who is unwilling to pay the price quoted by the releasing shipper can obtain pipeline capacity at cost-based rates. Firm shippers also would have difficulty engaging in price discrimination, because, given the ease with which capacity can be transferred between shippers, a releasing shipper would have trouble preventing arbitrage—a shipper which benefits from the lower price buying more capacity than it needs and reselling the excess to less-favored shippers.[107]

Besides the availability of pipeline capacity, the competitive pressures fostered by competition from released capacity will limit the potential exercise of market power. Many of the commenters argue that due to the competition for released capacity, release rates are low and firm shippers are unable to come close to recouping their investment in pipeline capacity.[108] CNG cites to a study commissioned by AGA and INGAA analyzing 17 major pipeline corridors, which showed that the average value of capacity release transactions varied from 31% to 76% of the maximum rate tariff rate applicable to the corridor.[109]

Since Order No. 636, capacity release transactions have grown significantly, averaging 20 trillion Btu/day, for a total of 7.4 quadrillion Btu for the 12 month period ending March, 1997.[110] Competition from numerous shippers releasing capacity, therefore, will also lessen the ability of firm shippers to exercise market power. The Commission's policy requiring pipelines to provide flexible receipt and delivery points rights has enhanced competition. Due to the ability to use alternate receipt and delivery points, capacity purchasers are not limited to purchasing capacity only from shippers holding the primary point rights the purchaser needs. A purchaser can obtain capacity from any of a number of shippers and use the flexibility to use alternate points to access the receipt and delivery points it needs. In this rule, the Commission is improving various aspects of the capacity release mechanism, by speeding up the nomination process and requiring pipelines to permit shippers to segment capacity, which will further enhance competition between releasing shippers. Thus, capacity available from other shippers together with the availability of pipeline capacity will limit the ability of releasing shippers to exercise market power.

As additional protection against the potential exercise of market power, the Commission in this rule is improving its reporting requirements to permit better monitoring of the marketplace and has recently instituted a revamped complaint process.[111] The improved reporting requirements will improve competition in the market by expanding shippers' information about potential capacity alternatives. Difficulty in obtaining information can reduce competition because buyers may not be aware of potential alternatives and cannot compare prices between those alternatives. The reporting requirements will expand shippers' knowledge of alternative capacity offerings by providing more information about the capacity available from the pipeline as well as those shippers holding capacity that is potentially available for release. The reporting requirements further will provide shippers with more accurate information about the value of capacity over particular pipeline corridors so that shippers can make more informed choices about the prices of capacity they may wish to purchase.

In addition to providing better information about competitive alternatives that will enhance competition, the improved reporting requirements will better enable shippers and the Commission to monitor the market. Thus, both shippers and the Commission will be better able to identify situations in which market power is being abused, and the Commission will have more information to use in tailoring remedies in individual cases as the need arises.

Thus, the removal of rate ceilings will improve shipper options, create a more efficient marketplace, and make the Commission's ratemaking policies more responsive to market forces. Reasonable protection against the exercise of market power by releasing shippers will be provided by continuing cost-of-service regulation of the pipelines and competition in the release market, together with enhanced reporting requirements that will improve information about capacity alternatives and shippers' ability to monitor the market for market power abuses.

4. Legal Basis for Removing the Rate Ceiling for Short-Term Capacity Release Transactions

Several commenters maintain that, under its statutory mandate, the Commission cannot legally rely upon market-based rates without making a finding that market power cannot be exercised.[112] APGA, for example, contends that the existence of the bundled sales market should not be used as justification for removing rate regulation in the capacity market. Process Gas Consumers (Process Gas Consumers I) and Indicated Shippers (Indicated Shippers Reply) contend the Commission cannot remove price caps for released capacity even if ceilings remain on pipeline capacity.

[107] *See* Comment of Mercatus (price discrimination cannot be maintained where releasing shipper cannot limit arbitrage).

[108] Comments of AGA I, Arkansas PSC, Consolidated Edison, Enron Pipelines, Illinois Commerce Commission, INGAA, NARUC, NASUCA, Nisource, Pennsylvania/Ohio Consumer Advocates, Pennsylvania PUC, Philadelphia Gas Works, Piedmont/UGI, PSC of Wisconsin, PUC of Ohio, and Washington Gas Light.

[109] The study cited is Henning & Sloan, Analysis of Short-Term Natural Gas Markets (Energy and Environmental Analysis, Inc., November 1998).

[110] Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0618(98), Deliverability on the Interstate Natural Gas Pipeline System 83 (1998).

[111] 18 CFR 385.206 (adopted by Complaint Procedures, Order No. 602, 64 FR 17087 (Apr. 8, 1999), III FERC Stats. & Regs. Regulations Preambles ¶ 31,071 (Mar. 31, 1999).

[112] Comments of Process Gas Consumers, Indicated Shippers, NGSA, APGA, IPAA.

The Commission concludes that the removal of the price cap for capacity release transactions, together with continued regulation of pipeline rates, comports with its statutory responsibilities. The Commission has the statutory obligation under the NGA to ensure that pipeline rates and services are just and reasonable. Establishing just and reasonable rates requires the Commission to protect consumers of natural gas from the exercise of monopoly power by pipelines,[113] while, at the same time, ensuring that those rates improve the competitive structure of the natural gas industry to maximize the benefits of wellhead decontrol.'' [114] In seeking to achieve these goals, the courts have recognized that the Commission is not bound to use any particular pricing formula in determining just and reasonable rates [115] and that cost-based regulation can be relaxed as long as the overall ''regulatory scheme'' ensures that rates are within a zone of reasonableness.[116] The Commission is permitted to move to lighter-handed regulation as long as it ensures that the goals and purposes of the statute will still be accomplished.[117] The courts have permitted the Commission to institute flexible pricing to improve market efficiency so long as the overall regulatory scheme protects against price gouging.[118] Market-based rates have been approved when the Commission has found sufficient protection against the exercise of market power.[119]

The Commission finds that the regulatory changes made in this rule ensure a regulatory scheme that protects against the exercise of market power and ensures that rates are within the ''zone of reasonableness'' even without a price cap on short-term capacity release transactions. In the first place, the removal of the rate cap for capacity release transactions does not effectively change the status quo, since the value of transportation in the bundled sales market can exceed maximum tariff-based rates. Thus, continuation of the maximum rate cap on unbundled capacity release transactions does little to protect against the exercise of market power by firm capacity holders. Its principal effect is to provide shippers with additional transportation options, to create greater efficiency in capacity allocation, and to move transactions from the less-well-reported bundled sales market to the better-reported transportation market. By removing the price cap from capacity release transactions, the Commission is not reducing protection for customers seeking released capacity, but is expanding their options and helping to foster a more efficient and transparent marketplace for released capacity.

In addition, the Commission is not adopting market-based rates for all capacity. It is removing rate regulation only from one element of the competitive mix—short-term capacity release transactions by shippers—while retaining regulation for sales of pipeline capacity. The Commission also is continuing to protect its primary constituency—captive long-term firm capacity holders—by continuing the same cost-of-service rate regulation that has been used for years.[120] The regulatory change in this rule affects only shippers buying short-term released capacity who are already at risk of not being able to acquire capacity.[121] As explained earlier, the Commission's regulation of pipeline transactions, as well as the operation of market forces, also will protect against the exercise of market power and keep capacity release rates within the zone of reasonableness.

AFPA contends that short-term shippers may be captive customers. But, short-term customers, those using interruptible or short-term firm pipeline service or relying on capacity release transactions, are, by the very nature of the services for which they contract, not captive. They are expressly taking the risk that during peak periods, they will be unable to obtain capacity and either are willing to forgo the use of gas entirely or are willing to pay the prices needed to obtain gas from alternative sources. Such customers, in fact, receive more protection if they can obtain the capacity they need by offering a sufficiently high price than if the price is regulated and they are unable to obtain capacity at all. If short-term customers want the insurance of having guaranteed transportation service, that security is available by obtaining long-term firm capacity from the pipeline.

Moreover, as explained in the previous section, the availability of regulated pipeline capacity as well as competition between holders of firm capacity mitigates the potential for releasing shippers to exercise market power. In *Environmental Action* v. *FERC*,[122] the court recognized that the Commission may need to relax price regulation in order to improve market efficiency and approved a flexible pricing program as long as the program maintained protections against the exercise of market power.[123] Here, the Commission similarly is improving the efficiency of capacity trading during peak periods while maintaining cost-of-service regulation for pipeline firm and interruptible service that will limit the ability of both firm capacity holders and the pipelines to exercise market power by withholding capacity.

Indicated Shippers suggest that removing the rate ceiling from capacity release transactions will permit firm capacity holders to exercise market power by withholding capacity from the market because they are not obligated to release that capacity. However, removing the rate ceiling will not permit a firm shipper to withhold capacity from the market to raise price above the maximum rate, because, in the short-run, that capacity always will be available from the pipeline as interruptible capacity, which the pipeline is obligated to sell at the approved just and reasonable rate. In the long run, pipeline firm transportation also is available as a check against short-term market power and the continuation of cost-of-service regulation for the pipelines provides an incentive for the pipeline to build additional capacity when justified by demand.

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[113] *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 610 (1944); *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 995 (D.C. Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988) (''The Natural Gas Act has the fundamental purpose of protecting interstate gas consumers from pipelines' monopoly power.'').

[114] Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101–29, 101st Cong., 1st Sess., at 6 (1989); Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Oder No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles (Jan. 1991–June 1996) ¶30,939, at 30,932 (Apr. 8, 1992).

[115] *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 602 (1944); *Elizabethtown Gas Company* v. *FERC,* 10 F.3d 866, 870 (D.C. Cir. 1993).

[116] *See* Farmers Union Central Exchange v. FERC, 734 F.2d 1486, 1509–10 (D.C. Cir. 1984).

[117] Farmers Union, 734 F.2d 1486 at 1510.

[118] *Environmental Action* v. *FERC,* 996 F.2d 401, 410 (D.C. Cir. 1993).

[119] *Elizabethtown Gas Company* v. *FERC,* 10 F.3d 866 (D.C. Cir. 1993).

[120] *See Maryland People's Counsel* v. *FERC,* 761 F.2d 768 (D.C. Cir. 1985); *Maryland People's Counsel* v. *FERC,* 761 F.2d 780 (D.C. Cir. 1985) (special concern for effect of program on core captive customers).

[121] *See American Gas Association* v. *FERC,* 912 F.2d 1496, 1518 (D.C. Cir. 1990) (interruptible and short-term capacity holders not entitled to the same protection against market power as long-term firm capacity holders).

[122] *Environmental Action* v. *FERC,* 996 F.2d 401 (D.C. Cir. 1993).

[123] As the Court stated:

We acknowledge that the flexible pricing that fosters trading among members of the Pool also permits price discrimination especially against captive utilities. Yet, given the benefits of this trading, the limited number of captive members, and the provisions for monitoring transactions and remedying any abuses of market power, we do not find that the Commission acted arbitrarily when it approved the use of flexible prices despite their admitted risk. 996 F.2d at 411.

Process Gas Consumers maintains that competition may not limit the market power held by LDCs because they control access to primary delivery points and that obtaining secondary point access from other firm holders may not be the equivalent of obtaining primary point access from the LDC, particularly during periods of constraint when the pipeline may interrupt secondary deliveries. Process Gas Consumers also maintains that LDCs, by virtue of their control over their own facilities, can exercise market power over customers behind the city-gate and contends the Commission should not remove price ceilings for LDCs unless the LDCs provide shippers with reasonable city-gate access.

The Commission does not find that LDCs should be treated differently than other firm shippers with respect to their ability to release capacity. Such a distinction would skew the capacity release market by creating different classes of customers: one class without a price ceiling and the LDCs with a price ceiling. An LDC also is not more likely than other firm shippers to exercise market power by withholding capacity, because if it tried to do so, the capacity would be available from the pipeline as interruptible transportation, which the pipeline is obligated to sell at just and reasonable rates.

Moreover, as Process Gas Consumers itself recognizes, the Commission's jurisdiction does not extend to LDC activity behind their city-gates, which are the province of state regulatory authorities. Complaints about LDCs handling of transportation on their own systems are properly directed to the state regulatory agencies with jurisdiction over those activities. To the extent that an LDC engages in specific abuses of its market power over interstate transportation capacity, the Commission can remedy such abuses through individual action. The improved reporting requirements together with the Commission's revised complaint process will enable both shippers and the Commission to discern and redress abuses of market power. The possibility of abuse in specific circumstances, which can be addressed on an individual basis, should not preclude the Commission from adopting a policy that benefits the industry as a whole by enhancing customer options and improving marketplace efficiency.

AlliedSignal complains that removal of the price cap will leave the market open to hysteria leading to exorbitant prices during times of peak demand. In the first place, high prices during peak demand periods can be a function of supply and demand forces that raise prices to allocate capacity during peak periods. As long as capacity is not being withheld from the market and no discrimination is taking place, the high prices are a reasonable and necessary competitive response to market conditions to allocate capacity to those needing it the most. Indeed, as shown by the period of rate regulation of wellhead prices, maintenance of regulated prices can distort the market by upsetting the balance between supply and demand.[124] In any event, continuation of rate regulation for capacity release transactions will not limit the effect of so-called market hysteria, since the Commission's rate regulation has no effect on the prices for bundled gas and transportation capacity. Removal of price regulation from short-term capacity release transactions, therefore, will not add to pricing problems during peak periods, but instead should help to minimize these problems by increasing customers' options.

Dynegy and Process Gas Consumers raise the questions of whether pipelines can avoid protections against the exercise of market power by transferring capacity to their affiliates. In one respect, transfers of capacity to affiliates will not enable the corporate entity to exercise market power. Affiliates, like LDCs or other firm capacity holders will not be able to exercise market power, because they cannot effectively withhold capacity. If the affiliate refuses to release capacity, the pipeline still is obligated to sell the capacity at just and reasonable rates and cannot conspire with the affiliate to withhold capacity.

In another respect, transfers of capacity to affiliates could be troublesome, but not because the affiliate could exercise market power in the release market. One aspect of Commission regulation is intended to ensure that pipelines have the incentive to expand their pipeline when it is economic to do so. Through cost-of-service of regulation, the Commission ensures that pipelines do not benefit by creating scarcity by refusing to build long-term capacity.[125] However, if a pipeline affiliate holds a large enough block of capacity on its related pipeline, the corporate entity as a whole could benefit if the pipeline refused to build capacity, creating greater scarcity and higher prices and profits for the affiliate, which is not subject to cost-of-service limitations. This problem exists only in cases where an affiliate holds a large enough portion of pipeline capacity that the corporate entity as a whole can make more by creating scarcity than by building additional capacity and earning a rate of return on its investment.

This theoretical problem, however, exists in today's market where pipeline affiliates are able to make bundled sales not subject to a rate cap. Yet, there seems little indication that profits from scarcity exceed those that can be earned through construction, since pipeline construction applications have not noticeably declined.[126] However, because of the possibility of affiliate abuse, the Commission will be particularly sensitive to complaints that pipelines, on which affiliates hold large amounts of transportation capacity, are refusing to undertake construction projects when demand for construction exists. In cases where such concerns are established, the Commission would need to take remedial measures. Depending on the circumstances, such remedies could include: requiring pipelines to put in taps to reduce capacity bottlenecks; requiring pipelines to build additional capacity when requested by customers willing to pay the costs of construction; limiting the rates at which the affiliate can release capacity; limiting the amount of capacity the affiliate can hold; or prohibiting the affiliate from holding capacity on its related pipeline.

B. Peak and Off-Peak Rates

Use of peak/off-peak, or seasonal, rates for pipeline services could improve efficiency in the market place by better accommodating regulation to seasonal demand for capacity, and at the same time could benefit long-term captive customers. Therefore, as discussed below, the Commission will permit pipelines to institute peak/off-peak rates for all short-term services, *i.e.*, short-term firm and interruptible

[124] *See Transcontinental Gas Pipe Line Corporation* v. *State Oil and Gas Board,* 474 U.S. 409, 420 (1986) (Natural Gas Act's artificial pricing scheme is a major cause of imbalance between supply and demand).

[125] Under cost-of-service regulation, the pipeline can only recover the costs of its investment in pipeline facilities. It cannot capture added revenues by refusing to build additional capacity thereby raising the price for capacity. The Commission's peak/off-peak rate policy articulated here similarly protects against this problem through the requirement that pipelines cannot recover more than their existing cost-of-service through peak/off-peak rates.

[126] From 1997 to October 1999, the Commission has certificated 30 major on-shore and off-shore projects, not including storage, totaling 12,594.8 MMCF/day of capacity. There are currently 13 major construction project applications, not including storage, pending at the Commission, totaling 6,440 MMcf/day of capacity. *See* Department of Energy/Energy Information Administration, Pub. No. DOE/EIA–0560, Natural Gas 1998 Issues and Trends, 18 (June 1999) (80 natural gas pipeline projects completed between January 1997 and December 1998).

service and multi-year seasonal contracts,[127] as one possible method of promoting allocative efficiency that is consistent with the goal of protecting customers from monopoly power. The current use of uniform maximum rates, where fixed costs are recovered in 12 monthly installments, was developed at a time when the vast majority of firm contracts were long-term contracts. The use of uniform maximum rates for long-term contracts is appropriate because, under an SFV rate design, once a shipper has committed to buy capacity for a year, the use of seasonal reservation charges will not affect the total amount the customer will pay.

However, the use of uniform maximum prices for short-term service can create situations where short-term customers are able to purchase peak capacity at a price that may be lower than its market value while the pipeline sells off-peak capacity at ''discounted'' rates. If short-term customers are able to purchase peak capacity at less than its market value and off-peak capacity at a discount, while the long-term customers pay a uniform maximum rate, the short-term customers will receive annual service at a lower cost than long-term shippers. This works to the disadvantage of captive customers with long-term contracts. Further, under this scenario, short-term shippers seeking winter-only service can obtain peak period capacity for a fraction of the annual cost of providing capacity, leaving the long-term shippers responsible for the remainder. This cost allocation disparity between short- and long-term shippers could increase as LDC contracts expire and more capacity is sold in the short-term market.

Peak/off-peak rates could allow pipelines to increase revenue recovery from short-term peak period shippers. Increased cost recovery from peak short-term services lessens the level of costs that need to be recovered from long-term customers and minimizes the cost shifting that occurs with off-peak discounting. By reducing the rates in the off-peak periods, peak/off-peak rates could reduce the need for discounts and reliance on discount adjustments. Many commenters[128] object to the Commission's current discount adjustment policy under which pipelines offering discounts are able, in the next rate case, to adjust maximum rates to reflect the discounts. Peak/off-peak rates could better reflect the value of capacity during peak and off-peak periods, thereby reducing the need to make discount adjustments.

In addition to benefitting captive long-term customers, use of peak/off-peak rates for short-term services could better reflect the true value of capacity during peak and off-peak periods, and thus improve allocative efficiency especially during peak periods when capacity is constrained and the price in a competitive market would exceed the average maximum rate. In the current marketplace, at times when demand for capacity exceeds the available capacity, pipelines cannot automatically allocate that capacity to the shipper placing the highest value on the capacity. Instead, they must allocate capacity *pro rata* or on the basis of a queue. This often prevents shippers who most value capacity from obtaining it. With peak/off-peak rates the pipeline would be able to allocate that capacity more efficiently to those shippers valuing the capacity the most. Charging shippers more for use during peak periods also can provide better price signals about the need for new construction. The demand for pipeline capacity at peak is a major factor in the pipeline's decision to add to its facilities.

Thus, peak/off-peak pricing for short-term services could promote several important policy goals. It could remove one of the biases favoring short-term contracts, and could lower the share of costs allocated to long-term transportation customers. It could increase efficiency in short-term markets by allowing prices to better reflect demand during peak periods. Therefore, as discussed below, the Commission will permit pipelines to implement value-based peak/off-peak rates for their short-term transportation services, within the pipeline's current cost-based revenue requirement. Under an SFV rate design, the use of peak/off-peak reservation charges for long-term contracts would not affect the total amount a long-term customer would pay over the year. Therefore, this policy will not apply to long-term contracts that are for 12 or more consecutive months of service. However, long-term customers can choose to pay peak/off-peak rates as a billing adjustment.

Rates developed under a peak/off-peak methodology will be higher at peak periods than off-peak periods. This result is the same as the result under the current uniform maximum rate method. Currently, the rates actually paid by shippers are higher during peak because the pipeline is generally able to charge the maximum rate at peak, but must discount rates during off-peak periods to customers that have alternatives available in the marketplace. Therefore, charging a higher rate during peak periods is consistent with current practice. However, peak/off-peak pricing would better match demand with price than does the current method. In allowing seasonal/peak pricing, the Commission is improving upon the existing pricing model and retaining the revenue constraints of its existing cost-based ratemaking regulatory model.

The Commission will allow the pipelines to determine the most appropriate method of implementation given the characteristics of their individual systems, consistent with the general principles discussed in this section. The Commission's discussion of peak/off-peak rates in this section, and its suggestion that pipelines voluntarily use peak/off-peak rates is a policy statement, and not a rule that imposes any requirements on pipelines or changes current Commission regulations.

1. Background

The Commission has long recognized the value of seasonal, or peak/off-peak rates, and in the NOPR sought comments on implementation of seasonal rates as one method of improving the regulatory scheme. The Commission's current regulations[129] and its precedent[130] recognize that peak/off-peak rates have a role in the ratemaking process, and the Commission has specifically recognized that differences in peak and off-peak demand may be considered in ratemaking. In the 1989 Rate Design Policy Statement, the Commission expressed concern that the derivation of rates without regard to seasonal variations in use of the pipeline does not properly ration peak capacity or lead to efficient use of the pipeline in periods of excess capacity.[131] The Commission suggested that pipelines could assign peak/off-peak costs by seasonal load factors, or assign the cost

[127] If a shipper contracts for capacity for certain months of the year, over a period of several years, but service is not continuous for every month of a year, the contract is similar to several short-term contracts, rather than to a long-term contract of a year or more, where the shipper purchases capacity in consecutive months during both peak and off-peak periods.

[128] See, for example, the comments of APGA, Brooklyn Union, FPL Group, Inc., Illinois Municipal Gas Agency, Mississippi Valley and Willmut Gas, NASUCA, New England Gas Distributors, Pennsylvania Office of the Consumer Advocate, Process Gas, and the Public Service Commission of Wisconsin.

[129] 18 CFR § 284.7(c)(3)(i) (1999).

[130] *See, e.g.,* Opinion No. 369, Panhandle Eastern Pipe Line Co., FERC ¶ 61,264 (1991); Maritimes & Northeast Pipeline, L.L.C., 80 FERC ¶ 61,346 (1997).

[131] Policy Statement Providing Guidance with Respect to the Designing of Rates (Rate Design Policy Statement), 47 FERC ¶ 61,295 at 62,054 (1989).

of transmission facilities used to provide service above the annual load factor to the peak period.[132]

Part 284 of the Commission's regulations has long contained the rate objectives that rates for peak periods should be designed to ration capacity and rates for off peak periods should be designed to maximize throughput.[133] These rate objectives are independent of the costs of providing service. Part 284 also requires that rates reasonably reflect any material variation in the cost of providing service due to whether the service is provided during a peak or non-peak period.[134] While the regulations specifically recognize the validity of seasonal rates to ration capacity, maximize throughput, and reflect cost differences, they do not limit the use of seasonal rates to these circumstances, and nothing in the Commission's regulations prohibits the use of peak/off-peak rates that reflect differences in peak and off-peak demand. Thus, peak/off-peak rates are consistent with the Commission's existing regulations, and no changes to the regulations are necessary to implement peak/off-peak rates.

The Commission recognizes that some of its prior decisions could be interpreted as limiting the use of peak/off-peak rates to circumstances where seasonal rate differences are cost-based.[135] Although the regulations require seasonal rates to reflect seasonal cost differences, the regulations do not preclude seasonal rates designed on other bases, and the Commission has approved peak/off-peak rates using a value based method for setting peak/off-peak rates.[136] The Commission clarifies that nothing in its prior decisions was intended to limit the use of peak/off-peak rates to situations where seasonal rate differences are cost-based.

Of these two methods, basing peak/off-peak rates on value of service concepts, rather than specific costs, is more consistent with the goal of providing efficient pricing signals. Those customers that value capacity more highly should expect to pay higher prices when capacity is scarce. The prices they would be willing to pay have little relationship to the accounting cost of the facilities used to provide additional service at peak periods. In practice, it is very difficult to identify specific facilities, with the exception of storage, that are used to provide transportation service at peak periods rather than year round. A similar problem occurs on most systems if one attempts to identify specific costs that are attributable to peak/off-peak usage.

2. Implementation

The Commission will facilitate the implementation of peak/off-peak rates with a flexible policy that will permit the use of a wide variety of peak/off-peak rate methods. The pipelines can make changes in their peak/off-peak rates on a monthly basis, within existing cost of service constraints. Pipelines can implement peak/off-peak rates either through a general section 4 rate case or a *pro forma* tariff filing. The following discusses the basic parameters applicable to peak/off-peak filings and the procedures to be followed in processing the filings.

a. Parameters for Establishing Peak/Off-Peak Rates. Value-based peak/off-peak rates are just and reasonable cost-based rates.[137] Like uniform maximum rates, peak/off-peak rates would be established by taking the pipeline's annual revenue requirement and deriving from it a daily or monthly rate. The difference in developing peak/off-peak rates and the current uniform maximum rate is that instead of dividing the annual revenue requirement by 365 to obtain a daily rate, different daily or monthly rates will be developed for peak and off-peak periods using one of several possible methods of measuring the value of capacity at peak and off-peak.[138] The sum of the daily or monthly rates, multiplied by the quantity used or reserved, still must not exceed the pipeline's annual revenue requirement, and thus, any increases in rates at peak must be offset by decreases in off-peak rates. In other words, if a shipper paid the peak and off-peak rate for the same volume of transportation every day of the year, the amount it paid annually for service would be no more than if it had paid the uniform maximum daily rate for the same transportation volume based on the same revenue requirement.

This requirement limits the rate the pipeline may charge. For example, if the pipeline wanted to charge a rate greatly in excess of the current uniform maximum rate in the four month period December through March, it would have to match this increase with a corresponding reduction in rates for the remaining months. This places a check on the ability of the pipelines to propose extraordinarily high rates during peak periods because any rate increase for peak periods must be matched by a rate decrease during the off-peak periods. This is a disincentive for pipelines to raise peak period rates to unrealistically high levels since this would require an off-setting lowering of off-peak rates that could compromise the pipeline's ability to recover maximum off-peak revenues.

As illustrated by the comments, there is more than one reasonable way to implement peak/off-peak rates based on value of service concepts. The methods proposed by the commenters include using a ratio of the prices for capacity release and IT on a system to develop a ratio,[139] looking at usage of compression to develop a ratio,[140] looking at peak/off-peak volumes/load factors to develop a ratio,[141] developing a ratio based on historic price differentials between receipt and delivery point prices, or allowing a shaping of prices to try to capture the value of the capacity,[142] and tailoring of contract demand levels during the year.[143] Other methods of developing peak/off-peak rates could include looking at the price at which capacity has traded, load factors, basis or other indexing, or other methods of measuring the value of capacity throughout the year. Since capacity prices are currently capped at uniform maximum rates, the historical data on pricing may not be the best indicator of the value.

Some methods may work better for certain systems than others. For example, on some systems' data may be more readily available to base peak/off-peak differences on basis differentials because the pipeline is directly connected to major market centers so that there is already considerable data on the value of the pipeline's capacity. On other systems where there is a wide swing in load factors from peak to off peak periods, a method based on load factors may make more sense.

Therefore, the best method of developing peak/off-peak rates will depend in part on the specific characteristics of each pipeline, and the

[132] *Id.*

[133] 18 CFR 284.7(b).

[134] 18 CFR 284.7(c)(3)(i).

[135] *See, e.g.,* Opinion No. 369, Panhandle Eastern Pipe Line Co., 57 FERC ¶ 61,264 at 61,831 (1991) (the Commission permitted seasonalization of the sales reservation charge, but found that, based on the facts of that case, seasonalized firm rates could not be justified based on the need to ration capacity).

[136] *See* Maritimes & Northeast Pipeline, L.L.C., 80 FERC ¶ 61,346 (1997).

[137] Rate Design Policy Statement, 48 FERC ¶ 61,122 at 61,446 (1989).

[138] Some of these methodologies are discussed below.

[139] See, *e.g.,* comments of Amoco.

[140] See, *e.g.,* comments of Columbia.

[141] See, *e.g.,* comments of Columbia.

[142] See comments of Texas Eastern/Algonquin, CMS Panhandle. Under this approach the pipeline would assess the relative value of capacity throughout the year and design reservation charges based on this assessment. The sum of the annual peak/off-peak reservation charges would equal the sum of the current annual average reservation charges.

[143] See comments of Enron Pipelines.

Commission will not adopt any one method of developing peak/off-peak rates, but will leave the details of the implementation of peak/off-peak rates to individual pipelines. The Commission will consider any reasonable method of implementation that is consistent with the general principles discussed in this section, but the pipeline will have the burden of proof to show that its proposed method is just and reasonable.

b. *Process for Implementing Peak/Off-Peak Rates.* The implementation of peak/off-peak rates could lead to higher pipeline revenues from short-term services since a pipeline could reduce off-peak price caps so that they would be close to recent discount history, and correspondingly increase peak price caps. The pipeline might see little or no reduction in off-peak revenues since market prices are usually below the uniform maximum price caps. Because the price cap would be higher in the peak with peak/off-peak rates, the pipeline's revenues should increase if it adopts peak/off-peak rates.

The process for implementing peak/off-peak rates, therefore, must take the increased revenues into account. One method for doing so would be for the pipeline to file a general rate case to implement peak/off-peak rates. In a general rate case, all pipeline costs and revenues can be examined and the appropriate revenue responsibility of each service can be decided. Thus, the rates for long-term services would be reduced in recognition that the pipeline could be expected to recover more revenues from short-term services.

However, the filing of general section 4 rate case may not be well-suited to this context. The Commission's rate methodology relies on a historical test period to project future throughput for each service, and revenue responsibility is assigned to each service based on those projections. There is no historical experience that would adequately project future short-term service demand with peak/off-peak pricing. Also, using general rate cases to implement peak/off-peak rates could be time consuming.

Therefore, the Commission will establish a procedure under which pipelines can establish peak/off-peak rates through a *pro forma* tariff filing so that the Commission and the parties will have an adequate opportunity to review the proposal prior to implementation. Under this procedure, the *pro forma* filing would be noticed with comments due on the pipeline's proposal within 21 days, rather than the 12 days permitted for tariff filings. The Commission would take action on the filing within 60 days. Pipelines interested in implementing peak/off-peak rates are encouraged to file proposals as soon as possible.

Consistent with the goal of benefitting long-term captive customers, if peak/off-peak rates result in the pipeline's recovering increased revenues from short-term peak services, those increased revenues should be used to offset the costs borne by long-term customers. Therefore, if the pipeline seeks to implement seasonal rates through a *pro forma* tariff filing, the pipeline must include in its proposal a revenue sharing mechanism that will provide for at least an equal sharing of any increased revenues with its long-term customers. The actual amount of the revenue credit can be negotiated with the pipeline's customers before or during the *pro forma* tariff proceeding. After 12 months experience with peak/off-peak rates, the pipeline must prepare a cost and revenue study and file the study with the Commission. Pipelines must file the cost and revenue study pursuant to the format prescribed in § 154.313 of the Commission's regulations.[144] The study must be filed within 15 months of implementing peak/off-peak rates. Based on the cost and revenue study, the Commission will determine whether any rate adjustments are necessary to the long-term rates, and may order such adjustments prospectively.

As explained above, one of the policy rationales for adopting peak/off-peak rates is that under the current cost-of-service rate methodology, underpricing short-term peak capacity results in the pipeline's long-term customers paying higher rates because a greater share of the pipeline's costs are recovered from its long-term rates. The Commission is seeking to lower the rates to long-term customers in recognition of the additional risks they take by signing long-term contracts. Therefore, if a pipeline moves to peak/off-peak rates it should benefit the pipeline's long-term customers, and a revenue sharing mechanism that benefits only long-term customers is appropriate.

The Commission will not require any specific method of determining the amount of additional revenues that are attributable to implementation of peak pricing, since the same approach may not work equally well on all pipelines. The pipeline must propose a reasonable method when it files to implement peak pricing. The issues involved in developing an appropriate revenue sharing mechanism may be more complex than deriving the seasonal rate itself, and these issues could be considered independently of the rate. Pipelines are encouraged to work with their customers to develop a method that has wide support. The method should be fair to the pipeline and its long-term customers and should be easy to implement. Whatever method is chosen, the pipeline is not required to share excess revenues if there really are none. A pipeline will not be required to share revenues if it demonstrates that its total revenues from peak/off-peak rates were less than the revenues allowed for the relevant services in its last rate case.

C. Term-Differentiated Rates

In the NOPR, the Commission stated that one method of reducing asymmetry of risk that favors short-term contracts, and of strengthening the long-term market would be to encourage contracts that contain lower maximum rates for longer term service than for shorter term service in recognition of the value of longer term contracts in limiting the pipeline's risk. The Commission sought comments on whether and how to encourage such term-differentiated rates. Upon review of the comments, the Commission has determined that term-differentiated rates should be available to the pipeline as one of several methods that could be used to price capacity more efficiently. As explained below, the Commission will not adopt any one method of establishing term-differentiated rates, but will permit a pipeline and its customers to develop specific methodologies suitable to the characteristics of the specific pipeline in a section 4 rate proceeding.

Term-differentiated rates would match price more closely with risk-adjusted value, and could result in a rate structure that prices capacity held for a longer term at a lower rate than capacity held for a shorter term. With term-differentiated rates, maximum posted rates for longer terms would be lower than rates for shorter term service on a per unit basis and at comparable load factors. Term-differentiated rates do not differentiate between seasons, but instead, differentiate based on the length of the contract. Term-differentiated rates would more accurately reflect in the price of service the relative levels of risk that pipelines must face when selling service for a shorter period than for a longer period, as well as the higher risks that customers face when they purchase service for a longer period of time.

As the Commission explained in the NOPR, a shorter term contract is riskier for the pipeline, and a higher rate would compensate the pipeline for this

[144] 18 CFR 154.313 (1999). *See* Trunkline LNG Company, 82 FERC ¶ 61,198 (1998), *aff'd,* 194 F.3d 68 (D.C. Cir. 1999).

additional risk. A shorter term contract provides greater flexibility and less risk to the shipper, and a higher rate would recognize and require payment for these benefits. The Commission has already recognized, in the context of oil pipeline rates, that the lower risk to the shipper and the higher risk to the pipeline, associated with shorter term contracts may properly be reflected in a higher rate for such service. In *Express Pipeline Partnership,*[145] the Commission explained that shorter term shippers have less risk because they have maximum flexibility to react to changes in their own circumstances or in market conditions, and are a greater risk to the pipeline because they do not provide the revenue assurances or planning assurances to the pipeline that long-term shippers do.

Several commenters[146] argue that term-differentiated rates are inconsistent with cost-based regulation. They argue that term-differentiated rates are not based on cost incurrence because there is no evidence that it costs more for the pipeline to meet the needs of short-term contracts. However, as explained above in the discussion of peak/off-peak rates, cost-based ratemaking is not simply a matter of strict cost incurrence. ''Value and costs are inexorably linked'' in ratemaking, and the Commission can legitimately consider the overall goals of its ratemaking policy in developing just and reasonable cost-based rates.[147] Further, the existence of long-term contracts reduces pipeline risks and therefore lowers its cost of capital.

Like peak/off-peak rates, term-differentiated rates would be cost-based, just and reasonable rates because the Commission will limit the rates in the aggregate to produce the pipeline's annual revenue requirement. The difference between developing constant average rates and term-differentiated rates is that instead of establishing a single rate cap for each service, as in current practice, with term-differentiated rates, different rates would be charged to different customers based on the length of their contract.

There are various methods that could be used to develop reasonable term differentiated rates. For example, in its comments, INGAA suggested that term-differentiated rates could be developed using a cost allocation approach that would allocate costs between shorter term and longer term service based on an allocation factor such as projected percentages of throughput.

Several commenters[148] asserted that the Commission should not approve term-differentiated rates as a ratemaking option without setting forth a specific proposal for comment in a generic proceeding. However, the Commission has concluded that since there is more than one appropriate method of establishing term-differentiated rates, and some methods might be more appropriate on certain pipelines than on others, it will not limit the pipeline to one method, but will allow the pipelines and the customers to work out the details of the methodologies in specific rate proceedings.

A pipeline may propose term-differentiated rates just for long-term services or for both short- and long-term services. The Commission recognizes that the use of term-differentiated rates for short-term services may enhance the potential for price discrimination, particularly during off-peak periods, by increasing the rate caps that would apply to short-term service acquired in off-peak periods. Consequently, a pipeline proposing term-differentiated rates for short-term services will need to fully explain the basis and justification for the price differentials.

Term-differentiated rates have a much greater potential for effecting the rates of all customers than peak/off-peak rates. Term-differentiated rates would raise the maximum tariff rates for some customers, and there should be a decrease in the maximum tariff rates for long term customers. The general reallocation of revenue responsibility among customer classes must be done through rate changes for all customers simultaneously in the section 4 rate filing in which the pipeline seeks to implement term-differentiated rates.

D. Voluntary Auctions

Auctions, if properly designed, can provide for efficient allocation of capacity and natural gas, reduce transaction costs in finding and arranging capacity transactions, and provide for more accurate dissemination of relative pricing information to the marketplace. Auctions also can be used as methods of mitigating the effects of market power by limiting the ability of sellers to withhold capacity, to price discriminate, or to show favoritism. With the growth of the Internet, electronic auctions have become an effective and efficient method of exchanging goods and services. Auctions increasingly are being used successfully in energy industries. Electronic auctions have been established to facilitate exchanges of gas. Auctions similarly are being used in the electric industry to allocate generation and transmission capacity. Pipelines have been using electronic open seasons to determine demand for new construction. The capacity release posting and bidding system itself is a form of auction.

A number of commenters recognize the potential value in the use of auctions, but urge the Commission and the industry to obtain greater familiarity with the use of auctions in order to obtain better understanding of the auction formats that work well and those that do not. Although the Commission is not moving forward with mandatory auctions for pipeline capacity as well as short-term released capacity at this time, the Commission is still of the view that more extensive use of auctions can provide a wide range of benefits to the gas industry. Pipelines are encouraged to file proposals for implementing auctions and this section discusses principles for evaluating such proposals. Third-parties also encouraged to develop capacity auctions, and, as discussed below, the Commission, in appropriate circumstances, may be willing to modify certain regulatory requirements to facilitate such auctions.

The existing third-party auctions for natural gas, for instance, may form the basis for the development of an efficient auction for transportation capacity or one that would combine the gas commodity and transportation capacity within a single auction format. Such auctions could resolve one of the objections to capacity-only auctions: that capacity-only auctions would force buyers to obtain capacity, without knowing whether they would be able to obtain gas at a reasonable price.[149] Pipelines also may find it efficient to use a form of auction to allocate short-term capacity on a monthly, daily, or even intra-day basis. As a result of restructuring under Order No. 636, most pipeline tariffs require that interruptible capacity be allocated based on price when the pipeline is unable to fulfill all nominations for service.[150] The use of a more formal auction method, therefore,

[145] 76 FERC ¶ 61,245, *reh'g denied,* 77 FERC ¶ 61,188, (1996).

[146] See, for example, comments of Dynegy, Amoco, and Indicated Shippers/

[147] Interstate Natural Gas Pipeline Rate Design, 48 ¶ 61,122 at 61,446 (1989).

[148] See, for example, comments of Process Gas Consumers.

[149] *See* Comment of Dynegy. Dynegy was concerned that if a shipper obtained capacity and then had to negotiate for gas, the gas producer would obtain leverage in the transaction, because the shipper had already committed to pay for capacity from a particular receipt point.

[150] *See* Robin Pipeline Company, 81 FERC ¶ 61,041, at 61,225 (1997); Pacific Gas Transmission Company, 76 FERC ¶ 61,258 (1996).

may be a reasonable method of allocating capacity.

The Commission also encourages pipelines and third-parties to consider establishing multi-pipeline or regional auctions. Such auctions could eliminate concerns expressed in the comments about possible difficulties in using auctions on individual pipelines to acquire a capacity path traversing multiple pipelines.[151] Pipelines in a region, for instance, could arrange with a third-party auctioneer to sell the pipelines' available capacity in the same auction as capacity release transactions in that region, thereby providing shippers with one-stop capacity shopping.

The Commission recognizes that some of its existing regulations may impede the development of auctions. For instance, Altra has identified the requirement that all capacity release transactions must be posted for bidding on pipeline Internet sites as a potential barrier to third-party auctions, because it would require the double posting of capacity: once on the third-party's auction mechanism and a second time on the pipeline's Internet site. The Commission also has required, and, in this rule is continuing to require, the publication of the names of shippers acquiring capacity from releasing shippers and the pipeline in order to provide price transparency and to permit effective monitoring of potential undue discrimination. In a properly designed auction, however, the requirement for posting the winning bidder's name may not be necessary, so long as the market price is disclosed. A waiver of the requirement to post the winning bidder's name, or to delay such posting, could be granted when the auction is designed in such a way that shippers can verify that the auction was properly conducted and the winning bid awarded fairly without favoritism.[152] Upon application by a third-party or pipeline, the Commission would consider waiving these or other regulatory requirements that unnecessarily impede the development of auctions. Pipelines, however, may need to continue to post the results of affiliate transactions unless they can demonstrate that the format of the auction and the results are designed in such a way as to preclude affiliate favoritism. The use of third-party auctioneers or certification may be methods of providing sufficient security against affiliate abuse.

An auction also may be a means by which a pipeline could sell some or all of its capacity without a price cap if the auction is designed in such a way as to protect against the pipeline's ability to withhold capacity and exercise market power. Not all types of capacity would have to be allocated through the auction process. For example, the pipeline may have a reasonable basis for limiting the auction only to short-term firm or interruptible capacity. The Commission also still sees value in permitting the pipelines to negotiate prearranged deals while they conduct auctions for remaining capacity, although, as discussed below, pipelines must not withhold available capacity from the auction simply because they believe a better pre-arranged deal may be arranged in the future.

Once capacity is placed in the auction, the pipelines must design the auction in ways to prevent the withholding of capacity and the exercise of market power. Capacity can be withheld by a pipeline in two primary ways: the pipeline can withhold capacity directly by not putting it into the auction; or it can indirectly withhold capacity through the use of a reserve price. In a proposal for auctions without a rate cap, all capacity available at that time of the auction would have to be included in the auction. The auction proposal also needs to address the appropriate limitations that should be placed on the level at which the pipeline can establish reserve prices, particularly whether different reserve prices should be established for peak and off-peak capacity.

While the Commission will not insist on any particular auction format for pipelines or third-parties, the Commission sets forth below some basic principles to which auctions should adhere:

- The timing of the auction should be predictable, and shippers potentially offering or bidding on capacity should have notice of when the auction will be held and what capacity will be included.
- The auction should be open to all potential bidders on a non-discriminatory basis.
- The auction should be user-friendly with information on the rules and procedures easily accessible to all.
- The bidding procedures as well as the methods for selecting the best bid should be fully disclosed prior to the auction. For instance, if net present values formulas are used, the discount rate and the method of calculation should be disclosed.
- There should be no favoritism in the determination of the winning bidder and mechanisms should be included to permit monitoring of how the selection criteria were applied. This would include methods of verifying any reserve price applied in an auction.
- Transaction information (such as prices, volumes, and receipt and delivery points) should be disclosed so that shippers can ascertain the value of transportation. The names of shippers may not need to be disclosed or could be disclosed at a later date if the auction results are verifiable and free from potential affiliate favoritism.

Adherence to these principles should help to ensure that auctions are transparent, verifiable, and non-discriminatory. The Commission strongly encourages pipelines and third-parties to begin the development of auction formats so that the industry will gain greater experience and familiarity with the use of auction techniques. Toward that end, Commission staff will be available to assist pipelines or third-parties in their development of auction formats.

III. Improving Competition and Efficiency Across the Pipeline Grid

The Commission in this rule is making changes to enhance competition and improve efficiency across the pipeline grid. By improving efficiency and shipper options, these changes should provide shippers with market mechanisms that will better enable them to avoid market power where it exists. The changes include revising Commission regulations to: require pipelines to revise their scheduling procedures so that capacity release transactions can be scheduled on a comparable basis with other pipeline services; require pipelines to permit shippers to segment capacity and to facilitate capacity release transactions; and require pipelines to offer services that shippers can use to avoid penalties and to provide shippers with additional information that will enhance their ability to avoid penalties. Pipelines must file *pro forma* tariff sheets to comply with these requirements by May 1, 2000. Interested parties will be provided 30 days to comment on the *pro forma* tariff filings.

A. Scheduling Equality

The Commission is adopting in this final rule, the proposal set forth in the NOPR to amend its regulations to include a new § 284.12(c)(1)(ii) to provide that pipelines must provide purchasers of released capacity the same ability to submit a nomination at the first available opportunity after consummation of the deal as shippers purchasing capacity from the pipeline. This will enable shippers to acquire released capacity at any of the nomination or intra-day nomination

[151] *See* Comments of Process Gas Consumers I, Wisconsin Distributors, Nicor Gas, PG&E, Shell Energy Services.

[152] For instance, the use of an independent firm to verify the results of the auction may be sufficient without the posting of winning shippers' names.

times, and nominate gas coincident with their acquisition of capacity. By enabling released capacity to compete on a comparable basis with pipeline capacity, this will foster a more competitive short-term market.

In the NOPR, the Commission explained that the current regulations put capacity obtained in the release market at a disadvantage compared to capacity obtained directly from the pipeline because nomination and scheduling opportunities for capacity release transactions are significantly circumscribed. As the Commission explained, pipelines can sell their interruptible and short-term firm capacity at any time, and shippers can schedule that capacity at the earliest available nomination opportunity. Further, shippers purchasing from the pipeline have three opportunities for intra-day nominations.[153] Similarly, capacity holders making delivered sales can nominate and schedule at every available opportunity. By contrast, shippers utilizing released capacity must consummate their deals by 9:00 AM in order to submit a nomination by 11:30 AM to take effect at 9:00 AM the next gas day, and they cannot use an intra-day nomination opportunity to submit a nomination for the current gas day.

In order to place capacity release transactions on a more equal footing with pipeline services, the Commission is amending its regulations to include a new § 284.12(c)(1)(ii) to provide that pipelines must provide purchasers of released capacity, like shippers purchasing capacity from the pipeline, with the opportunity to submit a nomination at the first available opportunity after consummation of the deal. The regulation specifically provides that the contracting process should not interfere with the ability of the replacement shipper to nominate at the time the transaction is complete. In the NOPR, the Commission explained that there are several ways that a pipeline can protect itself, and suggested that pipelines can institute procedures under which replacement shippers receive pre-approval of their credit-worthiness or receive a master contract, such as those given to interruptible shippers, permitting the replacement shipper to nominate under the contract at any time. The Commission will not require any specific method of compliance with this regulation, but will allow the pipeline to develop procedures suitable for its system.

The vast majority of the commenters fully supported the Commission's proposal.[154] These parties agree that providing replacement shippers with the same opportunities to nominate gas as the shippers nominating primary capacity will promote more competitive markets and help mitigate the pipeline's market power. For example, Dynegy characterizes the Commission's proposal as a ''common sense adjustment'' that will pave the way to more competitive markets and mitigate pipeline market power.

Several of the commenters asked the Commission to clarify the bumping right of replacement shippers in view of the new procedures.[155] For example, Industrials state that it seems clear that a replacement shipper should have the same bumping rights as any firm shipper vis-a-vis an interruptible shipper, but that the question of whether a replacement shipper should be able to bump secondary firm if the replacement shipper has primary firm is more difficult, and the Commission should clarify the entire issue of intra-day bumping of secondary firm by primary firm.

Nothing in the revised regulation adopted here changes the current rules on bumping, and the bumping rules in effect on each pipeline will remain unchanged and will continue to govern the priorities among shippers. A replacement shipper would, as a firm shipper, bump an interruptible shipper, subject to the requirement of notice to the interruptible shipper and an opportunity to renominate.[156] Generally, primary firm will not interrupt secondary firm on an intra-day basis once the gas has begun to flow, but again that rule is pipeline-specific, and will be governed by the particular pipeline's tariff.[157]

Some of the commenters suggested procedural changes which they state would expedite the execution of an agreement between the pipeline and the replacement shippers where such an agreement is required by the pipeline. For example, Dynegy suggests that the Commission require pipelines to adopt a master *pro forma* capacity release service agreement, or an umbrella agreement, that would include pre-approved credit, upon which replacement shippers can aggregate released capacity.

The regulation adopted by the Commission specifically provides that if the pipeline requires the replacement shipper to enter into a contract, ''the requirement for contracting must not inhibit the ability to submit a nomination at the time the transaction is complete.'' The Commission suggested in the NOPR several methods, including the type of procedure suggested by Dynegy, that pipelines could use to meet this requirement. The Commission will not mandate any one method, but will leave this to be resolved by the pipelines and shippers.

Dynegy argues the Commission should, in this proceeding, require all restrictions on capacity release to be removed. For example, Dynegy states that releasing shippers should be given the same rights as pipelines to sell capacity for less than a day. Further, Dynegy states that certain pipelines place other restrictions on released capacity, such as refusing to continue a discount if the capacity is released, requiring additional paperwork for capacity releases, requiring releasing shippers to remit to the pipeline any amounts received from the replacement shipper in excess of the releasing shipper's discounted rate, and requiring a deposit every time a capacity release bid is submitted.

Dynegy's concerns about discounting have been resolved by the Commission in prior proceedings. The Commission has specifically held that a discount cannot be conditioned on an agreement not to release the capacity, and a pipeline cannot refuse to continue a discount if capacity is released.[158] Further, Order No. 636–A specifically provides that ''a releasing shipper paying discounted rates is entitled to receive the proceeds from a release even if such proceeds exceed its reservation fee.'' [159] The Commission has recognized an exception to this general rule only if the pipeline and the releasing shipper negotiate a revenue sharing agreement that is approved as part of a general section 4 rate

[153] Standards for Business Practices of Interstate Natural Gas Pipelines, Final Rule, 63 FR 39509 (July 23, 1998), 84 FERC ¶ 61,031 (1998).

[154] For example, AEC Marketing, AF&PA, AGA, Amoco, Atlanta Gas Light, Colorado Springs, Columbia LDCs, Consolidated Natural, Duke Energy Trading, Exxon, Florida Cities, FPL Group, IPAA, Indicated Shippers, Louisville, Market Hub Partners, MichCon, Midland, NARUC, NEMA, NGSA, New England Gas Distributors, PanCanadian, Philadelphia Gas Works, Process Gas Consumers, *et al.,* Proliance, PSC of Kentucky, PSC of New York, PSC of Wisconsin, Sithe, Washington Gas Light, and Wisconsin Distributors.

[155] For example, see the comments of Industrials, New York Public Service Commission, and NGSA.

[156] *E.g.* Tennessee Gas Pipeline Corporation, 73 FERC ¶ 61,158 (1995).

[157] *See* El Paso Natural Gas Company, 81 FERC ¶ 61174 at 61,763 (1997).

[158] Natural Gas Pipeline Co., 84 FERC ¶ 61,099 (1998).

[159] Order No. 636–A, FERC Stats. & Regs. ¶ 30,950 at 30,562 (1992).

proceeding or specifically approved as a non-conforming discount agreement.[160]

In addition, there is no basis for a pipeline to charge a deposit every time capacity is released. Under the new regulation adopted here, as well as under GISB Standard 5.3.2, the pipeline must approve a contract within an hour, and therefore will know before gas flows under the release whether the replacement shipper is creditworthy. If the replacement shipper is creditworthy, then there is no basis for requiring a bond. The only time this issue would arise is when the replacement shipper is determined not to be creditworthy. In these circumstances, the pipeline could give the releasing shipper the option of posting a bond for the usage charge or assuming liability for the usage charge in the event of the replacement shipper's default.

Some of the other problems cited by Dynegy, such as additional paperwork for capacity release, should be alleviated by the rule adopted here. Creating equality in nominations for capacity release will foster a more competitive market. However, the Commission has recognized that some of the differences in the treatment of different types of capacity reflect differences in the nature of the services that should be preserved. The Commission is not prepared to say at this time that all differences in the treatment of capacity release are unwarranted and should be eliminated.

INGAA and Enron Pipelines argue that the different treatment of capacity release does not result from a lack of nomination opportunities, but stems from the deadline by which shippers currently must complete capacity release transactions. INGAA suggests that the problem could be solved by not requiring pre-posting and bidding for capacity release transactions. If the Commission does not accept this proposal, INGAA states that it would support revisions to the standard capacity release timeline to permit capacity release transactions to be conducted in the morning before the timely nomination deadline, rather than requiring such transactions to close on the day before nominations. INGAA states that an updated timeline is a better approach than setting a one-hour contracting requirement.

The rule adopted here will speed up the capacity release nomination process for pre-arranged deals, but the Commission will not change the requirement for posting and bidding for longer deals. Posting and bidding is necessary to continue to protect against undue discrimination, and where capacity release is for a period of a month or longer, posting and bidding should not interfere with execution of the contract.

The Coastal Companies state that while they do not oppose the goal of achieving parity between pipeline capacity and release capacity, they believe that the Commission's proposal will create additional unnecessary burdens on pipelines and shippers. Coastal states that, contrary to the Commission's assumption, shippers do not avoid capacity release, but instead seek out the capacity release market in order to maximize flexibility and minimize disclosure. They state that their companies are already handling release transactions expeditiously. Specifically, they state that ANR already has in its tariff a master agreement for replacement shippers to utilize, and CIG and WIC create a contract immediately at the time of the award. If the Commission does mandate these changes, the Coastal Companies ask the Commission to permit the pipelines to submit limited section 4 filings in order to recoup the costs associated with the mandated procedures.

Contrary to the assertion of the Coastal Companies, the comments received by the Commission on this issue indicated a general consensus that current restrictions on nominations and scheduling of capacity release do inhibit the use of release capacity, and that the Commission's proposal will alleviate this problem. If the Coastal Companies already expedite capacity release agreements and use a master contract, they should not have to make any significant changes in their procedures, and implementation should not be burdensome to them.

Finally, some commenters[161] have asked that the Commission eliminate the ''shipper must have title'' policy. For example, AGA asserts that the Commission should consider repeal of the policy because the market has changed since issuance of Order Nos. 436 and 636. Several other commenters ask that the Commission consider waivers of the shipper must have title policy for LDCs.[162]

The shipper must have title policy developed in the individual pipeline proceedings to implement open access transportation under Order No. 436, and was intended to assure nondiscriminatory access to transportation.[163] Thus, the policy predates the Commission's capacity release program established in Order No. 636, but the capacity release rules were designed with this policy as their foundation. For example, the rules are designed with all transactions conducted through the pipeline, with each shipper who acquired capacity contracting with the pipeline.

Under the capacity release rules, all allocations of capacity must be nondiscriminatory. The current regulations are designed to assure the transparency of capacity release transactions and thereby assure that capacity is allocated on a non-discriminatory basis. The regulations are also designed to assure that capacity is allocated to the highest bidder and thereby promote efficient pricing of capacity. Without the shipper must have title policy, it is unlikely that shippers would need to use capacity release because capacity holders could simply transport gas over the pipeline for another entity. These transactions would not be subject to any of the capacity release requirements, such as the reporting requirements or the allocation rules. Without the shipper must have title rule, the identity of the users of the pipeline's transportation and the conditions under which they moved gas would not be known.

It is possible that the Commission could revise the capacity release program so that it could operate without the shipper must have title policy and still achieve the objectives of nondiscriminatory, efficient allocation of capacity with transparency. However, this would require major revisions to the current capacity release regulations, and such a change is not within the scope of this proceeding. The Commission recognizes that the current policy may impose some transaction costs, but this is necessary to ensure the ability to achieve the Commission's regulatory objectives.

The Commission would consider any such changes to the capacity release program in a separate proceeding at a later date.

B. Segmentation and Flexible Point Rights

In Order No. 636, the Commission established two principles—flexible point rights and segmentation—that are important to creating efficient

[160] Natural Gas Pipeline Co., 82 FERC ¶ 61,289 (1998); 84 FERC ¶ 61,099 (1998).

[161] See, for example, comments of AGA, Atlanta Gas Light, Edison Electric, Brooklyn Union, Atlanta Gas Light Co.

[162] See, for example, comments of Columbia LDCs, Shell Energy, and ConEd.

[163] *E.g.,* Consolidated Gas Transmission Corp., 38 FERC ¶ 61,150 at 61,408 (1987) (''all shippers shall have title to the gas at the time the gas is delivered to the transporter and while it is being transported by the transporter''); Texas Eastern Transmission Corporation, 37 FERC ¶ 61,260 at 61,683–85 (1986)).

competition in the market, both between shippers releasing capacity and the pipeline as well as between releasing shippers.[164] Flexible point rights refer to the rights of firm shippers to change receipt or delivery point so they can receive and deliver gas to any point within the firm capacity rights for which they pay. Segmentation refers to the ability of firm capacity holders to subdivide their capacity into segments and to use the segments for different capacity transactions.

The ability to use flexible receipt and delivery point rights and to segment capacity enhances the value of firm capacity and the ability of firm capacity holders to compete with capacity available from the pipeline as well as capacity available from other releasing shippers. In the example used in Order No. 636, a shipper holding firm capacity from a primary receipt point in the Gulf of Mexico to primary delivery points in New York could release that capacity to a replacement shipper moving gas from the Gulf to Atlanta while the New York releasing shipper could inject gas downstream of Atlanta and use the remainder of the capacity to deliver the gas to New York. In order for such a transaction to work, both the releasing and replacement shippers need the right to change their receipt and delivery points from the primary points in their contracts to use other available points.

The combination of flexible point rights and segmentation increases the alternatives available to shippers looking for capacity. In the example, a shipper in Atlanta looking for capacity has multiple choices. It can purchase available capacity from the pipeline. It can obtain capacity from a shipper with firm delivery rights at Atlanta or from any shipper with delivery point rights downstream of Atlanta. The ability to segment capacity enhances options further. The shipper in New York does not have to forgo deliveries of gas to New York in order to release capacity to the shipper seeking to deliver gas in Atlanta. The New York shipper can both sell capacity to the shipper in Atlanta and retain the right to inject gas downstream of Atlanta to serve its New York market.

The Commission's segmentation policy was not included in the Commission's regulations. Moreover, the segmentation policy is not being uniformly implemented across the pipeline grid. Some pipelines may not permit segmentation at all or may only permit segmentation for release purposes, but not by the shipper for its own uses. In order to improve competition, the Commission is requiring pipelines to permit shippers to segment their capacity for their own use or for release to the extent operationally feasible.

Another issue raised in the NOPR concerned the Commission's policy with respect to relative priorities for shippers to use secondary points within their path and for confirmations at points of interconnection between pipelines. On these issues, the Commission has determined that a generally applicable regulation is not appropriate and that these issues are best handled on a case-by-case basis.

The Commission addresses below its determinations with respect to segmentation and with respect to relative priorities for shippers using secondary points and at points of pipeline interconnection.

1. Segmentation Policies

In the NOPR, the Commission sought comment on whether further regulatory change in its segmentation and flexible receipt and delivery point policies are needed to enhance competition. The Commission pointed out that the segmentation policy adopted in Order No. 636 applied to capacity release transactions and that the Commission had not required pipelines to permit shippers to segment capacity for their own use. The Commission further sought comment on limitations on the ability to use flexible receipt and delivery points in segmented releases that had been accepted in pipeline restructuring proceedings under Order No. 636.

In some restructuring proceedings, the Commission permitted pipelines to restrict replacement shippers' ability to choose primary points based on historic tariff provisions that limited primary point rights to the same level as the shipper's mainline contract demand.[165] But even at that time, the Commission questioned whether those restrictions were justified.[166] Although the Commission accepted the restrictions, the Commission also sought to minimize the effect of the restrictions on the ability to engage in segmented releases by permitting releasing and replacement shippers in segmented releases to choose separate primary point rights. The Commission found that because the releasing and replacement shippers were both shippers on the system, they should both be able to choose primary points consistent with their mainline contract demand:

> The releasing and replacement shippers must be treated as separate shippers with separate contract demands. Thus, the releasing shipper may reserve primary points on the unreleased segment up to its capacity entitlement on that segment, while the replacement shipper simultaneously reserves primary points on the released segment up to its capacity on that segment.[167]

Under this *Texas Eastern/El Paso* approach, the releasing shipper could protect its New York delivery point right by choosing Atlanta as its primary receipt point and New York as its primary delivery point, while the replacement shipper designated its primary receipt point as the Gulf and Atlanta as its primary delivery point. In this example, neither releasing nor replacement shipper held contract demand in excess of their mainline rights. In other cases, where historic contract demand restrictions did not apply, the Commission allowed replacement shippers in all circumstances to change primary points without the releasing shipper losing its primary point rights.[168]

Most shippers strongly support the ability to segment capacity and to use flexible receipt and delivery points to enhance competition throughout the pipeline grid.[169] They contend that pipelines' implementation of segmentation policies vary, with some pipelines permitting no segmentation at all and with little consistency in the way pipelines treat segmented releases. Dynegy contends that differences in segmentation policy among pipelines

[164] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,939, at 30,428, 30,420–21 (Apr. 8, 1992), Order No. 636–A, 57 FR 36128 (Aug. 12, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,950, at 30,559 n.151 (Aug. 3, 1992), Order No. 636–B, 61 FERC ¶ 61,272, at 61,997 (1992).

[165] *Compare* Transwestern Pipeline Company, 62 FERC ¶ a few,090, at 61,659, 63 FERC ¶ 61,138, at 61,911–12 (1993); El Paso Natural Gas Company, 62 FERC ¶ 61,311, at 62,982–83 (1993) (permitting pipelines to continue historic limitations on primary receipt point rights) *with* Northwest Pipeline Coporation, 63 FERC ¶ 61,124, at 61,806–08 (1993) (not permitting the pipeline to add such restrictions).

[166] Transwestern Pipeline Company, 62 FERC ¶ 61,090, at 61,659, 63 FERC ¶61,138, at 61,911–12 (1993).

[167] Texas Eastern Transmission Corporation, 63 FERC ¶ 61,100 at 61,452 (1993); El Paso Natural Gas Company, 62 FERC ¶ 63,311 at 62,991. *See also* Transwestern Pipeline Company, 61 FERC ¶ 61,332, at 62,232 (1992).

[168] *See* Northwest Pipeline Company, 63 FERC ¶ 61,124, at 61,806–08 n. 72 (1993).

[169] *See* Comments of AlliedSignal, AFPA, AGA, Columbia LDCs, Duke Energy Trading, Dynegy, Fertilizer Institute, IPAA, Market Hub Partners, Midland, NEMA, New England Distributors, NGSA, Nicor, PanCanadian, PSC of Wisconsin, Sithe, and Wisconsin Distributors.

has made it difficult to compete effectively on certain pipelines. It points out, for example, that on some pipelines, shippers can segment their capacity through the nomination process while other pipelines restrict segmentation to capacity release transactions, forcing shippers to release capacity to themselves in order to segment capacity. The shippers urge the Commission to clearly establish and standardize its segmentation policy.

INGAA supports the Commission's objective of implementing workable segmentation policies that broaden shippers' opportunities and increase competition. INGAA cautions, however, that any segmentation policy must be cognizant of the wide differences in pipeline configurations, some of which are less conducive to segmentation than others.[170] INGAA also recommends that the Commission adhere to its policy recently enunciated in *Tennessee*[171] that shippers do not have a right to release overlapping segments or to have the releasing and replacement shippers submit nominations that would have the effect of exceeding the contract demand of the original contract on any segment of the pipeline.

Shippers generally support a policy of permitting replacement shippers maximum flexibility to choose primary points in a segmented release that differ from those of the releasing shipper. In particular, they support the *Texas Eastern/El Paso* policy under which, in a segmented release, the replacement shipper is considered a new shipper who can choose primary receipt and delivery points from among the points available.[172] Some also support the position that, if a replacement shipper changes primary points, a releasing shipper should be able to regain its primary points after the release ends.[173] The pipelines generally oppose allowing segmented releases to expand primary receipt and delivery point rights on their systems or to permit the releasing and replacement shipper to hold more primary point capacity than the releasing shipper initially held.[174] Koch maintains that while the *Texas Eastern/El Paso* policy would work on some pipelines, it would not work on its system which is a reticulated or cancellated network without defined paths.

Although the Commission sought to ensure consistency during the restructuring proceedings under Order No. 636, the comments demonstrate that segmentation rights have not been implemented consistently across the pipeline grid. Accordingly, the Commission is adopting a regulation in new § 284.7(e) stating:

> An interstate pipeline that offers transportation service under subpart B or G of this part must permit a shipper to make use of the firm capacity for which it has contracted by segmenting that capacity into separate parts for its own use or for the purpose of releasing that capacity to replacement shippers to the extent such segmentation is operationally feasible.

This regulation will help achieve a more uniform and systematic application of segmentation rights across the interstate pipeline grid. Requiring pipelines to permit shippers to segment their capacity will increase the number of alternative capacity sources and therefore improve the competitiveness of the pipeline grid. The regulation further ensures a shipper's right to segment capacity for its own use as well as for release transactions. This will eliminate the inefficiencies present in the current system, such as shippers having to release capacity to themselves in order to segment their own capacity.[175]

Providing for more effective segmentation also is important in facilitating the development of market centers and liquid gas trading points. Without the ability to segment capacity, a shipper with firm-to-the-wellhead capacity on a long-line pipeline has an incentive to obtain gas from an upstream production area attached to the long-line pipeline, rather than at a downstream interconnect with another pipeline. Because the firm shipper has paid for upstream transportation in its demand charge, the shipper has to pay only a small usage charge to move gas from the production area to the shipper's delivery point. In contrast, if the shipper or its gas supplier does not hold firm capacity on the connecting pipeline, they would have to pay additional transportation charges for interruptible service or released capacity to move gas along the connecting route to the interconnect point. For example, if the price for gas at the upstream production area on the long-line pipeline is $2.00/MMBtu and the delivered gas price at the interconnect point is $2.15/MMBtu (with an implicit transportation value of $.15/MMBtu) and the firm shipper's usage charge is less than $.01/MMBtu, the shipper would save $0.14/MMBtu by purchasing gas at the upstream production area, rather than at the interconnect point.

Capacity segmentation, however, permits the shipper to release its capacity upstream of the market center for the market-determined value while retaining capacity downstream of that point in order to transport gas to market. In the prior example, the firm shipper's ability to release its upstream capacity for the market-determined value of $0.15/MMBtu would permit it to purchase gas for $2.15/MMBtu at the interconnect without suffering an economic loss. Segmentation, therefore, reduces the economic incentive to favor the pipeline on which the shipper holds firm capacity, making the development of a market center or gas trading point at the interconnect point more viable.

The regulation provides that segmentation must be permitted to the extent operationally feasible. This recognizes that, as INGAA points out, the configurations of some pipelines may make segmentation more difficult because these pipelines do not always provide straight-line paths. But the Commission expects a pipeline to permit segmentation to the maximum extent possible given the configuration of its system. Pipelines also need to make the process of segmentation as easy as possible, for example, by permitting segmentation to take place quickly and efficiently through the nomination process.

Pipelines will be required to make a *pro forma* tariff filing by May 1, 2000, showing how they will comply with this regulation. That filing must include whatever tariff changes are necessary for full compliance with the regulation or an explanation of how the pipeline's current tariff meets the requirements of the regulation. Pipelines claiming that all or any parts of their systems do not permit complete segmentation must demonstrate in their compliance filing why they must limit segmentation either to ensure service to other shippers or to ensure the operational integrity of their systems. Pipelines that are reticulated only in some portions of their system must permit full segmentation on the non-reticulated portion.

In the compliance filings, pipelines must provide operational justifications for restrictions on segmentation rights. As discussed above, some pipelines imposed restrictions on segmentation during the restructuring proceedings under Order No. 636 based on historic provisions in their tariffs. However, many of these historic tariff provisions

[170] *See also* Comments of Coastal, Koch, National Fuel.

[171] Tennessee Gas Pipeline Company, 85 FERC ¶ 61,052 (1998).

[172] *See* Comments of AFPA, AGA I, Amoco I, Consolidated Natural, National Fuel Gas Distribution, New England Distributors, Proliance, Reliant Energy, Sithe.

[173] *See* Comments of AGA I, Florida Cities, MichCon, Proliance, National Fuel Gas Distribution, and Sithe.

[174] *See* Comments of INGAA.

[175] *See* Comment of Dynegy.

date back to the pipelines' provision of merchant service and may no longer be justified for open access service provided in a more competitive market environment. In ruling on compliance filings, the Commission will not accept limitations on segmentation rights based solely on existing tariff conditions. Pipelines need to provide operational justifications for restricting the rights of shippers to effectively segment capacity and use flexible receipt and delivery points and must justify a proposal to deviate from the *Texas Eastern/El Paso* policy with respect to assignment of primary receipt and delivery points between releasing and replacement shippers.

2. Priorities for Capacity Within a Path

In Order No. 636, the Commission required pipelines to permit shippers to change receipt and delivery points or to use any receipt or delivery point within the zone for which the shipper pays as a secondary point with a priority greater than interruptible capacity. When pipelines implemented Order No. 636, they assigned priorities to the types of services they provide. The general practice was to accord the highest priority to capacity at primary points. Shippers using secondary points receive equal priority regardless of where their primary points are located in the zone, because the shippers are paying the same zone rate: shipper A, with a primary point upstream in the zone, has the same right to deliver to a downstream point in that zone as Shipper B with a primary point further downstream in the zone, even though shipper B's path goes past the secondary point, and shipper A's path does not. Thus, if the pipeline cannot serve all the nominations to secondary points, each shipper will receive a *pro rata* allocation of capacity. Interruptible capacity is assigned the lowest value.

A number of shippers contend that the Commission should adopt a regulation requiring that pipelines provide a shipper that is using a secondary point within its path a higher priority than a shipper in the same zone using a secondary point outside of its path (path approach).[176] Dynegy argues that where constraints occur, a shipper using a secondary point within its path may lose capacity because the pipeline curtails all secondary point nominations equally even though the pipeline could make a delivery to that secondary point. Dynegy contends that often the shipper with the priority path can still reach the upstream secondary point, but that it may have to pay the pipeline a fee for a backhaul to do so. Some pipelines also have proposed to provide higher priority to shippers within a primary path.[177] Koch and National Fuel, on the other hand, maintain that on their reticulated systems, shippers often do not have capacity paths and that, therefore, there cannot be a distinction between in-path and out-of-path secondary points.

The Commission has decided not to adopt the path approach as a generic policy. Providing priority to shippers within the path is not necessarily a more efficient allocation method than treating all shippers who pay the same rate equally. Capacity allocation is the most efficient when the capacity is allocated to the person placing the highest value on the capacity. In a perfect competitive environment, without transaction costs, the initial allocation of capacity among shippers will not matter because, through trading, capacity can be allocated to the highest valued user. Where transaction costs do exist, the goal of allocation should be to make the initial allocation to the party placing the highest value on obtaining the service in question. However, when dealing with the allocation of capacity to secondary points, there is no reason to believe that a shipper with a downstream primary delivery point necessarily places greater value on using a secondary point in the zone than a shipper paying the same rate with an upstream primary delivery point.

The real problem in allocating secondary receipt or delivery points in constraint situations is not with initial priority allocations, but with the pricing structure on pipelines. Pipelines charge all shippers within a zone the same rate even though many pipelines do not divide zones along constraint points: a single zone encompasses points upstream or downstream of the constraint. Thus, adoption of the path approach would require shippers paying for capacity in the upstream portion of the zone to pay the same rate as those shippers with capacity downstream of the constraint point, although the upstream shippers would, in many cases, be unable to reach points downstream of the constraint.

Because zones do not correspond with constraint points, adoption of the path approach also could result in difficulties in allocating primary point capacity. Shippers currently have an incentive to subscribe to the primary delivery points at which they most need gas, because nominations to primary points are accorded the highest scheduling priority. Under the path approach, however, all shippers within a zone will have an incentive to subscribe to a primary point as far downstream in the zone as they can even though the pipeline does not have sufficient capacity to satisfy all shippers' downstream requests for capacity. All shippers would have the incentive to move their primary points to the end of a zone because each shipper pays the same rate to subscribe to the downstream delivery point as its former upstream delivery point and, under the path approach, would obtain essentially the same priority to deliver to its former upstream delivery point as it would if it chose that upstream delivery point as its primary point. Meanwhile, by subscribing to the downstream primary delivery point, the shipper would obtain more valuable rights in the capacity release market because its path would go through the constraint point. As a consequence, adoption of the path approach could result in all shippers in a zone seeking to subscribe to downstream primary points even though the pipeline does not have sufficient capacity to provide all shippers with downstream capacity.

Making adjustments to secondary point priority, therefore, is not the most effective solution to the constraint problem. A more direct solution would be for the pipeline to revise its zone boundary so that the shipper upstream of the constraint point pays a lower rate than the shipper downstream of the constraint point.

Another approach to solving constraint issues is to design a capacity trading system for the future that improves upon the current system by permitting shippers to reallocate capacity rights after the pipeline has scheduled capacity and imposed whatever cuts may be applicable. For instance, if, due to constraints, the pipeline allocates capacity at secondary points on a *pro rata* basis, and the upstream shipper values the right to deliver to the secondary point more than the downstream shipper, an efficient capacity trading system would permit the upstream shipper to buy extra rights from the downstream shipper. Dynegy contends that, on some pipelines, shippers often are able to reach secondary delivery points even when the pipeline limits shipments to those points by paying to arrange a backhaul from their downstream primary delivery point to the upstream secondary delivery point. The

[176] *See* Comments of Dynegy, Enron Capital & Trade, Indicated Shippers, NEMA, National Fuel Gas Distribution, PanCanadian, PSC of Wisconsin, and Sithe.

[177] Panhandle Eastern Pipe Line Company, 87 F.E.R.C. ¶ 61,331 (1999).

Commission obviously cannot resolve the appropriateness of the pipeline's backhaul charge under the current system in this generic rulemaking. However, the payment of an added charge, either to the pipeline or to another shipper, might be appropriate to reflect the additional value the shipper places on the capacity if an efficient trading system were in place so there was effective competition to the pipeline's provision of a backhaul service.

Because some pipelines' reticulated systems do not provide shippers with capacity paths and because the path concept is not inherently a more efficient allocation system than the current system used on most pipelines, the Commission will not adopt a generic requirement that all pipelines adopt the path priority system. Issues relating to priority schemes on individual pipelines can be addressed in pipeline filings where all factors, such as zone boundaries, rate structures, and the effect of such changes on shippers and competition can be examined.

3. Confirmation Practices

The Commission is not adopting a generic regulation regarding pipeline confirmation practices. In the NOPR, the Commission asked if the current practices of pipelines in confirming gas flows across interconnect points between pipelines adversely affects capacity allocation. Confirmation refers to the practice by which a pipeline communicates with upstream and downstream parties (other pipelines, producers, LDCs, point operators) to determine whether a shipper submitting a nomination on its system will receive the nominated gas from the upstream producer or pipeline and whether the downstream pipeline or LDC is able to take delivery of that quantity of gas. If a nomination is not confirmed on either the upstream or downstream ends of the system, the shipper may not receive the amount of gas it has nominated.

The Commission requested comment on whether confirmation practices between interstate pipelines was affecting the allocation of primary and secondary capacity between pipelines. In particular, the Commission asked whether, when a constraint exists at an interconnect point, the general rule should be that the shipper with the higher priority on the downstream or take-away pipeline should receive priority.

The comments on this issue varied greatly. AGA advocates giving priority to the shipper on the downstream pipeline. Amoco argues priority should be given to the shipper on the upstream pipeline. Indicated Shippers argues that priority should be determined by the priority rules of the pipeline operating the interconnect point. NGSA contends the priority rule of the pipeline with the constraint should govern, but if the constraint is at the meter, then the priority rule of the party responsible for measurement at the meter should control. INGAA maintains that no changes in confirmation practices are necessary, since its companies report that very little gas flow has been affected by confirmation practices and no complaints have been made to the Commission about this issue. INGAA contends that, rather than favoring shippers with firm transportation either on the upstream or downstream pipeline, shippers should be responsible for contracting for primary or secondary firm capacity on both pipelines to assure their gas flows.

Given the lack of agreement among the industry and the paucity of complaints at this time, the Commission is not adopting a generic rule to govern confirmation at pipeline interconnects. However, the Commission agrees with INGAA's position that when pipelines do not have sufficient capacity at an interconnect to handle all nominations to that point, a shipper that has obtained firm capacity on both sides of an interconnect generally should have shipping priority over a shipper that is using interruptible transportation on one of the pipelines. If shippers believe that pipelines are not allocating capacity properly at interconnects, such problems can be handled individually through the complaint process.

C. Imbalance Services, Operational Flow Orders and Penalties

One of the fundamental purposes of this rule is to improve efficiency in the short-term market. The operational flow orders (OFOs) and penalties imposed by a pipeline to protect the integrity of the pipeline system are an area where improvements in efficiency can be achieved.

OFOs generally restrict service or require shippers to take particular actions. For instance, an OFO can reduce or eliminate tolerances for imbalances or contract overruns; institute severe penalties; or restrict intra-day nominations, the use of secondary receipt and delivery points, or firm storage withdrawals. Penalties are designed to deter shippers from creating imbalances, or from overrunning contract entitlements, and include penalties for physical imbalances (differences between commodity input and output), scheduling imbalances (differences between actual and scheduled quantities), and non-compliance with OFO and other tariff provisions.

While OFOs and penalties can be important tools to correct and deter shipper behavior that threatens the reliability of the pipeline system, the current system of OFOs and penalties is not the most efficient system of maintaining pipeline reliability. The manner in which pipelines impose OFOs and penalties often limits efficiency in the short-term market by restricting shippers' abilities to effectively use their transportation capacity. Shippers make purchasing decisions based on gas commodity prices in the market. OFOs can limit the ability of shippers to respond to prices in the market, undermining the fluidity of the commodity market. For example, an OFO that eliminates a secondary receipt point for a shipper may eliminate the shipper's access to alternate suppliers with the lowest priced gas, or force the shipper to points where it has no purchase or sales agreements. By eliminating or changing a transaction that otherwise would have taken place, an OFO can interfere with the liquidity of the commodity market.

Commission-authorized penalties provide an opportunity for shippers to engage in a form of penalty arbitrage, both across pipeline systems, and within a single pipeline system. Arbitrage across pipeline systems occurs where shippers intentionally overrun contract entitlements on those pipelines and LDCs that have the lowest penalties for contract overruns, and then flow gas to shippers on other systems with higher penalties, in an attempt to capture the economic gain of the difference in the level of penalties. In that situation, penalties skew the choices shippers might otherwise have made. The consequence is that, subsequently, pipelines in the area escalate their penalties to achieve the highest overrun/imbalance penalties. [178]

Penalty arbitrage on a single pipeline system involves pipelines' existing tariff provisions for remedying monthly imbalances of a shipper—often described as ''cash-outs.'' Under these provisions, shippers are allowed to cash-out net monthly imbalances using an average monthly price. That procedure invites shippers to game the system within the month. For example, a shipper may take more than it delivers when gas prices are higher than cash-out prices, and deliver more than it

[178] Panhandle Eastern Pipe Line Company, 78 FERC ¶ 61,202 at 61,876 (1997) (penalties ranging from $25 per Dth for variances of 5–10 percent to $200 for variances over 50 percent).

takes when gas prices are lower than cash-out prices. To the extent that pipelines rely on additional storage capacity to accommodate these imbalances, the arbitrage activity imposes costs on all shippers on the system through higher transportation rates that include more storage costs. In addition, at peak, arbitrage behavior may imperil systemwide reliability and trigger OFOs and emergency penalties that replace market forces with administrative rules.

In order to protect the reliability of their systems, many pipelines have responded to arbitrage on their systems by imposing stricter imbalance tolerances and higher penalties. High penalty levels often operate to limit and distort market forces. For example, the prospect of incurring high overrun and/or imbalance penalties, may cause shippers to fail to maximize their use of pipeline transportation, or to contract for more transportation capacity than they need.

The existence of arbitrage on and across pipeline systems indicates that in today's market, shippers are using penalties to achieve flexibility with respect to obtaining gas supplies and transportation capacity. In effect, shippers are treating the ability to overrun contract entitlements or create an imbalance as a ''service.'' Instead of buying gas or transportation, shippers are overrunning their contract entitlements, or taking more or less gas than they deliver, and paying cashouts and penalties, where that option is less expensive than purchasing gas or transportation directly. For example, by incurring an imbalance, a shipper is essentially borrowing gas from the pipeline, and the amount of the imbalance cash-outs and penalties are, in effect, the price for such borrowing. Indeed, during peak periods, the level of penalties can set the market price for gas since the maximum penalty level for overrunning a contract can set the maximum price that a shipper would pay for obtaining additional capacity.[179] In many cases, however, the amount of the penalty is unlikely to match the cost to the pipeline of providing this flexibility, so that other shippers must pay for some of the costs.

Since the penalty system is being used by shippers to indirectly gain needed flexibility, and engage in behavior that may be harmful to the system as a way to obtain such flexibility, the Commission finds that a general shift in Commission policy is warranted so that penalties are imposed only when needed to protect system integrity. Shippers need to be given tools that will enable them to reduce penalties without jeopardizing pipeline integrity, and shipper and pipeline incentives need to be properly structured to avoid the need to impose penalties. For example, simply because one shipper runs a positive imbalance, system integrity may not be jeopardized if other shippers run negative imbalances that offset the positive imbalance. The Commission has previously required pipelines in such situations to permit shippers to trade offsetting imbalances, which reduces the need for imbalance penalties while maintaining pipeline integrity.[180]

Another method of using market transactions to reduce the need for penalties is for pipelines or third-parties to enable shippers to avoid penalties by providing shippers with flexibility, directly, through the provision of separate imbalance management services, and to require the shippers who use that flexibility to pay for it. Thus, the Commission is refocusing its policy away from a ''command and control'' type of policy that fosters the use of OFOs and penalties to a ''service-oriented'' policy that gives shippers other options to obtain flexibility.

Under the new policy, pipelines will be required to provide imbalance management services, like parking and loaning service, and greater information about the imbalance status of shippers and the system, to make it easier for shippers to remain in balance in the first instance. Pipelines also will be required to permit third-parties to offer imbalance management services that will allow shippers to avoid imbalances. The use of these techniques will obviate the need for pipelines to rely on penalties to prevent or solve operational problems caused by shippers. This will allow penalties to be more narrowly crafted to focus on conduct that is truly detrimental to the system.

Equally as important as providing shippers with greater ability to avoid imbalances and penalties, is providing shippers with increased incentives to avoid imbalances and conduct harmful to the system. To this end, the Commission is encouraging pipelines to develop financial incentives for shippers to stay in balance, or to incorporate other types of incentives in the design of their imbalance management services. Replacing the negative incentive that penalties provide to deter behavior with more positive incentives to induce desirable shipper behavior will reduce imbalances and penalties, and may help alleviate gaming on pipeline systems.

Moreover, to effectively shift pipelines to the use of the non-penalty mechanisms described above to solve and prevent operational problems, it will be necessary to eliminate the pipelines' financial incentive to impose penalties and OFOs. Thus, the Commission is requiring pipelines to credit the revenues from penalties and OFOs to shippers.

More specifically, the Commission is revising its regulations governing standards for pipeline business operations and communications[181] to add three new provisions, concerning imbalance management, operational flow orders, and penalties, that establish several general policies designed to help shippers avoid penalties and OFOs, and help pipelines minimize their need for and use of penalties and OFOs. As described in more detail below, these provisions require pipelines to offer imbalance management services, to establish incentives and procedures to minimize the use of OFOs, to establish only those penalty structures and levels that are necessary and appropriate to protect the system, to credit penalty and OFO revenues to shippers, and to provide more imbalance information on a timely basis. To implement these new regulations, each pipeline will be required to make a *pro forma* compliance filing no later than May 1, 2000. In its filing, each pipeline must either propose *pro forma* changes to its tariff to implement the requirements discussed above, or explain how its existing tariff and operating practices are already consistent with, or in compliance with, the new requirements.

The policies set forth in the provisions below are the same general policies that the Commission proposed in the NOPR. There was considerable support among the commenters for the goals underlying the Commission's proposed policies.[182]

1. Policies Adopted by This Rule

a. Imbalance Management. The Commission is adopting a new subsection addressing imbalance

[179] *See* Industry Surveys the Damage as Winter's Strength Runs Out, Natural Gas Intelligence, April 22, 1996, at 1, 4 (penalty levels were a real factor in determining the price of gas during peak demand period in the Midwest).

[180] Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587–G, 63 FR 20072 (Apr. 23, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,062 (Apr. 16, 1998).

[181] These regulations appear in existing section 284.10, which the Commission is redesignating § 284.12.

[182] Comments of AEC, AF&PA, AGA, Columbia LDCs, Duke Energy, Dynegy, Exxon, Florida Cities, IPAA, Indicated Shippers, MichCon, Midland, NEMA, Philadelphia Gas Works, Process Gas Consumers, WGL, and Wisconsin Distributors.

management in its regulation governing the standards for pipeline business operations and communications. New § 284.12(c)(2)(iii), adopted herein, provides as follows:

(iii) *Imbalance management.* A pipeline must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of its shippers to manage transportation imbalances. A pipeline also must provide its shippers the opportunity to obtain similar imbalance management services from other providers and shall provide those shippers using other providers access to transportation and other pipeline services without undue discrimination or preference.

This provision establishes the policy that pipelines must provide to shippers, to the extent operationally feasible, imbalance management services, such as park and loan service, swing on storage service, or imbalance netting and trading. As part of this policy, the Commission specifically encourages the use of auctions for shippers to trade imbalances so that they can avoid the imposition of unnecessary penalties. In addition, under this policy, pipelines will not be permitted to give undue preference to their own storage or balancing services over such services that are provided by a third party. The Commission is requiring pipelines to include these imbalance management services as part of their tariffs.

The Commission expects pipelines to provide as many different imbalance management services as is operationally feasible, and to work to develop new, innovative services that help shippers manage or prevent imbalances. In order to give pipelines an incentive to develop these new imbalance management services, the Commission is not changing its current policy that pipelines may retain the revenues from a new service initiated between rate cases. In addition, the Commission particularly encourages pipelines to design imbalance management services that will give shippers a built-in incentive to utilize the service, or to otherwise stay in balance. Pipelines are also urged to create positive financial inducements for shippers to remain in balance or avoid behavior that is harmful to the system, rather than the negative incentives provided by penalties.

The Commission in Order No. 587–G has already taken a first step toward increasing shippers' abilities to manage imbalances by requiring that every pipeline: (a) Allow firm shippers to revise nominations during the day (thereby reducing the probability of imbalances caused by inaccurate nominations); (b) enter into operational balancing agreements at all pipeline to pipeline interconnections; (c) permit shippers to offset imbalances across contracts and trade imbalances amongst themselves when such imbalances have similar operational impact on the pipeline's system; and (d) provide notice of OFOs and other critical notices by posting the notice on their Internet web sites.[183] The other actions the Commission is taking in this rule will also help shippers avoid imbalances and penalties, and reduce the need for OFOs. For example, shippers will have an alternative means of acquiring capacity during peak periods, other than overrunning their contract entitlements and incurring unauthorized overrun penalties, now that the Commission is removing the price cap from released capacity.

However, many pipelines currently do not offer effective imbalance management services, such as swing on storage or parking and loaning services. Other pipelines already offer some imbalance management services, but could improve upon them, or supplement them with additional imbalance management services, to the extent operationally feasible. The ready availability of imbalance management services will make it easier for shippers to stay in balance and avoid causing operational problems. Thus, a further expansion of the number of services available on each pipeline that facilitate a shipper's ability to manage imbalances will significantly increase shippers' ability to avoid imbalances, and correspondingly reduce the need for pipelines to impose penalties.

Moving towards a system where customers pay directly for imbalance management services will impose the costs of those services on those shippers needing the service, minimizing the impact on other customers that require less flexibility. Thus, it should shift costs that are now collected from all shippers through general transportation charges to those shippers that most require the needed flexibility.

However, pipelines will not be permitted to implement the new imbalance services until they also implement imbalance netting and trading on their systems. Pipelines should not expect shippers to purchase new services until the shippers can determine whether imbalance trading will be adequate for their needs. Thus, the implementation of the new imbalance management services must coincide with the implementation of imbalance netting and trading. Since GISB has already approved business practice standards for imbalance netting and trading, pipelines should be able to implement imbalance netting and trading at the same time that they implement the new imbalance management services.

This policy is the same policy proposed in the NOPR. Various commenters offered their support for this principle, urging the need for pipelines to offer imbalance management solutions prior to imposing penalties.[184] The little opposition to this principle comes from INGAA, and several pipelines who maintain that no changes at all are needed to the Commission's penalty policy.[185] INGAA maintains that a policy requiring pipelines to provide imbalance management services is unnecessary given that pipelines must provide such services to stay competitive with those pipelines that already provide such services.[186] Williston Basin states that services such as park and loan service do not need to be mandated by the Commission. It asserts that the need for, and implementation of, imbalance management services should be between the pipeline and its shippers. Williston Basin argues that having the Commission require a ''cookie-cutter'' imbalance management service for all pipelines will not provide the best imbalance service for a specific pipeline.[187]

The Commission finds that requiring pipelines to provide imbalance management services, to the extent operationally feasible, is a key step in creating a policy that focuses more on providing flexible service options, minimizing the need for OFOs and penalties. The availability of imbalance management services is critical for providing many shippers with the flexibility they need to avoid or correct imbalances, which in turn obviates the need for pipelines to impose OFOs and penalties. The Commission must require pipelines to provide imbalance management services, despite the competitive incentive INGAA states pipelines already have to provide these services, since an incentive to provide

[183] Standards For Business Practices Of Interstates Natural Gas Pipelines, Order No. 587–G, 63 FR 20072 (Apr. 23, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,062 (Apr. 16, 1998). GISB's Executive Committee approved business practice standards for trading and netting of imbalances at its July 15–16, 1999 meeting, however the electronic standards have yet to be finalized. *Http://www.gisb.org/ec.htm* (Nov. 15, 1999).

[184] Comments of AF&PA, AlliedSignal, Amoco, Dynegy, FPL, Indicated Shippers, IPAA, and Shell.

[185] Comments of INGAA, Williston Basin, and Koch.

[186] Comments of INGAA at 107.

[187] Comments of Williston Basin at 35.

such services alone will not guarantee that each pipeline will in fact provide the services. However, to the extent pipelines are already motivated to provide imbalance management services to remain competitive, compliance with the requirement in this rule that pipelines offer such services should not be particularly difficult or burdensome.

With respect to Williston Basin's argument that the choice whether to provide imbalance management services and how to do so are business decisions that the Commission should allow each individual pipeline to make, the Commission stresses that by requiring pipelines to offer imbalance management services, the Commission is not dictating which services, or how many services, a pipeline must provide. Much of the decisionmaking, including whether the provision of such services is operationally practicable, is still left to the pipeline and its shippers. Also, the Commission is not dictating the exact details of these services for each pipeline, so that contrary to Williston Basin's understanding, the Commission is not imposing a one-size-fits-all imbalance management service on pipelines.

b. Operational Flow Orders. The Commission is adopting another new subsection in § 284.12(c)(2) of its regulations to govern OFOs. New § 284.12(c)(2)(iv), adopted herein, provides as follows:

(iv) *Operational flow orders.* A pipeline must take all reasonable actions to minimize the issuance and adverse impacts of operational flow orders (OFOs) or other measures taken to respond to adverse operational events on its system. A pipeline must set forth in its tariff clear standards for when such measures will begin and end and must provide timely information that will enable shippers to minimize the adverse impacts of these measures.

This provision establishes the policy that each pipeline must adopt incentives and procedures that minimize the use and potential adverse impact of OFOs. The imposition of OFOs may severely restrict the purchase and transportation alternatives available to a customer during peak periods, precisely when such alternatives are critically needed to enhance the opportunities of a shipper to purchase such services at the lowest competitive prices. Under current practice, pipelines have incentives to favor OFOs as the first option, not the last resort. The pipeline is likely to err on the side of using an OFO, because it bears the risk that if it does not, curtailment of load may result that could in turn precipitate strong public disapproval and law suits from firm customers. In contrast, shippers—not pipelines—bear the costs that result from imposition of OFOs. A pipeline could also prefer OFOs because it would limit or eliminate a shipper's ability to purchase transportation that would be in lieu of transportation services provided by that pipeline. In some cases, shippers have complained that OFOs have been issued too frequently, for too long, and were larger in scope than required to protect the integrity of system operations.[188]

In light of these considerations, it is appropriate to require the revision of existing pipeline tariffs to ensure that the imposition and adverse impact of OFOs are reduced to the maximum extent practicable.[189] Many commenters favored this proposal in the NOPR to make each pipeline's tariff conform to this standard.[190] Therefore, to implement this policy, the Commission is requiring each pipeline to revise its tariff in the following respects, to the extent necessary.

First, each pipeline's tariff must state clear, individual pipeline-specific standards, based on objective operational conditions, for when OFOs begin and end. This will enable shippers to better anticipate in advance, based on market conditions, when OFOs are likely to be in effect and to plan their business affairs accordingly.

Second, the tariff must require the pipeline to post, as soon as available, information about the status of operational variables that determine when an OFO will begin and end. For example, if an OFO will remain in effect until repairs are completed on a compressor, the pipeline must be required to update shippers on the status of the repairs.

Third, the tariff must state the steps and order of operational remedies that will be followed before an OFO is issued to assure that the OFO has the most limited application practicable and to limit the consequences of its imposition. For example, one requirement would be that a pipeline provide as much advance warning as possible of the conditions that may create an OFO and the specific OFO itself that would allow customers to respond to such conditions and/or prepare alternative arrangements in the event the OFO is implemented.

Fourth, the tariff must set forth standards for different levels or degrees of severity of OFOs to correspond to different degrees of system emergencies the pipeline may confront. For example, a large OFO penalty may be appropriate in severe cases, whereas a small OFO penalty may be appropriate in others.

Fifth, the tariff must establish reporting requirements that provide information after OFOs are issued on the factors that caused the OFO to be issued and then lifted. This requirement is in addition to the existing requirement that pipelines provide notice of OFOs and other critical notices by posting the notice on the pipelines' Internet web sites and by notifying the affected customers directly.[191]

A few commenters request that the Commission refrain from requiring pipelines to adopt tariff provisions designed to curb the use of OFOs. Enron Pipelines state that OFOs are a vitally important tool to effect operational changes by specific shippers causing problems, and are not designed to assess penalties.[192] Enron Pipelines believe that the potential for operating conflicts among shippers will only increase in the future, making OFOs increasingly important. Enron Pipelines argue that by requiring a pipeline to take all reasonable actions to minimize the issuance of OFOs, the Commission is essentially saying that it prefers that the pipeline take systemwide measures, such as the purchase of line pack gas, or the operation at reduced capacity levels, rather than the narrowly targeted solution of an OFO. Enron Pipelines do not believe that is the Commission's intent.

The requirement that pipelines establish standards and procedures for the imposition of OFOs, and the Commission's guidance to pipelines in that effort, is not meant to prevent pipelines from issuing OFOs where necessary, as Enron apparently believes. However, while the Commission is not committing pipelines to take systemwide measures to resolve operational problems, in some instances, it could be more appropriate to take actions other than issuing a specific OFO.

Williams, also, maintains that no major policy changes are needed regarding OFOs.[193] It asserts that any OFO problems are confined to only a few systems, and are not industry-wide.

[188] *See, e.g.,* NorAm Gas Transmission Company, 79 FERC ¶ 61,126 at 61,546–47 (1997); Southern Natural Gas Company, 80 FERC ¶ 61,233, at 61,890 (1997) Northern Natural Gas Company, 77 FERC ¶ 61,282 (1997); Panhandle Eastern Pipe Line Company, 78 FERC ¶ 61,202 (1997); Northwest Pipeline Company, 71 FERC ¶ 61,315 (1995).

[189] The requirement in this rule that pipelines automatically credit OFO penalty revenues to shippers will also help limit any incentive for the pipeline to use an OFO to generate revenues.

[190] Comments of AF&PA, AGA, Florida Cities, Indicated Shippers, IPAA, MichCon, Midland, NEMA, Proliance and Shell.

[191] Redesignated § 284.12(c)(3)(vi).

[192] Comments of Enron Pipelines at 48–50.

[193] Comments of Williams at 21–23.

Therefore, Williams suggests that rather than requiring pipelines to revise their existing OFO provisions, the Commission should monitor the frequency of OFOs on individual pipelines. Then, Williams states, if a pipeline frequently issues OFOs, a proceeding could be established to determine if changes are necessary to that pipeline's tariff. INGAA, as well, agrees with a pipeline-specific approach.[194]

The Commission disagrees with Williams that it is not necessary at this time to require all pipelines to develop OFO standards. The Commission is not requiring all pipelines to adopt the same, generic standards. The Commission is requiring OFO guidelines on an individual pipeline basis to allow each pipeline to devise a set of OFO procedures that are specific to its system, and that may take into account the pipeline's OFO track record. These guidelines will help limit the imposition of OFOs to only those that are necessary, as well as limit the incurrence and duration of necessary OFOs, so that shippers can rely more on market forces in making their decisions. However, the Commission may, in the future, decide also to monitor the frequency of OFOs on individual pipelines, and thereafter institute proceedings to determine if further tariff changes are warranted for particular pipelines, as Williams suggests. With respect to INGAA's concern, the guidelines set forth in this rule will not prevent pipelines from determining what OFO standards are appropriate for their systems, or from issuing OFOs where necessary.

c. Penalties. Finally, new §284.12(c)(2)(v), governing penalties and adopted herein, provides as follows:

(v) *Penalties.* A pipeline may include in its tariff transportation penalties only to the extent necessary to prevent the impairment of reliable service. Pipelines may not retain net penalty revenues, but must credit them to shippers in a manner to be prescribed in the pipeline's tariff. A pipeline must provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of the pipeline's system.

This new provision establishes three general principles with respect to penalties. First, penalties are not required, but to the extent that a pipeline assesses penalties, they must be limited to only those transportation situations that are necessary and appropriate to protect against system reliability problems. The Commission has authorized extremely high overrun and imbalance penalties for several pipelines on the basis that doing so was required to protect system integrity.[195] However, the Commission finds that there is not necessarily a connection between the high level of authorized penalties and the level that is necessary to ensure system reliability. By requiring that all penalties be necessary to prevent the impairment of reliable service, the Commission is requiring pipelines to narrowly design penalties to deter only conduct that is actually harmful to the system.

Also, the Commission is aware that some pipelines have penalties that are at the same level during peak and non-peak periods and may be imposed regardless of whether the pipeline is faced with emergency conditions.[196] Non-critical day penalties, or penalties imposed during off-peak periods, may not be the most appropriate and effective to protect system operations. Establishing a principle that all penalties must be necessary for reliable system operations will help ensure that penalties are appropriately drawn and tailored to reflect the potential harm to the system. Therefore, in the compliance filing to implement this principle, the Commission directs all pipelines to either explain or justify their current penalty levels and structures under these standards, or revise them to be consistent with this principle.

In cases in which penalties are needed to protect against harm to the pipeline system, the requirement that pipelines provide imbalance management services and permit third-parties to offer such services provides shippers with the flexibility to avoid conduct harmful to the system and penalties associated with such conduct. Thus, pipelines should be able to recraft their current broad penalty provisions in ways that directly focus on harm to the system and do not encourage the use of penalties as a substitute for obtaining services. As an example, pipelines may be able to change the methods by which they cash-out imbalances to eliminate the incentives for shippers to borrow gas from the pipeline because the cash-out price is less than the market price for gas. Rather than borrowing gas from the pipeline and paying the cash-out price, shippers can more directly obtain the flexibility they need by directly purchasing a parking and lending service from the pipeline or a third-party.

Second, new § 284.12(c)(2)(v) establishes the policy that a pipeline may not retain the revenues from penalties, but must credit them to shippers. The Commission is requiring pipelines to automatically credit all revenues from all penalties, net of costs, including imbalance, overrun, cash-out, and OFO penalties, to shippers. Ideally, penalty revenues should be credited only to non-offending shippers so that offending shippers are not able to recoup the penalties they have paid, and thus, shippers are given a positive incentive to avoid incurring penalties. It is possible for pipelines to construct penalty revenue crediting mechanisms that exclude shippers who were assessed the penalty from the revenue credits.[197] However, the Commission recognizes that for some pipelines it may be difficult to develop or implement such a penalty revenue crediting mechanism. Thus, the Commission will not prescribe on a generic basis the details of the revenue crediting mechanism, including which shippers will receive the penalty revenue credits. Instead, the Commission will permit each pipeline to formulate an appropriate method for implementing penalty revenue crediting on its system. Pipelines should include the detail of their revenue crediting mechanism in the *pro forma* tariff filings, discussed *infra,* that the Commission is requiring pipelines to make to comply with this new rule.

The Commission's policy has been to allow pipelines to retain penalty revenues until the next rate case, and then to permit penalty revenues to be taken into account in the rate case when developing a pipeline's revenue requirement. The theory underlying the Commission's policy was that a properly designed penalty deters violations, and thus, there should be little or no penalty revenues to credit. This rationale was upheld by the U.S. Court of Appeals for the D.C. Circuit in *Pennsylvania Office of Consumer Advocate* v. *FERC.*[198] There, the court rejected a claim that the pipeline should be required to credit back all penalty

[194] Comments of INGAA at 109–112.

[4] Regulation of Natural

[195] *See, e.g.,* Northern Natural Gas Company, 77 FERC ¶ 61,282, at 62,236 (1997); Panhandle Eastern Pipe Line Company, 78 FERC ¶ 61,202, at 61,876–77 (1997), *reh'g denied,* 82 FERC ¶ 61,163 (1998).

[196] *See* Tennessee Gas Pipeline Company, 81

[197] For example, under Northwest Pipeline Corporation's penalty revenue crediting mechanism, Northwest credits penalty revenues monthly only to shippers who were not assessed a penalty. *See* section 14(g) of the General Terms and Conditions of Northwest's tariff. Fourth Revised Sheet No. 232–D and Second Revised Sheet No. 232–E, third Revised Volume No. 1 of Northwest's FERC Gas Tariff.

[198] Pennsylvania Office of Consumer Advocate v. FERC, 131 F.3d 182 (D.C. Cir. 1997), *modified on other grounds,* 134 F.3d 422 (D.C. Cir. 1998) (*Pennsylvania*).

revenues to non-offending shippers, where in the prior year, no penalties had been assessed under the penalty rate at issue. The court agreed with the Commission that based on such circumstances, ''the mere possibility of revenue gains'' did not ''justif[y] a prospective requirement that the revenues be credited to customers.'' [199]

However, the prospect of retaining revenues from penalties offers an incentive for pipelines to propose or implement inappropriate penalties and OFOs that can hinder efficiency and competition. Also, to the extent the penalty revenues are not reflected in rates, since pipelines are no longer required to file rate cases on a periodic basis, the penalty provisions have had the ability to result in profit centers for the pipelines. [200]

Given the Commission's new emphasis in this rule on providing services to facilitate shippers' ability to avoid imbalances and penalties and providing inducements to shippers to remain in balance, rather than on penalties, the Commission does not expect that significant revenues will be generated from penalties. However, to the extent that penalty revenues are generated, the required crediting of penalty revenues will eliminate any economic incentive for pipelines to rely on penalties rather than inducements. The Commission is requiring penalty revenue crediting not so much for the purpose of preventing penalties from becoming a profit center, but more for the purpose of eliminating any financial incentive on the part of pipelines to impose penalties that would naturally hinder the pipelines' movement toward reliance on the provision of imbalance services, greater imbalance information, and shipper incentives.

In addition, requiring pipelines to credit penalty revenues to shippers also responds to concerns that the court had subsequent to its *Pennsylvania* decision, in *Amoco* v. *FERC*,[201] about allowing pipelines to retain penalty revenues. In *Amoco* v. *FERC*, the court found that the Commission had not adequately supported its finding that the proposed increase in the penalty level would not provide the pipeline with significant penalty revenues, especially where the pipeline had collected $1.8 million in overrun penalty revenues in the year prior to the pipeline's filing. The court remanded the case to the Commission for an explanation of how its decision to permit the pipeline to retain the penalty revenues and not require penalty revenue crediting is consistent with the NGA. Requiring the crediting of penalty revenues to shippers in this case will eliminate the potential for pipelines to receive penalty revenue windfalls, and consequently, the court's concern.

In the NOPR, the Commission suggested the crediting of penalty revenues as one of a number of options that could help pipelines to impose only necessary and appropriate penalties. The idea of crediting penalty revenues garnered much support in the comments.[202] However, a few parties are opposed to revenue crediting because they contend that no changes at all are necessary to the Commission's policies on penalties and OFOs.[203] They assert that the current penalty tariff provisions have been carefully crafted by pipelines and their customers, meet each pipeline's operational needs, and deter inappropriate conduct.

The Commission disagrees. Allowing pipelines to retain penalty revenues gives pipelines the wrong incentives for the design and imposition of penalties, and provides no incentive for the pipeline to develop other, non-penalty mechanisms that would give shippers incentives to control their imbalances. As stated above, the crediting of penalty revenues eliminates the pipelines' financial incentive to use and impose penalties.

Third, § 284.12(c)(2)(v) establishes the requirement that pipelines provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of its system as a whole. Under this policy, pipelines will be required to distribute to shippers the information that they currently have available on deliveries and imbalances at each shipper's delivery point, as well as on system imbalances. However, the Commission is not requiring pipelines to install upgraded, real time meters at receipt and delivery points.[204] In other words, the requirement that pipelines provide as much imbalance information as possible is not meant to require that pipelines make an investment in additional metering equipment. The Commission will leave the decision of when and where to install upgraded metering to the pipeline and individual shippers, based on their own economic and operational judgment. The Commission will continue the current policy of permitting pipelines and their shippers to address these cost issues as they arise, *i.e.,* in general rate cases or, as provided in the pipelines' tariffs. At this time, no change in this aspect of the Commission's policy is necessary.

The pipelines must disseminate the available imbalance information on a timely basis, so that shippers will have a reasonable opportunity to avoid penalties. The Commission will require pipelines to establish a system that notifies each shipper individually of the imbalance/delivery information that the pipeline possesses, or to give shippers access to such information via the Internet. The pipelines, however, may post relevant system imbalance information more generally. The obligation that such information be provided on a timely basis will vary from pipeline to pipeline, depending on the pipeline's penalties. For example, a pipeline that imposes imbalance penalties only on a monthly basis would have a different obligation to provide imbalance information to its shippers than a pipeline that imposes daily imbalance penalties.

Providing imbalance information on a timely basis will enhance the opportunities of a shipper to avoid penalties and help prevent penalty situations. Information on the precise level of a shipper's deliveries and imbalances will help the shipper avoid overruns and imbalances, and maximize the use of its transportation rights on the pipeline system. Providing such information might also allow pipelines to reduce the level of penalty-free tolerances and to thus reduce system costs (*e.g.,* storage capacity to provide such tolerances). Finally, such information, together with information on system imbalances, will facilitate the trading of imbalances and capacity, or other self-help measures, that in turn could alleviate or prevent conditions that imperil system integrity.

Under the regulations adopted in this rule, pipelines will only be able to impose penalties to the extent necessary. This requirement may result in either no penalties for non-critical days or higher tolerances and lower penalties for non-critical as opposed to critical days. To the extent that pipelines generally justify the imposition of penalties for non-critical days, the pipeline should not impose such penalties on shippers where the existing metering equipment does not

[199] *Id.,* 131 F.2d at 187.

[200] FERC Form No. 2 data indicate that gross penalty revenues from the 15 pipelines that attributed revenue to penalties amounted to approximately $24.3 million in 1996, $9.6 million in 1997, and $5 million in 1998. This reduction in gross penalty revenues may simply be a reflection of the relatively mild winters that have occurred in the past few years.

[201] 158 F.3d 593 (D.C. Cir. 1998).

[202] Comments of AGA, Dynegy, FPL, Indicated Shippers, Louisville, Minnesota, NASUCA, Nicor, Penn. PUC, process Gas Consumers, and PSC of Wisconsin.

[203] Comments of INGAA, Koch, Williams, and Williston Basin.

[204] This is consistent with the NOPR proposal.

provide the shipper with sufficiently accurate information about its imbalance status so that the shipper can take actions to avoid the penalty. During non-critical periods, to the extent a pipeline can justify having a penalty at all, the pipeline will only be allowed to impose penalties in time frames comparable to the information it collects and disseminates to shippers, and for which reasonable notice and opportunity to cure overruns and imbalances is given. For example, if shippers are given information about their overrun and imbalance status on a daily basis, daily tolerances and penalties may be adopted. However, if shippers are given this information only on a monthly basis, only monthly penalties may be imposed. This approach will provide the pipeline with the appropriate incentive to install upgraded metering equipment if controlling imbalances at the point in question is important to the operation of its system.

During critical operating periods, however, the Commission will still permit pipelines to impose penalties on shippers when real-time metering, and/or timely reporting of shippers' imbalance status is not available. The need to maintain system integrity during critical days is of sufficient importance that the Commission does not want to limit the pipelines' ability to deter conduct that may be harmful to other shippers even if it cannot provide current information.

The Commission proposed this restriction as one of two options for addressing situations where, at particular receipt or delivery points, the pipeline might not have the type of metering and related equipment that would provide the shipper with timely information on its deliveries and imbalances. A number of commenters supported this option.[205] The other option presented in the NOPR was to require the pipeline to install equipment sufficient to provide shippers at those points with timely information on imbalances and deliveries. Many commenters opposed that option because it raises difficult issues, such as who should pay the costs of purchasing and installing the equipment. Requiring the pipeline to install adequate metering equipment at those points is inconsistent with the Commission's determination not to require upgraded metering equipment at all points. The Commission is not adopting this option.

While a significant percentage of the commenters support requiring pipelines to provide, on a timely basis, as much information as possible on imbalances and overrun status of each shipper, and system imbalance status,[206] several commenters object to the Commission's requiring pipelines to provide ''as much information as possible.'' National Fuel argues that this standard is nebulous, and is likely to result in the posting of much useless information. National Fuel requests that the Commission modify the proposed policy to require that pipelines ''provide, on a timely basis, a quantification of the imbalance and overrun status of each shipper and the imbalance of the pipeline's system.'' [207] Williston Basin maintains that the Commission should not require pipelines to provide as much volume information as possible, but should require pipelines to provide appropriate volume information on a net benefit basis and the relevance of the volume information to the specific pipeline and its shippers.[208] Consolidated Natural states that the language of the new provisions suggests that a pipeline must have real time measurement equipment in place.[209] It asserts that pipelines' existing business, measurement and computer systems cannot manage the calculation of more detailed or more timely information.

The Commission is requiring the provision of only as much information as the pipelines already have available on shippers' imbalance and overrun status, and on system imbalance status. The Commission reiterates that it is not requiring that pipelines upgrade their existing business, measurement, and computer systems to provide this information. Also, the Commission does not wish to limit this information to a quantification of the shippers' imbalance and overrun status, and system imbalance status. There may be other information about imbalances, particularly with respect to system imbalances, that pipelines have available that could aid shippers in planning their actions and avoiding imbalances and penalties.

Atlanta, also, has a concern with the Commission's requirement that pipelines provide timely imbalance information.[210] Atlanta asserts that increasing the amount of information available to shippers will not be sufficient to prevent shippers from incurring imbalances unless shippers have the appropriate incentives to avoid imbalances. Atlanta believes that shippers currently have the ability to control their imbalance activity, but choose not to because they find it economically beneficial to game the system. Atlanta supports requiring pipelines to provide as much information as possible, but only in conjunction with the provision of incentives for shippers to remain in balance. Further, Atlanta maintains that forbidding pipelines to impose imbalance penalties during non-critical periods where the pipeline has failed to notify the shipper of the imbalance situation will exacerbate the imbalance problem by removing disincentives for shippers to incur imbalances.

The Commission agrees with Atlanta that the existence of proper incentives for shippers to avoid imbalances is of paramount importance. The policy being adopted here, focused on avoiding penalties and reducing the need for penalties, is intended precisely to promote such incentives. The measures the Commission is taking here are designed to move the pipeline away from the use of negative incentives—penalties and OFOs—to the use of positive incentives to control shipper behavior. It is up to the pipeline to develop such positive incentives. However, the Commission's actions here are laying the groundwork for, and will facilitate, the pipelines' efforts in this direction. For example, by requiring pipelines to offer imbalance management services, the Commission is prompting pipelines to become creative in developing such services that may not only make it easier for pipelines to avoid imbalances, but may also provide built-in incentives for shippers to stay in balance. Also, the provision of timely information of shipper and system imbalance status, together with the pipeline's ability to establish appropriate imbalance penalties, should in and of itself produce good incentives for shippers to stay in balance.

The Commission does not agree with Atlanta, however, that forbidding pipelines from imposing non-critical day penalties where the pipeline has failed to notify the shipper of the imbalance strips away shipper incentives to comply with tariff requirements. To the extent that pipelines continue to use a negative incentive, such as a penalty, to encourage shippers to remain in balance and deter behavior, it is a matter of basic fairness that the pipeline give notice of the imbalance situation and the opportunity to cure the imbalance prior

[205] Comments of Florida DMS, Louisville, NGSA, Process Gas Consumers, and TransCanada.

[206] Comments of AlliedSignal, Florida Cities,NEMA, NGSA, Paiute, Process Gas Consumers, PUC of Ohio, Dynegy, and PSC of Wisconsin.

[207] Comments of National Fuel at 5.

[208] Comments of Williston Basin at 35.

[209] Comments of Consolidated Natural at 25–26.

[210] Comments of Atlanta at 17–18.

to imposing a penalty that is not critical to operations.

2. Future Consideration of Penalty and OFO Issues

The Commission is adopting the general policies set forth above as an initial step toward increasing shipper flexibility to avoid penalties, and minimizing the need to impose penalties. However, in the NOPR, the Commission sought comment on a variety of options for implementing and expanding these general policies. For example, the Commission requested comment on whether more appropriate penalties might result from establishing uniform penalties and OFOs across pipelines on a national or regional basis, revising pipelines' cash-out procedures, or establishing a ''no-harm, no-foul'' policy that would permit beneficial imbalances to escape penalties. The comments to the NOPR produced no strong consensus on most of the specific options that the Commission presented for implementing and expanding the general policies.

As a result, while it is appropriate to take a modest step toward remedying the inefficiencies caused by penalties and OFOs through the adoption of the general policies, it is premature, without additional study and examination of the market, to undertake the more ambitious policies presented as options in the NOPR, or many of the detailed suggestions for a revised Commission policy on penalties that the commenters presented.[211] The Commission recognizes that they may hold promise for the future. Thus, the Commission will continue to monitor the natural gas market and the role penalties play in that market, as the industry responds to the initial changes being adopted in this final rule to the Commission's penalty and other policies, and to the GISB standards for imbalance management recently put into place. In the event that the inefficiencies associated with penalties and OFOs persist, the Commission will revisit whether the more comprehensive and innovative policy changes are necessary.

To facilitate the Commission's consideration of additional, more significant changes in the Commission's penalty policy, if necessary after some experience under the rules adopted here, the Commission or its Staff may convene an industry-wide conference to examine the need for further generic reform of the industry's penalty standards. Such a conference would explore whether there are commodity arbitrage problems on individual systems and gaming across pipelines and LDCs due to different penalty levels, and whether it is feasible to set penalties and OFO standards on a regional or national basis.

IV. Reporting Requirements for Interstate Pipelines

The free flow of information regarding the natural gas market is critical to the successful creation of a competitive and efficient marketplace. Access to relevant information is necessary for shippers to make informed decisions about capacity purchases, and for the Commission and shippers to monitor transactions to determine if market power is being exercised. Also, as competition is improved in the natural gas marketplace by the changes the Commission is making in this final rule, the ready availability of information will become increasingly important, both for efficient trading and for the monitoring for the exercise of market power.

The market needs several different types of information, both for decision-making and monitoring purposes: information on capacity transactions, such as rates, contract duration, and contract terms; information on the structure of the market; and information on capacity availability. Transactional information provides price transparency so shippers can make informed purchasing decisions, and also permits both shippers and the Commission to monitor actual transactions for evidence of the possible abuse of market power. Information on market structure enables shippers and the Commission to know who holds or controls capacity on each portion of the pipeline system, so the potential sources of capacity can be determined. Information on the amount of capacity available at receipt and delivery points and on mainline segments, as well as on the daily amount of capacity that pipelines schedule at these points, helps shippers structure gas transactions and casts light on whether shippers or the pipeline may be withholding capacity.

The Commission's current regulations already require the reporting and maintenance of much of the necessary information.[212] However, the information required by the existing regulations gives market participants and the Commission an uneven picture of the market because the reporting requirements are different for competing types of capacity, both in terms of the content of the information and the formats used to report the information. For instance, pipelines are required to post detailed information on capacity release transactions, including the releasing and replacement shipper names, the rate paid, and points covered by the release, when the transactions occur.[213] In contrast, pipelines are only required to file limited information on their discount transactions well after the transaction has taken place.[214] In addition, some information needed to enable shippers to effectively make capacity decisions and monitor the market is not currently required by the existing regulations, such as certain point-specific data.

Therefore, the Commission is revising its reporting requirements in a few main respects to improve the availability and usefulness of the information currently reported. First, the Commission is changing and consolidating the reporting formats in which it collects the information, including the time frames within which information is reported, to enable the Commission to equalize the reporting requirements for capacity release transactions and pipeline transactions, and to simplify the overall reporting system. The new reporting system reduces the amount of periodic reporting to the Commission currently required, and instead relies on Internet posting and maintenance of information. Second, the Commission is adding certain data to the information that is already collected on pipeline transactions, the structure of the market, and capacity availability in various reporting formats. Specifically, the most significant additional information being required here is receipt and delivery point data in the report on pipeline transactions and the Index of Customers, certain organizational and personnel information on affiliates, and information on design and scheduled capacity and service outages. Third, the Commission is reorganizing its regulations to consolidate all of the existing and new Part 284 reporting requirements into a single, new § 284.13 governing open-access reporting requirements for interstate pipelines.

Under the new requirements, as detailed below, pipelines will be required to provide transactional information, information regarding capacity and service outages, an index of firm transportation customers, and information concerning marketing

[211] Comments of AF&PA, Amoco, Dynegy, Process Gas Consumers, and Exxon.

[212] Information is currently provided through a variety of formats: the capacity release reporting standards (§ 284.10(b)(1)(v), Capacity Release Related Standards 5.4.1, 5.4.3), the Index of Customers § 284.106(c)), the discount report (§ 284.7(c)(6)), and the maintenance requirement for discount information (§ 250.16(d)).

[213] 18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.1, 5.4.3.

[214] 18 CFR 284.7(c)(6).

affiliates, most of which is already reported or maintained.[215]

- The transactional information on firm and interruptible transportation will be provided by posting the information on the pipelines' Internet web sites and through downloadable files. The transactional information on firm transportation, whether provided by the pipeline or through capacity release, is to be reported contemporaneously with the transaction. The information on interruptible transportation will be provided daily.
- The capacity information will provide information on available, scheduled, and design capacity and service outages through posting on the pipelines' web site and through downloadable files. The information on available and scheduled capacity will be posted daily. Information on design capacity will be posted one time (and thereafter maintained on the web site), and then updated as necessary. Service outages will be posted when required.
- The Index of Customers will be provided through a quarterly filing with the Commission, as well as by posting the information quarterly on the pipelines' Internet web sites.
- The affiliate information will be posted on the pipelines' Internet web sites, and will be updated within three days of changes in the information.

A. Transactional Information

To assure parity of the transactional information that is reported for capacity release transactions and for pipeline transactions, the Commission is requiring that pipelines provide the same information about their firm and interruptible transactions as is currently reported about capacity release transactions, in the same format. Therefore, the Commission is adding a new § 284.13(b) that will require pipelines to post on their Internet web site, and provide downloadable files of, transactional information about their own capacity transactions and released capacity transactions.[216] Pipelines will be required to keep the firm and interruptible transactional information, described below, available on their web sites for 90 days. In accordance with the Commission's existing regulations, pipelines will also have to archive this information after the 90-day period expires, maintaining the information for a period of three years.[217]

Specifically, for firm service, pipelines will be required to post the following information, contemporaneously with the execution of the contract: the names of the parties to the contract; an identification number for each shipper, such as a DUNS number; the contract number for the shipper receiving service and for the releasing shipper; the rate charged under each contract and the maximum rate, if applicable; the duration of the contract; the receipt and delivery points and zones or segments covered by the contract, as well as the common transaction point codes; the contract quantity, or volumetric quantity under a volumetric release; special terms and conditions applicable to a capacity release and special details pertaining to a pipeline transportation contract;[218] and any affiliate relationship between the pipeline and the shipper or between the releasing and replacement shipper.

For interruptible transportation, the pipeline will be required to post the following information on a daily basis: The name of the shipper; a shipper identification number; the rate charged and maximum rate, if applicable; the receipt and delivery points and zones or segments over which the shipper is entitled to nominate gas, as well as the common transaction point codes; the quantity of gas the shipper is entitled to nominate; special details pertaining to a pipeline transportation contract; and any affiliate relationship between the shipper and the pipeline.

The Commission is also eliminating the separate discount report previously required by § 284.7(c)(6). It will no longer be required, since the same information will be reported under the reports on firm and interruptible transactions in new § 284.13(b). However, pipelines will be required to continue to file discount reports until September 1, 2000, when they are required to comply with the new reporting requirements.

Pipelines already provide, via the Internet, virtually all of the above transactional information for capacity release transactions, at the time of the transaction.[219] However, under the current regulations, pipelines are required to provide limited transactional information for their own capacity transactions, and the information that is required is neither as timely nor as easy to access as the capacity release information. Currently, pipelines must file discount reports, which require only some information on firm and interruptible transactions at less than the maximum rate—the name of the shipper, the maximum rate, the rate actually charged, and any corporate affiliation between the pipeline and the shipper.[220] The discount report does not include any information on volumes, the receipt and delivery points for the transaction, or the duration of the contract. And, the discount report is filed, but not posted electronically, 15 days after the close of the billing period applicable to the transaction. Thus, the information provided in the discount report is limited in nature, is provided well after the transaction has taken place, and is filed with the Commission, rather than posted on the pipeline's EBB or on the Internet.

Some information regarding firm transactions is available in the Index of Customers, which requires that pipelines file the following information electronically with the Commission and on the pipelines' EBBs for each customer receiving firm transportation or storage service: the customer name, the amount of capacity held, the duration of the contract, and the applicable rate schedule.[221] However, the Index of Customers cannot truly be considered a transactional report, since it does not provide any price information or information on the capacity path held by the shipper. Therefore, it is of limited use in monitoring transactions for discrimination. In addition, the Index of Customers is only filed quarterly, and therefore reflects only those shippers that have contracts with the pipeline on the quarterly filing day. As a result, it is inadequate to capture shipper and contract information for short-term firm contracts that may begin and end within a quarterly filing period.

Thus, the discount report only provides some after-the-fact information regarding transactions at less than the maximum rate, the Index of Customers only provides some quarterly information regarding firm contracts, and neither reporting requirement provides any transactional information with respect to interruptible transactions at the maximum rate. Consequently, the content and reporting formats of the existing reporting requirements for pipeline transactions are inadequate to give shippers and the

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[215] As a result of consolidating the reporting requirements into one place in the regulations, § 284.13 also includes the annual report on peak day capacity and storage capacity, and the semi-annual storage report, which are filed with the Commission. The Commission is not changing these regulations in this rule.

[216] While new § 284.13(b) enumerates information the Commission needs for firm and capacity release transactions, it does not replace the existing GISB capacity release data set.

[217] Section 284.10(c)(3)(v), redesignated as § 284.12(c)(3)(v).

[218] Under this requirement, a pipeline must report any special conditions attached to a discounted transportation contract, such as requirements for volume commitments to obtain the discount.

[219] 18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.1, 5.4.3. The only exceptions are that some pipelines are not required to report whether a capacity release transaction is between a releasing shipper and an affiliate, and contract numbers are not required to be reported.

[220] 18 CFR 284.7(c)(6).

[221] 18 CFR 284.106(c)(3).

Commission a real-time snapshot of what price capacity sold for on a particular day. The pipeline data and reporting formats are not comparable to the existing reporting requirements for capacity release transactions. The reporting of the same information required to be provided in the capacity release reports, in the same format, is necessary with respect to pipeline transactions for shippers to have a complete and comprehensive view of the market.

The transactional reporting requirements the Commission is adopting here are generally the same reporting requirements proposed in the NOPR, with a few minor modifications. The Commission is adding to the firm and interruptible transactional reports proposed in the NOPR the maximum rate under each pipeline contract, to enable the magnitude of any discounts to be known, since the existing discount report is now subsumed within the reports on firm and interruptible transactions. In addition, the Commission is adding to the transactional reporting requirements an individual shipper identification number, such as a DUNS number, to the extent one exists for a particular shipper, so that it will be easier to link together, or match-up, customer-specific data from different reports. The Commission is also adding the common point codes for the receipt and delivery points. The Commission has previously adopted the consensus recommendation of GISB that pipelines use common transaction point codes.[222]

Many commenters support the reporting requirements the Commission proposed in the NOPR and is adopting in this rule.[223] Some commenters even advocate that the Commission should impose greater reporting requirements than those proposed in the NOPR.[224] Other commenters, though, object to the Commission requiring pipelines to disclose specific information about pipeline transactions on confidentiality grounds.[225] They argue that such information, particularly customer names, receipt and delivery points, and contract numbers, is commercially sensitive information, which, if disclosed contemporaneously with the transaction, will cause shippers competitive harm.

For instance, Dynegy argues that disclosure of individual contract numbers and receipt and delivery points will make it easy for shippers to track the chain of title to determine where other shippers' supply came from and where it will end up. Dynegy states that knowledge of this information, together with the rates paid for the transportation, will allow shippers to undercut or steal other shippers' transactions.[226] Dynegy does indicate, however, that it might not object to the release of such information to only the Commission, with appropriate confidentiality protection. Dynegy further maintains that it does not object to the disclosure of this information with respect to pipelines' transactions with their affiliates because there is an overriding need for pipelines to report such information for their marketing affiliates that outweighs concerns about commercial sensitivity.[227]

Similarly, Duke asserts that there is no need to identify specific shipper's nominated capacity at each point because such information would give shippers knowledge of their competitor's general marketing strategy and allow shippers to deduce the identity of the markets themselves. Duke states that the identity of the shipper should be redacted from postings.[228]

Some commenters maintain that requiring pipelines to report the additional transactional information may have the unintended effect of increasing bundled sales activity.[229] They state that because many shippers do not want to have the details of their transactions disclosed, they currently avoid capacity release transactions in favor of bundled sales transactions. Thus, the commenters argue that a policy of immediate disclosure of transactional information for pipeline transactions will cause even greater bundled sales transactions, and thereby frustrate the Commission's goal of increased market transparency.

In addition, the opposing commenters request that if the Commission decides to require public disclosure of the transactional information, at a minimum, it should not require the immediate disclosure of the information, but should revise the timing of the reporting requirement.[230] They request that the reporting of the information, particularly the identity of the shipper, be delayed, so pipelines and shippers are not given an opportunity to use such information to gain a competitive advantage. They suggest delays ranging from 30 days after the transaction, to six months after service under the contract begins.

The Commission finds that the disclosure of detailed transactional information is necessary to provide shippers with the price transparency they need to make informed decisions, and the ability to monitor transactions for undue discrimination and preference. Shippers need to know the price paid for capacity over a particular path to enable them to decide, for instance, how much to offer for the specific capacity they seek. While the Commission acknowledges that the disclosure of shipper names is not necessary for this type of decisionmaking and price transparency, the disclosure of the identity of the shipper in each transaction, together with the price and capacity path information on each shipper's transaction, is necessary to enable shippers and the Commission to effectively monitor for potential undue discrimination or undue preference. The disclosure of all of the transactional information without the shipper's name will be inadequate for other shippers to determine whether they are similarly situated to the transacting shipper for purposes of revealing undue discrimination or preference. For example, the disclosure of the name of the shipper in the transaction may help other shippers to determine whether a transacting shipper may be entitled to a discount because it is fuel-switchable. In addition, the disclosure of the identity of shippers in the transactional reports enables shippers and the Commission to determine how much total firm capacity (both pipeline capacity and released capacity) a shipper holds on each individual pipeline, as well as on connecting pipelines. Such information is important for examining market power

[222] See redesignated 18 CFR 284.12(b)(1)(v) Capacity Release Related Standards (Version 1.3), Firm Transportation and Storage-Award Notice, tab 8, at 2, tab 8 EDI, at 17–18. Under this provision, however, a pipeline can use a propriety code if no common transaction point code exists, but will have two months within which to obtain a common code for that point.

[223] *E.g.,* Comments of AEC, AF&PA, AGA, Amoco, CPUC, Duke Energy, Enron Capital, Florida Cities, Florida DMS, Industrials, Louisville, NEMA, Penn. PUC, Proliance, PSC or Kentucky, PUC of Ohio, Soutehrn Co. Services, WGL, and Wisconsin Distributors.

[224] Comments of Amoco, Indicated Shippers, New England, Southern Company Services, TransCanada, WGL, and Wisconsin Distributors.

[225] Comments of Coastal, Dynegy, Duke, Process Gas Consumers, NICOR, PUC of Ohio, Sithe, Tejas, Williams, and Williston Basin.

[226] Comments of Dynegy at 14–15.

[227] Comments of Dynegy at 8 and 14.

[228] Comments of Duke at 7.

[229] Comments of Coastal 93–94 and PUC of Ohio at 8. The comments of the PUC of Ohio on this point are limited to the disclosure of the transacting parties' identities.

[230] *See* Comments of Dynegy at 16, NICOR, at 21, and Industrials at 89.

and whether a shipper has sufficient market presence to unduly discriminate.

Moreover, the general regulatory scheme of section 4 of the Natural Gas Act is based on the public disclosure of all prices and contracts.[231] Thus, the posting of customer-specific information in the transactional reports being required here is consistent with this statutory framework. In addition, in requiring the shipper identity to be disclosed, the Commission is not changing or reversing its treatment of shipper names in the reporting requirements. The names of shippers are currently required to be posted for capacity release transactions and for discount transactions in the discount reports.

Finally, to be meaningful for decisionmaking purposes, the transactional information must be reported at the time of the actual transaction. A delayed reporting of the information 30 days or more after the transaction has occurred, as some commenters suggest, will not be timely enough to enable shippers to use the information on a day-to-day basis to make purchasing decisions. At that point, the information is historical, and is of no value for current decisionmaking. In other words, the knowledge of what capacity sold for what price 30 days earlier would not aid shippers in making a current capacity decision. Some commenters advocate a delayed posting of the shippers' names only. The Commission acknowledges that immediate disclosure of shippers' names is not necessary for the Commission and other shippers to monitor for undue discrimination and preference. A delayed posting of the shipper names would suffice for the monitoring purpose for which the names are needed. However, a requirement that pipelines report different transactional information at different times is likely to be impracticable to implement, creating a burden that outweighs the need for confidentiality. Because it is necessary for all of the other transactional information to be posted at the time of the transaction, the Commission will require the identity of the shipper for each transaction also to be disclosed at the time of the transaction.

Commenters also have concerns regarding the burden that the Commission's revised transactional reporting requirements will place on pipelines.[232] For example, some commenters contend that requiring pipelines to post information on interruptible transactions on a daily basis is too burdensome.[233] Williston Basin states that requiring these data on a daily basis is akin to uploading each pipeline's daily interruptible nominations (including all intraday cycles) on its Internet web site every day.[234] It asserts that a pipeline's single timely nomination cycle can be thousands of records long, and that multiplying this by the intraday cycles day after day will prove to be an enormous amount of data. PSC of New York states that it may be impossible or impractical to post interruptible transactions before gas flows. PSC of New York suggests that the posting of interruptible transactions should be required as soon as possible after gas flows.[235] In contrast, Amoco argues that the Commission should require the posting of all interruptible transactions contemporaneous with the execution of the contract.

The Commission does not expect that the burden of complying with the transactional reporting requirements will be great. Most of the information required for the pipeline's transactional report on firm and interruptible service is already required to be reported or maintained under existing requirements, such as the Index of Customers, the discount report, or the affiliate discount information maintenance requirement in § 250.16(d) of the Commission's regulations, albeit separately, and in different formats.[236] Thus, the burden will not be in collecting or gathering the data, but will largely be in creating the new formats for displaying the information on the pipelines' Internet web sites. Pipelines may, however, be able to adapt their already existing capacity release data sets to apply to pipeline transactions without much difficulty. Moreover, the Commission is reducing the periodic reporting currently required under the regulations by eliminating the monthly discount report.

While the Commission is requiring that some new data, not required in existing reports, be posted on firm and interruptible transactions, it is not an extensive amount of information compared to what is already provided. For the firm transactional report, the Commission is adding the receipt and delivery points and the zones or segments under the contract, the common transaction point codes, the contract number, a shipper identification number, and special terms and conditions applicable to a capacity release and special details pertaining to a pipeline transportation contract. Similarly, for the interruptible transactional report, the Commission is adding the receipt and delivery points and zones or segments, the common transaction point codes, the contract quantity, a shipper identification number, and special details pertaining to a pipeline transportation contract. Further, these additional data are information that pipelines use in the course of their daily business activities, and thus, have in their possession, so that pipelines should not encounter great difficulty in assembling the information. Again, for pipelines to comply with the new reporting requirements, their task will be to develop a method for displaying the information on the web sites.

The Commission recognizes that the quantity of data to be posted on interruptible transactions could be voluminous for some pipelines. However, in order for shippers to have a true understanding of pricing in the marketplace, they must know what prices are being paid for interruptible transportation service and when such interruptible prices change. The existing discount report for interruptible transactions at less than the maximum rate is inadequate because it provides only a monthly average of the price paid. Since the prices for interruptible service can change daily, it is necessary for the pipeline to post interruptible transactions on a daily basis. In addition, the Commission emphasizes that the Commission is requiring the posting of these data once daily, not contemporaneously with the execution of each contract.

B. Information on Market Structure

To provide shippers with a more useful picture of the structure of the market for both decisionmaking purposes and monitoring purposes, The Commission is expanding two of its reporting requirement regulations: the Index of Customers and the affiliate regulations.

1. Index of Customers

Pipelines currently file with the Commission, and post on their Internet web sites, on the first business day of each calendar quarter, an Index of Customers under existing § 284.106(c)(3) of the regulations, which provides the names of shippers holding

[231] 15 U.S.C. 717(c).

[232] Comments of AGA, Koch, MichCon, Tejas, and Williston Basin.

[233] Comments of Williston Basin and PSC of New York I.

[234] Comments of Williston Basin at 32.

[235] Comments of PSC of New York I at 14–15.

[236] The only true gap in the information currently reported is information on interruptible transactions at the maximum rate, since the discount reporting requirements, by definition, do not apply to maximum rate transactions.

firm capacity, the amount of capacity they hold, the applicable rate schedule, and the contract effective and expiration dates. The Commission is adding the following new information requirements to the Index of Customers, which is now § 284.13(c): The receipt and delivery points held under the contract and the zones or segments in which the capacity is held; the common transaction point codes; the contract number; a shipper identification number, such as DUNS; an indication whether the contract includes negotiated rates; the names of any agents or asset managers that control capacity in a pipeline rate zone; and any affiliate relationship between the pipeline and the holder of capacity.

The Commission is requiring that pipelines report the receipt and delivery points and zones or segments in which the capacity is held so that the capacity path held by the shipper can be traced, and the data can be used to determine which shippers can compete in providing capacity on segments of the pipeline. The contract number and shipper identification number are needed on the Index of Customers, as well as on the report of capacity release transactions, so capacity can be traced through release transactions to reveal how much total capacity each shipper holds. In addition, in the current market, shippers may be using agents or asset managers to manage their capacity, and such managers may be given wide latitude over the way in which capacity is used. Requiring that pipelines disclose the names of the agents or asset managers will help to show the degree of control over pipeline capacity that an agent or asset manager may exercise. This will aid in the detection of potentially anticompetitive market dominance. Finally, to permit effective monitoring of the capacity held on pipelines, it is necessary to know any affiliate relationship between the pipeline and a shipper or a shipper's agent or asset manager in order to determine the total amount of capacity held by the parent entity.

The information in the Index of Customers that the Commission is requiring in this rule is different from the information that the Commission proposed in the NOPR to include in the Index of Customers. Essentially, as described below, the Commission is requiring less information with respect to agency and affiliate relationships to be reported than the Commission proposed to require in the NOPR.

In the NOPR, the Commission proposed to require pipelines to report for each customer the names of any agents or asset managers that control 20 percent or more of capacity in a pipeline rate zone, as well as the rights of the agent or asset manager with respect to managing the transportation service. Several commenters objected to this reporting requirement.[237]

Dynegy indicates that it holds a number of agency arrangements with pipeline customers under which it sometimes provides an array of services, and which its competitors would want to replicate. Dynegy argues that if the breadth and depth of agency relationships are disclosed, an agent will be stripped of any competitive advantage it has gained through experience and commercial expertise.[238] Dynegy also contends that to the extent that the market would learn of an agency relationship, the ability of that agent or asset manager to act on behalf of a large shipper without moving the market would be significant reduced.

WGL, in its comments, states that it is unclear what purpose is served by this reporting requirement.[239] WGL believes that if the information disclosed is limited to the details of operational rights, the release of such information may not be objectionable. However, WGL contends that contracts between the shipper and the agent/asset manager may contain sensitive commercial information, and in many cases where the shipper is an LDC, such agreement is subject to local regulatory review. Coastal requests that the Commission limit the scope of this requirement to the disclosure of only the existence of an agent or asset manager, when known by the pipeline, not the rights of the agent or asset manager, which may be impossible for the pipeline to track.[240]

The Commission finds that asset manager reporting is needed to reveal potentially unhealthy market dominance by an asset manager that would not otherwise be apparent. However, the reporting of only the names of any asset manager or agent, without including the details of the asset manager/agency relationships, will be adequate for this purpose. Thus, the Commission is requiring pipelines to report the names of asset managers or agents, but not the agent's/asset manager's rights with respect to managing the transportation service. However, the Commission will require that all asset managers or agents be identified, not just those that manage 20 percent of more of the transportation service in a pipeline rate zone. The determination of which asset managers and agents meet this 20 percent threshold requirement may be too difficult to make in many instances. In addition, the Commission disagrees with Dynegy that reporting the names of asset managers or agents of customers will somehow reveal the identity of the particular customer the asset manager or agent is acting on behalf of during contract negotiations. Since the asset manager or agent presumably would have several clients, the market would not know which client a given gas purchase would be for. There is no requirement that the actual capacity transactions arranged by the asset manager or agent be reported.

The Commission is also reducing the information required in the Index of Customers with respect to affiliates from what was proposed in the NOPR. In the NOPR, the Commission proposed to require that pipelines indicate, in the Index of Customers, any affiliate relationship between the pipeline and the holder of capacity, and any affiliate relationship between holders of capacity.

Several commenters objected to the requirement that pipelines identify affiliate relationships among holders of capacity.[241] PG&E objects to this requirement when such affiliate relationships involve third parties unrelated to the pipeline responsible for the posting.[242] PG&E and Williston Basin argue that pipelines do not have access to such information, nor the ability to obtain or ensure the accuracy of such information. Similarly, National Fuel maintains that it may not be practical for a pipeline to identify every affiliate relationship between a particular shipper and every other shipper using the pipeline's system.[243] At a minimum, National Fuel argues, this requirement should be limited to major holders of capacity—perhaps those holding 20 percent of the pipeline's capacity—and that the onus should be on the capacity holder to identify whether it is affiliated with the pipeline's other shippers. Dynegy, also, asserts that this requirement gives pipelines too much discretion to research their shipper's transactions.[244]

As a result of these comments, the Commission has reconsidered its proposal to require the reporting of third-party affiliates. The Commission agrees with the commenters that it may not be feasible for pipelines to

[237] Comments of Dynegy, WGL, and Coastal.

[238] Comments of Dynegy at 13.

[239] Comments of WGL at 15.

[240] Comments of Coastal at 94.

[241] Comments of PG&E, National Fuel, Dynegy, and Williston Basin.

[242] Comments of PG&E at 18–19.

[243] Comments of National Fuel Gas Supply at 4–5.

[244] Comments of Dynegy at 12.

accurately identify their customers' affiliates. Therefore, the Commission is requiring that pipelines identify only their own affiliates, and not affiliate relationships among customers.

Dynegy and others that object to the disclosure of customer names, receipt and delivery points and contract numbers required in the transactional reports in § 284.13(c) also object to the requirement that they be disclosed in the Index of Customers, on the same bases of confidentiality and burden. Some commenters argue that the transactional reports and the Index of Customers are duplicative.[245]

The rationale for including customer names, receipt and delivery points and contract numbers in the Index of Customers is essentially the same as it is for including such information in the transactional reports. The additional information being required in the Index of Customers, particularly the receipt and delivery points and zones or segments in which capacity is held, which raises the most concern with respect to burden for commenters, is necessary for shippers to determine who holds capacity, the amount, and where it is held. Such information reveals potential sources of capacity for shippers making purchase decisions, provides information on market concentration and structure, and will permit shippers to better monitor for potential undue discrimination or preference. The benefits and importance of requiring the posting of the additional data in the Index of Customers outweigh the concerns of the commenters about confidentiality, just as it does with respect to the transactional reports.

With respect to the burden of posting the additional information in the Index of Customers, some of the additional Index of Customer data—the affiliate indicator and the delivery points under the contract—are already reported or maintained for discounted transactions. Pipelines will simply have to add this and the other, new, data (contract number, shipper identification number, receipt points, whether the contract includes negotiated rates, and the names of any agent/asset manager) to the existing data sets for the current Index of Customers. In addition, as discussed above, the Commission has reduced the burden that some of the informational requirements for the Index of Customers proposed in the NOPR would otherwise have place on pipelines (*i.e.,* the identification of affiliate and agent/asset manager relationships). In sum, the additional reporting burden with respect to the Index of Customers should not be too great given that the additional information, for the most part, is straightforward information that is a part of each shipper's contract.

Finally, the information required in the Index of Customers is not duplicative of the information in the transactional reports. The Index of Customers provides a snapshot view of who holds firm capacity on each pipeline that otherwise could not be obtained without continuously tracking every firm capacity transaction. Conversely, the transactional reports are necessary to provide the price information that is not included, and would be meaningless to include, in the quarterly Index of Customers.

2. Affiliate Regulations

The Commission is expanding its affiliate regulations to provide more information to permit monitoring and self-policing of affiliate transactions. The Commission is revising § 161.3(l) of the standards of conduct for interstate pipelines to specifically require that pipelines with marketing affiliates post certain information concerning their affiliates on their Internet web sites, and to update the information within three business days of any change.[246] These revisions also will apply to pipelines with sales operating units.[247] Under revised § 161.3(l), the Commission is requiring that pipelines post a list of the names of operating personnel and facilities shared by the interstate pipeline and its marketing affiliate. The pipelines currently provide this information in their tariffs, under § 250.16(b)(1); however this new requirement will make such affiliate information easily available on the Internet.

The Commission also is requiring pipelines, under § 161.3(l), to post on their Internet web sites comprehensive organizational charts that include several types of information, set forth below. The Commission has adopted a similar requirement for the posting of organizational charts and job descriptions in the electric industry, to help monitor and protect against improper communications between transmission and wholesale merchant function employees.[248]

First, the pipeline must post an organizational chart showing the organizational structure of the parent corporation and indicating the relative position within the corporate structure of the pipeline and all marketing affiliates.

Second, the pipeline must post an organizational chart showing business units, job titles, job descriptions, and chain of command for all positions within the pipeline, including officers and directors. The pipeline need not include such information for clerical, maintenance, and field positions, since employees in those positions would not have access to information concerning the processing or administration of requests for service. The job titles and descriptions must include the employee's title, duties, and an indication whether the employee is involved in transportation or gas sales. Employees involved in transportation or gas sales include any member of the board of directors, officers, managers, supervisors, and regulatory and technical personnel with duties involving day-to-day gas purchasing, marketing, sales, transportation, operations, dispatching, storage, or related activities.[249] In addition, the pipeline must also include the names of supervisory employees who manage non-clerical employees involved in transportation or gas sales.

Third, for all employees shared by the pipeline and a marketing affiliate, the pipeline must post an organizational chart showing the business unit or sub-unit within the marketing affiliate organizational structure in which the shared employee is located, the employee's name, the employee's job title, and job description within the marketing affiliate, and the employee's position within the chain of command of the marketing affiliate.

The reporting requirements being adopted here are essentially the same general requirements proposed in the NOPR. However, the Commission has decreased the reporting burden that would have been required by the NOPR. In the NOPR, the Commission proposed to require pipelines to post detailed organizational charts, including detailed employee job descriptions, for the pipelines' marketing affiliates. In this

[245] *E.g.,* Comments of Williams.

[246] The regulation adopted here incorporates the changes in the affiliate regulations made previously in Docket No. RM98–7–000, Reporting Interstate Natural Gas Pipeline Marketing Affiliates on the Internet, III FERC Stats. & Regs. Regulations Preambles ¶ 31,064 (July 30, 1998), 63 FR 43075 (Aug. 12, 1998).

[247] 18 CFR 284.286 (c) (requiring pipelines with sales operating units to comply with standards of conduct applicable to marketing affiliates).

[248] *See* American Electric Power Service Corporation, 81 FERC ¶ 61,332 (1997), 82 FERC ¶§ 61,131, *order on reh'g,* 83 FERC ¶ 61,357 (1998).

[249] Order No. 497–E, *order on rehearing and extending sunset date,* 59 FR 243 (January 4, 1994), FERC Stats. & Regs. 1991–1996 ¶ 30,958 at 30,996 (December 23, 1993) (defining ''operating employee'').

final rule the Commission is not requiring organizational charts for the marketing affiliates, except to the extent that they share employees with the pipeline, and the reporting requirement is limited to data regarding the shared employee. The Commission is making this change to conform the affiliate reporting requirements for pipelines to those required for the electric utilities.

Several commenters fully support the reporting requirements that were proposed.[250] Dynegy maintains that these reporting requirements are a valuable tool to police pipeline affiliate activities, as well as a resource for contacting employees within a corporation. Several commenters also oppose these affiliate reporting requirements, particularly the requirement that pipelines post organizational charts and employee names.[251] Williston Basin objects to the posting of organizational charts, names, and job descriptions for marketing affiliates. Williston Basin argues that the Commission has never before imposed a marketing affiliate reporting requirement on pipelines that do not conduct business with the marketing affiliate. Williston Basin also maintains that requiring the names of pipeline and marketing affiliate employees to be posted on the pipeline's web site, even though their job requirements do not entail contact with outside parties, would violate the personal privacy of those employees.

Requiring that pipelines post shared personnel, organizational charts, job titles and descriptions, and the names of senior employees is essential to ensure that pipelines deal fairly with their customers. These reporting requirements will act to deter undue discrimination and preference, and will permit the market to monitor and self-police affiliate transactions.

In response to Williston Basin, the Commission clarifies that all of the marketing affiliate reporting requirements in part 161, including the new requirements added here, apply only to pipelines that conduct transportation transactions with their marketing or brokering affiliates.[252] Also, as stated above, the Commission is not requiring the detailed organizational charts for marketing affiliates, to which Williston Basin objects, in all instances. Only where there are shared employees between the marketing affiliate and the pipeline is the pipeline required to post information regarding the shared employee's position within the marketing affiliate. The Commission further clarifies that it is requiring posting of the names of only senior employees. A pipeline will not be required to post the names of non-senior employees, so concerns about privacy for lower level employees are somewhat misplaced.

C. Information on Available Capacity

In § 284.8(b)(3) of the Commission's existing regulations, pipelines are required to post information about the amount of operationally available capacity at receipt and delivery points, on the mainline, in storage fields, and whether the capacity is available directly from the pipeline or through capacity release.[253] In new § 284.13(d)(1), being adopted here, the Commission is continuing to require that pipelines post this information, and is adding the following information on capacity availability to the information that is already collected: The total design capacity of the point or segment; the amount of capacity scheduled at each point on a daily basis; and information on planned and actual service outages that would reduce the amount of capacity available. The Commission expects that the pipelines will provide advance notice of planned outages or service disruptions so that shippers can plan for these events.

Information on the total design capacity of the point or segment, and the amount of capacity scheduled on a daily basis is needed for shippers to monitor capacity availability. With respect to the information on outages, while some pipelines currently post such information on outages, it is not currently a Commission requirement. Requiring pipelines to provide information on outages will enable shippers to better make decisions about their use of capacity because they will know whether the available capacity will be reduced on a particular day. Such information will also help in monitoring capacity withholding by revealing reasons for reductions in scheduled quantities.

These reporting requirements for available capacity are the same reporting requirements proposed in the NOPR. Some commenters, however, object to the additional reporting requirements on capacity availability,[254] while others appear to object to the continuation of the existing reporting requirements on operationally available capacity.[255]

Specifically, several pipelines argue that it will be difficult to comply with the additional requirements for posting design and scheduled capacity because for some pipeline configurations, and for particular pipeline segments, capacity is not fixed, but is dependent on operating conditions or operational strategies that may vary depending on requests for service. For instance, Coastal states that on web-like systems, the design capacity at particular points or segments is a function of the usage of other parts of the system, which varies constantly, particularly with the implementation of three intraday nomination cycles.[256] CMS Pipelines state that they do not have the computer and technology capability to provide the additional capacity information in real time. For example, they assert that field outages that affect capacity are not conveyed immediately to the EBB. CMS Pipelines also add that human intervention, judgment and decisionmaking can all affect the determination of available capacity.

More generally, CNG asserts that it cannot provide detailed information about available capacity over particular paths or segments, or in particular storage facilities, and lists a number of variables that influence the capacity available at any given moment.[257] CNG argues that because such variables determine the level of available capacity at any given time, it is meaningless for pipelines to report calculated capacities throughout its system. In addition, some commenters appear to suggest that the Commission limit the existing reporting of operationally available capacity to key points, such as interconnections, market hubs, and points that are frequently constrained.[258]

In contrast, a few commenters argue that the Commission should require pipelines to post more information on available capacity than was proposed.[259] For example, Dynegy maintains that shippers need information on design capacity, operationally available capacity, and actual and maximum flows, not only at all receipt and delivery points and on the mainline, but also at each point of

[250] Comments of Dynegy, Indicated Shippers, and PUC of Ohio.

[251] Comments of Williston Basin, Williams, and Tejas.

[252] 18 CFR 161.1. However, as provided in § 161.1, the marketing affiliate reporting requirements in part 161 apply not only to marketing affiliates, but also to pipeline sales operating units.

[253] 18 CFR 284.8(b)(3); 18 CFR 284.10(b)(1)(iv)(1997), Electronic Delivery Mechanism Related Standards 4.3.6; 18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.13.

[254] Comments of Coastal, CMS Pieplines, and Williams.

[255] Comments of CNG, and Peoples.

[256] Comments of Coastal at 93.

[257] Comments of CNG at 33–34.

[258] Comments of Peoples at 15 and Philadelphia Gas Works at 1.

[259] *E.g.*, Comments of Dynegy at 1–7.

constraint and segment. Dynegy also asserts that shippers need information on unsubscribed capacity and capacity under expiring or terminating agreements, and that they need such information at least 18 months in advance of when the capacity will become available. Similarly, Industrials request that the Commission require pipelines to post on the Internet detailed, rolling information regarding capacity becoming available over the next 18 months. Exxon, also, requests that the Commission require the posting of capacity under contracts that are due to expire in four months.

Several clarifications of this reporting requirement are needed to respond to the commenters' concerns. First, as stated above, the Commission's current regulations require pipelines to post operationally available capacity at receipt and delivery points, on the mainline, and in storage fields.[260] The Commission did not propose in the NOPR to change these requirements, and in this rule is not modifying such requirements. Pipelines have been able to comply with the regulations requiring the reporting of operationally available capacity, and thus, there is no reason to modify such requirements. Pipelines must continue to report available capacity as required in the Commission's existing regulations, which necessarily involves pipelines taking into account operational variables.

Second, pipelines have information on the amount of capacity scheduled at each point or segment, and, therefore, should be able to post that data on a daily basis. In fact, GISB Standard 1.3.2 requires pipelines to inform shippers of scheduled quantities. However, the Commission is not requiring that pipelines post scheduled capacity at all points *and* segments. If, as some pipelines argue, it is difficult for them to provide scheduled capacity on segments of their systems, they need only post scheduled capacity for their receipt and delivery points. The Commission is requiring the posting of scheduled capacity for either receipt and delivery points, or segments, whichever makes the most sense for a particular pipeline system.

Third, the Commission understands that it may be difficult for some pipelines to calculate the total design capacity of each point or segment on its system, due to operational or usage variables or particular system configurations. In those instances, pipelines must post design capacities for the most common operating conditions of their systems, such as peak period or off-peak period. In addition, the Commission clarifies that the posting of the total design capacity of the points or segments is not a daily posting requirement. Rather, pipelines must update this information from time-to-time as changes in design capacity occur.

Finally, the Commission does not find it necessary to require pipelines to provide even more detailed information on design capacity and operationally available capacity than the Commission is requiring in this rule, or to provide information on the future availability of capacity. Currently, shippers can obtain information on firm capacity that will be coming available in the future by reviewing the Index of Customers, which includes contract expiration dates. With respect to requiring more detailed capacity information, including flow data, at not just receipt and delivery points, but also at constraint points and segments, as Dynegy suggests, the Commission finds that the reporting of scheduled capacity at each receipt and delivery point is sufficient, and that shippers should be aware of which points or segments are constrained.

D. Coordination With GISB Standardization Efforts

The Commission recognizes that pipelines have just completed preparing their systems for the Year 2000 and are in the process of making changes to comply with Commission requirements to transfer data from Electronic Bulletin Boards to Internet web sites by June 1, 2000. The Commission, therefore, will require pipelines to implement the new data reporting requirements by September 1, 2000.

Pipelines are required to provide much of the information in the revised reporting requirements by posting the information on their Internet web sites and in downloadable file formats. The industry, through the Gas Industry Standards Board (GISB), has developed, and is in the process of improving, standards for providing currently required information both on pipeline web sites and through downloadable file formats, using Electronic Data Interchange ASCX12 (EDI) formats.[261] GISB also is examining whether to provide such downloads in flat ASCII file formats as well. GISB already has developed standards and the pipelines are posting some of the information in the revised regulations, such as capacity release information and operationally available capacity. Pipelines will continue to post that information pursuant to the GISB standards.

Ultimately, GISB needs to develop standards for the new reporting requirements (including pipeline firm and interruptible transportation transactions, design capacity, constraint information, and scheduled capacity) both for the presentation of the information on pipeline web sites and the provision of the information in Electronic Data Interchange ASCX12 (EDI) or ASCII file formats.

The Commission encourages GISB to try and to complete the process of standardization in time for the September 1, 2000 implementation date. But the Commission recognizes that such a schedule may be ambitious given the other changes to electronic communication GISB is now in the process of developing. Because the provision of the new information is important both to improve market transparency and for monitoring, the Commission will require pipelines to provide this information in non-standardized formats in the event GISB is unable to develop the datasets in time for September 1, 2000 implementation. Pipelines, however, will not have to develop individual EDI file formats for the information during the period when GISB is developing the standards. Pipelines only will have to post the information on their web sites and provide flat ASCII file downloads for the relevant information. In addition, the Commission will issue in the near future revisions to its instruction for the electronic filing of the Index of Customers report to accommodate the new information required by this rule.

The revised reporting requirements also call for the provision of both shipper names and a unique numeric identifier for each shipper. These requirements apply to both the Internet postings and the electronic file downloads. This requirement represents a change from the current practice under the GISB standards of providing only numeric identification in electronic file downloads. The industry, through GISB, has chosen to use the numbers developed by Dun & Bradstreet (D&B) as the numeric identifier for shipper names (DUNS numbers). Where pipelines use numeric identifiers in electronic communications without the accompanying shipper name, the Commission has required pipelines to provide a table that cross-references

[260] 18 CFR 284.8(b)(3); 18 CFR 284.10(b)(1)(iv)(1997), Electronic Delivery Mechanism Related Standards 4.3.6; 18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.13.

[261] *See* Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587–I, 63 FR 53565, 53569–75 (Oct. 6, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,067, at 30,737–46 (Sept. 29, 1998).

shipper names with the applicable DUNS numbers.[262] GISB has worked out an arrangement with D&B to verify the accuracy of the DUNS numbers used by pipelines and to post a cross-reference table on the GISB web site.

The Commission finds that the use of numeric identifiers for shippers is of great value, particularly for electronic processing, because electronic identifiers make electronic processing easier and eliminate confusion that may be introduced through the use of names alone, such as different spellings or abbreviations for the same entity. The Commission also appreciates GISB's agreement with DUNs to provide for verification of pipeline DUNS numbers, because that improves the accuracy of these numbers. The Commission, therefore, is requiring that all pipelines which have not yet had their DUNS numbers verified by D&B submit their numbers to D&B for verification.

The Commission, however, is concerned with the current GISB standards which require the reporting of DUNS numbers only for electronic file downloads and do not contain a field for shipper names. While the GISB cross-reference table is extremely useful for associating the names and DUNS numbers, the Commission has noticed that with respect to almost all pipelines, the cross-reference table generally omits a small, but not insignificant, percentage of shippers, who are presumably new shippers on the system. One solution for this problem would be to require pipelines to make immediate updates to the cross-reference table when new shipper names are added. But it would appear difficult and burdensome for the pipelines to institute procedures to ensure that whenever a new shipper is added to their systems, they remember to inform GISB of the addition to the cross-reference table. The need for such frequent changes also will pose administrative burdens for GISB, as well as make Commission monitoring of pipeline compliance more burdensome.

Due to the difficulties and burdens of maintaining an accurate cross-reference table, the Commission has determined instead to require pipelines to provide both a name and a number in both their Internet postings and downloadable files. When GISB next updates its standards for electronic file downloads, it needs to include fields so that pipelines can include both the shipper name and the DUNS numbers in the electronic file. Until those changes occur, the pipelines must continue to use the cross-reference table and to update their information on that table at monthly intervals.

[262] 18 CFR 284.10(c)(3)(iii) (existing regulations) 18 CFR 284.13(c)(3)(iii) (revised regulations).

V. Other Pipeline Service Offerings

In the NOPR, the Commission sought comment on whether, in light of the changes occurring in the natural gas market, the Commission should revise or eliminate the right-of-first refusal (ROFR)[263] and revise its current regulations with respect to non-conforming service agreements[264] to permit pre-approval of negotiated terms and conditions of service between pipelines and shippers. As discussed below, the Commission finds that some narrowing of the ROFR is needed so that it interferes as little as possible with the efficiency of the market while continuing to protect captive customers. As discussed earlier, the Commission has determined that further inquiry into the question of pre-approved negotiated terms and conditions is needed. In light of the decision not to move forward with pre-approved negotiated terms and conditions, the Commission will discuss several aspects of this decision, including its policies regarding non-conforming service agreements and the interrelation between negotiated terms and conditions of service and negotiated rates.

A. Right of First Refusal

In the NOPR, the Commission considered whether any changes to the right of first refusal and its five-year term matching cap are appropriate in light of the changes that have occurred in the marketplace since implementation of Order No. 636. Upon consideration of the comments, the Commission has decided to retain the right of first refusal with the five-year term matching cap, but narrow the scope of the right. In the future, the right of first refusal will apply only to maximum rate contracts for 12 or more consecutive months of service. Because the right of first refusal will apply only to maximum rate contracts, there will be no regulatory right of first refusal for contracts containing negotiated rates. This modification is consistent with the purpose of the right of first refusal to protect the historical service of long-term captive customers. This limitation on the right of first refusal strikes the appropriate balance between the need to protect captive customers and the need to balance the risks between pipelines and existing shippers.

[263] 18 CFR 284.221(d)(1999).

[264] 18 CFR 154.1(d) and 154.112(b)(1999).

1. Background

In Order No. 636, the Commission amended its regulations to permit pre-granted abandonment of transportation contracts. In order to protect captive customers from the pipelines' monopoly power, and permit them to continue to receive the historical service upon which they had relied, the Commission conditioned pre-granted abandonment on the right of first refusal.[265] Pursuant to the right of first refusal, an existing shipper with a long-term firm contract can retain its service from the pipeline by matching the rate and length of service of a competing bid for that service. The rate is capped by the pipeline's maximum tariff rate, and the requirement that the existing shipper must match the length of the contract term of a competing bid is limited to a contract length of five years.[266] In *UDC* v. *FERC,*[267] the court found that the right of first refusal mechanism with a cap on the contract length was an adequate means of protecting customers from pipelines' market power.

In the NOPR, the Commission explained that increased competition in the commodity and capacity markets since Order No. 636, affords greater protection to shippers from monopoly power. Further the Commission observed that since restructuring, some small LDCs no longer have to hold capacity on the pipeline in order to receive gas, and that, in fact, many LDCs have chosen not to hold capacity on pipelines. The Commission suggested that these changes could indicate that a right of first refusal is no longer necessary to protect shippers.

The Commission was also concerned that the right of first refusal with the five-year matching cap provides a disincentive for an existing shipper to enter into a contract of more than five years, and results in a bias toward short-term contracts. Therefore, the Commission proposed in the NOPR to eliminate the term matching cap from the right of first refusal. In addition, the Commission stated that it would consider other options for modifying the right of first refusal, including whether it should be eliminated in its entirety, whether the length of the term matching

[265] 18 CFR 284.221(d) (1999).

[266] In Order No. 636–A, the Commission adopted a term matching cap of 20 years. In *UDC* v. *FERC,* the court approved the basic right of first refusal and approved the concept of a term matching cap, but found that the Commission had not adequately explained the 20-year cap. In Order No. 636–C, the Commission concluded that a matching cap of 5 years was appropriate given the trend to shorter contracts.

[267] 88 F.3d 1105, 1139 (D.C. Cir. 1996), *cert. denied,* 117 S. Ct. 1723 (1997).

cap should be changed, and whether a right of first refusal should be a matter of negotiation between the parties.

In the comments on the NOPR, the proposal to eliminate the five-year term matching cap was generally opposed by shippers and shipper groups,[268] as well as by several state agencies.[269] These commenters argue that, contrary to the Commission's assertions in the NOPR, increased competition does not afford customers sufficient protection from the pipelines' market power. They state that the Commission itself acknowledges that pipelines still possess market power in the long-term market where the right of first refusal is applicable, and for that reason did not propose to eliminate rate regulation in the long-term market. They argue that removing the five-year cap would require the shipper to commit to capacity for a term well beyond what would be prudent in light of the risks of doing business in the evolving market place. In addition, they argue that eliminating the right of first refusal or the five-year cap is not legally justified in light of the court's decision in *UDC* v. *FERC.*

Several of these commenters argue that the Commission should strengthen the right of first refusal by reducing the term-matching cap.[270] For example, ConEd argues that a one-year cap is appropriate because LDCs must be able to assemble economically priced packages of transportation capacity without putting reliability at risk or needlessly creating stranded costs. Several parties, including Brooklyn Union/Keyspan and Consolidated Edison of New York, ask the Commission to enhance the right of first refusal by clarifying that an existing shipper may exercise its right of first refusal as to a geographic portion of the existing contract.

On the other hand, the pipelines [271] argue that the right of first refusal should be eliminated because it no longer serves any purpose since increased competition affords customers protection from monopoly power. If the right of first refusal is not eliminated in its entirety, they argue that at a minimum, the term-matching cap should be removed. These parties assert that the right of first refusal reduces competition and distorts the competitive environment by denying the pipeline and a willing third party the right to contract for longer than the cap period. Further, they argue that the right of first refusal places disproportionate risks on the pipelines because the pipeline must bear the risk of standing ready to serve the existing shipper indefinitely, while the shipper has no such obligation.

2. Discussion

The purpose of the right of first refusal is to protect captive long-term customers from the pipelines' exercise of monopoly power.[272] It is based on the customer's reliance on the pipeline for its historical service.[273] It protects existing customers by providing them with the right to continue their existing service by matching the highest competitive bid for the service, up to the maximum rate and up to a period of five years. At the same time, by requiring that existing customers match competitive bids, the right of first refusal recognizes the role of market forces in determining contract price and term.

As markets become more competitive, and the secondary market continues to develop, it may become unnecessary to protect any customer with a right of first refusal. However, upon consideration of the comments, the Commission has determined that it cannot at this time reach the conclusion that all long-term shippers have sufficient competitive options to warrant elimination of the right of first refusal in its entirety. The Commission, therefore, will retain a right of first refusal and will retain, for the present, the five-year matching cap. However, the right of first refusal will apply in the future only to maximum rate contracts for 12 or more consecutive months of service.

Limiting the right of first refusal to maximum rate contracts of 12 or more consecutive months of service is consistent with its original purpose to protect long-term captive customers from the pipeline's monopoly power. If the customer is truly captive and has no alternatives for service, it is likely that its contract will be at the maximum rate. Shippers that are not captive customers and have alternatives in the marketplace do not need the protection of the right of first refusal.

In addition, the ROFR will apply only when the contract provides for 12 or more consecutive months of service. This is a different result than the Commission reached in *North American Energy Conservation, Inc.* v. *CNG Transmission Corp.*[274] under the current regulations, which provide that the right of first refusal applies to ''a contract with a term of one year or more.'' [275] In that case, the Commission concluded that the right of first refusal applied to a contract with a duration of 15 months that provided for two noncontinuous periods of seasonal service, each one of which was for less than 12 months. The Commission held that, under the current regulations, it was the term of the contract rather than the term of the service that determined the applicability of the right of first refusal. In the future, the right of first refusal will apply only when the contract provides for at least 12 consecutive months of service; it will be the term of the service rather than the term of the contract that will determine the applicability of the right of first refusal. Again, this is consistent with the purpose of the right of first refusal to protect long-term captive customers. Seasonal service is short-term service, even if the contract providing for the service is of a duration of more than a year, and the right of first refusal is intended to protect long-term customers.

With this modification captive customers still will be able to continue to receive their historical service as long as they pay the maximum rate. And, the pipeline is not disadvantaged by the right of first refusal if the contract is at the maximum rate. However, if a shipper has sufficient alternatives that it can negotiate a rate below the just and reasonable rate, it should not have the protection afforded by the right of first refusal. In these circumstances, the pipeline should be able to negotiate with other interested shippers. This limitation on the right of first refusal strikes the appropriate balance between the need to protect captive customers and the need to better balance the risks between the shipper and the pipeline.

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[268] For example, AGA, APGA, Allied Signal, American Forest & Paper Assoc., Amoco Energy Trading Co., *et al.,* Atlanta Gas Light, Brooklyn Union Gas Co. and Keyspan Gas, Colorado Springs Utilities, Columbia LDCs, Consolidated Edison Co. of New York, the Fertilizer Institute, Florida Cities, FPL Group, and New England Gas Distributors.

[269] *E.g.,* Illinois Commerce Commission, Minnesota Department of Public Service, Pennsylvania Office of Consumer Advocate and Pennsylvania Public Utility Commission, New York Public Service Commission, Wisconsin Public Service Commission, Ohio Public Utilities Commission.

[270] For example, Brooklyn Union and Keyspan Gas, Consolidated Edison Co. of New York, and New England Gas Distributors argued that the term matching cap should be reduced to one year. The Pennsylvania Office of Consumer Advocate and the Pennsylvania Public Utility Commission suggested shortening the matching cap to two years, and revisiting the issue periodically. PSE&G suggested shortening the term to 2–3 years. AGA also suggested shortening the term.

[271] *E.g.,* INGAA, Williams, Tejas, Williston, Enron Interstate Pipelines.

[272] UDC v. FERC, 88 F.3d 1105, 1140 (D.C. Cir. 1996), *cert denied,* 117 S. Ct. 1723 (1997); Order No. 636–C, 78 FERC ¶ 61,186 at 61,772–773 (1997).

[273] *Id.*

[274] 88 FERC ¶ 61,255, *reh'g,* 89 FERC ¶ 61,122 (1999).

[275] 18 CFR 284.221(d)(2).

The maximum rate that the existing shipper must meet in order to exercise its right of first refusal may be higher than its current rate. The Commission's regulations provide that a shipper whose contract is expiring is entitled to renew that contract by matching the highest bid up to the maximum rate,[276] but, there is nothing in the right of first refusal that guarantees that the maximum rate will remain the same. The Commission recognized in its recent Policy Statement concerning Certification of New Interstate Natural Gas Pipeline Facilities (Certificate Policy Statement),[277] that a shipper exercising its ROFR could be required to match a bid up to a maximum rate higher than the historic maximum rate applicable to its capacity in certain limited circumstances: when a pipeline expansion has been completed and an incremental rate exists on the system; the pipeline is fully subscribed; and there is a competing bid above the maximum pre-expansion rate applicable to existing shippers.[278]

The existing customers should not be required to subsidize expansion projects that are implemented during the term of their contracts. While their contracts are in effect, it would be inequitable to raise their rates to include the costs of expansion projects that will not be used to provide them with service. Thus, it is logical to price the new project incrementally and without subsidies from the rates of the existing shippers. However, when the existing customer's contract expires, the existing customer should be treated similarly to new customers for pipeline capacity, who face rates higher than the pre-expansion historic rate.[279] Under the policy conditions established by the Commission (fully subscribed expansion, at least one bid above the existing rate, and a rate mechanism established in advance), there would be insufficient capacity to satisfy all the demands for service on the system. When insufficient capacity exists, a higher matching rate will improve the efficiency and fairness of capacity allocation, within the limits imposed by cost-of-service ratemaking, by allowing new shippers who place greater value on obtaining capacity than the existing shipper to better compete for the limited capacity that is available.

The logic for using a higher matching rate would not apply if the system were not fully utilized, and in those circumstances, the existing customer could exercise its right of first refusal by agreeing to pay the historic maximum rate. This protects an existing captive customer against the exercise of market power by the pipeline because the pipeline cannot insist on the shipper paying a higher rate unless its expansion is fully subscribed and there is another bid for capacity at a rate above the historic maximum rate charged the existing shipper. These conditions ensure that the pipeline is unable to use its market power over captive customers to withhold capacity from the market to raise price. Price will exceed the current maximum rate charged the existing shipper only when a higher price is needed to allocate scarce capacity.

As the Commission explains in the Certificate Policy Statement,[280] to adjust the maximum rate applicable to shippers exercising their ROFR in these circumstances, the pipeline would have to establish a mechanism for reallocating costs between the historic and incremental rates so all rates remain within the pipeline's cost-of-service.[281] The mechanism can be established either through a general section 4 rate case or through the filing of *pro forma* tariff sheets which would provide the Commission and the parties with an opportunity to review the proposal prior to implementation. The Commission would review the proposed mechanism to determine how well it achieves the following objectives: capacity pricing that permits as efficient an allocation of capacity as is possible under cost-of-service ratemaking; protection against the exercise of market power by the pipeline (through withholding of capacity, for example, or the potential for skewed bidding); protection against the pipeline's overrecovery of its revenue requirement; and equity of treatment between shippers with expiring contracts and new shippers to the system seeking comparable service.

Application of this approach could lead to rates for shippers exercising their ROFR that are higher than their existing vintaged rate. But this will occur only if the preconditions are met—the pipeline is full and there is a competing bid higher than the pre-expansion rate so that a higher rate is needed to allocate available capacity—and the Commission has accepted the pipeline's mechanism for determining rates as just and reasonable.

In the Certificate Policy Statement, the Commission explained that it is important for the rates for the new capacity to send the correct price signals so that shippers can decide whether the new capacity is really needed. As the Commission further explains in its clarification order in that proceeding, there is tension between sending efficient pricing signals to expansion customers and to customers whose contracts are expiring, while remaining within the pipeline's revenue requirement. There may be a number of ways to recompute rates to effectively balance these interests. The Appendix to that order provides two examples of potential approaches to the recomputation of rates, one in which the expansion rate is recomputed to establish the maximum matching rate and the other where the system average rate is used as the matching rate. Under these approaches, as contracts of existing shippers expire, the costs and contract demand represented by these contracts are reallocated between the existing and expansion service without changing the pipeline's overall revenue requirement.

The Commission will not change the length of the term matching cap at this time. The Commission concluded in Order No. 636–C that a five-year cap was appropriate given the evidence in that record of industry trends in contract length.[282] The record there showed that five years was the median length of long-term contracts entered into since January 1, 1995.[283] None of the commenters presented evidence to support the conclusion that a five year contract is atypical in the current market.[284]

Further, the Commission will not enhance the right of first refusal by holding that it can be exercised for a

[276] 18 CFR 284.221(d)(1999).

[277] Docket No. PL99–3–000, FERC ¶ 61,277 (1999).

[278] Under this procedure, the pipeline cannot require the existing shipper to pay a rate higher than that of competing bidder. For example, if the historic maximum rate is $1/MMBtu, the maximum rate the existing shipper has to match is $2/MMBtu, and the competing bid is $1.50/MMBtu, the pipeline must sell the capacity to the existing shipper if it is willing to match the $1.50 bid.

[279] *Cf.* PG&E Gas Transmission, Northwest Corporation, 82 FERC ¶ 61,289, at 62,124–26 (1998) *aff'd Washington Water Power Co.* v. *FERC*, No. 98–1245 (D.C. Cir. Feb. 1, 2000) (for permanent releases of capacity taking place after an expansion, the replacement shippers should pay the same rate as the expansion shippers).

[280] Docket No. PL 99–3000, Order Clarifying Statement of Policy

[281] *Cf.* Viking Gas Transmission Company, 89 FERC ¶ 61,204 (1999) (rejecting tariff filing to raise matching rates under a ROFR where, among other things, the filing did not readjust existing and expansion rates).

[282] Order No. 636–C, 78 FERC at 61,773–74.

[283] 78 FERC at 61,774.

[284] Several commenters suggested that the Commission should take additional evidence on current contract length and reduce the length of the cap if that evidence warrants. See, *e.g.*, comments of New England Gas Distributors. The Commission could undertake this analysis of industry trends in a future proceeding, but will retain the five-year cap for the present.

geographic portion of the existing contract, as requested by several commenters. The purpose of the right of first refusal is to protect the captive customer's historical service, and therefore it should apply only when the existing shipper is seeking to contract for its historical capacity. The right of first refusal is a limited right and it was never intended to permit shippers to increase or change their service.[285] It is intended to be a means of defense against pipeline market power, not a mechanism to award an existing shipper a preference over a new shipper for different service.

In Order No. 636–B, the Commission clarified that the right of first refusal permits the existing capacity holder to elect to retain a volumetric portion of its capacity subject to the right of first refusal, and permit the pipeline's pregranted abandonment to apply to the remainder of the service.[286] The Commission has explained that this is intended to ensure against the inefficient or unnecessary retention of capacity at the expiration of the contract.[287] Unbundling has reduced the role of LDCs in providing transportation service. In 1998, over 80 percent of industrial users purchased their capacity directly from the pipeline or from marketers rather than from an LDC.[288] Allowing LDCs to decrease their contractual volumes when they exercise the right of first refusal makes this capacity available to industrials and marketers. Thus, under the right of first refusal, if the LDC's market shrinks because its former sales customers are purchasing their own gas in the wholesale market, the LDC can reduce the volumes it has under contract.

However, Order No. 636 did not include within the right of first refusal the option to contract for a geographic portion of the historical capacity, and permitting an existing shipper to exercise its right of first refusal for a geographic portion of its historical service is not consistent with its purpose. A shipper that can terminate a geographic portion of its historical service must have alternatives in the marketplace that can substitute for its historical service, and therefore is not a captive customer that requires the protection of the right of first refusal. In its comments, Con Ed gives an example of a shipper that has a contract for service from the pipeline's production area to points in the market area, and argues that the shipper should be able to retain its right of first refusal to capacity in the market area without being required to retain capacity in the production area. In this example, the shipper clearly has competitive options for transporting its gas and does not need the protection of a right of first refusal to protect its historical service.

Moreover, permitting the exercise of the right of first refusal for a geographic portion of the historical capacity could leave the capacity unused and thus burden the pipeline and its other customers with the cost of this unused capacity. This is the significant distinction between permitting a shipper to exercise its right of first refusal for a portion of the contractual volumes and permitting a shipper to exercise its right of first refusal for less than the full length of haul. With the development of the pipeline grid, the need to hold capacity to access traditional supply areas has diminished and thus there is more likelihood that reductions in geographic capacity will lead to unused capacity on some segments. In contrast, exercise of the right of first refusal for less than the full contractual volume is unlikely to have the same impact on the pipeline and its shippers because with retail unbundling that capacity is likely to be contracted to move gas to the end-users previously served by the LDC. Gas consumption has not been shrinking, rather the contracting patterns have been changing.

Therefore, maintaining the Commission's current policy and not expanding the right of first refusal beyond its original scope as set forth in Order No. 636 strikes the appropriate balance between protecting the historic service of the captive customer and not burdening the pipeline and its other customers with unused capacity.

The Commission's ruling that a shipper cannot exercise its right of first refusal for a portion of its length of haul is also consistent with the rationale of the court's decision in *Municipal Defense Group* v. *FERC*.[289] In that decision, the court upheld the Commission's approval in *Texas Eastern Transmission Corp.,*[290] of a proposal by the pipeline to award new capacity on the basis of a net present value determination. The Commission held that while the small customers had special treatment for their existing service,[291] they must compete on an equal basis with other customers for additional capacity. The court agreed, and stated that there was no reason to extend the special treatment given to small customers beyond their existing service in order to enable them to increase their capacity at a subsidized rate. Similarly, there is no basis for permitting customers with a right of first refusal to use that right to obtain an advantage over other customers in seeking to change their service to a shorter haul.

Several parties ask the Commission to clarify that shippers who have rollover or evergreen clauses in their contracts have the right to terminate a volumetric portion of that contract and exercise their right of first refusal with regard to the remaining portion of the contract.[292] These parties state that clarification is necessary because certain pipelines have taken the position that the right of first refusal protects only shippers whose contracts do not contain rollover or evergreen clauses. The commenters state that these pipelines have concluded that while the right of first refusal permits a customer to renew its contract for less that its full MDQ, this right does not extend to a customer with a rollover contract. The commenters state that clarification of this issue is necessary at this time because many LDC long-term contracts will be expiring over the next few years.

There are two possible sources of a shipper's right of first refusal. First, shippers have the right of first refusal as provided in the Commission's regulations. Thus, all shippers with a qualifying contract, (*i.e.*, a contract of 12 months or more and, in the future, at the maximum rate), can continue to receive their service from the pipeline by matching the rate, up to the maximum rate, and the length of service, up to a period of five years, of a competing bid for that service. Under the right of first refusal conveyed by § 284.221(d) of the regulations, shippers always have this regulatory right of first refusal, regardless of the provisions of their contract.

Second, a pipeline and its shippers may agree to include a right of first refusal roll-over or evergreen clause in their contracts. If a contractual right of first refusal, rollover or evergreen clause

[285] As the Commission stated in Williams Natural Gas company, 65 FERC ¶ 61,221 at 62,013 (1993), "the character of the service being provided under the expiring contract cannot be changed through use of the right of first refusal."

[286] Order No. 636–B at 30,634–35.

[287] Williams Natural Gas Co., 83 FERC ¶ 61,052 at 61,299 (1998).

[288] Energy Information Administration, Natural Gas Annual 1998, 35–37, 39, 41 (October 1999).

[289] 170 F.3d 197 (D.C. Cir. 1999).

[290] 79 FERC ¶ 61.258 (1997), *reh'g*, 80 FERC ¶ 61,270 (1997).

[291] Small customers received a discounted rate on the pipeline pursuant to a settlement in the pipeline's Order No. 636 proceeding, and argued that the net present value method would be prejudicial to them because the value of their bids would be less that the value of bids of larger customers paying a higher rate.

[292] See comments of AGA and Con Ed.

would allow the shipper to exercise a right of first refusal in situations where the regulatory right would not apply, the shipper may rely on its contractual rights in lieu of the regulatory right of first refusal. The choice is for the shipper to make. But, the shipper always has, at a minimum, the regulatory right of first refusal. As the Commission recently stated, ''a ROFR is a regulatory right that may achieve the same purpose as a contractual rollover, but it is a right guaranteed by the regulations and not dependent on the contract.'' [293] Under the right of first refusal in § 284.221(d), which is an exercise of the Commission's abandonment authority under NGA Section 7(b), a contractual right of first refusal may broaden the regulatory right of first refusal, but it may not narrow it.

The regulatory right of first refusal includes the right of the existing shipper to elect to retain a volumetric portion of its capacity subject to the right of first refusal, and permit the pipeline's pregranted abandonment to apply to the remainder of the service.[294] Therefore, the Commission clarifies that a customer with a contract that qualifies for a regulatory right of first refusal may exercise that regulatory right for a volumetric portion of the capacity, regardless of whether the contract contains a rollover or evergreen clause.

Existing discounted long-term contracts that are now subject to the right of first refusal will be grandfathered, and the right of first refusal will apply at their expiration. However, the new rate limitation will apply to any of the contracts that are re-executed and, therefore, the right of first refusal will not apply if the re-executed contracts are not at the maximum rate. The grandfathering of current contracts gives all shippers notice of the new limitation, and the opportunity to re-execute their current contracts in view of this change. Further, the provisions of the pipelines' current tariffs will continue to govern the right of first refusal process until the pipeline files revised tariff sheets to limit the right of first refusal consistent with this discussion.

B. Negotiated Terms and Conditions of Service

In the Commission's policy statement on Alternatives to Traditional Cost-of-Service Ratemaking,[295] the Commission set forth its policy permitting pipelines the flexibility to negotiate rates so long as the shipper continued to have the option of choosing recourse service from the pipeline. The availability of a recourse service at just and reasonable rates was considered to provide reasonable protection against the exercise of market power. But the Commission at the time expressed concern about whether to permit individual negotiation of terms and conditions of service and requested further comment on whether such flexibility should be permitted. In the NOPR, the Commission proposed to permit pipelines to file tariff provisions providing for pre-approved authority to negotiate terms and conditions of service without making a separate tariff filing, so long as the pipeline adhered to a series of requirements intended to protect against degradation of recourse service.

There was a significant split among the commenters on this issue. Pipelines and LDCs strongly supported the implementation of negotiated terms and conditions of service as ways in which pipelines could attract new customers, particularly gas fired electric generation and industrial customers.[296] INGAA asserts, for instance, that gas fired electric generation has service requirements that differ from those provided in typical tariff-based services. AGA similarly asserts that permitting negotiation of services will permit pipelines to tailor services to fit the different circumstances of individual customers. Those supporting pre-approval for negotiated terms and conditions maintain that the Commission can provide adequate oversight to avoid undue discrimination, degradation of recourse service, and reduced competition.

Those on the other side were equally vociferous in opposing pre-approval for negotiated terms and conditions of service.[297] These parties argue that the need for negotiated terms and conditions has not been demonstrated, because open access tariffs have been successful in serving all types of customers, and that even without pre-approval for negotiated terms and conditions of service, the electric generation market has shown the greatest growth of any natural gas consumption segment. These parties argue that allowing pipelines to negotiate terms and conditions of service gives rise to significant dangers to competitive markets, including the danger of discrimination in pricing, timing, and terms of service and that negotiated terms and conditions exacerbates affiliate advantages, permits pipelines to degrade recourse services, and harms the secondary market which depends on the sale of a uniform product. Moreover, they argue that the protections proposed by the Commission to avoid problems created by negotiated terms and conditions of service raise problems of their own and will not prevent the degradation of recourse service. These parties assert that instead of permitting negotiated terms and conditions, the Commission should continue to enhance the flexibility of tariff services.

The Commission has determined not to provide pipelines, at this time, with authority to file for pre-approval of the right to negotiate terms and conditions of service with individual customers. Given the changes occurring in the marketplace, it is not yet clear that pre-approval for negotiated terms and conditions is necessary. Although pipelines and some gas fired generators support allowing negotiation of terms and conditions of service that will directly address the generators' service needs,[298] other generators are not convinced that such negotiation flexibility is necessary or that it outweighs the risks of discrimination to those not receiving the negotiated services.[299] Pipelines also have been able to create open access tariff-based services with enhanced flexibility for scheduling and handling imbalances without having to negotiate terms and conditions of service with individual shippers.[300] Indeed, in this rule, the Commission is requiring that pipelines provide imbalance management services that will better enable all customers to deal with the potential risks of imbalance penalties.

The negotiation of terms and conditions of service further is directly related to the question whether the Commission needs to revise fundamental aspects of its regulatory policy to accommodate a dual market

[293] *North American Energy Conservation, Inc.* v. *CNG Transmission,* 88 FERC ¶ 61,255 at 61,809 (1999).

[294] Order No. 636–A, FERC Stats. & Regs. (1991–1996) ¶ 30,950 at 30,635 (1992).

[295] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, 61 FR 4633 (Feb. 7, 1996), 74 FERC 61,076 (1996).

[296] *See* Comments of AGAI, INGAA, Southern Natural, Williams, Coastal Companies, Enron Capital and Trade.

[297] *See* Comments of Amoco Energy Trading, Arkansas Gas Consumers, Dynegy, Indicated Shippers, NGSA, Process Gas Consumers Group, PSC Wisconsin.

[298] *See* Comments of Sithe, Sempra Energy, EEI.

[299] *See* Comments of Midland, Florida Cities, Dynegy, FPL.

[300] *See* Reliant Energy Gas Transmission Company, 87 FERC ¶ 61,228 (1999) (hourly flexibility service designed to meet needs of gas generators); Mojave Pipeline Company, 79 FERC ¶ 61,347 (1997); Colorado Interstate Gas Company, 83 FERC ¶ 61,273 (1998) (parking and loan service).

structure in which some shippers with sufficient alternatives and negotiating leverage want to negotiate rates and terms and conditions of service while other shippers remain captive, still subject to the pipeline's market power and to undue discrimination. The development of a two-track regulatory model, as discussed earlier, requires further study of the interrelation between various aspects of Commission regulatory policy, such as whether rates should continue to support pipeline revenue requirements and how rates should be designed in a dual market to protect captive customers.

In light of the questions about the need for and effects of negotiated terms and conditions and the interrelation between negotiated terms and conditions of service and other long-term regulatory issues that were not the subject of this proceeding, the Commission has decided not to move forward at this time to provide pipelines with pre-approval to negotiate terms and conditions of service. To the extent that pipelines, in certain circumstances, find that they are unable to file an open access tariff-based service to accommodate particular needs, and that individual negotiation is the only feasible method of providing service to a particular shipper, the pipeline is still permitted under the Commission's regulations to file a non-conforming contract with the Commission.[301] Such a filing has to be made at least 30 days prior to the proposed effective date,[302] which gives other parties and the Commission the opportunity to review all aspects of the non-conforming contract to determine whether the contract is unduly discriminatory or preferential or would negatively affect the service provided to other shippers.

The determination not to move forward at this juncture with pre-approved negotiated terms and conditions of service raises the question of how the Commission will differentiate between negotiated rates, permissible under the Commission's negotiated rates policy,[303] and negotiated terms and conditions of service. While formulating a generic definition of rate applicable to all potential situations is not possible, the Commission generally considers negotiated terms and conditions to be related to operational conditions of transportation service. A negotiated rate would not include conditions or activities related to the transportation of gas on the pipeline, such as scheduling, imbalances, or operational obligations, such as OFOs. By contrast, negotiated rate agreements can include the price, the term of service, the receipt and delivery points, and the quantity.

[301] 18 CFR 154.1(d).

[302] 18 CFR 154.207.

[303] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, and Regulation of Negotiated Transportation Services of Natural Gas Pipelines 61 FR 4633 (Feb. 7, 1996), 74 FERC 61,076 (1996).

VI. Reorganization of Part 284 Regulations

The Commission is reorganizing certain portions of its part 284 regulations to better reflect the nature of services in the short-term market and to consolidate its Part 284 reporting and filing requirements in a single section. Aside from the regulatory revisions discussed in the body of the preamble, the Commission is not making substantive changes to the regulations, but is making changes to conform its regulations with the new organizational structure.

Because capacity release has become an integral part of the short-term market, the Commission is moving its capacity release regulations from subpart H of part 284 to the same location in its regulations as pipeline firm and interruptible service (newly designated § 284.7 (firm service), § 284.8 (release of firm service), and § 284.9 (interruptible service)).[304]

In addition, reporting and filing requirements for pipeline services under part 284 are presently scattered throughout Part 284. For example, the Index of Customers and storage reports are presently located in subpart B, § 284.106, which deals with interstate pipelines performing transportation service under the Natural Gas Policy Act (NGPA). But these regulations are then applied to interstate pipelines performing open access services in subpart G, § 284.223. Other reporting requirements are located throughout various substantive provisions of Part 284.[305] The Commission is collecting these requirements into new § 284.13 applicable to interstate pipelines transporting gas under Subpart B (transportation under section 311 of the NGPA) and Subpart G (open access transportation under the NGA). Reporting requirements specific to Subpart B pipelines (by-pass reports) remain in subpart B.

[304] To eliminate redundancy between § 284.7 dealing with pipeline firm service and § 284.9 dealing with pipeline interruptible service, § 284.9 is being revised to cross-reference the sections of § 284.7 that are applicable to both sections.

[305] *See, e.g.*, 18 CFR 284.8(b)(3) and 284.9(b)(3) (requirements to provide information on available capacity), 284.7(c)(6) (discount reports), 284.12 (filing of capacity).

Commenters did not object to the reorganization. Dynegy contends the Commission should not be proposing a requirement for pipelines to file the semi-annual storage report in § 284.14(e) which discloses shippers' names. But the semi-annual storage report is not a new requirement. Pipelines were required to provide this information under existing § 284.102 (b), and the Commission finds no basis for removing a currently applicable requirement. The storage report, however, is being revised to eliminate section (6) requiring pipelines to file the related docket numbers in which the pipeline reported storage related injections and withdrawals. This information is no longer relevant since, after Order No. 636, pipelines are no longer required to file the ST reports on which the injection and withdrawal information was included.

The following is the new outline for subpart A of part 284.

284.1 Definitions.
284.2 Refunds and interest.
284.3 Jurisdiction under the Natural Gas Act.
284.4 Reporting.
284.5 Further terms and conditions.
284.6 Rate interpretations.
284.7 Firm transportation service.
284.8 Release of firm transportation service
284.9 Interruptible transportation service.
284.10 Rates.
284.11 Environmental compliance.
284.12 Standards for pipeline business operations and communications
284.13 Reporting requirements for interstate pipelines.

VII. Implementation Schedule

The regulatory changes made in this rule are being implemented at different times and will require the pipelines to make tariff or *pro forma* tariff filings. The following summarizes the implementation and compliance schedule for the rule.

1. *Maximum Ceiling Rate for Capacity Release Transactions.* The regulation removing the maximum ceiling rate for short-term capacity release transactions will become effective as of the date of this rule. Pipelines must file within 180 days to remove inconsistent tariff provisions and can incorporate this filing into any other tariff filing made by the pipeline within the 180 day period.

2. *Scheduling, Segmentation, Penalty Regulations.* To comply with the regulations governing scheduling of capacity release transactions, segmentation, and penalties, pipelines are required to make *pro forma* tariff filings by May 1, 2000. Thirty days will be provided for the filing of comments and protests. After review of the filing and comments or protests, the

Commission will determine whether further procedures are needed and the effective date for any tariff changes.

3. *Reporting Requirements.* Pipelines must comply with the reporting requirements by September 1, 2000, in accordance with the procedures discussed earlier.

4. *ROFR.* The regulatory change to the ROFR becomes effective on the date this rule becomes effective. Pipelines that have different provisions in their tariffs can, but are not required to, file to modify their existing tariffs to accord with the regulatory changes made in this rule. Until such filing is accepted, the pipeline's current tariff provisions will continue to apply.

VIII. Information Collection Statement

The Office of Management and Budget's (OMB) regulations in 5 CFR 1320.11 require that it approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency. Upon approval of a collection of information, OMB shall assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this Final Rule shall not be penalized for failing to respond to these collections of information unless the collections of information display valid OMB control numbers.

The collections of information related to the subject of this Final Rule fall under FERC–545, ''Gas Pipeline Rates: Rate Change (Non-Formal)'' (OMB Control No. 1902–0154); FERC–549 ''Gas Pipeline Rates: Natural Gas Policy Act; Title III Transactions'' (OMB Control No. 1902–0086); FERC–549B ''Capacity Information'' (OMB Control No. 1902–0169) and FERC–592 ''Marketing Affiliates of Interstate Pipelines'' (OMB Control No. 1902–0157).

Under this Final Rule, the overall reporting requirements will be increased based on the addition of certain information, namely the receipt and delivery point data in transactional reports and the Index of Customers plus organizational and personnel information on affiliates. However, there will also be a reduction in the amount of periodic reporting to the Commission and the elimination of the requirement to submit discount reports. On the whole, the Commission estimates that the revised reporting schedule will increase the existing reporting burden by a total of 77,847 hours. The bulk of the increase will not be extensive, relying not on collecting the data but in creating new formats for displaying the information on the pipelines' Internet websites.

Public Reporting Burden: The burden estimates for complying with this proposed rule are as follows: (reductions in parentheses)

Data collection	No. of respondents	No. of responses per respondent	Estimated burden hours per response	Total annual hours
FERC–545	100	1.4	115.2	16,128
FERC–549	78	1	(2.7)	(211)
FERC–549B	100	333.9	183.86	61,391
FERC–592	74	1	7.28	539
Total				77,847

The total annual hours for collection (including recordkeeping) is estimated to be 77,847.

Information Collection Costs: The average annualized cost for all respondents is projected to be the following (savings in parentheses):

	FERC–545	FERC–549	FERC–549B	FERC–592	Totals
Annualized capital/startup costs	643,529	0.00	1,455,662	0.00	2,099,191
Annualized costs (Operations & maintenance)	221,374	(11,315)	1,836,578	28,905	2,075,542
Total annualized costs	864,903	(11,315)	3,292,240	28,905	4,174,733

Title: FERC–545, 549, 549B and 592.

Action: Proposed Data Collections.

Respondents: Business or other for profit, including small businesses.

Frequency of Responses: On occasion.

Necessity of Information: The proposed rule seeks to establish reporting requirements that will provide information needed for the market to operate more efficiently and for shippers and the Commission to effectively monitor transactions for undue discrimination and the exercise of market power. Information on market structure enables the Commission to know who holds or controls capacity on each portion of the pipeline system, so the potential sources of capacity can be determined. The information required in the current regulations is not as complete as that required in this rule and provides inconsistent information for competing types of capacity, both in terms of the content of the information and the formats used to report the information.

Internal Review: The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements. The internal review involves among other things, an examination of the necessity and adequacy of the information required, and the design, cost, reliability, and redundancy of the information. The data collected will enable the industry and the Commission to monitor the structure, conduct, and performance of the gas industry. This information will enable the Commission to monitor changes in the marketplace that affect Commission regulatory policy and help in identifying, and responding to, markets where light-handed regulation may be appropriate as well as markets in which constraints on competition still exist. These requirements conform to the Commission's plan for efficient information collection, communication, and management within the natural gas pipeline industry.

One-hundred-forty-three comments were filed in response to the NOPR. While the Commission did not receive any comments concerning its estimates for reporting burden, seven entities commented on the additional reporting burden placed upon them by the changes made in this rule. The Commission has addressed their concerns within the preamble of the rule in the appropriate section. Further, as required under OMB regulations, the Commission submitted the NOPR to OMB for review. OMB noted acceptance of the NOPR, but took no action on the NOPR. In its response, OMB stated that the Commission should submit its information requests when it takes final action.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, (Attention: Michael Miller, Office of the Chief Information Officer, Phone: (202) 208–1415, fax: (202) 273–0873, E-mail: *mike.miller@ferc.fed.us*) or the Office of Management and Budget, Office of Information and Regulatory Affairs, Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–3087, fax: (202) 395–7285.

IX. Environmental Analysis

The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[306] The Commission has categorically excluded certain actions from these requirements as not having a significant effect on the human environment.[307] The actions taken here fall within categorical exclusions in the Commission's regulations for rules that are clarifying, corrective, or procedural, for information gathering, analysis, and dissemination, and for sales, exchange, and transportation of natural gas that requires no construction of facilities.[308] Therefore, an environmental assessment is unnecessary and has not been prepared in this rulemaking.

X. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act of 1980 (RFA)[309] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The regulations adopted here impose requirements on interstate pipelines, which generally are not small businesses. Accordingly, pursuant to section 605(b) of the RFA, the Commission certifies that the regulations adopted herein will not have a significant adverse impact on a substantial number of small entities.

XI. Document Availability

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.fed.us*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

From FERC's Home Page on the Internet, this information is available in both the Commission Issuance Posting System (CIPS) and the Records and Information Management System (RIMS).

— CIPS provides access to the texts of formal documents issued by the Commission since November 14, 1994.

— CIPS can be accessed using the CIPS link or the Energy Information Online.

The full text of this document will be available on CIPS in ASCII or WordPerfect 8.0 format for viewing, printing, and/or downloading.

— RIMS contains images of documents submitted to and issued by the Commission after November 16, 1981. Documents from November 1995 to the present can be viewed and printed from FERC's Home Page using the RIMS link or the Energy Information Online icon. Descriptions of documents back to November 16, 1981, are also available from RIMS-on-the-Web; requests for copies of these and older documents should be submitted to the Public Reference Room.

User assistance is available for RIMS, CIPS, and the Website during normal business hours from the Help line at 202–208–2222 (E-Mail to *WebMaster@ferc.fed.us*) or the Public Reference Room at 202–208–1371 (E-Mail to *public.referenceroom@ferc.fed.us*).

During normal business hours, documents can also be viewed and/or printed in FERC's Public Reference Room, where RIMS, CIPS, and the FERC Website are available. User assistance is also available.

XII. Effective Date

These regulations are effective March 27, 2000, with the exception of the removal of paragraph (c)(6) of redesignated § 284.10, which will be effective on September 1, 2000. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects

18 CFR Part 154

Natural gas; Pipelines; Reporting and recordkeeping requirements.

18 CFR Part 161

Natural gas; Reporting and recordkeeping requirements.

18 CFR Part 250

Natural gas; Reporting and recordkeeping requirements.

18 CFR Part 284

Continental shelf; Incorporation by reference; Natural gas; Reporting and recordkeeping requirements.

By the Commission. Commissioner Hébert concurred with a separate statement attached.

David P. Boergers,

Secretary.

In consideration of the foregoing, the Commission amends Part 154, Part 161, Part 250, and Part 284, Chapter I, Title 18, *Code of Federal Regulations,* as follows.

PART 154—RATE SCHEDULES AND TARIFFS

1. The authority citation for Part 154 continues to read as follows:

Authority: 15 U.S.C. 717–717w; 31 U.S.C. 9701; 42 U.S.C. 7102–7352.

§ 154.111 [Amended]

2. In § 154.111(a), remove the words ''§ 284.106 or § 284.223'' and add, in their place, the word ''§ 284.13(c)''.

PART 161—STANDARDS OF CONDUCT FOR INTERSTATE PIPELINES WITH MARKETING AFFILIATES

3. The authority citation for Part 161 continues to read as follows:

Authority: 15 U.S.C. 717–717w, 3301–3432; 42 U.S.C. 7101–7352.

4. Section 161.3 is amended as follows:

a. In paragraph (h)(2), revise all references to ''§ 284.10(a)'' to read ''§ 284.12'' wherever it appears, revise the phrase ''Electronic Bulletin Board operated pursuant to'' and add in its place the phrase ''Internet web site operated complying with'' wherever it appears, revise the phrase ''EBB'' and add in its place the phrase'' Internet web site'' wherever it appears, and revise the phrase ''Electronic Bulletin Board'' and add in its place the phrase ''Internet web site'' wherever it appears; and

b. Revise paragraph (l) to read as follows:

[306] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987).

[307] 18 CFR 380.4.

[308] See 18 CFR 380.4(a)(2)(ii), 380.4(a)(5), 380.4(a)(27).

[309] 5 U.S.C. 601–612.

§ 161.3 Standards of conduct

* * * * *

(l)(1) A pipeline must post the names and addresses of its marketing affiliates on its web site on the public Internet and update the information within three business days of any change. A pipeline must also state the date the information was last updated. Postings must conform with the requirements of § 284.12 of this chapter.

(2) A pipeline must post the following information on its Internet web site complying with § 284.12 of this chapter and update the information within three business days of any change, posting the date on which the information was updated:

(i) A complete list of the names of operating personnel and facilities shared by the pipeline and its marketing affiliates; and

(ii) Comprehensive organizational charts showing:

(A) The organizational structure of the parent corporation with the relative position in the corporate structure of the pipeline and all marketing affiliates;

(B) For the pipeline, the business units, job titles and descriptions, and chain of command for all positions, including officers and directors, with the exception of clerical, maintenance, and field positions. The job titles and descriptions must include the employee's title, the employee's duties, whether the employee is involved in transportation or gas sales, and the name of supervisory employees who manage non-clerical employees involved in transportation or gas sales.

(C) For all employees shared by the pipeline and a marketing affiliate, the business unit within the marketing affiliate organizational structure in which the employee is located, the employee's name, job title and job description in the marketing affiliate, and the employees position within the chain of command of the marketing affiliate.

PART 250—FORMS

5. The authority citation for Part 250 continues to read as follows:

Authority: 15 U.S.C. 717–717w, 3301–3432; 42 U.S.C. 7101–7352.

6. Section 250.16 is amended as follows:

a. Paragraph (b)(1) is removed, paragraph (b)(2) is redesignated as (b)(1), and a new paragraph (b)(2) is added and reserved.

b. In paragraph (c)(2), revise all references to ''284.10(a)'' to read ''284.12'' in paragraph (c)(2), revise the phrase ''Electronic Bulletin Board'' and add, in its place, the phrase ''Internet Web site'' and in paragraph (c)(2), revise the phrase ''Electronic Bulletin Boards'' and add, in its place, the phrase ''Internet Web sites''.

PART 284—CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

7. The authority citation for Part 284 continues to read as follows:

Authority: 15 U.S.C. 717–717w, 3301–3432; 42 U.S.C. 7101–7532; 43 U.S.C. 1331–1356.

§ 284.12 [Removed]

8. Part 284 is amended by removing § 284.12.

9. Part 284 is amended by redesignating the sections as set forth in the following redesignation table:

Old section	New section
284.7	284.10
284.8	284.7
284.10	284.12
284.243	284.8

10. In newly redesignated § 284.7, paragraph (b)(3) is removed and paragraph (b)(4) is redesignated as paragraph (b)(3), paragraphs (d) and (e) are redesignated as paragraphs (e) and (f) respectively, and new paragraph (d) is added to read as follows:

§ 284.7 Firm transportation service.

* * * * *

(d) *Segmentation.* An interstate pipeline that offers transportation service under subpart B or G of this part must permit a shipper to make use of the firm capacity for which it has contracted by segmenting that capacity into separate parts for its own use or for the purpose of releasing that capacity to replacement shippers to the extent such segmentation is operationally feasible.

* * * * *

11. Newly redesignated § 284.8 is amended as follows:

a. In paragraph (d), revise all references to ''electronic bulletin board'' to read ''Internet web site'' wherever it appears; and

b. Paragraph (i) is added to read as follows:

§ 284.8 Release of firm transportation service.

* * * * *

(i) *Waiver of maximum rate ceiling.* Until September 30, 2002, the maximum rate ceiling does not apply to capacity release transactions of less than one year. With respect to releases of 31 days or less under paragraph (h), the requirements of paragraph (h)(2) will apply to all such releases regardless of the rate charged.

12. In § 284.9, paragraphs (c) and (e) are removed, paragraph (d) is redesignated as paragraph (c), and paragraph (b) is revised to read as follows:

§ 284.9 Interruptible transportation service.

* * * * *

(b) The provisions regarding non-discriminatory access, reasonable operational conditions, and limitations contained in § 284.7 (b), (c), and (f) apply to pipelines providing interruptible service under this section.

* * * * *

§ 284.10 [Amended]

13. In newly redesignated § 284.10, paragraph (c)(6) is removed.

14. In newly redesignated § 284.12, paragraphs (c)(1)(ii) and (c)(2)(iii) through (v) are added to read as follows:

§ 284.12 Standards for pipeline business operations and communications.

* * * * *

(c) * * *

(1) * * *

(ii) *Capacity release nominations.* Pipelines must permit shippers acquiring released capacity to submit a nomination at the earliest available nomination opportunity after the acquisition of capacity. If the pipeline requires the replacement shipper to enter into a contract, the contract must be issued within one hour after the pipeline has been notified of the release, but the requirement for contracting must not inhibit the ability of the replacement shipper to submit a nomination at the earliest available nomination opportunity.

(2) * * *

(iii) *Imbalance management.* A pipeline must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of its shippers to manage transportation imbalances. A pipeline also must provide its shippers the opportunity to obtain similar imbalance management services from other providers and shall provide those shippers using other providers access to transportation and other pipeline services without undue discrimination or preference.

(iv) *Operational flow orders.* A pipeline must take all reasonable actions to minimize the issuance and adverse impacts of operational flow orders (OFOs) or other measures taken to respond to adverse operational events on its system. A pipeline must set forth in its tariff clear standards for when such measures will begin and end and must provide timely information that will enable shippers to minimize the adverse impacts of these measures.

(v) *Penalties.* A pipeline may include in its tariff transportation penalties only to the extent necessary to prevent the impairment of reliable service. Pipelines may not retain net penalty revenues, but must credit them to shippers in a manner to be prescribed in the pipeline's tariff. A pipeline must provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of the pipeline's system.

* * * * *

15. Part 284 is amended by adding § 284.13 to read as follows:

§ 284.13 Reporting requirements for interstate pipelines.

An interstate pipeline that provides transportation service under subparts B or G of this part must comply with the following reporting requirements.

(a) *Cross references.* The pipeline must comply with the requirements in Part 161, Part 250, and Part 260 of this chapter, where applicable.

(b) *Reports on firm and interruptible services.* An interstate pipeline must post the following information on its Internet web site, and provide the information in downloadable file formats, in conformity with § 284.12 of this part, and must maintain access to that information for a period not less than 90 days from the date of posting.

(1) For pipeline firm service and for release transactions under § 284.8 of this part, the pipeline must post, contemporaneously with the execution or revision of a contract for service:

(i) The full legal name of the shipper, and identification number, of the shipper receiving service under the contract, and the full legal name, and identification number, of the releasing shipper if a capacity release is involved or an indication that the pipeline is the seller of transportation capacity;

(ii) The contract number for the shipper receiving service under the contract, and, in addition, for released transactions, the contract number of the releasing shipper's contract;

(iii) The rate charged under each contract;

(iv) The maximum rate, and for capacity release transactions not subject to a maximum rate, the maximum rate that would be applicable to a comparable sale of pipeline services;

(v) The duration of the contract;

(vi) The receipt and delivery points and zones or segments covered by the contract, including the industry common code for each point, zone, or segment;

(vii) The contract quantity or the volumetric quantity under a volumetric release;

(viii) Special terms and conditions applicable to a capacity release and special details pertaining to a pipeline transportation contract; and

(ix) Whether there is an affiliate relationship between the pipeline and the shipper or between the releasing and replacement shipper.

(2) For pipeline interruptible service, the pipeline must post on a daily basis:

(i) The full legal name, and identification number, of the shipper receiving service;

(ii) The rate charged;

(iii) The maximum rate;

(iv) The receipt and delivery points and zones or segments covered by the contract over which the shipper is entitled to transport gas, including the industry common code for each point, zone, or segment;

(v) The quantity of gas the shipper is entitled to transport;

(vi) Special details pertaining to the contract; and

(vii) Whether the shipper is affiliated with the pipeline.

(c) *Index of customers.* (1) On the first business day of each calendar quarter, an interstate pipeline must file with the Commission an index of all its firm transportation and storage customers under contract as of the first day of the calendar quarter that complies with the requirements set forth by the Commission. The Commission will establish the requirements and format for such filing. The index of customers must also posted on the pipeline's Internet web, in accordance with standards adopted in § 284.12 of this part, and made available from the Internet web site in a downloadable format complying with the specifications established by the Commission. The information posted on the pipeline's Internet web site must be made available until the next quarterly index is posted.

(2) For each shipper receiving firm transportation or storage service, the index must include the following information:

(i) The full legal name, and identification number, of the shipper;

(ii) The applicable rate schedule number under which the service is being provided;

(iii) The contract number;

(iv) The effective and expiration dates of the contract;

(v) For transportation service, the maximum daily contract quantity (specify unit of measurement), and for storage service, the maximum storage quantity (specify unit of measurement);

(vi) The receipt and delivery points and the zones or segments covered by the contract in which the capacity is held, including the industry common code for each point, zone, or segment;

(vii) An indication as to whether the contract includes negotiated rates;

(viii) The name of any agent or asset manager managing a shipper's transportation service; and

(ix) Any affiliate relationship between the pipeline and a shipper or between the pipeline and a shipper's asset manager or agent.

(3) The requirements of this section do not apply to contracts which relate solely to the release of capacity under § 284.8, unless the release is permanent.

(4) Pipelines that are not required to comply with the index of customers posting and filing requirements of this section must comply with the index of customer requirements applicable to transportation and sales under Part 157 as set forth under § 154.111(b) and (c) of this chapter.

(5) The requirements for the electronic index can be obtained from the Federal Energy Regulatory Commission, Division of Information Services, Public Reference and Files Maintenance Branch, Washington, DC 20426.

(d) *Available capacity.* (1) An interstate pipeline must provide on its Internet web site and in downloadable file formats, in conformity with § 284.12 of this part, equal and timely access to information relevant to the availability of all transportation services, including, but not limited to, the availability of capacity at receipt points, on the mainline, at delivery points, and in storage fields, whether the capacity is available directly from the pipeline or through capacity release, the total design capacity of each point or segment on the system, the amount scheduled at each point or segment on a daily basis, and all planned and actual service outages or reductions in service capacity.

(2) An interstate pipeline must make an annual filing by March 1 of each year showing the estimated peak day capacity of the pipeline's system, and the estimated storage capacity and maximum daily delivery capability of storage facilities under reasonably representative operating assumptions and the respective assignments of that capacity to the various firm services provided by the pipeline.

(e) *Semi-annual storage report.* Within 30 days of the end of each complete storage injection and withdrawal season, the interstate pipeline must file with the Commission a report of storage activity. The report must be signed under oath by a senior official, consist of an original and five conformed copies, and contain a summary of storage injection and withdrawal activities to include the following:

(1) The identity of each customer injecting gas into storage and/or withdrawing gas from storage, identifying any affiliation with the interstate pipeline;

(2) The rate schedule under which the storage injection or withdrawal service was performed;

(3) The maximum storage quantity and maximum daily withdrawal quantity applicable to each storage customer;

(4) For each storage customer, the volume of gas (in dekatherms) injected into and/or withdrawn from storage during the period; and (5) The unit charge and total revenues received during the injection/withdrawal period from each storage customer, noting the extent of any discounts permitted during the period.

16. In § 284.102, paragraph (c) is revised to read as follows:

§ 284.102 Transportation by interstate pipelines.

* * * * *

(c) An interstate pipeline that engages in transportation arrangements under this subpart must file reports in accordance with § 284.13 and § 284.106 of this chapter.

* * * * *

17. In § 284.106, paragraphs (b) through (c) are removed, the paragraph (a) designation and the associated heading are removed, and the section heading is revised to read as follows:

§ 284.106 Notice of bypass.

* * * * *

18. In § 284.221. paragraph (d)(2)(ii) is revised to read as follows:

§ 284.221 General rule; transportation by interstate pipelines on behalf of others.

* * * * *

(d) * * *

(2) * * *

(ii) Gives notice that it wants to continue its transportation arrangement and will match the longest term and highest rate for its firm service, up to the applicable maximum rate under § 284.10, offered to the pipeline during the period established in the pipeline's tariff for receiving such offers by any other person desiring firm capacity, and executes a contract matching the terms of any such offer. To be eligible to exercise this right of first refusal, the firm shipper's contract must be for service for twelve consecutive months or more at the applicable maximum rate for that service.

* * * * *

19. In § 284.223, the paragraph (a) designation is removed and paragraph (b) is removed.

§§ 284.10, 284.123, 284.221, 284.261, 284.263, 284.266, and 284.286 [Amended]

In addition to the amendments set forth above, in 18 CFR part 284, the following nomenclature changes are made:

a. In Subparts B through L, revise all references to ''§ 284.7'' to read ''§ 284.10'' wherever it appears in ''§§ 284.221, 284.261, 284.263, and 284.266.''

b. In Subparts B through L, revise all references to ''§§ 284.8–284.13'' to read ''§§ 284.7–284.9 and §§ 284.11–284.13'' wherever it appears, in ''§§ 284.261 and 284.263.''

c. In newly redesignated §§ 284.10(c)(1) and (c)(2), revise all references to ''§ 284.8(d)'' to read''§ 284.7(e)''.

d. In § 284.123 (b)(1), revise all references to ''§§ 284.8'' to read''§§ 284.7''.

e. In § 284.286(b), revise all references to ''§§ 284.8(b)(2)'' to read ''§§ 284.7(b)(2)''.

f. In section 284.286(c), revise all references to ''§§ 161.3(c), (e), (f), (g), and (h)'' to read ''§§ 161.3(c), (e), (f), (g), (h), and (l)''.

Note. The following Appendix will not appear in the Code of Federal Regulations.

Appendix

Comments Filed in Docket Nos. RM98–10–000 & RM98–12–000 [310]

Commenter	Abbreviation	Docket No.
AEC Marketing (USA) Inc	AEC	RM98–10–000.
Alabama Gas Corporation	Alagasco	RM98–10–000.
Allenergy Marketing Company, LLC, Enron Energy Services, Inc., Enserch Energy Services, Inc. and Statoil Energy, Inc.	Allenergy	RM98–10–000 & RM98–12–000 (joint filing).
Alliance Pipeline L.P	Alliance	RM98–10–000 & RM98–12–000 (joint filing).
AlliedSignal Inc	AlliedSignal I	RM98–10–000.
AlliedSignal Inc	AlliedSignal II	RM98–12–000.
Altra Energy Technologies, Inc	Altra	RM98–10–000.
American Forest & Paper Association	AF&PA I	RM98–10–000.
American Forest & Paper Association	AF&PA II	RM98–12–000.
American Gas Association	AGA I	RM98–10–000.
American Gas Association	AGA II	RM98–12–000.
American Public Gas Association	APGA	RM98–10–000 & RM98–12–000 (joint filing).
Amoco Energy Trading Corporation and Amoco Production Company.	Amoco I	RM98–10–000.
Amoco Energy Trading Corporation, Amoco Production Company, Burlington Resources Oil & Gas Co., and Marathon Oil Company.	Amoco II	RM98–12–000.
Arkansas Gas Consumers	Arkansas Gas Consumers	RM98–10–000.
Arkansas Public Service Commission	Arkansas PSC	RM98–10–000 & RM98–12–000 (joint filing).
Atlanta Gas Light Company	AGLC I	RM98–10–000.
Atlanta Gas Light Company	AGLC II	RM98–12–000.
Baltimore Gas and Electric Company	BG&E I	RM98–10–000.
Baltimore Gas and Electric Company	BG&E II	RM98–12–000.

[310] Parties filing a single document in response to the NOPR in Docket Nos. RM98–10–000 and the NOI in Docket No. RM98–12–000 are denominated as a joint filing.

Commenter	Abbreviation	Docket No.
Brooklyn Union Gas Company and Keyspan Gas East Corporation.	Brooklyn Union	RM98–10–000 & RM98–12–000 (joint filing).
Canadian Association of Petroleum Producers and Alberta Department of Energy.	CAPP/ADOE	RM98–12–000.
City of Hamilton, Ohio	City of Hamilton, Ohio	RM98–10–000.
CMS Panhandle Pipe Line Companies	CMS Panhandle	RM98–10–000 & RM98–12–000 (joint filing).
Coastal Companies	Coastal I	RM98–10–000.
Coastal Companies	Coastal II	RM98–12–000.
Colorado Springs Utilities	Colorado Springs I	RM98–10–000.
Colorado Springs Utilities	Colorado Springs II	RM98–12–000.
Columbia Gas of Kentucky, Inc., Columbia Gas of Maryland, Inc., Columbia Gas of Ohio, Inc., Columbia Gas of Pennsylvania, Inc., and Columbia Gas of Virginia, Inc.	Columbia LDCs	RM98–10–000 & RM98–12–000 (joint filing).
Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company.	Columbia	RM98–10–000 & RM98–12–000 (joint filing).
Conoco Inc	Conoco	RM98–10–000 & RM98–12–000 (joint filing).
Consolidated Edison Company of New York, Inc	ConEd	RM98–10–000 & RM98–12–000 (joint filing).
Consolidated Natural Gas Company	Consolidated Natural I	RM98–10–000.
Consolidated Natural Gas Company	Consolidated Natural II	RM98–12–000.
Consumers Energy Company	Consumers Co	RM98–12–000.
Cove Point LNG Limited Partnership	Cove Point	RM98–10–000.
Delta Natural Gas Company	Delta	RM98–10–000.
Duke Energy Trading and Marketing, LLC	Duke Energy	RM98–10–000 & RM98–12–000 (joint filing).
Dynegy Inc	Dynegy	RM98–10–000 & RM98–12–000 (joint filing).
Edison Electric Institute	EEI	RM98–10–000 & RM98–12–000 (joint filing).
El Paso Energy Corporation Interstate Pipelines	El Paso Energy	RM98–10–000 & RM98–12–000 (joint filing).
El Paso Natural Gas Company	El Paso Natural	RM98–10–000 & RM98–12–000 (joint filing).
Enron Capital & Trade Corporation	Enron Capital	RM98–10–000 & RM98–12–000 (joint filing).
Enron Interstate Pipelines	Enron Pipelines	RM98–10–000 & RM98–12–000 (joint filing).
Entergy Services, Inc	Entergy	RM98–10–000 & RM98–12–000 (joint filing).
Exxon Corporation	Exxon	RM98–10–000 & RM98–12–000 (joint filing).
Fertilizer Institute	Fertilizer Institute	RM98–10–000 & RM98–12–000 (joint filing).
Florida Cities	Florida Cities	RM98–10–000 & RM98–12–000 (joint filing).
Florida Department of Management Services	Florida DMS	RM98–10–000.
Foothills Pipe Lines Ltd	Foothills	RM98–10–000 & RM98–12–000 (joint filing).
FPL Group, Inc	FPL	RM98–10–000 & RM98–12–000 (joint filing).
Illinois Commerce Commission	Illinois Commerce Comm	RM98–10–000 & RM98–12–000 (joint filing).
Illinois Municipal Gas Agency	IMGA	RM98–10–000 & RM98–12–000 (joint filing).
IMD Storage, Transportation and Asset Management Company, LLC.	IMD	RM98–10–000 & RM98–12–000 (joint filing).
Independent Oil and Gas Association of Pennsylvania	IOGA–PA	RM98–10–000 and RM98–12–000 (joint filing).
Independent Oil and Gas Association of West Virginia	IOGA–WV	RM98–10–000 & RM98–12–000 (joint filing).
Independent Oil and Gas Association of New York	IOGA–NY	RM98–10–000 & RM98–12–000 (joint filing).
Independent Oil and Gas Association of Kentucky	IOGA–KY.	
Independent Petroleum Association of America	IPAA	RM98–10–000 & RM98–12–000 (joint filing).
Indicated Shippers	Indicated Shippers	RM98–10–000 & RM98–12–000 (joint filing).
Interstate Natural Gas Association of America	INGAA	RM98–10–000 & RM98–12–000 (joint filing).
Iowa Utilities Board	Iowa	RM98–10–000 & RM98–12–000 (joint filing).
John A. Bell, Jr	John A. Bell, Jr	RM98–10–000.

Commenter	Abbreviation	Docket No.
K N Pipelines, Inc	K N	RM98–10–000 & RM98–12–000 (joint filing).
Koch Gateway Pipeline Company	Koch I	RM98–10–000.
Koch Gateway Pipeline Company	Koch II	RM98–12–000.
Louisville Gas and Electric Company (Jan. & April)	Louisville	RM98–10–000 & RM98–12–000 (joint filing).
Market Hub Partners, L.P	Market Hub Partners	RM98–10–000 & RM98–12–000 (joint filing).
Michigan Consolidated Gas Company	MichCon	RM98–10–000 & RM98–12–000 (joint filing).
Midland Cogeneration Venture Limited Partnership	Midland	RM98–10–000 & RM98–12–000 (joint filing).
Millennium Pipeline Company, L.P	Millennium	RM98–10–000 & RM98–12–000 (joint filing).
Minnesota Department of Public Service	Minnesota	RM98–10–000 & RM98–12–000 (joint filing).
Mississippi Independent	Mississippi Independent	RM98–10–000.
Mississippi Valley Gas Company, Willmut Gas Company, City of Vicksburg, Mobile Gas Service Corporation, Wheeler Basin Natural Gas Company, Clarke-Mobile Counties Gas District.	Mississippi Valley	RM98–10–000 & RM98–12–000 (joint filing).
National Association of State Utility Consumer Advocates	NASUCA	RM98–10–000 & RM98–12–000 (joint filing).
National Association of Regulatory Utility Commissioners	NARUC	RM98–10–000 & RM98–12–000 (joint filing).
National Energy Marketers Association	NEMA	RM98–10–000 & RM98–12–000 (joint filing).
National Fuel Gas Distribution	National Fuel Distribution	RM98–10–000 & RM98–12–000 (joint filing).
National Fuel Gas Supply Corporation	National Fuel	RM98–10–000.
Natural Gas Supply Association	NGSA	RM98–10–000 & RM98–12–000 (joint filing).
New England Gas Distributors	New England	RM98–10–000 & RM98–12–000 (joint filing).
New York Mercantile Exchange	NYMEX	RM98–10–000.
Nicor Gas	Nicor	RM98–10–000.
Nisource, Inc	Nisource	RM98–10–000.
North Carolina Natural Gas Corporation	NC Natural Gas	RM98–10–000 & RM98–12–000 (joint filing).
Northern Municipal Distributors Group and The Midwest Region Gas Task Force Association.	Northern Municipal I	RM98–10–000.
Northern Municipal Distributors Group and The Midwest Region Gas Task Force Association.	Northern Municipal II	RM98–12–000.
Northwest Industrial Gas Users	NWIGU	RM98–10–000 & RM98–12–000 (joint filing).
Northwest Natural Gas Company	NW Natural	RM98–12–000.
Ohio Oil & Gas Association	OOGA	RM98–10–000 & RM98–12–000 (joint filing).
Oklahoma Independent Petroleum Association	OIPA	RM98–10–000 & RM98–12–000 (joint filing).
Paiute Pipeline Company	Paiute	RM98–10–000.
PanCanadian Petroleum Limited and PanCanadian Energy Services, Inc.	PanCanadian	RM98–10–000 & RM98–12–000 (joint filing).
Peco Energy Company	Peco	RM98–12–000.
Pennsylvania Office of Consumer Advocate and the Ohio Consumers' Counsel.	Penn./Ohio Advocate	RM98–10–000 & RM98–12–000 (joint filing).
Pennsylvania Oil & Gas Association	Penn. Oil & Gas Assoc	RM98–10–000 & RM98–12–000 (joint filing).
Pennsylvania Public Utility Commission	Penn. PUC	RM98–10–000 & RM98–12–000 (joint filing).
Peoples Energy Corporation	Peoples Energy I	RM98–10–000.
Peoples Energy Corporation	Peoples Energy II	RM98–12–000.
Pepco Energy Company	Pepco	RM98–12–000.
PG&E Corporation	PG&E	RM98–10–000 and RM98–12–000 (joint filing).
Philadelphia Gas Works	Philadelphia Gas Works	RM98–10–000 & RM98–12–000 (joint filing).
Piedmont Natural Gas Company, Inc. and UGI Utilities, Inc	Piedmont/UGI	RM98–10–000 & RM98–12–000 (joint filing).
Pipeline Transportation Customer Coalition	P/L Customer Coalition	RM98–10–000 & RM98–12–000 (joint filing).
Portland Natural Gas Transmission System	PNGTS	RM98–10–000.
Process Gas Consumers Group—American Iron and Steel Institute, Georgia Industrial Group, Aluminum Company of America and United States Gypsum Company.	Process Gas Consumers I	RM98–10–000.

Commenter	Abbreviation	Docket No.
Process Gas Consumers Group—American Iron and Steel Institute, Georgia Industrial Group, Aluminum Company of America and United States Gypsum Company.	Process Gas II Consumers	RM98–12–000.
Production Area Rate Design Group	Production Area Group	RM98–10–000 & RM98–12–000 (joint filing).
Proliance Energy, LLC	Proliance	RM98–10–000 & RM98–12–000 (joint filing).
Public Service Commission of the State of New York	PSC of New York I	RM98–10–000.
Public Service Commission of the State of New York	PSC of New York II	RM98–12–000.
Public Service Commission of the Commonwealth of Kentucky	PSC of Kentucky	RM98–10–000 & RM98–12–000 (joint filing).
Public Service Commission of Wisconsin	PSC of Wisconsin I	RM98–10–000.
Public Service Commission of Wisconsin	PSC of Wisconsin II	RM98–12–000.
Public Service Electric and Gas Company	PSE&G	RM98–10–000 & RM98–12–000 (joint filing).
Public Utilities Commission of the State of California	CPUC	RM98–10–000 & RM98–12–000 (joint filing).
Public Utilities Commission of Ohio	PUC of Ohio	RM98–10–000.
Regulatory Studies Program of the Mercatus Center, George Mason University.	Mercatus	RM98–10–000 & RM98–12–000 (joint filing).
Reliant Energy Gas Transmission Company and Mississippi River Transmission Corporation.	Reliant	RM98–10–000 & RM98–12–000 (joint filing).
Sempra Energy	Sempra Energy	RM98–10–000 & RM98–12–000 (joint filing).
Shell Energy Services Company, LLC	Shell	RM98–10–000.
Sithe Energies, Inc	Sithe	RM98–10–000 & RM98–12–000 (joint filing).
Southern Company Energy Marketing L.P	Southern Co. Energy	RM98–10–000.
Southern Company Services, Inc	Southern Co. Services	RM98–10–000 & RM98–12–000 (joint filing).
Southern Natural Gas Company	Southern Natural	RM98–10–000 & RM98–12–000 (joint filing).
Southwest Gas Corporation	Southwest Gas	RM98–10–000 & RM98–12–000 (joint filing).
Tejas Offshore Pipelines, LLC	Tejas I	RM98–10–000.
Tejas Offshore Pipelines, LLC	Tejas II	RM98–12–000.
Tennessee Valley Authority	TVA	RM98–10–000 and RM98–12–000 (joint filing).
Texas Eastern Transmission Corporation and Algonquin Gas Transmission Company.	TETCO/Algonquin	RM98–10–000 & RM98–12–000 (joint filing).
The Customer Coalition	The Customer Coalition	RM98–10–000.
The Railroad Commission of Texas	TRRC	RM98–10–000 & RM98–12–000 (joint filing).
TransCanada Gas Services, A Division of TransCanada Energy, LTD.	TransCanada	RM98–10–000 & RM98–12–000 (joint filing).
TransCapacity Limited Partnership	TransCapacity	RM98–10–000.
UGI Utilities, Inc	UGI	RM98–10–000 and RM98–12–000 (joint filing).
Vector Pipeline L.P	Vector	RM98–10–000 & RM98–12–000 (joint filing)
Washington Gas Light Company	WGL I	RM98–10–000.
Washington Gas Light Company	WGL II	RM98–12–000.
Williams Companies, Inc	Williams I	RM98–10–000.
Williams Companies, Inc	Williams II	RM98–12–000.
Williston Basin Interstate Pipeline Company	Williston Basin	RM98–10–000 & RM98–12–000 (joint filing).
Wisconsin Distribution Group	Wisconsin Distributors	RM98–10–000 & RM98–12–000 (joint filing).

Hebert, Commissioner, *concurring.*

Without question, the steps taken in this rule, with one exception, are a significant victory for pricing flexibility necessary to stride confidently toward a market-based approach for transportation of natural gas instead of retaining elements of price controls.

The removal of the price cap on capacity release transactions provides multiple benefits to the marketplace. Capacity release transactions become a viable alternative to bundled sales of natural gas. The incentive provided by the alternative will result in a more efficient use of existing capacity, storage facilities and peak shaving devices. Revenues resulting from capacity release transactions can materially benefit customers by reducing cost shifting. Peak and off-peak rates should also benefit customers in future rate proceedings through minimizing discounts during off-peak periods.

Through this rule, I believe this Commission will gain a better understanding of the value of pipeline capacity and will provide proper pricing alternatives to the industry. It remains vital to the consumer that market demand for capacity not be ignored, nor unaddressed, in our efforts to ensure a reliable and sufficient infrastructure for the transportation of natural gas. I can only hope this Commission will embrace the need for capacity, specifically the northeast. In light of the concerns vehemently expressed by Secretary Richardson on the rising price of heating oil in the northeast, this Commission must act in a reasonable manner and with the interest of the consumers at heart, wherever they are located. Delay, as well as unnecessary environmental and economic hurdles remain unacceptable.

Further, the two-year waiver period concerning the removal of the price caps on capacity release transactions is also unacceptable. The data provided to me appears clear and convincing that removal of the price caps is a positive and substantiated step designed to benefit the consumer. The studies, contained in this docket as well as the information gathered by the staff, are more than sufficient to justify a permanent removal of the price caps. I will continue to advocate this position in order to ultimately remove the price caps of capacity release transactions. This Commission needs to move toward price reforms, not price controls.

Therefore, I respectfully concur.

Commissioner Curt L. Hébert, Jr.

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