§ 95.8003 VOR Federal Airways Changeover Points Airway Segment V–76 Is Amended to Delete

From	To	Changeover points	
		Distance	From
Lubbock, TX VORTAC	Big Spring, TX VORTAC	71	Lubbock
V–81 is Amended to Delete			
Lubbock, TX VORTAC	Midland, TX VORTAC	71	Lubbock

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 284

[Docket Nos. RM91–11–006 and RM87–34–072; Order No. 636–C]

Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

Issued February 27, 1997.

AGENCY: Federal Energy Regulatory Commission. Energy.

ACTION: Final rule; order on remand.

SUMMARY: In *United Distribution Cos.* v. *FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *petitions for cert. filed*, 65 U.S.L.W. 3531–32 (U.S. Jan. 27, 1997) (No. 96–1186, *et al.*) (*UDC*), the Court of Appeals for the District of Columbia Circuit affirmed the Commission's restructuring of the natural gas industry in the Commission's Order No. 636. (Final rule published at 57 FR 13267, April 16, 1992). In UDC, the Court remanded six issues to the Commission for further explanation or consideration. This order complies with the Court's remand.

FOR FURTHER INFORMATION CONTACT:

Richard Howe, Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426, (202) 208–1274;

Mary Benge, Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 (202) 208–1214.

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Note: Appendix A, containing Tables 1 and 2, and Appendix B, containing Tables 1 through 5 are not being published in the Federal Register but are available from the Commission's Public Reference Room.

Before Commissioners: Elizabeth Anne Moler, Chair; Vicky A. Bailey, James J. Hoecker, William L. Massey, and Donald F. Santa, Jr.

Pipeline Service Obligations and Revisions to Regulations to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol (Docket Nos. RM91–11–006 and RM 87–34–072; Order No. 636–C)

Order on Remand

Issued February 27, 1997.

In *United Distribution Companies* v. *FERC* (*UDC*),[1] the United States Court of Appeals for the District of Columbia Circuit upheld the Commission's Order No. 636[2] ''in its broad contours and in most of its specifics.''[3] In so doing, the Court affirmed the Commission's restructuring of the natural gas industry, but remanded six issues to the Commission for further explanation or consideration. This order complies with the Court's remand.

In light of the Court's remand, the Commission has reexamined Order No. 636, and of necessity, the changes in the natural gas industry that have occurred since restructuring. Based on reconsideration of the remanded issues, the Commission reaffirms certain of its previous rulings and reverses others.

I. Introduction

In Order No. 636 the Commission required interstate pipelines to restructure their services in order to improve the competitive structure of the natural gas industry. The regulatory changes were designed ''to ensure that all shippers have meaningful access to the pipeline transportation grid so that willing buyers and sellers can meet in

[1] *United Distrib. Cos.* v. *FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *petitions for cert. filed*, 65 U.S.L.W. 3531–32 (U.S. Jan. 27, 1997) (No. 96–1186, *et al.*) (*UDC*).

[2] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, [Regs. Preambles Jan. 1991–June 1996] FERC Stats. & Regs. ¶ 30,939 (1992), *order on reh'g*, Order No. 636–A, [Regs. Preambles Jan. 1991–June 1992] FERC Stats. & Regs. ¶ 30,950 (1992), *order on reh'g*, Order No. 636–B, 61 FERC ¶ 61,272 (1992), *reh'g denied*, 62 FERC ¶ 61,007 (1993).

[3] *UDC*, 88 F.3d at 1191.

a competitive, national market to transact the most efficient deals possible.'' [4] To achieve this goal, the Commission required pipelines to restructure their services to separate the transportation of gas from the sale of gas, and to change the design of their transportation rates. The Commission also required pipelines to permit firm shippers to resell their capacity rights, creating national procedures for trading transmission capacity. The Commission adopted a new flexible delivery point policy and took various other actions in order to promote the growth in market centers. In addition, the Commission adopted policies to govern the pipelines' recovery of transition costs that would arise from the restructuring.

In *UDC*, the Court affirmed the major elements of the restructuring rule—the unbundling of sales and transportation,[5] the use of an SFV rate design, the capacity release rules, the curtailment provisions, the right-of-first refusal mechanism, and the recovery of transition costs. Specifically, the Court affirmed the Commission's regulation of capacity release including restrictions on non-pipeline releases,[6] its ban on buy/sell transactions,[7] and its adjustments to pipelines' rates, including the authority to increase those rates under section 5 of the Natural Gas Act (NGA) in the circumstances presented.[8] The Court further held that the Commission has jurisdiction over the curtailment of third-party supplies.[9]

The Court remanded six aspects of the rule for further explanation or consideration, although the Court permitted the rule to stand as formulated pending the Commission's final action on remand.[10] First, the Court remanded the issue of no-notice transportation eligibility, particularly the Commission's restriction on the entitlement to no-notice transportation service to those customers who received bundled firm-sales service on May 18, 1992.[11] The Court found that the Commission had not adequately explained the ''disadvantaging of former bundled firm-sales customers who converted under Order No. 436.'' [12] Second, while the Court upheld the basic right-of-first-refusal mechanism, with its matching conditions of rate and contract term,[13] it remanded as to the Commission's selection of a twenty-year term-matching cap.[14] Specifically, the Court found that the Commission had not adequately explained how the twenty-year cap protects against pipelines' market power, and the failure to explain why it looked at new-construction contracts in arriving at the twenty-year figure.[15]

Third, the Court remanded the issue of SFV rate mitigation for further explanation of the requirement that initial rate mitigation measures must be applied on a customer-by-customer basis, and the phased-in measures must be applied on a customer-class basis.[16] The Court found that the Commission had not adequately justified its preference for customer-by-customer mitigation over customer-class mitigation.[17] The Court was particularly concerned by arguments of the pipelines that customer-by-customer mitigation would increase the risks that a pipeline will fail to collect its costs.[18] Fourth, the Court remanded the Commission's deferral to individual restructuring proceedings the eligibility of small customers on downstream pipelines for a one-part small-customer rate.[19] The Court found that the Commission made an arbitrary distinction between former indirect small customers of an upstream pipeline who are now direct customers, and small customers who have always been direct customers of the same upstream pipeline.[20]

Fifth, the Court found that the Commission had not adequately explained the requirement that pipelines allocate ten percent of Gas Supply Realignment (GSR) costs to interruptible customers.[21] The Court's principal concern was the lack of justification for the allocation figure of ten percent, as opposed to another percentage or allocation method.[22] Finally, the Court remanded the Commission's decision to exempt pipelines from sharing in GSR costs.[23] The Court required further explanation of why the Commission used ''cost spreading'' and ''value of service'' principles to allocate costs to the pipelines' customers, but reverted to traditional ''cost causation'' principles to justify exempting pipelines from those costs.[24]

Pipelines began implementing the requirements of Order No. 636 in 1993, and restructured services now have been in effect for three heating seasons. Significant changes have occurred in the natural gas industry since the development of the record in the Order No. 636 proceeding, many of which are a direct result of restructuring. Thus, the Commission's actions on remand necessarily will reflect the insight gained from restructuring.

Since Order No. 636, substantial progress has been made toward realizing the Commission's goal of opening up the pipeline grid to form a national gas market for gas sellers and gas purchasers to meet in the most efficient manner. Today, there are 38 operating market centers as compared to only six when Order No. 636 issued.[25] These market centers provide a variety of services that increase the flexibility of the system and facilitate connections between gas sellers and buyers. These services commonly include wheeling, parking, loaning, and storage.[26] In addition, electronic trading of gas and capacity rights, which did not exist at the time of Order No. 636, is now offered at over 20 market centers and other transaction points throughout North America. Electronic trading systems enable buyers and sellers to discover the price and availability of gas at transaction points, submit bids, complete legally binding transactions, and prearrange capacity release transactions.

In addition to the information provided by electronic trading services, electronic information services offer capacity release and tariff information

[4] Order No. 636, [Regs. Preambles Jan. 1991—June 1996] FERC Stats. & Regs. at 30,393.

[5] The mandatory unbundling remedy itself was not challenged; however, appellants challenged four peripheral aspects of the remedy which were addressed by the Court. First, the Court upheld the rule that customers must retain contractual firm-transportation capacity for which the pipeline receives no other offer. Second, the Court deferred to individual proceedings the issue of pipelines' ability to modify storage contracts without NGA section 7(b) abandonment proceedings. Third, the Court declared moot the challenge to the Commission's rule that transportation-only pipelines may not acquire capacity on other pipelines. Fourth, as discussed further in this order, the Court remanded for further consideration the Commission's decision that only those customers who received bundled firm-sales service on May 18, 1992, are entitled to no-notice transportation service.

[6] *UDC*, 88 F.3d at 1152–54.

[7] *Id*. at 1157.

[8] *Id*. at 1166.

[9] *Id*. at 1148.

[10] *Id*. at 1191.

[11] *Id*. at 1137.

[12] *Id*.

[13] *Id*. at 1139–40.

[14] *Id*. at 1141.

[15] *Id*.

[16] *Id*. at 1174.

[17] *Id*.

[18] *Id*.

[19] *Id*. at 1175.

[20] *Id*. at 1174–75.

[21] *Id*. at 1188.

[22] *Id*. at 1187.

[23] *Id*. at 1190.

[24] *Id*. at 1189.

[25] Energy Info. Agency, DOE, No. DOE–EIA–0560(96), Natural Gas Issues and Trends (Dec. 1996).

[26] Wheeling, offered at 33 market centers, is the transfer of gas from one interconnected pipeline to another. Parking, offered at 29 market centers, is when the market center holds the shipper's gas for a short time for redelivery within approximately 15 days. Loaning, offered at 20 market centers, is a short-term advance to a shipper by the market center operator which is repaid in kind by the shipper. Storage is offered at 16 market centers.

aggregated from pipeline electronic bulletin boards, gas futures pricing information,[27] weather information, and determination of least cost routing. Such information was not widely available electronically before Order No. 636.

Capacity release is also playing an increasingly significant role in permitting the reallocation of firm pipeline capacity to customers most desiring it. For example, in October 1996, the Commission estimates that released capacity held by replacement shippers accounted for about 23 percent of firm transportation contract demand, for a group of 30 pipelines for which capacity release data was obtained.[28] Capacity release permits shippers to release the rights to transportation on the segments of a pipeline they do not need, and to acquire firm rights in segments that connect to other supply areas, on a temporary or permanent basis. Because of this ability to obtain firm transportation access to supply regions throughout the North American continent, shippers have less need to renew contracts for firm capacity over the entire length of the pipelines that have traditionally served them from supply basins in the south and southwestern parts of the United States.[29]

The construction and development of the pipeline grid that continues today will increase this flexibility for shippers. In the Eastern region of the United States, construction has been undertaken to add pipeline capacity to meet peak day demand along traditional pipeline paths,[30] and to add paths to new supply regions.[31] The interstate pipeline grid is undergoing significant expansion in other regions also to access new supply basins, and to create new paths from existing supply basins to additional markets.[32] As new supply basins and paths develop, issues associated with shippers' relinquishment (''turn-back'') of capacity along older pipeline routes from the traditional supply areas have arisen as firm contracts come up for renewal. The Commission has addressed such capacity issues on pipelines serving the Midwest[33] and Southern California,[34] and on other pipelines serving traditional production areas.[35] It is possible that as other pipelines' long-term contracts expire, additional capacity will become unsubscribed because shippers now have more flexibility to choose different suppliers and pipeline routes than they had prior to restructuring. The Commission and the industry have sought creative ways to market excess capacity so that pipelines can recover their costs.[36]

The Commission continues to refine its policies to reflect current circumstances. The Commission is considering possible improvements in the capacity release rules, so that pipeline capacity can be traded more efficiently.[37] The Commission has also adopted uniform national business standards for interstate pipelines,[38] and the process of standardizing practices for interstate transportation is a continuing effort.[39] Because of all these changes in the industry, the Commission's views on the issues remanded by the Court, of necessity, are different from the Commission's views in 1992 when it issued Order No. 636.

In summary, on remand the Commission has decided to modify its no-notice policy, on a prospective basis, to the extent the prior policy restricts entitlement to no-notice service to any particular group of customers. Further, the Commission will reverse its selection of a twenty-year matching term for the right of first refusal and instead adopt a five-year matching term. The Commission will reaffirm its decision to first require customer-by-customer mitigation of the effects of SFV rate design. In addition, the Commission will reaffirm its decision to establish the eligibility of customers of downstream pipelines for the upstream pipeline's one-part small-customer rate on a case-by-case basis. The Commission will reverse the requirement that pipelines allocate ten percent of GSR costs to interruptible customers, and instead will require pipelines to propose the percentage of their GSR costs their interruptible customers must bear in light of the individual circumstances present on each pipeline. Finally, the Commission will reaffirm its decision to exempt pipelines from sharing in GSR costs.

II. Eligibility Date for No-Notice Transportation

In Order No. 636, in connection with the conclusion that bundled, city-gate, firm sales service was contrary to section 5 of the NGA, the Commission required pipelines to provide a ''no-notice'' transportation service. Under no-notice transportation service, firm shippers could receive delivery of gas on demand up to their firm entitlements on a daily basis, without incurring daily scheduling and balancing penalties. The purpose of no-notice service was to enable firm shippers to meet unexpected requirements such as sudden changes in temperature. The Commission required that pipelines offer no-notice service only to those

[27] Since 1990, futures contracts have provided information about expected prices each month for the next two years, and these prices are reported daily.

[28] This estimate is derived from downloaded data posted on pipelines' electronic bulletin boards as required by 18 CFR § 284.10(b).

[29] For example, in Tennessee Gas Pipeline Co., Opinion No. 406, 76 FERC ¶ 61,022 at 61,127–29 (1996), customers argued they should not be compelled to pay for or hold firm rights to capacity in the production area when they only want capacity in the market area. *See also* Transcontinental Gas Pipe Line Corp., Opinion No. 405, 76 FERC ¶ 61,021 at 61,061 (1996) (discussing the significance of segmenting capacity).

[30] For example, in Docket No. CP96–153–000, Southern Natural Gas Co. has applied for authorization to expand its pipeline facilities by 76,000 Mcf/day of capacity, primarily to serve existing customers wishing to increase their firm contract quantities. *See* Southern Natural Gas Co., 76 FERC ¶ 61,122 (1996). The Commission recently authorized CNG Transmission Corp. to construct a pipeline loop between two points in Schenectady Co., New York, to alleviate potential service interruptions to Niagara Mohawk Power Corp.'s distribution system. CNG Transmission Corp., 74 FERC 61,073 (1996).

[31] In Docket Nos. CP96–248–000 and CP96–249–000, Portland Natural Gas Co. has proposed to construct a new 242-mile pipeline extending from Troy, Vermont, to Haverhill, Massachussets. In Docket Nos. CP96–178–000, CP96–809–000 and CP96–810–000, Maritimes & Northeast Pipeline, LLC also propose to construct new pipeline facilities in Northern New England.

[32] For example, Northern Border Pipeline Company, in Docket No. CP95–194–000 and Natural Gas Pipeline Company of America, in Docket No. CP96–27–000, have proposed to construct new pipeline facilities to bring Canadian gas to the Chicago area.

[33] Natural Gas Pipeline Co. of America, 73 FERC ¶ 61,050 (1995).

[34] El Paso Natural Gas Co., 72 FERC ¶ 61,083 (1995) (rejecting El Paso's proposed ''exit fee'' to reallocate costs associated with turned-back capacity); Transwestern Pipeline Co., 72 FERC ¶ 61,085 (1995) (approving a settlement including a mechanism to share the costs and burdens associated with capacity relinquishment).

[35] Tennessee Gas Pipeline Co., 77 FERC ¶ 61,083 at 61,358 (1996) (permitting rate design changes in a contested settlement based, in part, on Tennessee's concern that 70 percent of its firm contracts would expire by the year 2000); Transcontinental Gas Pipe Line Corp., Opinion No. 405–A, 77 FERC ¶ 61,270 (1996) (deferring potential capacity turn-back issues until closer to the expiration date of the contracts at issue).

[36] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, Statement of Policy and Request for Comments, 74 FERC 61,076 (1996); NorAm Gas Transmission Co., 75 FERC ¶ 61,091 at 61,310 (1996).

[37] Secondary Market Transactions on Interstate Natural Gas Pipelines, 61 FR 41046 (1996), IV FERC Stats. & Regs. ¶ 32,520 (to be codified at 18 CFR part 284) (proposed July 31, 1996).

[38] Standards for Business Practices of Interstate Natural Gas Pipelines, Order No. 587, 61 FR 39053 (1996), III FERC Stats. & Regs. ¶ 31,038 (1996) (to be codified at 18 CFR parts 161, 250, and 284).

[39] Standards for Business Practices of Interstate Natural Gas Pipelines, 61 FR 58790 (1996), IV FERC Stats. & Regs. ¶ 32,521 (to be codified at 18 CFR part 284) (proposed Nov. 13, 1996).

customers eligible for firm sales service at the time of restructuring.

The Court remanded for further explanation of this limitation on the no-notice service requirement.[40] Section 284.8(a)(4) of the regulations, adopted by Order No. 636, requires pipelines ''that provided a firm sales service on May 18, 1992 [the effective date of Order No. 636]'' to offer the no-notice service.[41] The eligibility cut-off for no-notice service was established in Order No. 636-A, in which the Commission held that pipelines were required to offer no-notice transportation service ''only to customers that were entitled to receive a no-notice firm, city gate, sales service on May 18, 1992.''[42] The Commission also strongly encouraged pipelines to make no-notice service available to their other customers on a non-discriminatory basis.

On appeal, the Court addressed the issue of whether the Commission should have required pipelines to offer no-notice transportation service not only to customers who remained sales customers on May 18, 1992, but also to former bundled firm sales customers who had converted to open access transportation before Order No. 636 (conversion customers). The Court found the Commission had not adequately explained why the conversion customers should not also have a right to receive no-notice service. The Court held that the Commission's desire to begin the experiment with no-notice service on a limited basis does not explain or justify the disadvantaging of former sales customers who converted before Order No. 636.[43] The Court also held that, while conversion customers had no right to expect to receive no-notice service, neither did customers who were still receiving bundled sales service on May 18, 1992.[44] Finally, the Court held that the Commission had not provided substantial evidence to support its assumption that bundled sales customers relied more heavily on reliability of transportation service than did conversion customers.[45] The Court accordingly remanded the issue of no-notice transportation eligibility to the Commission for further explanation.[46]

At the time of Order No. 636, considerable uncertainty existed whether pipelines would be able to perform no-notice service on a widespread basis. Many pipelines had indicated in their comments that they would not be able to provide no-notice transportation service.[47] However, at a technical conference held on January 22, 1992, pipelines made statements to the contrary. In Order No. 636, the Commission relied upon those later assertions. Nevertheless, on rehearing of Order No. 636, rehearing petitions from pipelines such as Carnegie Natural Gas Company (Carnegie) and CNG Transmission Corporation (CNG) indicated there was still some uncertainty among pipelines whether they would be able to provide reliable no-notice service.[48] In addition, pipelines asked the Commission to limit no-notice transportation service to existing sales customers at current delivery points with the option to extend the service on a nondiscriminatory basis where the pipeline had adequate capacity and delivery capacity.[49] The rehearing requests of bundled sales customers also reflected a continuing concern that unbundled services could not replicate the quality of the bundled sales services.[50]

In light of such uncertainty, the Commission decided to limit the requirement for pipelines to offer no-notice service to include only those customers who were then bundled sales customers. It appeared to the Commission that bundled sales customers relied more heavily on the reliability of the transportation service embedded within the sales service they were receiving than the conversion customers relied on the reliability of their transportation service. This is because no-notice service was an implicit part of bundled sales, but was not a part of unbundled transportation. During the period between Order Nos. 436 and 636, sales customers generally converted to transportation only to the extent that they did not need the higher quality of the transportation service embedded within bundled sales service.[51] In many cases, sales customers converted some, but not all, of their sales contract demand. These customers relied on their retained pipeline sales service to obtain gas during peak periods since sales service was equivalent to a no-notice service. Customers used their converted transportation service as a base load service to obtain cheaper gas from non-pipeline suppliers throughout the year.[52] The comments filed in the record of Order No. 636 also indicated that non-converted, or partially-converted customers placed more reliance on the reliability of the transportation service embedded within the bundled sales service.[53]

The post-restructuring experience with no-notice service has been quite varied, but the early concerns about the ability of pipelines to provide reliable no-notice service were not realized. Some pipelines had no bundled sales customers when Order No. 636 took effect, and thus were not required to offer no-notice service as part of their restructuring and did not do so. In the one restructuring proceeding[54] where customers who had converted to transportation before Order No. 636 indicated a desire for no-notice service, the pipeline offered them the service, but they ultimately refused it because they found it too expensive.

Some pipelines have, post-restructuring, expanded their offering of no-notice service. While Williams Natural Gas Company (Williams)

[40] UDC, 88 F.3d at 1137.

[41] 18 CFR 284.8(a)(4).

[42] Order No. 636-A, [Regs. Preambles Jan. 1991-June 1996] FERC Stats. & Regs. at 30,573.

[43] UDC, 88 F.3d at 1137.

[44] Id.

[45] Id.

[46] Id.

[47] For example, the Interstate Natural Gas Association of America (INGAA) took the position that the bundled, citygate firm sales service was essential to the providing of no-notice and instantaneous service. See also Initial Comments of Texas Eastern Transmission Corp., Panhandle Eastern Pipe Line Co., Trunkline Gas Co., and Algonquin Gas Transmission Company (PEC Pipeline Group) at 16–17.

[48] For example, Carnegie and CNG asserted that before unbundling, the pipeline's system manager could rely on storage, system supply gas, linepack, and upstream pipeline deliveries. They argued that unbundling would deprive the system manager of the use of some or all of these resources and restrict the manager's ability to operate the system in the most efficient, system-wide manner. CNG Transmission Corp., Request for Rehearing at 32; Carnegie Natural Gas Co., Request for Rehearing at 42–3.

[49] INGAA, United Gas Pipe Line Co., ANR Pipeline Co., and Colorado Interstate Gas Co.

[50] The American Public Gas Association argued that firm sales service could not be replicated without assured access to firm storage service. Request for Rehearing at 12–20, *citing* initial comments of the Distributors Advocating Regulatory Reform at 74. Similarly, Citizens Gas & Coke Utility complained that Order No. 636 did not discuss no-notice gas supplies, storage capacity allocation, or the use of flexible receipt points for meeting the needs of high priority customers. Request for Rehearing at 2–3.

[51] Order No. 636, [Regs. Preambles Jan. 1991-June 1996] FERC Stats. & Regs. at 30,402.

[52] For example, Order No. 636 found that in 1991, 60 percent of peak day capacity on the major pipelines that made bundled sales was still reserved for pipeline sales service. Order No. 636 also found: While pipeline sales were less than 20 percent of total throughput on the major pipelines, during the three day period of peak usage, pipeline sales were approximately 50 percent of total deliveries. The seasonal nature of the pipeline sales indicates that customers rely on pipeline sales during periods when capacity is most likely to be constrained. Order No. 636, [Reg. Preambles Jan. 1991-June 1996] FERC Stats. & Regs. at 30,400.

[53] Id. at 30,403 n.68 (quoting reply comments of United Distribution Companies at 7: ''The remaining pipeline sales service is largely used to provide swing service during the winter months and therefore cannot be converted absent comparable transportation.'').

[54] Questar Pipeline Co., 64 FERC ¶ 61,157 (1993).

originally refused a group of conversion customers' requests for no-notice service,[55] a number of the conversion customers eventually obtained no-notice service under new contracts with the pipeline.[56] More recently, Mid Louisiana Gas Company (Mid Louisiana) faced the loss of its no-notice customers to a lower-priced competing intrastate bundled service. In an effort to retain the customers, Mid Louisiana proposed to reconfigure its no-notice service to reduce costs and make its no-notice service a more attractive option.[57] Mid Louisiana also expanded its offering of no-notice service to all firm transportation customers, not just those former sales customers previously eligible for no-notice service.

According to data published by the Interstate Natural Gas Association of America, no-notice service represented 17 percent of total pipeline throughput in 1995, an increase from 15 percent the previous year.[58] This increase in the volume of no-notice service provided is consistent with the pattern the Commission has observed in the industry. Some pipelines, such as Mid Louisiana, Questar, and Williams, have been providing no-notice service beyond the minimum requirements directed by the Commission in Order No. 636-A.

The Commission cannot retroactively change Order No. 636's limitation on the pipeline's requirement to offer no-notice service since it is impossible to change past service. However, given the varied experience with no-notice service since restructuring, and in light of the Court's remand, the Commission will no longer continue to limit the pipeline's no-notice service obligation to the pipeline's bundled sales customers at the time of restructuring.

The Commission intends no other changes to the pipeline's obligation to provide no-notice service as provided in section 284.8(4) of the Commission's regulations. If a pipeline offers no-notice service, the Commission will require it to offer that service on a non-discriminatory basis to all customers who request it, under the nondiscriminatory access provision in § 284.8(b)(1).[59] The Commission is aware that since all pipelines were not required during restructuring to offer no-notice service, some pipelines may not have the facilities and the capacity available to do so. The Commission's open-access policy has always been that interstate pipelines must offer open-access transportation to all shippers on a nondiscriminatory basis, to the extent capacity is available.[60] The nondiscriminatory access condition does not obligate pipelines to expand their capacity or acquire additional facilities to provide service. Thus, a pipeline offering no-notice transportation service must do so only to the extent the pipeline has capacity available (including the storage capacity that may be needed to perform no-notice service).

The Commission believes that a prospective change in policy based on current circumstances will satisfy the needs of all shippers who desire no-notice service. This approach is consistent with the fact that some pipelines, such as Mid Louisiana, Williams, and Questar, have already shown a willingness to expand their no-notice service beyond the Commission's basic requirement. However, to the extent there are shippers who desire no-notice service and cannot obtain it for any reason, such cases are appropriately resolved on an individual basis, rather than in a generic rulemaking proceeding.

III. The Twenty-Year Contract Term

Order No. 636 authorized pregranted abandonment of long-term firm transportation contracts, subject to a right of first refusal for the existing shipper. Under the right of first refusal, the existing shipper can retain service by matching the rate and the term of service in a competing bid. The rate is capped by the pipeline's maximum tariff rate, and the Commission capped the term of service at twenty years. The twenty-year term-matching cap was not set forth in the Order No. 636 regulations themselves, but was explained in the preamble and is part of each pipeline's tariff. In Order No. 636, the Commission indicated that pipelines and customers could agree to a different cap.[61] As part of the restructuring obligations, pipelines were required to include in their tariffs the rules and procedures for exercising the right of first refusal, including the matching term cap to apply on that pipeline.

The Court found that the basic right of first refusal structure protects against pipeline market power,[62] and the Court approved the concept of a contract term-matching limitation ''as a rational means of emulating a competitive market for allocating firm transportation capacity.'' [63] The Court, nevertheless, judged inadequate the Commission's explanations for selecting twenty years as an outer limit for an existing customer to bid before securing the continuation of its rights under an expiring contract.[64] Based upon the arguments of LDCs, the Court found inadequate the Commission's explanation that the twenty-year term balances between preventing market constraint and encouraging market stability. The Court concluded that the Commission failed to explain why the twenty-year cap ''adequately protects against pipelines' preexisting market power, which they enjoy by virtue of natural-monopoly conditions;'' [65] and why the ''twenty-year cap will prevent bidders on capacity-constrained pipelines from using long contract duration as a price surrogate to bid beyond the maximum approved rate, to the detriment of captive customers.'' [66]

Further, the Court found that the Commission's reliance on the fact that twenty-year contracts have been traditional in cases involving new construction did not sufficiently explain the selection of a twenty-year term for renewal contracts on existing facilities.[67] Accordingly, while the Court held that the Commission had justified the right-of-first-refusal mechanism, with its twin matching conditions of rate and contract term, it remanded the twenty-year term cap for further consideration.[68]

The right-of-first-refusal mechanism was, and is, intended to protect existing

[55] Williams Natural Gas Co., 65 FERC ¶ 61,221 (1993), *reh'g denied,* FERC ¶ 61,315 (1994).

[56] Williams Natural Gas Co., 77 FERC ¶ 61,277 (1996).

[57] Mid Louisiana Gas Co., 76 FERC ¶ 61,212 (1996).

[58] Foster Natural Gas Report, No. 2098 (Sept. 9, 1996).

[59] 18 CFR 284.8(b)(1).

[60] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, [Regs. Preambles 1982–1985] FERC Stats. & Regs. ¶ 30,665 at 31,516–17 (1985).

[61] In the restructuring proceedings of Alabama-Tennessee Natural Gas Co., Mississippi River Transmission Corp., Northern Natural Gas Co., and Trunkline Gas Co., as a consequence, the pipeline and its customers agreed to 10-year caps.

[62] *UDC,* 88 F.3d at 1140.

[63] *Id.*

[64] *Id.* at 1140–41.

[65] *Id.* at 1140.

[66] The Court dismissed other arguments against the twenty-year term. In response to the claim that a contract term-matching requirement disadvantaged industrial customers because of the possible short useful life of a particular productive asset, the Court noted the industrial customers' ready access to alternative fuels, and greater access than consumers served by LDCs. *UDC,* 88 F.3d at 1140. The Court also rejected the contention that the twenty-year cap discriminated against industrial customers in light of their shorter-term natural gas needs than other customers. The Court found that although the cap may affect different classes of customers differently, since all parties have an equal opportunity to bid for capacity, the cap did not violate NGA section 5. *Id.* at 1141 and n.47.

[67] *Id.* at 1141.

[68] *Id.*

customers and provide them with the right of continued service, while at the same time recognizing the role of market forces in determining contract price and term. As the Commission held in Order No. 636–A, when a contract has expired, it is most efficient, within regulatory restraints, for the capacity to go to the bidder who values it the most, as evidenced by its willingness to bid the highest price for the longest term.[69] The pipeline's maximum tariff rate is one regulatory restraint, as the bidding for price cannot go above that rate. The Commission set a cap on term-matching in order to avoid shippers on constrained pipelines being forced into contracts with pipelines for longer terms than they desired.

The term-matching cap is relevant mainly on capacity constrained pipelines. However, term-matching also could become necessary in situations where the contract path goes through constrained points. As the Court recognized, where capacity is not constrained, there is no need for an existing customer to match a competing bid, since the pipeline will have sufficient capacity to serve both the existing customer and any new customer that desires service.[70] While the Court approved the concept of a contract term-matching limitation, it found the basis for the particular cap chosen lacking.[71]

In determining the maximum term that an existing customer should be required to match in order to retain its capacity after its current contract expires, the Commission must weigh several factors. On the one hand, the cap should protect captive customers from having to match competing bids that offer longer terms than the competing bidder would have bid ''in a competitive market without pipelines' natural monopoly.'' [72] On the other hand, the Commission does not wish to constrain unnecessarily the ability of shippers who value the capacity the most to obtain it for terms of the desired length. The Court has recognized that the Commission's task in setting the term-matching cap involves the selection of a ''necessarily somewhat arbitrary figure.'' [73]

The Commission has reexamined the record of the Order No. 636 proceedings, as well as data concerning contract terms that have become available since industry restructuring. The Commission can find no additional record evidence, not previously cited to the Court, that would support a cap as long as the twenty-year cap chosen in Order No. 636. Due to changes in the Commission's filing requirements instituted after restructuring,[74] pipelines now must file, in an electronic format, an index of customers, which is updated quarterly and includes the contract term.[75] The data that are now on file have enabled the Commission to determine average contract terms, both before and since the issuance of Order No. 636. For pre-Order No. 636 long-term contracts, the average term was approximately 15 years.[76] The data show that since Order No. 636, pipelines have entered into substantially shorter contracts than before. Post-Order No. 636 long-term contracts had an average term of 9.2 years for transportation, and 9.7 years for storage. For all currently effective contracts (both pre- and post-Order No. 636), the average term is 10.3 years for transportation and 10 years for storage. Moreover, as shown in Appendix A, the trend toward shorter contracts is continuing. About one quarter to one third of contracts with a term of one year or greater, entered into since Order No. 636, have had terms of one to five years.[77] However, nearly one half of such contracts entered into since January 1, 1995, have had terms of one to five years.[78]

This information strongly suggests that since the issuance of Order No. 636, few, if any, pipeline customers have been willing, or required, to commit to twenty-year contracts for existing capacity. In the only case to come before the Commission to resolve a controversy about the pipeline's right-of-first-refusal process, the customers were required to commit to five-year terms in order to retain the capacity.[79] The industry trend thus appears to be contract terms that are much shorter than twenty years.

On remand, the Commission intends to select a cap to be generally applicable to all pipelines. However, the current data lead us to conclude that the term must be significantly shorter than the twenty-year cap approved in Order No. 636. In addition, the Commission recognizes that the selection of a different cap on remand must be supported by the record. In the Order No. 636 rulemaking, as the Court pointed out, ''most of the commentators before the agency had proposed much shorter-term caps, such as five years.'' [80] For example, Associated Gas Distributors (AGD) argued on rehearing of Order No. 636–A that a five-year cap would provide ''the most equitable balance between the LDC's needs to retain some flexibility in its gas supply portfolio and the pipeline's concern for financial stability.'' [81] Public Service Electric & Gas Company and New Jersey Natural Gas Company argued that a five-year cap would avoid unnecessary retention of capacity by LDCs, which, given their general public utility obligation to serve, ''will err on the side of retaining capacity they might not need, rather than risking permanent loss of such capacity.'' [82] A number of other parties also argued in favor of a five-year matching term.[83] In addition, five years is approximately the median length of long term contracts entered into since January 1, 1995.

Based upon the record developed in the Order No. 636 proceeding, and the information available in the Commission's files, the Commission establishes the contract matching term cap at five years. The five-year cap will avoid customers' being locked into long-term arrangements with pipelines that they do not really want, and will therefore be responsive to the Court's concerns. The five-year cap also has the advantage of being consistent with the current industry trend of short-term contracts, as indicated by the Commission's newly-available data.[84]

[69] Order No. 636–A, [Regs. Preambles Jan. 1991–June 1996] FERC Stats. & Regs. at 30,630.

[70] *UDC*, 88 F.3d at 1140.

[71] *Id*.

[72] *Id*.

[73] *Id*. at 1141 n.44.

[74] Revisions to Uniform System of Accounts, Forms, Statements, and Reporting Requirements for Natural Gas Cos., Order No. 581, [Regs. Preambles Jan. 1991–June 1996] FERC Stats. & Regs. ¶ 31,026 (1995), *reh'g*, Order No. 581–A, [Regs. Preambles Jan. 1, 1991–June 1996] FERC Stats. & Regs. ¶ 31,032 (1996).

[75] 18 CFR 284.106(c).

[76] Using the October 1, 1996 Index of Customers filings, the Commission calculated the average lengths of long-term contracts (contracts with terms of more than one year) entered into before the April 8, 1992 issuance of Order No. 636, versus those entered into after that date. For pre-Order No. 636 contracts, the average contract term for transportation was 14.8 years, and for storage, the average term was 14.6 years.

[77] Appendix A, p. 1.

[78] Appendix A, p. 2.

[79] Williams Natural Gas Co., 69 FERC ¶ 61,166 (1994), *reh'g*, 70 FERC ¶ 61,100 (1995), *reh'g*, 70 FERC ¶ 61,377 (1995), *appeal pending sub nom*. City of Chanute v. FERC, No. 95–1189 (D.C. Cir.).

[80] *UDC*, 88 F.3d at 1141.

[81] Sept. 2, 1992 Request for Rehearing and Clarification at 13.

[82] Sept. 2, 1992 Request for Rehearing at 6.

[83] *E.g.*, Northern States Power Co. (Minnesota) and Northern States Power Co. (Wisconsin), Sept. 1, 1992 Request for Rehearing at 4–6; New Jersey Board of Regulatory Commissioners, Sept. 2, 1992 Request for Rehearing at 2; New Jersey Natural Gas Co., May 8, 1992 Request for Rehearing at 6; UGI Utilities, Inc., Sept. 2, 1992 Request for Rehearing at 27; the Industrial Groups, Sept. 2, 1992 Request for Rehearing at 18.

[84] The American Gas Association (AGA), INGAA, and UDC have filed pleadings proposing different courses of action regarding the contract matching term. AGA urges the Commission either to

Continued

The Commission will require all pipelines whose current tariffs contain term caps longer than five years to revise their tariffs consistent with the new maximum cap, regardless of whether this issue is preserved in the individual restructuring proceedings. The Commission will consider on a case-by-case basis whether any relief is necessary in connection with contracts renewed since Order No. 636. The Commission will entertain on a case-by-case basis requests to shorten a contract term if a customer renewed a contract under the right-of-first-refusal process since Order No. 636 and can show that it agreed to a longer term renewal contract than it otherwise would have because of the twenty-year cap.

IV. Customer-by-Customer v. Customer-Class Mitigation

In order to mitigate the cost-shifting effects of SFV rate design, the Commission required pipelines to phase in SFV rates for some customer classes over a four-year period. However, the Commission required pipelines to first seek to avoid significant cost shifts to individual customers (rather than customer classes) by using alternative ratemaking techniques such as seasonal contract demand.

The Court found that the Commission had not adequately explained its preference for customer-by-customer mitigation over customer-class mitigation.[85] The Court was especially concerned by the argument that the ''establishment of rates on a customer-by-customer basis increases the risks that a pipeline will fail to collect its total costs during the period in which rates are in effect.'' [86] This issue was remanded for the Commission to further examine the question of whether the initial mitigation measures should be implemented on the basis of customer class.[87]

This issue arises because, under MFV, half of the fixed costs in the reservation charge were allocated among customers on the basis of peak demand (the ''D–1'' charge), and the other half were allocated on the basis of annual usage (the ''D–2'' charge). Under the SFV method, however, a pipeline's fixed costs are allocated among customers based on contract entitlement alone. As the Court recognized, the adoption of SFV would shift costs to low load-factor customers, in part by ''measuring usage solely based on peak demand, rather than annual usage.'' [88] The Commission, while finding that the impact of placing all of a pipeline's fixed costs in the reservation charge would facilitate an efficient transportation market and support a competitive gas commodity market, found it appropriate to minimize significant cost-shifting to ''maintain the status quo with respect to the relative distribution of revenue responsibility.'' [89] In explaining how to minimize cost shifts, the Commission held in Order No. 636–B that a ''significant cost shift'' test was to be applied to each customer.[90] The Commission further explained that its goal was to maintain the status quo and not to provide the opportunity for some customers ''to make themselves better off at the expense of other customers.'' [91] Instead, the Commission intended each individual customer's revenue responsibility to stay substantially the same.

The purpose of mitigation was, in a sense, to replicate the role the D–2 component played under MFV rate design. Under MFV rate design, the D–2s operated in essence on a customer-by-customer basis, since each customer got a different D–2 based on its annual usage. The result was a lower allocation to low load factor customers within a class than high load factor customers in the same class. This effect of D–2s was thus customer-specific.

Pipelines tend to have relatively few customer classes, but those classes have many members. As a result, customers within a single class have widely varying load factors and other characteristics. Therefore, the implementation of SFV, together with the elimination of the D–2 component in MFV rate design, caused substantial cost shifts among customers within particular customer classes. Mitigation by class does nothing to minimize those cost shifts. In the proceedings to implement each pipeline's restructuring, it became clear that the customer-by-customer approach was preferable because mitigation could be structured in accordance with the individual circumstances and needs of each customer. Thus, while Order No. 636 provided for mitigation on the basis of customer class as well as on a customer-by-customer basis, in fact, in the individual proceedings, the customer class approach was never used.

Another reason the Commission preferred customer-by-customer mitigation was that the risks to the pipeline, that it would underrecover its cost of service, could be examined and minimized on a case-by-case basis in the individual restructuring proceedings. As a general matter, the customer-by-customer mitigation was carried out by using seasonal contract demands. [92] That method, as implemented by the Commission, did not make it more likely that the pipeline would fail to recover its revenue requirement.[93] It simply uses seasonal measures to reallocate costs in order to avoid significant shifts in revenue responsibility.

Since the Commission directed, in Order No. 636–B, that each customer's revenue responsibility could not change significantly with the use of SFV, the rates would provide for the same revenue stream pre- and post-SFV. In the case of only one pipeline—Williston Basin Pipeline Company—has there been any problem of the pipeline not recovering its costs, and that grew out of the unusual circumstances that developed after restructuring.[94] That matter is now at issue in the pipeline's pending rate case, which is in hearing

eliminate the cap or to select a cap of no more than three years. However, AGA does not provide any basis for its argument that three years, as opposed to any other term shorter than twenty years, is the appropriate cap for the Commission to adopt. UDC supports AGA's proposal and argues that the majority of ''long-term'' contracts now and in the foreseeable future will average four years or less. INGAA argues that the right-of-first refusal requirement should only attach to contracts with terms of at least ten years or longer, and that the Commission should reduce the matching term to ten years. INGAA submits that this would correspond to the length of contract commonly required for new construction, as well as to the needs of the market.

[85] *UDC*, 88 F.3d at 1174.

[86] *Id.* (quoting Pipelines' Brief at 27).

[87] *Id.*

[88] *Id.* at 1170.

[89] Order No. 636–B, 61 FERC at 62,014.

[90] *Id.* at 62,016.

[91] *Id.*

[92] Northwest Pipeline Corp., 63 FERC ¶ 61,130 (1993), *order on reh'g* 65 FERC ¶ 61,055 (1994); Mississippi River Transmission Corp., 64 FERC ¶ 61,299 (1993).

[93] The use of seasonal contract demands enables firm customers to lower their daily reservation quantities for the off peak season and keep the higher quantity needed for the peak season.

[94] In Williston's restructuring proceeding, the Commission accepted Williston's proposal to allow the one customer on its system requiring mitigation (Wyoming Gas) to shift to Williston's one-part rate schedule for small customers. As a consequence, Wyoming Gas pays Williston only when it transports gas, including paying any GSR costs. Williston Basin Interstate Pipeline Co., 63 FERC ¶ 61,184 (1993). In May 1995, Wyoming Gas built a 15-mile extension and connected its facilities with Colorado Interstate Gas System, allowing it to bypass Williston. As a result, Wyoming Gas has reduced its takes from Williston by 35 percent. Williston recently asked the Commission to allow it to convert its existing one-part rate to a two-part rate, with a reservation charge, for Wyoming Gas. Williston has proposed an alternative method of mitigating the cost shift to Wyoming Gas. Williston's proposal, in Docket No. RP95–364, went into effect January 1, 1996, and is in hearing as part of Williston's general rate case. Williston Basin Pipeline Co., 73 FERC ¶ 61,344 (1995), *order on reh'g*, 74 FERC ¶ 61,144 (1996); Order on Motion Rates and Request for Stay, 74 FERC ¶ 61,081 (1996).

before an administrative law judge, and the issue will be addressed in that proceeding. In all other cases, the pipelines' concerns about cost recovery never materialized. Therefore, it appears that this issue has no continuing vitality today. As a result, we see no need to effect changes to the previous ruling. The issues presented in Williston's case can be addressed on a case-specific basis.

V. Small-Customer Rates for Customers of Downstream Pipelines

In Order No. 636, the Commission assured small customers that they could continue to receive firm transportation under a one-part volumetric rate computed at an imputed load factor, similar to the manner in which their previous sales rates were determined. The Commission thus required pipelines to offer a one-part small-customer transportation rate to those customers that were eligible for a small-customer sales rate on the effective date of restructuring.[95] On rehearing of Order No. 636-A, the issue arose whether the Commission should require upstream pipelines to offer their small-customer rate to the small customers of downstream pipelines, who became direct customers of the upstream pipeline as a result of unbundling. The Commission held in Order No. 636-B that this issue should be raised in the upstream pipeline's restructuring proceeding, to ''enable the parties to consider the small customers' need for such a service on the upstream pipeline and the impact of the additional small customers on the rates charged to the upstream pipeline's current customers under the small customer schedule and its customers paying a two-part rate.'' [96]

The Court found that the Commission made an arbitrary distinction between former indirect small customers of an upstream pipeline and small customers who were direct customers of the upstream pipeline.[97] Despite the Commission's indication in Order No. 636–B that the Commission would consider the need for such discounts on a case-by-case basis, the Court agreed with appellants' contention, that it is ''unfair and unreasonable to make them demonstrate * * * a need [for a small customer rate] in restructuring proceedings when that need has already been presumed for other small customers.''[98] Thus, the Court remanded the issue to the Commission for further consideration of ''whether or not the small customer benefits should be made available to the former downstream small customers.'' [99]

The Commission's ruling, that the issue would be considered on a pipeline-by-pipeline basis, rather than in a generic rulemaking, did not represent an unwillingness by the Commission to fully consider the needs of the former downstream small customers. One of the objectives of Order No. 636's requirement that pipelines offer a subsidized, one-part transportation rate to their former small sales customers was to maintain a status quo for that class of customers, subject to a few changes in terms and conditions adopted in the Rule.[100]

Any changes in the size of the subsidized, small customer class on a pipeline necessarily affect the pipeline's other customers. Under traditional cost-based ratemaking, rates are generally designed to recover the pipeline's annual revenue requirement.[101] Costs are allocated to customer classes based on contract capacity entitlements and projected annual or seasonal volumes. Small customer rates, however, involve an adjusted cost allocation to permit them to pay less for their service than they would if their rates were designed based on actual purchase levels. Small customers have historically been charged rates derived from a higher-than-actual, imputed load factor because these customers often ''lack the flexibility to construct storage and lack industrial load to balance their purchases,'' [102] and because they serve the distinct function of delivering gas primarily to residential and light commercial users.[103] During the restructuring process, the Commission intended for pipelines to retain the same imputed load factor for the small customer transportation rate that had previously been used to compute the small customer sales rate.[104]

Since a one-part, small-customer rate is a subsidized rate, eligibility criteria for the small-customer class and the size of that class is always a contentious issue in a pipeline rate case. Before restructuring, pipelines and their customers usually arrived at the small-customer eligibility cutoff through negotiations. The class size and eligibility criteria therefore differ on each pipeline. Changes to the eligibility criteria for the small customer rate, particularly those that enlarge the size of the class, upset the prior cost allocation among the customer classes. Those customers who are not in the small customer class experience a cost shift because they must pick up a greater share of the pipeline's costs. The determination of class size and eligibility requires consideration of the customer profile of each pipeline and the individual circumstances present on each system, and ultimately is the result of pragmatic adjustments.[105]

Before Order No. 636, the pipelines had a relatively stable group of customers. Order No. 636, however, greatly expanded the number of customers a pipeline would serve, and the cost-shifting effects of a significant expansion of the class of customers eligible for the rate were not known. Circumstances vary widely throughout the pipeline industry. For example, the upstream-most pipelines serving production areas, such as Texas and the Gulf of Mexico, may serve ten or more downstream pipelines. Therefore, allowing all the small customers of all those downstream pipelines automatically to qualify for small

[95] Section 284.14(b)(3)(iv) of the regulations adopted by Order No. 636 required pipelines to include in their restructuring compliance filings tariff provisions offering one-part small-customer rates for transportation, to the class of customers eligible for that pipeline's small-customer sales rate on May 18, 1992. Section 284.14 contained provisions governing the implementation of pipeline restructuring and setting forth the contents of pipeline compliance filings. In Order No. 581, the Commission deleted Section 284.14 from the regulations because the regulation was no longer necessary following the completion of restructuring. Revisions to the Uniform System of Accounts, Forms, Statements, and Reporting Requirements for Natural Gas Cos., Order No. 581, 60 FR 53019 (October 11, 1995), II FERC Stats. & Regs. ¶ 20,000 *et seq.* (regulatory text), III FERC Stats. & Regs ¶ 31,026 (1995) (preamble).

[96] Order No. 636–B, 61 FERC at 62,020.

[97] *UDC*, 88 F.3d at 1174–75.

[98] *Id.* at 1174.

[99] *Id.* at 1175.

[100] Order No. 636-B, 61 FERC at 62,019.

[101] The Commission's traditional cost-based ratemaking is a five-step process. The first task is to determine the pipeline's overall cost of service. The second task is to functionalize the pipeline's costs by determining to which of the pipeline's operations or facilities the costs belong. The third task is to categorize the costs assigned to each function as fixed costs (which do not vary with the volume of gas transported) or variable, and to classify those costs to the reservation and usage charges of the pipeline's rates. The fourth step is to allocate the costs classified to the reservation and usage charges among the pipeline's various rate zones and among the pipeline's various classes of jurisdictional services. The fifth step is to design each service's rates for billing purposes by computing unit rates for each service. The fifth step is called rate design. *See* Order No. 636, [Regs. Preambles Jan. 1991–June 1996] FERC Stats. & Regs. at 30,431.

[102] Texas Eastern Transmission Corp., 30 FERC ¶ 61,144 at 61,288 (1985).

[103] Tennessee Gas Pipeline Co., 27 FERC ¶ 63,090 at 65,375 (1984).

[104] Order No. 636–B, 61 FERC at 62,019.

[105] *See* FPC v. Natural Gas Pipeline Co. of America, 315 U.S. 575, 586 (1941) (holding that rate-making bodies are ''free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.'') *See also* Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 589 (1945) (''Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It is not an exact science.'').

customer status on the upstream pipeline could shift substantial costs to the relatively few existing non-pipeline direct customers of the upstream pipeline. The Commission could not, through a generic ruling, be certain this would not happen.

The circumstances of Tennessee Gas Pipeline Company (Tennessee) and its three downstream pipelines illustrate some of the factors to be taken into account with respect to the issues of small customer class size and eligibility.[106] During restructuring, small customers of three pipelines downstream from Tennessee (East Tennessee, Alabama-Tennessee, and Midwestern) became direct customers of Tennessee, as well as the downstream pipelines. Tennessee originally proposed to offer a one-part rate only to its direct small customers and those customers of downstream pipelines that took service directly from Tennessee prior to restructuring. Tennessee proposed to continue using its pre-existing eligibility cutoff of 10,000 Dth/day for the one-part rate. Tennessee added a different, two-part rate schedule for its former small sales customers and to other small customers of downstream pipelines. Tennessee requested an eligibility cutoff of 5,300 Dth/day for the two-part rate schedule because it was the highest criterion used in the tariffs of Tennessee's downstream pipelines.[107]

The Commission found that the lack of a one-part rate for small former sales customers on Tennessee's downstream pipelines would lead to inequitable results. The Commission thus required Tennessee to offer the one-part rate to those downstream customers otherwise eligible for small customer rates on the downstream pipelines, and held that the eligible level would be set at 5,300 Dth/day or less. The Commission analyzed the cost shifting effect of enlarging the small-customer class and found that the particular increase to the eligible class under consideration would affect only a small percentage of Tennessee's daily transportation contract demand.[108] A generic determination concerning the class of eligible customers simply would not have permitted the Commission to fully consider the needs of the small customers and the impact of expanding class size and eligibility on the other customers. Therefore, based on further consideration, the Commission reaffirms its decision to determine, on a case-by-case basis, the eligibility of customers of downstream pipelines for the upstream pipeline's small-customer rate.

VI. Pipelines' Exemption From GSR Costs

A. Summary of Commission Conclusion on Remand

In UDC, the Court remanded to the Commission the issue of the pipelines' recovery of prudently incurred GSR costs. While the Court did not question the basic principle that recovery of such costs is appropriate, it did take issue with the Commission's decision to provide pipelines the opportunity to recover their prudently incurred costs in a manner that differed from the approach taken by the Commission in the Order Nos. 500/528 series (hereinafter Order Nos. 500/528).

Observing that the petitioners challenging the Order No. 636 recovery mechanism noted ''remarkable similarities'' between Order Nos. 436 and 636, the Court stated that it ''[i]nitially, agreed with petitioners that the Commission's stated rationale for allocating take-or-pay costs to pipelines substantially applied in the context of GSR costs as well.'' [109] The Court found that ''Order No. 636 is based on principles of cost spreading and value of service that are, in turn, premised on the notion that all aspects of the natural gas industry must contribute to the transition to an unbundled marketplace.'' [110] Accordingly, the Court remanded the matter to the Commission for further consideration. In so doing, the Court expressly ''did not conclude that the Commission necessarily was *required* to assign the pipelines responsibility for some portion of their GSR costs,'' [111] but rather that the Commission's stated reasons did not rise to the level of reasoned decisionmaking.

The Commission readily acknowledges that there are noteworthy similarities between the take-or-pay problems underlying Order No. 436 and the Order Nos. 500/528 series and the GSR recovery issues addressed by the Commission in Order No. 636. Those similarities include, as the Court observed, the fact that the GSR costs to be recovered as transition costs in Order No. 636 arise from the same provisions in producer-pipeline contracts that gave rise to the take or pay problem addressed in Order Nos. 500/528. Another equally important similarity is that in both Order Nos. 500/528 and in Order No. 636, the Commission was attempting to fashion a mechanism to provide pipelines a means for recovering prudently incurred gas supply costs.

There are, however, compelling differences as well. In Order Nos. 500/528 the Commission was attempting to deal with the cost consequences of a failure in gas markets, resulting in a major suppression of demand for gas, coupled with mandated monthly increases in the wellhead ceiling prices for gas. This market failure had its origins in events that preceded the Commission's open access initiatives in Order No. 436 and persisted for a number of years thereafter.[112] A number of factors contributed to the extraordinary circumstance in which pipelines were continuing to incur huge contractual liabilities that could not be, and were not being, recovered in rates. As discussed below, Order No. 380 contributed significantly to the problem by prohibiting the pipelines from including commodity costs in their minimum bills. Order No. 436 exacerbated that problem, particularly by giving customers the ability to convert from sales to transportation service without either providing an appropriate transition cost recovery mechanism so that departing parties would bear some responsibility for the cost consequences associated with their departure or relieving the pipelines of their service obligation. They were still obligated to provide service to their customers when called upon but they could not depend upon those customers to purchase gas on an ongoing basis.[113] However, the inability of pipelines to recover their huge take-or-pay liabilities was, at bottom, the direct result of extraordinary market failures overhanging the pipeline-customer sales relationship that had traditionally provided the means by which pipelines recovered their prudently incurred costs.

In the face of these extraordinary market conditions, the Commission adopted extraordinary measures. As

[106] Customers of Tennessee's downstream pipelines include East Tennessee Customer Group and Tennessee Valley, the petitioners on this issue in *UDC*.

[107] East Tennessee used a volumetric maximum of 4,046 Dth/d; Midwestern Gas Co. used 5,233 Dth/d; and Alabama-Tennessee Natural Gas Co. used 2,564 Dth/d. East Tennessee Natural Gas Co., 63 FERC ¶ 61,102 (1993); Midwestern Gas Transmission Co., 63 FERC ¶ 61,099 (1993); and Alabama-Tennessee Natural Gas Co., 63 FERC ¶ 61,054 (1993).

[108] Tennessee Gas Pipeline Co., 65 FERC ¶ 61,224 at 62,064 (1993), *appeal pending sub nom.* East Tennessee Group v. FERC, (D.C. Cir. No. 93–1837 filed Aug. 20, 1993).

[109] 88 F.3d at 1188.

[110] *Id.* at 1190.

[111] *Id.* at 1188 (emphasis in original).

[112] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol, Order No. 500–H, [Regs. Preambles 1986–1990] FERC Stats. & Regs. ¶ 30,867 at 31,509–14 (1989), *aff'd in relevant part,* American Gas Ass'n v. FERC, 912 F.2d 1496 (D.C. Cir. 1990).

[113] Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988).

discussed below, in Order Nos. 500/528 the Commission created a mechanism to facilitate settlement of the take-or-pay liabilities, to free gas markets of the burdens of a problem that experience demonstrated would not be resolved through traditional cost recovery mechanisms, *with or without* open access transportation requirements. In that context, (and given the Court's decision in *AGD* requiring the Commission to address the take-or-pay problem as a condition to maintaining open access transportation) the Commission's overriding concern was to restore order to the markets promptly by encouraging settlements that could move the industry past economic stalemate. Of necessity, the Commission's objectives could only be achieved by foregoing efforts to assign costs and ''responsibility'' among the various industry participants through conventional means.

In those circumstances, and to facilitate settlement, the Commission found that because no one segment of the industry could be held accountable for the complex circumstance leading to the take-or pay problem, it required all industry participants, including pipelines, to participate in the solution. In exchange for a pipeline's agreement to absorb some part of its take-or-pay costs, the pipeline was granted a rebuttable presumption that its costs were prudently incurred, significantly reducing its risk that a further portion of its costs would be disallowed as not prudently incurred.

In stark contrast to the circumstances surrounding Order Nos. 500/528, Order No. 636 was not issued in the context of market conditions that precluded pipelines from a meaningful opportunity to seek recovery of prudently incurred costs. While at the time of Order No. 636 there were, of course, individual contracts that were priced higher than the prevailing market prices for gas, this ''market circumstance'' did not render pipeline gas supply costs unrecoverable. To the contrary, pipelines had the ability to seek recovery of costs incurred under those contracts, so long as their sales customers continued to purchase gas from them.

However, Order No. 636 effected significant regulatory changes, largely to the benefit of users of the transportation system and purchasers of gas, that directly resulted in the inability of pipelines to recover their gas supply costs from their sales customers (who were allowed to convert to transportation customers by Order No. 636).

After carefully reviewing the Court's concerns in *UDC* and the circumstances surrounding the cost recovery issues in both Order Nos. 500/528 and Order No. 636, the Commission believes that it must reaffirm its conclusion in Order No. 636 that pipelines should be permitted an opportunity to recover 100 per cent of prudently incurred GSR costs. As described below, the Commission finds that the extraordinary market circumstances that gave rise to the requirement for pipeline absorption of gas supply costs in Order Nos. 500/528 were not present at the time of Order No. 636. In the absence of the special circumstances that gave rise to the justification for pipeline absorption as required in Order Nos. 500/528, and in light of the fact that the regulatory changes in Order No. 636 directly led to the incurrence of GSR costs, the Commission reaffirms its conclusion in Order No. 636 that pipelines should be permitted an opportunity to recover 100 percent of costs that are determined to be eligible gas supply realignment costs and are prudently incurred. [114]

B. Scope of Commission's Decision

The Commission's disposition of this matter on remand does not affect the resolution of GSR costs for most pipelines. Since Order No. 636, the Commission has approved settlements between most pipelines and their customers resolving all issues concerning those pipelines' recovery of their GSR costs. In addition, in two GSR proceedings, no party sought rehearing of the Commission's acceptance of the pipeline's GSR recovery proposal.[115] None of the GSR settlements contains a provision permitting the settlement to be reopened as to the absorption issue.[116] Therefore, the Court's remand of the GSR cost absorption issue does not affect the settled GSR proceedings. Regardless of the Commission's decision on remand concerning absorption of GSR costs, the GSR settlements and the final and non-appealable orders will remain binding on the subject pipelines and their customers.[117] To the extent that pipelines have voluntarily elected to enter into settlements that require absorption of some portion of the GRS costs to avoid protracted litigation of eligibility and prudence challenges, we do not disturb that result.

However, there has as yet been no settlement of the proceedings initiated by Tennessee to recover its GSR costs.[118] There has also been no settlement of a recent filing by NorAm Gas Transmission Company (NorAm) and two recent filings by ANR Pipeline Company (ANR) to recover their GSR costs.[119] Also, while the Commission has approved a settlement concerning Southern Natural Gas Company's (Southern) recovery of GSR costs, several of Southern's customers were severed from that settlement.[120] In addition, the settlement approved by the

[114] The Court gave several examples of reasons which might justify not requiring pipelines to absorb a share of their GSR costs. These were: (1) a finding that ''unbundling under Order No. 636 benefits consumers so much more than it does the pipelines that the pipelines should bear few or no GSR costs,'' *UDC*, 88 F.3rd at 1189, (2) a finding that ''the pipelines' contribution to the industry's transition has already been so disproportionately large vis-a-vis consumers that they are entitled to be excused from further responsibility, *Id*., and (3) a finding that requiring the pipeline segment of the industry to absorb GSR costs would ''raise substantial concerns about its financial health,'' *Id.* at 1189 n. 99. The pipeline industry is not in such precarious financial condition that absorption would threaten its financial viability. However, the Commission does not believe that the Court precluded the Commission from using the rationale discussed below in this order.

[115] Trunkline Gas Co., 72 FERC ¶ 61,265 (1995); Williston Basin Interstate Pipeline Co., 70 FERC ¶ 61,009 (1995).

[116] On November 25, 1996, the Missouri Public Service Commission (MoPSC) filed, in this rulemaking docket, a motion asserting that Williams' GSR settlement left open the issue whether Williams must absorb its GSR costs in excess of $50 million. On December 10, 1996, Williams filed an answer, arguing that its settlement provides for it to recover 100 percent of those costs, without regard to the outcome of appeals of Order No. 636. In a separate order in the dockets in which Williams is seeking recovery of GSR costs in excess of $50 million, the Commission has upheld Williams' interpretation of its settlement. Williams Natural Gas Co., 78 FERC ¶ 61,068 (1997).

[117] /Similarly, after the court's decision in Associated Gas Distribs. v. FERC, 893 F.2d 348 (D.C. Cir. 1989) (AGD II), that the Order No. 500 method of allocating fixed take-or-pay charges violated the filed rate doctrine, the Commission exempted from the Order No. 528 order on remand all pipelines whose recovery of take-or-pay costs had been resolved either by settlement or by final and non-appealable order. Order No. 528, 53 FERC ¶ 61,163 at 61,594 (1990).

[118] On January 28, 1997, the Administrative Law Judge in Tennessee's GSR proceedings (Docket Nos. RP93–151–000 *et al.*) required the participants to file a joint status report concerning their settlement negotiations by February 7, 1997. The status report indicated that almost all parties have agreed to a settlement in principle. On February 21, Tennessee reported to the ALJ that the parties expect to file a settlement by February 28, or shortly thereafter.

[119] /NorAm made its first filing to recover GSR costs on August 1, 1996, following the *UDC* decision. The Commission accepted and suspended the filing, subject to this order on remand. NorAm Gas Transmission Co., 76 FERC ¶ 61,221 (1996). The Commission has approved settlements of ANR's first three GSR proceedings. ANR Pipeline Co., 72 FERC ¶ 61,130 (1995); 74 FERC ¶ 61,267 (1996). However, those settlements did not address ANR's recovery of any subsequent GSR costs. On October 31, 1996, ANR filed to recover additional GSR costs in Docket No. RP97–47–000. ANR Pipeline Co., 77 FERC ¶ 61,130 (1996). That proceeding has not yet been settled. In addition, on January 31, 1997, ANR made another GSR filing in Docket No. RP97–246–000.

[120] /Southern Natural Gas Co., 72 FERC ¶ 61,322 at 62,329–30, 62,355–6 (1995), *reh'g denied*, 75 FERC ¶ 61,046 (1996).

Commission concerning the recovery of GSR costs by Panhandle Eastern Pipe Line Company (Panhandle) does not resolve how it will recover any GSR costs which it may file in the future.[121] Therefore, since the recovery of GSR costs does remain an issue in some cases, the Commission must address the issue remanded by the Court. The following describes in greater detail the basis for the Commission's decision to reaffirm it's decision in Order No. 636 with respect to recovery of GSR costs.

C. The Regulatory Framework

The Commission's task in both Order Nos. 500/528 and Order No. 636 was to determine a method for pipelines to recover their prudently incurred costs arising from the non-market responsive take-or-pay contracts entered into during the late 1970s and early 1980s. Take-or-pay costs are part of a pipeline's expenses. As the Court of Appeals held in *Mississippi Power Fuel Corp.* v. *FPC*,[122] pipelines must be allowed an opportunity to recover their prudently incurred expenses:

> Expenses * * * are facts. They are to be ascertained, not created, by the regulatory authorities. If properly incurred, they must be allowed as part of the composition of rates. Otherwise, the so-called allowance of a return upon investment, being an amount over and above expenses, would be a farce.

The Court of Appeals has recently reiterated that holding, and emphasized the Supreme Court's longstanding admonition that regulatory agencies must recognize prudently incurred expenses in establishing just and reasonable rates:

> More than a half century ago, the Supreme Court admonished regulatory agencies to ''give heed to all legitimate expenses that will be charges upon income during the term of regulation.''

Mountain States Telephone & Telegraph Co. v. *FCC*, 939 F.2d 1021, 1029 (D.C. Cir. 1991) (*citing West Ohio Gas Co.* v. *Public Utilities Comm'n of Ohio* 294 U.S. 63, 74 (1935)). Of course, recovery may be denied if particular costs (1) are not used and useful in performing the regulated service [123] or (2) have been imprudently incurred.

Consistent with the Supreme Court's admonishment that regulatory agencies recognize prudently incurred expenses, the Commission has a particular obligation not to ignore or disallow expenses incurred by pipelines as a result of the Commission's own regulatory actions. For that reason, as the Court of Appeals pointed out in *Public Utilities Comm'n of Cal.* v. *FERC*, 988 F.2d 154, 166 (1993), the Commission,

> With the backing of this court, has been at pains to permit pipelines to recover * * * [Order Nos. 500/528 take-or-pay costs] which have accumulated less through mismanagement or miscalculation by the pipelines than through an otherwise beneficial transition to competitive gas markets.

As more fully discussed below, the Order No. 636 GSR costs are the direct result of the transition to unbundled transportation service required by Order No. 636. In Order No. 636, the Commission prohibited pipelines from continuing their practice of bundling sales of natural gas with transportation rights and required pipelines making unbundled sales to do so through a separate arm of the company. Order No. 636 gave pipeline sales customers an immediate right to terminate gas purchases from the pipeline.[124] In light of the substantial improvement in the quality of stand-alone transportation service required by Order No. 636, almost all sales customers immediately terminated their sales service during restructuring, leading to the termination of the pipelines' merchant business. The Commission has developed standards for eligibility for GSR cost recovery designed to limit GSR costs solely to those costs caused by Order No. 636.[125] For that reason, the Commission has given pipelines an opportunity to recover the full amount of their GSR costs.

However, as discussed below, the massive take-or-pay settlement costs addressed by Order Nos. 500/528—unlike GSR costs—were not the direct result of the Commission's regulatory actions. Rather, they arose from market conditions beginning in the early 1980s which would have rendered a portion of the costs unrecoverable, regardless of the Commission's initiation of open access transportation in Order No. 436. In those unique circumstances, while the Commission created a special recovery mechanism to permit the pipelines to recover their take-or-pay settlement costs, the Commission also required pipelines using that mechanism to absorb a share of the costs.

D. The Treatment of Costs in Order Nos. 500/528

In order to understand the basis for the Commission's different treatment of Order No. 636 GSR costs and Order Nos. 500/528 take-or-pay costs, it is necessary first to review the circumstances which led to the Order Nos. 500/528 absorption requirement and the Commission's reasons for that requirement.

1. The Factual Context of Order Nos. 500/528

The industry's take-or-pay crisis developed before the Commission initiated open access transportation in Order No. 436. The Commission made this finding in Order No. 500–H.[126] The severe gas shortages of the 1970's led to enactment of the NGPA, which initiated a phased decontrol of most new gas prices and established ceiling prices for controlled gas, including incentive prices for price-controlled new gas higher than the ceiling prices previously established by the Commission under the NGA.[127] To avoid future shortages, pipelines then entered into long-term take-or-pay contracts at the high prices made possible by the NGPA, and those high prices stimulated producers to greatly increase exploration and drilling.[128] All participants in the natural gas industry expected both demand and prices to continue increasing indefinitely.

However, by 1982 demand was falling, due to a number of factors including unexpectedly strong competition from alternative fuels, the recession of the early 1980s, and warmer than normal weather. By 1983, demand for natural gas was 17 percent below its 1979 level. As a result, the supply of natural gas (*i.e.*, current deliverability from the nation's gas wells) exceeded demand for natural gas by 4 Tcf, or nearly 20 percent of total deliverability.[129] This deliverability

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[121] /Panhandle Eastern Pipe Line Co., 72 FERC ¶ 61,108 (1995).

[122] 163 F.2d 433, 437 (D.C. Cir. 1947).

[123] *Tennessee Gas Pipeline Co.* v. *FERC*, 606 F.2d 1094, 1109 (D.C. Cir. 1979), *cert denied*, 445 U.S. 920, *cert. denied*, 447 U.S. 922 (1980) (''current ratepayers should bear only legitimate costs of providing service to them'').

[124] The Commission's only requirement for pipelines to continue to offer to sell gas at cost-based rates was a requirement that they offer small customers such sales service for a one-year transition period. Order No. 636–A, [Regs. Preambles Jan. 1991–June 1992] FERC Stats. & Regs. at 30,615.

[125] See Texas Eastern Transmission Co., 65 FERC ¶ 61,363 (1993).

[126] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol, Order No. 500–H, [Regs. Preambles 1986–1990] FERC Stats. & Regs. ¶ 30,867 (1989), aff'd in relevant part, *American Gas Ass'n* v. *FERC*, 912 F.2d 1496 (D.C. Cir. 1990).

[127] *Id.* at 31,509.

[128] *Id.* at 31,509–10.

[129] As the Commission found in Order No. 500–H:

> By 1982, demand for gas was falling. High natural gas prices, combined with decreasing oil prices, led to increased fuel switching, particularly as customers who did not already have the necessary equipment to burn alternative fuels installed it. The recession of the early 1980's and warmer than normal weather further decreased demand. These factors combined to create an excess of the supply

surplus persisted for the remainder of the 1980s.

This unexpected change in market conditions caused pipelines, as early as 1982, to start incurring significant take-or-pay liabilities under the take-or-pay contracts entered into with the expectation of continued high demand. By year-end 1983, nearly two years before Order No. 436 issued, pipeline take-or-pay exposure was $5.15 billion.[130] However, despite the deliverability surplus, both wellhead gas prices and the gas costs reflected in the pipelines' rates continued to increase. Similarly, the average residential cost of gas continued to rise.[131] These price increases at a time of oversupply were primarily the result of the inflexible supply arrangements between producers, pipelines, LDCs, and consumers, under which most gas users could obtain gas only through purchases from the pipeline. The Commission's first major action to address those supply arrangements was the issuance of Order No. 380 [132] on May 25, 1984, requiring pipelines to eliminate commodity costs from their minimum bills.

Take-or-pay exposure increased to $6.04 billion by year-end 1984.[133] By the end of 1985, just two months after Order No. 436 issued and before any pipeline had accepted a blanket certificate under Order No. 436, pipelines had outstanding take-or-pay liabilities of $9.34 billion.[134] In 1986, as pipelines were just beginning to implement open access transportation under Order No. 436, the pipelines' outstanding unresolved take-or-pay liabilities peaked at $10.7 billion.[135]

In short, although Order No. 436 exacerbated pipelines' existing take-or-pay problems by making it easier for the pipelines' traditional sales customers to purchase from alternative suppliers, Order No. 436 did not cause those problems. Rather, the pipelines' take-or-pay problems were caused by an excess of supply over demand in the natural gas market which arose in the early 1980s due to the convergence of a number of factors, many entirely unrelated to the Commission's exercise of its regulatory responsibilities. As a result, even before Order No. 436 issued, the natural gas industry already faced a massive problem in which pipelines were contractually bound to take or pay for high-priced gas which market conditions suppressed demand and prevented them from reselling at prices which would recover their costs. Simply put, at the time of Order No. 436, the market was requiring substantial cost absorption entirely apart from any regulatory action of the Commission.

The Commission and the industry had never previously faced a take-or-pay problem of this nature. In earlier times, pipelines had made take-or-pay payments to particular producers, and the Commission had a policy of permitting such payments to be included in rate base and then recovered as a gas cost when the pipeline later took the gas under make-up provisions in the contract.[136] By 1983, however, with their total take-or-pay exposure over $5 billion, the pipelines could not manage their take-or-pay problems, and stopped honoring the bulk of their take-or-pay liabilities.[137] They then sought settlements with the producers to reform or terminate the uneconomic take-or-pay contracts and to resolve outstanding take-or-pay liabilities.

Because pipelines had never previously incurred significant take-or-pay settlement costs, the Commission had no policy concerning whether and how pipelines were to recover those costs. The Commission commenced establishing such a policy in an April 1985 policy statement,[138] just six months before Order No. 436. When Order No. 500 issued in August 1987, few take-or-pay settlement costs had yet been included in pipelines' rates. However, since the pipelines' outstanding take-or-pay liabilities were in the neighborhood of $10 billion, it was clear that pipelines would incur massive costs in their settlements with producers.

2. The Policies of Order Nos. 500/528

When the Commission first addressed the issue of how pipelines should recover their take-or-pay settlement costs in Order No. 500, it did so under the shadow of the pipelines' vast outstanding take-or-pay exposure. As a result, the fundamental premise of Order No. 500 was, as the Court expressed it in *KN Energy* v. *FERC*, that ''the extraordinary nature of this problem requires the aid of the entire industry to solve it.''[139] In order to accomplish this result, Order No. 500 established an equitable sharing mechanism for pipelines to use in recovering their take-or-pay settlement costs, as an alternative to recovery through their commodity sales rates.[140] Relying on ''cost spreading'' and ''value of service'' principles, the Commission permitted pipelines using the equitable sharing mechanism to allocate their take-or-pay settlement costs among all their customers. The Commission also required the pipelines to absorb a portion of their costs.[141]

The Court was of the view that Order Nos. 500/528 based the absorption requirement on the ''cost spreading'' and ''value of service'' principles.[142] However, Order No. 528–A,[143] where the Commission gave its fullest justification for that absorption requirement, did not rely on either of those principles to support the absorption requirement. [144] Rather,

of natural gas (*i.e.*, current deliverability from the nation's gas wells) over the demand for natural gas. The deliverability surplus persisted for the remainder of the 1980's. In 1982 the deliverability surplus was about 1.5 Tcf, or 8.3 percent of total deliverability. By 1983, with the demand for natural gas 17 percent below its 1979 level, the deliverability surplus was about 4 Tcf, or nearly 20 percent of total deliverability.

Id. at 31,510.

[130] *Id*.

[131] The residential cost of gas rose from $5.17 in 1982 to $6.12 in 1984. *Id*.

[132] Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Bill Provisions, Order No. 380, [Regs. Preambles 1982–1985] FERC Stats. Regs. ¶ 30,571 (1984).

[133] *Id*.

[134] *Id*. at 31,513.

[135] *Id*.

[136] Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations, Regulations Preambles 1982–85 ¶ 30,637 at 31,301 (1985).

[137] In Order No. 500–H, the Commission found that, although pipelines incurred total take-or-pay exposure over the period January 1, 1983 through June 30, 1987 of over $24 billion, they only made take-or-pay payments totalling $.7 billion. Order No. 500–H, Regulations Preambles 1986–1990 ¶ 30,867 at 31,514.

[138] Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations, [Regs. Preambles 1982–85] Stats & Regs. ¶ 30,637 (1985).

[139] 968 F.2d 1295, 1301 (D.C. Cir. 1992).

[140] Order No. 500 also increased the pipelines' bargaining power to negotiate settlements with producers through the take-or-pay crediting program.

[141] The Court in *KN Energy* upheld the Commission's use of cost spreading in connection with the allocation of take-or-pay costs among a pipeline's open access customers. However, the Court never reviewed the Order Nos. 500/528 requirement that pipelines absorb a share of the take-or-pay costs. AGA v. FERC, 888 F.2d 136, 152 (D.C. Cir. 1989), holding the absorption requirement not ripe for review. *Accord*: AGA v. FERC, 912 F.2d 1496 (D.C. Cir. 1990).

[142] *UDC*, 88 F.3d at 1188.

[143] Order No. 528–A, 54 FERC ¶ 61,095 (1991).

[144] The Commission's use of cost spreading and value of service principles to allocate take-or-pay costs among all the pipeline's open access customers was, as the Court suggested in *KN Energy*, 968 F.2d at 1302, ''only a minor departure'' from the traditional ratemaking principle that costs should be allocated among customers based on cost causation. Ordinarily, the cost causation principle is used to assign the pipeline's cost-of-service among customers. Its underlying premise is that each customer should be responsible for the costs its service causes the pipeline to incur. A necessary corollary is that the pipeline may, if the market permits, recover 100 percent of the costs it prudently incurs to serve its customers. Otherwise, the customers would not be responsible for all the

Continued

Order Nos. 500/528 consistently recognized the Commission's traditional obligation to ''provide a pipeline a reasonable opportunity to recover its prudently incurred costs.'' [145] However, Order No. 528–A reasoned that, because the take-or-pay problem was caused more by general market conditions than by any regulatory action of the Commission and the underlying take-or-pay contracts were no longer used and useful, it was appropriate to require the pipelines to share in the losses arising from those market conditions.[146]

E. The Treatment of Costs in Order No. 636

The nature of the take-or-pay problem had changed dramatically by the time of Order No. 636. That difference in circumstances accounts for the different policies applied by the Commission in Order No. 636.

1. The Factual Context of Order No. 636

By 1992, when Order No. 636 issued, the world had changed, and the unique circumstances out of which the Order Nos. 500/528 absorption requirement arose no longer existed. Pipelines were no longer incurring substantial costs in connection with their take-or-pay contracts which they were unable to recover in sales rates, as they had been when Order No. 436 issued. While some of the uneconomic take-or-pay contracts of the late '70s and early '80s remained in effect and some pipelines were still working to resolve some past take-or-pay liabilities, there was no longer an industry-wide take-or-pay problem.[147]

In contrast to the situation when Order No. 436 issued, at the time of Order No. 636 most pipelines were no longer incurring new take-or-pay liabilities, even under their few remaining old, unresolved contracts.[148]

Following Order No. 500, pipelines made a massive effort to reform their supply contracts by negotiating with producers settlements of thousands of take-or-pay contracts which either eliminated the uneconomic take-or-pay provisions or terminated the contracts altogether.[149] By the time Order No. 636 issued, pipelines had succeeded in reforming nearly all their supply contracts at a total cost, in settlement payments to producers, of nearly $10 billion.[150] For example, at the hearing in Docket No. RP92–134–000 concerning Southern's Mississippi Canyon construction costs, Southern provided testimony that by 1987 it had succeeded in renegotiating its supply arrangements such that it was no longer incurring additional take-or-pay liabilities.[151]

Another reason that pipelines were not incurring new take-or-pay liabilities when Order No. 636 issued is that, after Order No. 436, unlike after Order No. 636, pipelines continued to perform a significant sales service. This was at least in part because, as the Commission found in Order No. 636, open access transportation service under Order No. 436 was not comparable to the transportation component of bundled sales service. As a result, through such strategies as purchasing gas in the summer, storing it in their storage fields, and then reselling it during periods of peak demand and prices in the winter, at the time of Order No. 636 the pipelines could meet most of their minimum take requirements even in their remaining high-priced contracts. Many pipelines expected to continue providing such a sales service indefinitely into the future. For example, on the day before the June 30, 1991 issuance of the Notice of Proposed Rulemaking which led to Order No. 636, Southern and some of its sales customers filed a comprehensive settlement that would have assured a continued sales service by Southern.[152]

Similarly, on March 10, 1992, less than a month before issuance of Order No. 636, ANR filed a settlement under which it would have continued a bundled sales service.[153]

Order No. 636 upset this relatively stable situation and created a new jeopardy for the recovery of pipeline gas supply costs. Order No. 636 prohibited pipelines from continuing their bundled sales service and resulted in the termination of the pipelines' merchant business. While Order No. 436 had only required pipelines to permit their customers to convert from sales to transportation service over a phased five-year schedule,[154] Order No. 636 gave pipeline sales customers an immediate right to terminate their entire sales service. Order No. 636 also required pipelines to substantially improve the quality of their stand-alone transportation service. As a result, the pipelines' remaining sales customers switched to transportation-only service, with almost all of them immediately terminating their sales service during restructuring.

Order No. 636 also made it more difficult for pipelines to manage their take-or-pay contracts in several other ways. Unlike Order No. 436, Order No. 636 required pipelines to give up most of their storage capacity so that they were less able to pursue such strategies as storing gas purchased in the summer, when sales were too low to meet minimum purchase obligations, for subsequent resale in the winter, when sales levels were higher. In addition, before Order No. 636, many of the pipelines that had the take-or-pay contracts with producers had downstream pipeline customers who were continuing to purchase some gas. However, Order No. 636 required the downstream pipelines also to unbundle, resulting in the loss of the downstream pipelines as sales customers.

The pattern of pipeline filings with the Commission to recover take-or-pay related costs is consistent with the conclusion that Order No. 636 reopened a take-or-pay problem that had been largely resolved. As shown in Table 1 of Appendix B to this order, since Order No. 436, pipelines have filed to recover a total of approximately $12.1 billion in take-or-pay related costs, including about $10.4 billion filed pursuant to Order Nos. 500/528 and $1.7 billion filed as Order No. 636 GSR costs. Fully 81.7 percent of the total $12.1 billion amount was filed, pursuant to Order

costs their service causes the pipeline to incur. For this reason the cost causation principle is not used to assign costs to the pipeline. Order Nos. 500/528 used cost spreading and value of service principles simply to extend the chain of causation to assign costs to a broader group of customers. KN Energy, 968 F.2d at 1302.

[145] Order No. 500–H, [Regs. Preambles 1986–1990] FERC Stats. & Regs. at 31,575.

[146] Order No. 528A, 54 FERC at 61,303–5 (1991).

[147] In late 1989, the Commission found in Order No. 500–H that pipelines' settlements with producers ''have substantially resolved the existing take-or-pay liabilities of most pipelines, and all the pipelines have made significant progress in resolving their problems.'' Order No. 500–H, [Regs. Preambles 1986–90] FERC Stats. & Regs. at 31,523. The Commission also terminated the take-or-pay crediting program effective December 31, 1990, on the ground that such a program no longer would be necessary. *Id.* at 31,529.

[148] Similarly, when the Commission initiated open access transmission in the electric industry in Order No. 888, most electric utilities were recovering their electric generating costs in the rates charged their customers. Therefore, the Commission concluded that it would not be reasonable to require electric utilities to bear losses that, unlike the Order Nos. 500/528 take-or-pay costs, arise as a direct result of Congress' and the Commission's change in regulatory regime through FPA section 211 and Order No. 888. *See* Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, III FERC Stats. & Regs. ¶ 30,——at 31,——(Order No. 888–A) (1997). The Commission's approach to Order No. 636 GSR costs is similar to its approach in Order No. 888 to stranded electric generation costs.

[149] *See Id.* at 31,522–3 and 31,536.

[150] *See* Appendix B, Table 1.

[151] Southern Natural Gas Co., 72 FERC ¶ 61,322 at 62,358 (1995).

[152] However, during Southern's Order No. 636 restructuring proceeding, all its sales customers decided to take transportation only service and Southern terminated its merchant function. *Id.* at 62,362–3.

[153] ANR Pipeline Co., 59 FERC ¶ 61,347, *reh'g*, 60 FERC ¶ 61,145 (1992).

[154] 18 CFR 284.11(d)(3).

Nos. 500/528, before Order No. 636 issued in April 1992. *See* Table 2.

Since Order No. 636, pipelines have continued to make some filings to recover take-or-pay related costs under Order Nos. 500/528. This is because the only costs eligible for recovery as Order No. 636 GSR costs are costs that are tied to the restructuring required by Order No. 636. However, as shown by Table 2, post-Order No. 636 filings to recover take-or-pay related costs pursuant to Order Nos. 500/528 represent only 4.2 percent of the total take-or-pay related costs filed with the Commission since Order No. 436. Table 3, showing costs filed for recovery under Order Nos. 500/528, by quarter, demonstrates graphically the dramatic decline in such costs before Order No. 636, and the relative insignificance of such costs thereafter.

That take-or-pay was no longer an industry-wide problem at the time of Order No. 636 is also suggested by the fact that just two pipelines—Southern and Tennessee—account for approximately 65 percent of all take-or-pay related costs filed with the Commission as Order No. 636 GSR costs.[155] Moreover, the sudden spike in GSR costs filed with the Commission in late 1993, continuing to an extent in 1994, as pipelines were just implementing their Order No. 636 restructuring is consistent with a conclusion that Order No. 636 reopened a take-or-pay problem that had been largely resolved. *See* Tables 4 and 5.

2. The Policies of Order No. 636

Based on the changing nature of the take-or-pay problem reviewed above, the Commission holds that the rationale supporting the Order Nos. 500/528 absorption requirement is not valid for the GSR costs caused by Order No. 636. The rationale used in Order Nos. 500/528 does not support a requirement that pipelines absorb a share of their Order No. 636 GSR costs. In the factual context faced by the Commission at the time of Order No. 636, the bedrock ratemaking principle, that pipelines must be given an opportunity to recover the full amount of their prudently incurred costs, required the Commission to establish a different mechanism for pipelines to recover their Order No. 636 GSR costs. This is particularly so, because these costs were caused by the Commission's regulatory actions.

When Order No. 636 issued, pipelines were generally taking gas under their remaining take-or-pay contracts and no longer accumulating significant additional take-or-pay obligations. Thus, those contracts could no longer reasonably be analogized to a failed gas supply project, the analogy used to support the Order Nos. 500/528 absorption requirement.[156] As a result, the Commission's section 5 action in Order No. 636 reopened a take-or-pay problem that had been largely resolved. The termination of the pipelines' merchant business as a result of Order No. 636 created a situation in which the pipelines simply lacked an ability to manage and sell the natural gas supply portfolio they had under contract. In these circumstances, where the Commission's own regulatory action in Order No. 636 rendered the pipelines' supply contracts no longer used and useful, the Commission believes that pipelines should be allowed full recovery of transition costs caused by Commission action.

Moreover, the Commission only permits 100 percent recovery of GSR costs arising in connection with supply contracts which were part of an overall gas supply portfolio that was commensurate with the pipeline's merchant obligation—in other words contracts which were used and useful when Order No. 636 issued. *See Texas Eastern Transmission Co.*, 65 FERC ¶ 61,363 (1993). Where the pipeline cannot show that its costs satisfy the eligibility standards developed in *Texas Eastern*, the costs are only eligible for Order Nos. 500/528 recovery and a portion must be absorbed. Indeed, since Order No. 636, pipelines have filed to recover, pursuant to Order Nos. 500/528, over $500 million in costs which they recognized were not caused by Order No. 636. Moreover, when parties have questioned whether claimed GSR costs meet the *Texas Eastern* standards, the Commission has required pipelines to demonstrate their eligibility at a hearing. Thus, through its GSR eligibility standards, the Commission ensures that the costs for which 100 percent recovery is permitted are in fact caused by the Commission's regulatory actions in Order No. 636.

Eligible GSR costs are similar to other stranded pipeline merchant costs which Order No. 636 rendered no longer used and useful and whose recovery the Court approved in *UDC*, 88 F.3d at 1178–80. Order No. 636 permitted pipelines to file under NGA section 4 to recover 100 percent of costs ''incurred by pipelines in connection with their bundled sales services that cannot be directly allocated to customers of the unbundled services.'' [157] Those costs included costs incurred in connection with upstream pipeline capacity and storage capacity that a pipeline no longer needs because its sales service terminated due to restructuring. In the section 4 cases where recovery of these costs has been sought, the Commission has recognized that its action in Order No. 636 rendered the costs no longer used and useful, and the Commission has accordingly permitted the full amount of the eligible and prudently incurred costs to be amortized as part of the pipeline's cost-of-service, although not included in rate base.[158] In *UDC*, the Court approved this approach.[159] The GSR costs have become stranded in an identical manner, and therefore pipelines should be afforded the same opportunity for full recovery of their prudently incurred GSR costs.

Moreover, the fact that Order No. 636 led to the complete termination of most pipelines' merchant function, unlike the situation after Order No. 436, means that the Commission cannot now take the Order Nos. 500/528 approach of offering the pipelines the alternative of seeking 100 percent recovery through their sales commodity rates. Rather, the recovery mechanism provided by Order No. 636 is the only available mechanism for recovering GSR costs. Therefore, if the Commission did not permit pipelines to seek recovery of the full amount of their GSR costs through the mechanism provided by Order No. 636, the Commission would be denying recovery by regulatory decree, not simply allowing market forces to prevent full recovery.

As the Commission has previously found, Order No. 636 substantially benefits all gas consumers. It is for that reason that the Commission required that GSR costs be allocated among all the pipelines' customers. In an October 22, 1996 petition for further proceedings on remand, the Pennsylvania Office of Consumer Advocate (POCA) suggested that Order No. 636 also benefitted pipelines by (1) allowing them to terminate their relatively risky merchant functions, while (2) retaining the relatively stable transportation operations bolstered by the guarantee of substantial fixed cost recovery under SFV rates. POCA asserts that in return for these benefits pipelines should be required to absorb a portion of their transition costs. However, as discussed above, most pipelines were not incurring current financial losses in connection with their merchant functions at the time of Order No. 636.

[155] *See* Table 1.

[156] Order No. 528–A, 54 FERC at 61,304.

[157] Order No. 636, [Regs. Preambles Jan. 1991-June 1996] FERC Stats. & Regs. at 30,662.

[158] *See* Equitrans, Inc. 64 FERC ¶ 61,374 at 63,601 (1993).

[159] *UDC*, 88 F.3d at 1178–80.

Yet the termination of those merchant functions caused a number of pipelines to incur significant expenses, including the costs of shedding the gas supplies they had contracted for to serve their sales customers. Therefore, the Commission does not see the pipelines' termination of their merchant functions as a ''benefit'' justifying the Commission to require the pipelines to absorb a portion of the resulting expenses.[160] This is particularly so, in light of the Supreme Court's admonishment that regulatory agencies must recognize prudently incurred costs.[161] That is an obligation the Commission takes especially seriously when, as here, its own regulatory actions have caused the costs.[162]

The Commission also does not believe that the shift to an SFV rate design, for the recovery of the pipelines' transmission costs, is relevant to the issue of the pipelines' recovery of the costs of realigning their gas supplies which supported their merchant function. To the extent SFV alters the risks a pipeline faces in connection with its performance of transportation service, the appropriate place to make an adjustment is in the allowed return on equity embodied in the pipelines' transportation rates.[163]

In conclusion, the Commission has consistently applied traditional ratemaking principles to the issue of the pipelines' recovery of transition costs. However, the different factual contexts addressed by Order Nos. 500/528 and Order No. 636 led the Commission to approve different recovery mechanisms in those orders. Even before the Commission initiated open access transportation in Order No. 436, the market was preventing pipelines from recovering costs incurred under their take-or-pay contracts. The Order Nos. 500/528 absorption requirement reflected the preexisting effect of the market, which would have required absorption even without open access transportation under Order No. 436.

However, the Commission's regulatory actions in Order No. 636 have caused the pipelines to incur the GSR costs and rendered the underlying gas supply contracts no longer used and useful. In these circumstances, traditional ratemaking principles require the Commission to allow the pipelines an opportunity to recover the full amount of the expenses caused by its actions. And the Commission has been careful, through the eligibility standards developed in *Texas Eastern*, to limit Order No. 636 GSR recovery to the costs actually caused by the Commission's actions in Order No. 636. Accordingly, the Commission reaffirms Order No. 636's holding that pipelines may recover 100 percent of their GSR costs.

VII. Recovery of GSR Costs From IT Customers

In Order No. 636-A, the Commission required pipelines to allocate 10 percent of GSR costs to interruptible transportation customers. The Industrial End-Users challenged this decision on appeal and contended that unbundling confers no real benefit on that class of customers, who therefore should not be responsible for paying GSR costs. The Small Distributors and Municipalities took the opposite view and asserted that the Commission should have allocated more GSR costs to interruptible transportation customers. The Court agreed with the Commission that interruptible transportation customers benefitted from Order No. 636, through, *inter alia*, access to low cost transportation that is available through the capacity release mechanism.[164]

The Court faulted the Commission, however, for failing to explain why it selected the figure of ''10%''. The Court could not discern how the Commission got from allocating some GSR costs to allocating 10% of those costs to interruptible transportation customers, emphasizing that the law ''requires more than simple guess-work,'' and remanded the issue to the Commission for further consideration.[165]

As discussed above, the Commission has approved settlements between most pipelines and their customers concerning those pipelines' recovery of their GSR costs. Therefore, the Court's remand of the interruptible allocation issue does not affect the settled GSR proceedings. However, the issue of how much GSR costs should be allocated to interruptible service remains open on several pipeline systems. As discussed above, there has been no settlement resolving the recovery of GSR costs by Tennessee and NorAm. Also, the settlements which the Commission has approved in the GSR proceedings of several other pipelines do not resolve the interruptible allocation issue as to all of those pipelines' GSR costs. The Commission has interpreted the settlement of Williams' recovery of GSR costs as leaving open the issue of what portion of Williams' GSR costs in excess of $50 million should be allocated to interruptible service.[166] The interruptible allocation issue is also unresolved to the extent it affects the GSR costs which Southern may recover from the customers which the Commission severed from the settlement of Southern's GSR proceedings. Finally, the issue is unresolved as to any GSR costs which ANR and Panhandle may seek to recover in the future.[167]

The Commission continues to believe that pipelines should allocate some portion of their GSR costs to interruptible service. The Court upheld the Commission's holding that interruptible transportation customers benefit from unbundling under Order No. 636.[168] As the Court stated,

> An active market for firm transportation would seem likely to drive down the cost of less desirable interruptible transportation, and while the additional use of firm transportation under Order No. 636 may crowd out some interruptible transportation, that results at least in part from customers converting from interruptible to firm service * * *. Further still, interruptible transportation customers do clearly benefit from Order No. 636 through access to low cost transportation that is available through the Commission's capacity release mechanism.[169]

These benefits received by interruptible customers clearly justify

[160] *See UDC,* 88 F.3d at 1189.

[161] West Ohio Gas Co. v. Public Utilities Comm'n of Ohio, 294 U.S. at 74. *Mountain States Telephone & Telegraph Co.* v. *FCC,* 939 F.2d at 1029.

[162] *Public Utilities Comm'n of Cal.* v. *FERC,* 988 F.2d 154, 166 (1993) (The Commission ''with the backing of this court, has been at pains to permit pipelines to recover [take-or-pay costs] . . . which have accumulated . . . through an otherwise beneficial transition to competitive gas markets'').

[163] In determining the returns on equity allowed in individual rate cases after the shift to SFV, the Commission has refused to make any special downward adjustments based on the pipeline's shift to SFV. However, that has been because the Commission has found that the equity markets have already taken the Commission's shift to SFV into account. Therefore, the DCF analysis used by the Commission to establish return on equity reflects the shift to SFV without the need for any special adjustment. See Transcontinental Gas Pipe Line Corp., 71 FERC ¶ 61,305 at 62,196 (1995); 75 FERC ¶ 61,039 at 61,125–6 (1996); 76 FERC ¶ 61,096 at 61,506 (1996).

[164] *UDC,* 88 F.3d at 1187.

[165] *Id.* at 1187–88.

[166] Williams Natural Gas Co., 75 FERC ¶ 61,022 at 61,071, *reh'g denied*, 76 FERC ¶ 61,092 (1996).

[167] The Commission has approved four settlements concerning Natural's recovery of GSR costs from various groups of customers. Natural Gas Pipeline Company of America, 67 FERC ¶ 61,174 (1994), and 68 FERC ¶ 61,388 (1994). Those settlements are generally binding on the parties notwithstanding the outcome of the judicial review of Order No. 636, with certain limited exceptions as to particular settlement provisions. Any party to Natural's GSR proceedings believing that those settlements permit a change in the allocation of costs to interruptible service as a result of the Court's remand of that issue may file in the relevant Natural GSR proceedings a statement explaining why it so interprets the settlements. Otherwise, the Commission will presume that the issue has been settled as to all of Natural's GSR costs.

[168] *UDC,* 88 F.3d at 1187.

[169] *Id.*

the allocation of at least some GSR costs to interruptible service.

However, on remand, the Commission has determined not to require that the percentage of GSR costs so allocated must be 10 percent for all pipelines. As the Court recognized, different pipelines perform different levels of interruptible service. Among the pipelines that potentially could be affected by a departure from the generic 10 percent allocation, interruptible transportation comprises a widely varying percentage of the pipelines' total throughput for the first nine months of 1996—from 2.87 percent (Panhandle) to 21.68 percent (ANR).[170] Given this fact, it is not appropriate to require all pipelines to allocate the same percentage of their GSR costs to interruptible service. If the same percentage of GSR costs were allocated to interruptible service no matter how much interruptible service a pipeline performs, interruptible customers on pipelines performing little interruptible service could bear a disproportionate share of the pipeline's GSR costs (absent discounts).

Therefore, the Commission will, instead, require each individual pipeline, whose GSR proceedings have not been resolved, to propose the percentage of its GSR costs its interruptible customers should bear in light of the circumstances on its system. Pipelines which have filed to recover GSR costs before the date of this order, and whose GSR recovery proceedings have not been resolved by settlement or final and non-appealable Commission order, must file such proposals in their individual GSR proceedings within 180 days of the date of this order. Interested parties will be given an opportunity to comment on each pipeline's proposal. If the pipeline's proposal is protested, the Commission will set the proposal for hearing in the GSR cost recovery proceeding in which the proposal is made. Those hearings will permit the interested parties to develop a record on which the Commission can base its ultimate decision in each case.

This approach will allow the Commission and the parties to develop an allocation of GSR costs to interruptible service that is tailored to the specific circumstances of the few pipelines where the issue is still alive. The Commission also expects that such hearings will provide the parties a forum to discuss settlement of this issue. The Commission encourages the parties to seek to settle this and all other outstanding issues related to GSR recovery.

[170] Interruptible transportation comprises less than ten percent of total throughput on Panhandle, NorAm (5.89 percent), and Tennessee (9.81 percent). Pipelines for which interruptible transportation comprises greater than 10 percent of total throughput are Williams (17.72 percent), Natural (13.11 percent), Southern (11.17 percent), and ANR. The weighted average percentage of interruptible transportation throughput among all pipelines that report such data is approximately 18 percent. The Commission has determined all of the above percentages based on the pipelines' reports, pursuant to FERC Form No. 11, of the total volumes they transported during the first nine months of 1996 and their interruptible volumes during the same period.

The Commission Orders

(A) Order No. 636 is reaffirmed, in part, and reversed, in part, as discussed in the body of this order.

(B) Within 180 days of the issuance of this order, any pipeline with a right-of-first-refusal tariff provision containing a contract term cap longer than five years must revise its tariff consistent with the new cap adopted herein.

(C) Within 180 days of the issuance of this order, pipelines which have filed to recover GSR costs before the date of this order, and whose GSR recovery proceedings have not been resolved by settlement or final and non-appealable Commission order, must file, in their individual GSR proceedings, a proposed allocation of GSR costs to its interruptible customers as discussed in the body of this order.

By the Commission.

Lois D. Cashell,

Secretary.

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DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 522

Implantation or Injectable Dosage Form New Animal Drugs; Sarafloxacin Hydrochloride

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect approval of a supplemental new animal drug application (NADA) filed by Abbott Laboratories. The supplement provides for use of sarafloxacin hydrochloride solution for injection in 18-day embryonated broiler eggs for control of early chick mortality associated with *Escherichia coli* organisms susceptible to sarafloxacin.

EFFECTIVE DATE: March 6, 1997.

FOR FURTHER INFORMATION CONTACT: George K. Haibel, Center For Veterinary Medicine (HFV–133), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–594–1644.

SUPPLEMENTARY INFORMATION: Abbott Laboratories, 1401 Sheridan Rd., North Chicago, IL 60064–4000, filed a supplement to NADA 141–018 that provides for use of sarafloxacin hydrochloride solution for injection (SaraFlox® Injection) in 18-day embryonated broiler eggs in addition to approved use in day-old broiler chickens for control of early chick mortality associated with *E. coli* organisms susceptible to sarafloxacin. The supplement is approved as of January 21, 1997, and the regulations are amended by revising 21 CFR 522.2095(d) to reflect the approval. The basis of approval is discussed in the freedom of information summary.

In accordance with the freedom of information provisions of 21 CFR part 20 and 514.11(e)(2)(ii), a summary of safety and effectiveness data and information submitted to support approval of this application may be seen in the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857, between 9 a.m. and 4 p.m., Monday through Friday.

Under section 512(c)(2)(F)(iii) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 360b(c)(2)(F)(iii)), this approval qualifies for 3 years of marketing exclusivity beginning January 21, 1997, because this supplement contains substantial evidence of the effectiveness of the drug involved, studies of animal safety, or human food safety studies (other than bioequivalence or residue studies), required for approval and conducted or sponsored by the applicant. Marketing exclusivity applies only to use in 18-day embryonated broiler eggs.

The agency has carefully considered the potential environmental effects of this action. FDA has concluded that the action will not have a significant impact on the human environment, and that an environmental impact statement is not required. The agency's finding of no significant impact and the evidence supporting that finding, contained in an environmental assessment, may be seen in the Dockets Management Branch (address above) between 9 a.m. and 4 p.m., Monday through Friday.

List of Subjects in 21 CFR Part 522

Animal drugs.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner