

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Regulation of Short-Term Natural Gas) Docket No. RM98-10-000
Transportation Services)

Regulation of Interstate Natural Gas) Docket No. RM99-12-000
Transportation Services)

**REQUEST OF THE NATURAL GAS SUPPLY ASSOCIATION
FOR REHEARING OF ORDER NO. 637**

Pursuant to Section 19 of the Natural Gas Act (“NGA”), 15 U.S.C. § 717r (1994), and Rule 713 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.713 (1999), the Natural Gas Supply Association (“NGSA”) requests rehearing of certain aspects of Order No. 637, the Final Rule on regulation of short-term and interstate natural gas transportation services (the “Order” or “Rule”).¹

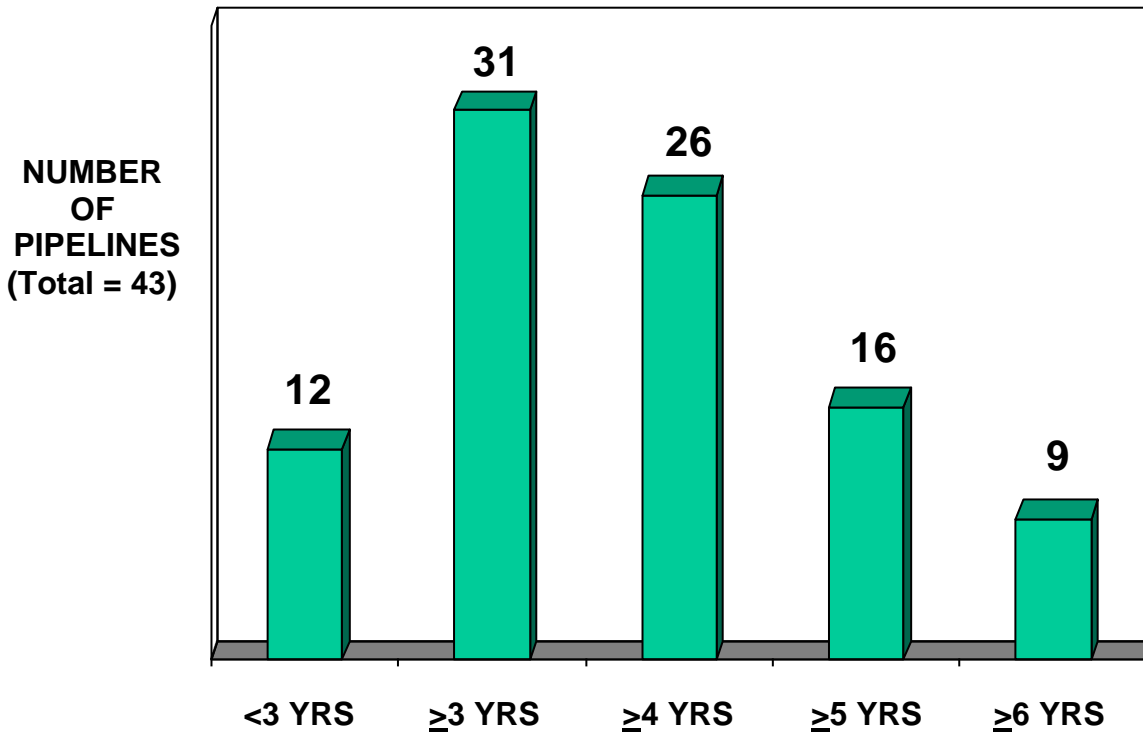
Highlighted in this submission is NGSA’s request that if the Commission proceeds with its experiment in lifting rate caps for short term released capacity, despite requiring neither market power studies nor effective mitigation measures, the Commission provide certain safeguards *up front* to lessen the ability of pipelines and their affiliates to use

¹ See *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, 65 Fed. Reg. 10156 (February 25, 2000), 90 FERC ¶ 61,109 (February 9, 2000) (all citations to the Order in this submission will be to the slip opinion issued February 9, 2000).

their market power. The Commission has recognized in its “FERC First” initiative that it should regulate more proactively in light of market place realities. NGSAs wholeheartedly endorse the Commission’s attempts to become more active in ensuring that abuses do not occur in the market, and outlines below several steps the Commission should take *now* to (1) limit the potential for abuse, (2) reduce not only actual discrimination, but also the *perception* that pipelines and their affiliates are engaging in discrimination, and (3) thereby move the natural gas transportation industry toward a more competitive market place. In this regard, the Commission has acknowledged the convergence occurring between the electric and natural gas industries. As this convergence proceeds, the Commission should ensure that where differences in regulatory treatment are not warranted, the natural gas and electricity industries are regulated the same. In particular, there does not appear to be any basis for the current differing regulatory treatment of affiliates and affiliate abuse between the two industries.

NGSA further emphasizes that implementation of the seasonal rates permitted by the Order requires that there be a Section 4 rate proceeding, either when such rates are initially implemented or, at a minimum, within a reasonable time frame (NGSA recommends one year) after adoption of such rates. Pipelines are not altruistic and will not file rate cases when it is not in their own best interests to do so. Indeed, an analysis of the time lapsed since pipelines’ last rate case filings shows that 31 pipelines filed their last rate case 3 or more years ago, and 9 have not filed within the last six or more years, as shown in the following Figure 1:

FIGURE 1
TIME LAPSED SINCE LAST RATE CASE



Source: NGSAs Analysis Of Major Interstate Pipelines Using Commission Issuance Posting System (CIPS) and the Records and Information Management System (RIMS) from FERC Energy Information Online

Implementing seasonal rates without a Section 4 rate review results in “double-dipping” (*i.e.*, the collection of revenues above a pipeline’s annual revenue requirement) because it allows pipelines to continue their current discount adjustment, while increasing peak seasonal rates. Permitting seasonal rates without a Section 4 rate review not only results in excess revenues, it provides one more incentive for pipelines to avoid a general Section 4 rate review – the goal of keeping their current discount adjustments while collecting increased seasonal rates. For these reasons, NGSAs urges the Commission to ensure that pipelines’ revenues are reasonably related to annual cost-based revenue requirements and therefore condition acceptance of seasonal rates upon agreement to file a Section 4 proceeding.

SUMMARY

NGSA commends the Commission for issuing an order that, in many respects, will improve competition and efficiency in the natural gas industry and will enable the Commission's staff to be more proactive in monitoring the pipeline transportation services market. Improved reporting requirements will achieve greater transparency, which benefits industry participants and also facilitates active staff involvement in monitoring the transportation services market. The Order further advances competition and efficiency by establishing scheduling equality between released capacity shippers and other firm shippers; by permitting shippers to segment capacity for their own use as well as for capacity release transactions; by prohibiting pipelines from inhibiting third parties from providing imbalance services; and by limiting pipelines' use of penalties and operational flow orders.

While taking these positive steps, the Commission wisely refrained from taking certain other steps that would have resulted in discrimination and inhibited competition. The Commission correctly determined not to lift the rate caps on pipelines' primary capacity, which would have allowed pipelines with market power to abuse such power. In addition, the Commission appropriately refused to adopt preapproval of negotiated terms and conditions of service, finding that no need for such preapproval had been demonstrated. Such preapproval would result in preferential contracts, particularly agreements favoring pipelines' affiliates. Moreover, permitting a plethora of differing terms and conditions of service also would have threatened competition in the secondary markets because there cannot be a thriving, real-time market for secondary capacity or any product unless the product is standardized to a significant extent. NGSA further commends the Commission for determining that any switch to term-differentiated rates must be examined in the context of a Section 4 rate case. The Commission

correctly found that the shifting of costs among classes of customers that occurs when adopting term-differentiated rates necessarily must be examined and resolved in the context of a rate case.

In two important respects, however, the Order should be modified. *First*, the Commission lifted price caps for short-term capacity release transactions without either finding an absence of market power, or imposing effective mitigation measures such as auctions. In particular, the Order lifts price caps without imposing conditions to mitigate the market power exercised by pipelines acting in conjunction with their affiliates.² The Commission should recognize that opportunities for affiliate abuse already exist; that such opportunities are substantially increased by lifting the price cap on short-term capacity releases; that such abuse is difficult to detect and to correct after-the-fact; and that affiliate abuse has serious, long-term consequences, including the substantial lessening of competition in the market place. The value of after-the-fact remedies is limited, particularly when compared to the effectiveness of preventive measures that are reasonable and can be implemented now.

Second, the Commission should not permit pipelines to adopt seasonal rates without requiring a Section 4 review of such rates -- either when initially filed, or at a minimum after assessing the actual experience from implementing the rates. Such a review is necessary to prevent overcollection of revenues and to provide customers with the benefits of minimized discounting, as described in the Order, as well as to account for any general reallocation of

² The references to pipeline “affiliate(s)” in this rehearing request refer not only to pipeline marketing affiliates, but also to all entities affiliated with a pipeline that possess interests in interstate pipeline capacity on their related or home pipeline, including pipelines’ LDC affiliates, affiliated asset managers, and electric affiliates that acquire interests in capacity on their related pipeline. See Part II.A.2, supra, discussing need to expand definition of affiliate and of operating employee.

revenue responsibility among customers. Surprisingly, despite statements to the contrary, the Order actually *encourages* pipelines to overcollect revenues through seasonal rates. It is unjust and unreasonable to give any portion of overcollections to pipelines; rather, overcollections should be returned to all shippers. NGSA supports a pipeline's right to an opportunity to recover prudently incurred costs. However, the Order inadvertently creates many opportunities for pipelines to over-recover revenues, such as permitting pipelines to retain up to 50% of excess revenues collected through seasonal rates, and permitting pipelines to charge for imbalance services without any future requirement to allocate costs to those services. Based on a number of assertions made by the Commission in the Order,³ we do not believe that is what the Commission intended.

Finally, NGSA respectfully requests reconsideration or clarification of the issues set forth in Attachment A to this submission.

³ See, e.g., Order at 96 (pipelines must implement seasonal rates “within the pipeline’s current cost-based revenue requirement”); at 100-101 (similar); see also discussion in Part III.A., *infra*.

DISCUSSION

I. Lifting The Price Cap For Capacity Release Transactions Has Not Been Shown To Be Justified And Could Cause Serious Harm.

The Commission should not have lifted price caps on the sale of short term released capacity without either (1) requiring evidence that sellers of such capacity – including pipelines’ own affiliates – lack market power, or (2) imposing effective mitigation measures. Indeed, the NOPR recognized the danger market power poses in the secondary, as well as the primary, market. *See* FERC Stats. & Regs. Proposed Regs. [1988-1998] ¶ 32,533 at 33,441-442 (July 29, 1998). The NOPR therefore proposed mitigating measures, such as a mandatory auction, to compensate for removing rate caps. *Id.* at 33,442. The Order, however, lifts rate caps on short-term released capacity without any requirement of a market power study to demonstrate the absence of market power, and without requiring any effective mitigating measures. The voluntary auctions permitted by the Order obviously will be employed by pipelines only when the auctions benefit the pipelines, and thus are no check on market power. Elsewhere, the Commission has required a market power study before granting sellers authority to charge market-based rates.⁴ The Commission has not justified a different approach here.

The Order’s stated rationales for not being concerned about market power in secondary markets do not withstand scrutiny. The primary justification provided is the claim

⁴ *See Koch Gateway Pipeline Co.*, 85 FERC ¶ 61,013 (Oct. 2, 1998) (holding that Koch failed to meet its burden under the NGA of proving that it lacks market power), *reh’g denied*, 89 FERC ¶ 61,046 (Oct. 14, 1999). The Commission, for example, also requires a market power study to support granting market-based rate authority with respect to sales of electric generation. *See Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223, and its progeny.

that interruptible transportation available from pipelines will prevent firm shippers from withholding capacity or otherwise exercising market power. But interruptible transportation is rarely an adequate substitute for firm capacity, particularly during peak periods. The Commission's own orders recognize this fact.⁵ A purchaser of interruptible transportation can be bumped by purchasers of firm capacity, in the second and even third nomination cycle, and is quite likely to be bumped during periods of peak demand, when capacity is in short supply. In addition, shippers which hold a significant amount of firm capacity on pipelines can create artificial periods of peak demand by nominating, but not actually using, just enough capacity to drive up the demand for firm service while decreasing the availability of interruptible transportation. Relying on interruptible transportation would be like relying on stand-by rather than a confirmed airline reservation at a time of peak demand when one needed to get to an important meeting. Shippers during peak periods must purchase firm capacity to ensure that they will be able to transport gas; hence, interruptible transportation is no substitute and no check on market power.

The Order also rationalizes that “the removal of the rate cap for capacity release transactions does not effectively change the status quo, since the value of transportation in the bundled sales market can exceed maximum tariff-based rates.” Order at 85. In effect, the Order appears to be saying that shippers may already be exercising monopoly power in the bundled released retail sales market, so why be concerned if releasing shippers exercise such power in

⁵ See *Koch Gateway Pipeline Co.*, 85 FERC ¶ 61,013 at 61,041 (holding that “[s]ince Koch has not shown that IT is an acceptable substitute for FT on its system, its subsequent analyses are also invalid because they incorporate the assumption that the two services are comparable”);

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short-term capacity markets? The answer to that question is two-fold. *First*, this is an abdication of the Commission’s statutory responsibility to establish just and reasonable transportation rates in markets over which the Commission has authority. *Second*, this abdication harms all customers in the released capacity market, including producers, who will pay rates inflated by the exercise of market power rather than cost-justified rates.

The Order’s rationale focuses only on the impact of lifting price caps on downstream purchasers of gas bundled with transportation. The Commission has ignored the effect of lifting the price caps on upstream gas suppliers that need to purchase short-term released capacity to transport gas to downstream market centers or other destinations. Lifting the price caps allows shippers to extract rates above maximum tariff rates at any point along a pipeline, not just in the downstream market area. These customers are very much affected by the price level of short-term released capacity. In short, the secondary transportation market *does* matter.

The Order also states that competition among sellers of released capacity will serve as a check on market power. *See* Order at 80. Yet, there is no evidence of the level of competition that may exist.⁶ Moreover, as discussed below, pipeline affiliates now hold

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Koch Gateway Pipeline Co., 89 FERC at 61,130 (“the periodic unavailability of IT service renders it an inapt substitute for FT service on Koch’s system”).

⁶ *See Koch Gateway Pipeline Co.*, 85 FERC ¶ 61,013 at 61,045 (1998) (holding that “there is no evidence in this proceeding on which to base a determination that marketers are good alternatives to Koch’s services or that Koch cannot exercise market power because of marketers”).

substantial portions of pipeline capacity, further indicating that competition among sellers of released capacity is, at least in some areas, not significant.

II. If The Commission Nonetheless Determines To Proceed With An Experimental Lifting Of Rate Caps For Short Term Capacity Releases, It Must Implement Safeguards.

If the Commission nevertheless determines to proceed with a two-year experiment in lifting rate caps despite the significant market power concerns cited above, it should implement, *up front*, certain safeguards to at least lessen the ability of pipelines and their affiliates to use their market power.

A. Most Importantly, The Commission Should Pay Special Attention To The Economic Incentives Created For Abuses Of Its Experimental Program By Pipelines In Conjunction With Their Affiliates.

The Order does not mitigate the market power of pipelines and their affiliates. In fact, by lifting the price for released capacity and introducing other initiatives, the Order *increases* incentives for affiliates to purchase even more long-term capacity, thereby reducing the number of participants in short-term and long-term markets.

Affiliates of some pipelines are increasingly buying substantial amounts of capacity on related pipelines.⁷ Moreover, affiliates that bid for capacity on their related pipelines

⁷ For example, El Paso Natural Gas recently “signed a \$38.5 million 15-month contract with its marketing affiliate [El Paso Merchant Energy] that covers one-third of the transportation on its system.” 19 *Natural Gas Intelligence* (Feb. 21, 2000) at 1. As another example, recently a Koch affiliate bought 23 out of 25 bcf of storage on Koch’s pipeline. See Protest filed by Dynegy Marketing and Trade, Marathon Oil Company, Amoco Production Company and Amoco Energy Trading Corporation on February 15, 2000 (refiled February 16, 2000) in FERC Docket No. RP96-320-029. As a third example, Northern Natural Gas Company recently entered into a negotiated rate transaction with its affiliate, Enron North America Corporation, in which Northern allegedly committed “295,000 MMBtu/day, which represents nearly one-third of

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have an advantage over non-affiliates, and can bid with relatively less risk than non-affiliates, because the revenues from their bid stay within the corporate family. There is thus less risk to affiliates with respect to over-bidding.

The Order increases incentives for affiliates to purchase even more capacity on their affiliated pipelines. If the cap is lifted, a corporation which owns both a pipeline and its marketing affiliate, or other affiliates holding firm pipeline capacity, has a compelling economic incentive to replace the pipeline with its affiliates as the sellers of capacity on the system because the capacity then becomes sold as released capacity at unregulated prices. Affiliates benefit from lifting the ceiling on short-term released capacity, and have an incentive, along with the pipeline, to withhold capacity, both to increase the prices received for short-term released capacity and for seasonal peak capacity. In this regard, non-affiliates generally cannot afford to withhold capacity because they still pay for, and will not be reimbursed for, capacity that they neither use nor sell. A pipeline's affiliates, however, can afford to withhold firm capacity, and thereby cause artificial shortages of firm capacity and drive up such capacity's price, because the capacity that they withhold in times of peak demand will likely be sold by their pipeline affiliate as interruptible transportation ("IT"). Hence, the "corporate family" has lost little or nothing by withholding firm capacity, because the corporate family sells it as IT. Shippers purchase the less reliable IT while scrambling to find, and bidding up the price for, the firm capacity held by the pipeline's affiliates. Pipeline affiliates are thus in a position – *not* shared by non-affiliates – to

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Northern's field area capacity" to Enron. *Northern National Gas Co.*, 89 FERC ¶ 61,195 at 61,599 (1999).

withhold capacity at little or no cost to the corporate family as a whole, and thereby drive up the price of firm released capacity.⁸

Affiliates holding long-term capacity, along with pipelines, would also benefit from the seasonal rate revenue crediting (*i.e.*, the 50-50 split) contained in the Order, and from any term-differentiated rates ultimately adopted. In sum, several of the initiatives introduced by the Order (including lifting the price cap, offering seasonal rates, enabling pipelines and their affiliates to share in seasonal rate revenue crediting, and providing term-differentiated rates) work together to increase the value of long-term capacity and the incentive of pipelines' affiliates to hold more of such capacity.

As pipeline affiliates hold more capacity, available capacity and liquidity are reduced and competition impaired in the secondary market. Moreover, as just noted above, affiliates, unlike non-affiliates, are able to withhold capacity from the secondary market with little risk and, in conjunction with their related pipelines, shift capacity back and forth between the short-term released capacity market and the interruptible transportation market to their best advantage.

⁸ If affiliates contract for more firm capacity than they can use themselves, they have an array of strategies available to them to drive up prices for firm capacity, and can also fall back on having their related pipeline sell unused capacity as IT. For example, an affiliate may nominate its entire contract amount in the first nominating cycle, thereby displacing shippers that normally buy IT, and creating increased demand and prices for firm capacity. On the second cycle, the affiliate could reduce the amount it has nominated, in order to take advantage of the higher firm capacity prices and sell firm transportation. (A firm capacity holder can indiscriminately raise or lower its nomination amounts in the second cycle.) An affiliate -- particularly one holding substantial amounts of market area storage acquired from the pipeline -- can employ a second stratagem. The affiliate has the ability to nominate its full contract amount regardless of whether it is certain it can sell sufficient gas. Any gas that is not sold can be shipped to and stored in the

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In light of the existing opportunities for, and allegations of, affiliate abuse,⁹ and the manner in which the Order expands those opportunities and enhances incentives for affiliate abuse, the Commission should adopt measures now to at least limit the potential for such abuse. Just as significantly, the measures suggested below contribute to and move the industry toward a more competitive market place.

1. The Commission Should Adopt Certain Measures Now To Deter Affiliate Abuse.

NGSA endorses the use of the five measures identified by the Commission to *remedy* affiliate abuses. The Order, at 92-93, identifies the following five remedial measures that the Commission may take upon discovering affiliate abuse: (i) requiring pipelines to put in taps to reduce capacity bottlenecks; (ii) requiring pipelines to build additional capacity when requested by customers willing to pay the costs of construction; (iii) limiting the rates at which the affiliate can release capacity; (iv) limiting the amount of capacity the affiliate can hold; or (v) prohibiting the affiliate from holding capacity on its related pipeline.

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affiliate's market area storage. In this manner, all or most all IT shippers would be bumped off, and enormous demand for firm capacity can be generated.

⁹ The Commission has already been presented with allegations of affiliate abuse. *See, e.g.*, Amoco Production Company's complaint against Natural Gas Pipeline Company of America, FERC Docket No. RP97-232, and the Commission's March 26 and May 27, 1998 orders on rehearing therein; the Protest filed on February 15, 2000 (refiled February 16) in FERC Docket No. RP96-320-029; *Koch Gateway Pipeline Co.*, 90 FERC ¶ 61,227 (Mar. 1, 2000) ("Koch's filing and the joint protest raise some very serious concerns as to whether Koch's proposed negotiated rate agreements represent a pattern of conduct that favors its affiliates"); 19 *Natural Gas Intelligence* (Feb. 21, 2000) at 1 (describing El Paso Natural Gas's 15-month contract with its market affiliate covering one-third of the transportation on its system).

But NGSAs urge the Commission not to wait to implement several of these measures. The Commission should establish measures that *prevent* the exercise of market power by pipelines and their affiliates, rather than simply waiting to take remedial steps when the Commission receives complaints about blatant abuses of market power. In other words, the Commission can, and should, be proactive as well as reactive.

The Commission has recognized in its “FERC First” initiative that it should regulate more proactively in light of market place realities. NGSAs whole-heartedly endorse the Commission’s attempts to become more active in ensuring that abuses do not occur in the market. Here, there is a need to take steps to prevent market power abuses by affiliates. Transactions occur quickly; thus, entities often cannot recover after-the-fact for, nor accurately calculate, damages suffered through paying inflated rates or being denied transportation service. Moreover, the complaint process is costly and time consuming; for these and other reasons, shippers or potential shippers who have been injured are often reluctant to bring complaints against pipelines and their affiliates. The complaint process often puts pipeline customers in the uncomfortable position of antagonist in order to ensure fairness in the market. The Commission expressly recognized that the complaint process suffers from all of the foregoing shortcomings in its recently issued Order No. 2000 regarding regional transmission organizations.¹⁰

¹⁰ The Commission held:

transmission customers are reluctant to make even informal complaints because they fear retribution by their transmission supplier; the complaint process is costly and time-consuming; the Commission’s remedies for violations do not impose sufficient financial consequences on the transmission provider to act as a significant deterrent; and, in the fast-paced business of power marketing, there may be no adequate remedy for the lost short-term sales opportunities in after-the-fact enforcement.

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Therefore, of the five measures identified in the Order to remedy affiliate abuse, the Commission should, at the very least, adopt the first two measures *now* as conditions for lifting the ceiling on sales of short-term released capacity. That is, the Commission should require, as a condition for lifting the price cap on sales of released capacity on a pipeline, that the pipeline demonstrate that it has included in its tariff provisions that require the pipeline to: (1) install taps to reduce bottlenecks that contribute to capacity constraints and market power; and (2) build additional capacity when customers are willing to pay the costs of construction. These measures should be adopted now as a preventative check on affiliate abuse.¹¹

The Commission should also seriously consider putting in place *now* a third measure – capping the rates at which an affiliate can release capacity on its related pipeline. *See* Order at 93. As noted above, by lifting the rate on short-term released capacity, the Commission has provided affiliates with an enormous incentive to expand the capacity they hold on affiliated pipelines. We have already seen this trend in the last few months. *See* discussion in n.7, *supra*. In addition, affiliates on a significant number of pipelines already hold substantial percentages of firm capacity. A review of firm capacity under contract as of January 1, 2000, shows that on 16 of 42 interstate pipelines analyzed, affiliates held more than 20% of the firm capacity under contract. *See* Attachment B at 1. Moreover, on 5 of these pipelines, affiliates held more than 60% of the firm capacity under contract. *Id.* Furthermore, affiliates have the ability to out-bid

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Order No. 2000, FERC Stat. and Reg. ¶ 31,089 at 31,005 n. 70.

¹¹ *See, e.g., Dominion Resources, Inc. and Consolidated Natural Gas Co.*, 89 FERC ¶ 61,162 (Nov. 10, 1999) (conditioning approval of merger on requirements that applicants adopt “open season and open taps commitments” and apply Standards of Conduct to the “corporate family” of the merged entity).

non-affiliates for capacity with relatively less risk. Without a cap on the rates marketers may charge for released capacity on affiliated pipelines, there is extreme danger that such affiliates will continue to increase the capacity they hold, further monopolizing and reducing the liquidity of markets for released capacity. As discussed further below, the Commission also needs to expand pipeline reporting requirements to require pipelines to report actual usage or non-usage of scheduled capacity to enable customers to attempt to determine when discrimination is occurring.

The Commission should adopt the foregoing measures, and those that are discussed in following sections, not only to limit the exercise of market power by pipelines and their affiliates and to reduce the incentives for pipeline affiliates to hold more capacity, but also to reduce the perception that pipelines favor their affiliates and discriminate against non-affiliates. The Commission held in its recent Order No. 2000 that the *perception* that discrimination is occurring, as well as actual discrimination, harms the development of competitive markets.¹² Here, there exists the perception that pipelines and their affiliates exercise and benefit from market power and are discriminating against non-affiliates with respect to the assignment of capacity and related services such as storage. The Commission needs to take steps to dispel this perception and restore confidence that pipelines have neither the incentive nor the ability to favor their affiliates.

¹² See Order No. 2000, FERC Stat. and Regs. at 31,005 slip op. at 37 (“allegations of discrimination are serious because, if nothing else, they represent a perception by market participants that the market is not working fairly. If market participants *perceive* that other participants have an unfair advantage through their ownership or control of transmission facilities, it can inhibit their willingness to participate in the market, thus thwarting the development of robust competition”) (emphasis added).

2. The Definitions Of Affiliate And “Operating Employee” Should Be Expanded.

The definition of “affiliate” should be expanded to cover all entities that hold interstate pipeline capacity and that have a corporate affiliation with the pipeline. These would include affiliated asset managers, LDC affiliates and electric affiliates. When the Commission undertook the restructuring resulting in Order No. 636, asset managers did not exist as they do today, and it was not anticipated that other types of affiliates would hold pipeline capacity. Moreover, the Commission should amend its regulations to require that third-party contractors who perform the functions of “operating employees” under the Commission’s regulations¹³ are subject to the same restrictions as actual operating employees.

3. The Commission Should Consider Adopting For Natural Gas Pipelines Affiliate Safeguards Similar To Those Adopted For Electric Utilities.

The Commission has acknowledged the convergence occurring between the electric and natural gas industries. Indeed, as a consequence of this convergence, the Commission has created a new Office of Markets, Tariffs and Rates (“OMTR”) that will assist the Commission in developing policies for and monitoring both industries. The Commission has thus created “a truly convergent gas, oil and electric staff that will give [the Commission] greatly enhanced leverage and expertise in the future.”¹⁴ As this convergence of both industries and FERC staff proceeds, the Commission should ensure that where differences in regulatory treatment are not warranted, the natural gas and electricity industries should be regulated the

¹³ See Order No. 497-E, 59 Fed. Reg. 243, FERC Statutes and Preambles ¶ 30,987 at 30,996 (1993).

¹⁴ “Office Of Markets, Tariffs And Rates Open For Business,” Commission news release issued February 23, 2000.

same. In particular, there does not appear to be a basis for differing treatment of affiliates and affiliate abuse between the two industries. On the electric side, the Commission has just issued Order No. 2000, which requires that electric utilities submit plans to join Regional Transmission Organizations (“RTOs”) or explain why they have been unsuccessful in formulating such plans. With respect to electric utilities that market power themselves or have power marketing affiliates, such “market participants” are not allowed to control RTOs, either through voting power or ownership. The Commission is thus being extremely vigilant to prevent affiliate abuse with respect to the sale of transmission services on the electricity side. *See, e.g.*, Order No. 2000-A, Order on Rehearing, FERC Docket No. RM99-2-001 (Feb. 25, 2000), slip op. at 25-26 (rejecting Duke Energy Corporation’s argument that the Commission should adopt for the electricity industry the more lenient standards regarding affiliates found in the natural gas industry).

There do not appear to be structural or other differences between the electric and natural gas industries that would support different treatment for pipelines with marketing affiliates than for electric utilities with marketing affiliates. Indeed, the recent spate of affiliate abuse allegations in the natural gas industry discussed above, *see* footnote 9, *supra*, indicates that the same cause for concern exists in both industries. The Commission should, therefore, consider adopting for the natural gas industry safeguards similar in effect to those adopted for the electricity industry. Short of adopting the use of independent third parties or “pure” transportation entities to market gas transmission capacity through competitive bidding processes, as was done in Order No. 2000, the Commission should be liberal in applying any or all of the five protective measures outlined in Order No. 637 at 92-93.

4. The Commission Should Revise The Process For Bidding On Primary Pipeline Capacity.

As noted above, the Order increases opportunities for affiliate abuse by, among other things, increasing the incentive of pipeline affiliates to purchase even more capacity. Under these circumstances, we urge the Commission to adopt changes to the procedures for bidding on pipeline capacity, in order to check the abuse of market power by affiliates.

First, the Commission should cap affiliate bids for pipeline capacity to a term not to exceed five years, for purposes of calculating the net present value of bids by pipeline affiliates.¹⁵ Otherwise, pipeline affiliates will have an undue preference in bidding against non-affiliates and generally will be able to out-bid most other potential shippers by simply increasing the term of their bid. As previously noted, pipeline affiliates face relatively less risk in increasing the term of their bids, since their bids simply transfer money between affiliates – *i.e.*, all revenue generated by the bids stays within the corporate family.

Second, the Commission should eliminate the ability of pipeline affiliates to exercise rights of first refusal (“ROFR”) and should instead require open seasons. A pipeline affiliate can already meet or beat the bid of any non-affiliate and with much less risk in either an open season or when exercising an ROFR. Requiring affiliates to participate in an open season rather than having ROFR would lessen their ability to retain and expand the capacity already under their control by removing the additional advantage obtained through ROFR of knowing what competitors have bid and simply matching it.

¹⁵ The Commission has similarly adopted five years as a maximum term in the context of exercising rights-of-first-refusal. *See* Order at 210-12.

Third, the Commission should require competitive bidding for all available primary pipeline capacity, and should require a new open season process if subsequent negotiated transactions produce changes to any of the terms of the initial open season. In this manner, prearranged deals (some involving affiliates) in which terms are “sweetened” without providing an opportunity for all market participants to bid for capacity under the new terms, would be avoided.

B. Any Lifting Of Rate Caps Should Occur Simultaneously With A Pipeline’s Compliance With The Order’s New Reporting Requirements.

At a minimum, the Commission should not permit the removal of rate ceilings for short-term released capacity until the Order’s new reporting requirements take effect, which currently is scheduled for September 1, 2000. As the Commission has acknowledged, the new reporting requirements are an integral part of increasing the Commission’s monitoring capabilities and its move toward more market-driven transportation rates. Removal of rate ceilings for short-term capacity releases and the new reporting requirements should be implemented simultaneously in order for the benefits of increased reporting to be realized. In particular, customers should, at the very least, have at their disposal the means to determine whether pipelines are failing to make capacity available or whether undue preferences are being provided. Moreover, because pipelines may request extensions of the September 1 reporting requirement – thereby lengthening the period during which rate ceilings will have been lifted without adequate reporting of available capacity -- the Commission should provide that the ceilings may only be lifted when a pipeline complies with the reporting requirements.

As discussed further in Attachment A, the Commission should also expand pipeline reporting requirements to require that pipelines report not only available capacity and

scheduled capacity but also scheduled capacity that is not used. Customers need to know about non-utilized scheduled capacity to determine whether parties are withholding capacity.

C. The Commission Should Reaffirm That Lifting The Rate Caps Is An Experiment.

The Order describes the lifting of rate caps as an experiment that is to last until September 30, 2002, for the purpose of providing two winters' worth of data with which to examine the effects of this policy change. Order at 73-74. As the Order correctly notes, *id.*, there is no evidentiary basis at present for lifting price caps as a permanent measure. The Commission should reaffirm that lifting the caps is an experiment limited to two years and that it will not be extended until there has been a thorough review of the results of the experiment. Such a review should include an opportunity for all interested parties to present their views regarding whether the program should be continued and, if so, with what modifications. Moreover, the Commission should clarify that it is not precluded from shortening the experimental period if problems surface with lifting the price cap.

D. The Commission Should Respond Quickly To Major Changes Occurring In The Market During The Period Of Its Experiment.

The Order would have the effect of lifting ceiling rates during a period of significant changes in the natural gas industry, changes that may increase, rather than decrease, market concentration and market power. Mergers of natural gas pipeline companies are occurring, as well as mergers between natural gas pipeline companies and electric utility industry participants. Furthermore, as already discussed, pipelines' affiliates are purchasing large percentages of pipeline capacity. For the duration of the Commission's experiment with lifting ceiling prices on short-term released capacity, the Commission must continuously monitor market developments to assess the impact of lifting price caps. The Commission should further provide opportunities for interested parties to identify particular instances where the lifting of

price caps is harming participants in the markets for short-term released capacity. Where changes occur that are harming participants during the two-year experimentation period, the Commission should be willing to take remedial actions, including ending the waiver of rate caps on short-term released capacity sales where appropriate.

III. The Commission Should Not Permit Seasonal Rates Without Section 4 Rate Review And Has Provided No Justification For Permitting Pipelines To Retain Indefinitely Revenues In Excess Of Cost-Based Annual Revenue Requirements.

The Commission should condition implementation of seasonal rates on a requirement that at the very least, pipelines initiate a Section 4 rate proceeding after an initial period of experience with such rates. As discussed further below, a Section 4 rate review is an absolute necessity for ensuring that a pipeline does not consistently exceed its annual revenue requirement because of implementation of seasonal rates. Moreover, there is no distinction between implementation of seasonal rates and of term-differentiated rates that justifies requiring Section 4 remedies for the latter, *see* Order at 110, but not for the former. Finally, allowing pipelines to retain any portion of overcollections – *i.e.*, revenues above annual revenue requirements -- creates an incentive to over-collect, thereby producing unjust and unreasonable rates.

A. There Must, At A Minimum, Be A Section 4 Rate Proceeding To Review Seasonal Rates After An Initial Period Of Implementation.

At a minimum, the Commission should require, as a condition of accepting seasonal rates where a pipeline submits merely a *pro forma* tariff rather than making a Section 4 rate filing, that the pipeline agree to file a Section 4 rate proceeding within a reasonable time frame specified by the Commission after implementation of such rates. NGSAs believe that twelve months is a reasonable and sufficient period in which to obtain data and reasonable projections in order to develop seasonal rates and that, at a minimum, the Commission should

require agreement to the condition that a pipeline make a Section 4 rate filing shortly after the end of its first twelve months of experience with seasonal rates. Once such a rate filing is made, seasonal rates could thereafter be adjusted using annual cost-revenue studies submitted by the pipeline, as outlined by the Commission in the Order.¹⁶

A Section 4 rate filing to review the reasonableness of seasonal rates is an absolute necessity for assuring that a pipeline's annual revenue requirement is not exceeded. The Order recognizes that even with seasonal rates, pipelines should collect only enough revenue to satisfy their cost-based revenue requirement. Therefore, "the Commission will permit pipelines to implement value-based peak/off-peak rates for their short-term transportation services, *within the pipeline's current cost-based revenue requirement.*" Order at 96 (emphasis added). "In allowing seasonal/peak pricing, the Commission is improving upon the existing pricing model *and retaining the revenue constraints of its existing cost-based ratemaking regulatory model.*" *Id.* (emphasis added). Thus, while it is true that the specific peak and off-peak rates selected may be based on "value of service concepts, rather than specific costs," Order at 99, nonetheless, the overall rates collected through seasonal rates must not exceed the pipeline's annual revenue requirements. As stated in the Order: "Value-based peak/off-peak rates are just and reasonable *cost-based rates.*" Order at 100 (emphasis added).¹⁷

¹⁶ However, the Commission should clarify that submitting these annual cost-revenue studies constitutes a Section 4 exercise with the attendant Section 4 safeguards (*e.g.*, collecting rates subject to refund).

¹⁷ The Order explains in great detail that seasonal rates, like uniform maximum rates, still must not produce revenues in excess of costs:

Like uniform maximum rates, peak/off-peak rates would be established by taking the pipeline's annual revenue requirement and deriving from it a daily or monthly rate. The

(Continued . . .)

Although seasonal rates and long-term rates are to be calculated to recover no more than a pipeline's annual revenue requirement, the Commission notes that a pipeline's revenues from short-term services "should" increase "if it adopts peak/off-peak rates." Order at 103. Pipelines may submit *pro forma* tariff filings in which pipelines "reduce off-peak price caps so that they would be close to recent discount history, and correspondingly increase peak caps." *Id.* By charging what they are already receiving in off-peak periods, and increasing rates during peak demand periods, while keeping long-term rates the same, pipelines will likely collect revenues in excess of annual revenue requirements. *See* Order at 103-105. As the Commission acknowledges, all pipelines' maximum rates have *already* been raised to reflect the discounts they offer, *see* Order at 94-95,¹⁸ a kind of seasonal rate in itself, and pipelines are already provided a full opportunity to recover revenue requirements. Permitting pipelines to raise peak rates while establishing off-peak rates at or above the discounted rates they already receive results in double-dipping if maximum rates that have already been adjusted to account for discounting are not adjusted again to account for adoption of seasonal rates.

(Continued . . .)

difference in developing peak/off-peak rates and the current uniform maximum rate is that instead of dividing the annual revenue requirement by 365 to obtain a daily rate, different daily or monthly rates will be developed for peak and off-peak periods using one of several possible methods of measuring the value of capacity at peak and off-peak. The sum of the daily or monthly rates, multiplied by the quantity used or reserved, still must not exceed the pipeline's annual revenue requirement, and thus, any increases in rates at peak must be offset by decreases in off-peak rates. [Order at 100-101 (footnote omitted).]

¹⁸ The Commission notes that under its current discount adjustment policy, "pipelines offering discounts are able, in the next rate case, to adjust maximum rates to reflect the discounts." Order at 95.

The Commission explicitly recognizes that requiring pipelines to file a general rate case to implement seasonal rates would be one method of preventing excess revenue recovery. Order at 103-04. The Commission observes, however, that a general section 4 rate case “may not be well-suited” for this task during initial implementation because there would be “no historical experience that would adequately project future short-term service demand with peak/off-peak pricing.” Order at 104. However, after one-year of implementing seasonal rates, there *would* exist the historical data with which to conduct a section 4 rate review in which “all pipeline costs and revenues can be examined and the appropriate rate responsibility of each service can be decided.” Order at 103. NGSAs urge the Commission to fulfill its obligation to conduct such a general rate review to assure that pipelines do not overcollect revenue, and that appropriate rate responsibility is assigned to each service.

In this regard, there is no distinction between implementation of seasonal rates and of term-differentiated rates. The Commission recognizes that implementation of term-differentiated rates *must* be done through a general Section 4 rate proceeding because such rates “would raise the maximum tariff rates for some customers, and there should be a decrease in maximum rates for long-term customers.” Order at 110. Such a “general reallocation of revenue responsibility among customer classes must be done through rate changes for all customers simultaneously in [a] section 4 rate case” *Id.* As the Commission acknowledges, seasonal rates will similarly result in raising the maximum tariff rate for some customers, and “the rates for long-term services would be reduced in recognition that the pipeline could be expected to recover more revenues from short-term services.” Order at 103-04. Seasonal rates, too, result in a “[g]eneral reallocation of revenue responsibility among customer classes,” and, therefore, must

be implemented for all customers “simultaneously” in a Section 4 rate proceeding, at least after a reasonable period of experience with seasonal rates.

B. Because Some Pipelines Rates Are Already Stale, Implementing Seasonal Rates Increases The Need For Rate Review.

A general rate case is further required to establish just and reasonable seasonal rates because some pipelines’ current rates are long overdue for review. Since issuance of Order No. 636, the Commission has not had a policy of requiring, as a condition for acceptance of new rate filings, that pipelines agree to periodically initiate Section 4 rate proceedings entailing a general review of whether pipelines’ rates have lost their relationship to costs.¹⁹ During this period, many pipeline rates have grown stale and no longer reflect revenue requirements. *See* Attachment B at 2-4. Rates become disconnected from costs as time passes through changes in use patterns (including billing determinants such as contract demand levels, and throughput), changes in the level of discounting required (especially if demand increases), changes in costs and depreciation. A recent analysis by NGSAs of forty-five pipeline Form 2 filings, for example, demonstrates that pipeline O&M costs have been dramatically reduced, from \$8.2 billion to \$4.8 billion, a drop of 41% for all pipelines from 1994 to 1998. *See* Attachment B at 5. Moreover, an analysis of rate cases conducted by NGSAs (based on FERC online records) shows that major interstate pipelines have filed significantly fewer rate cases in the last three years compared to the previous three years. *See* Attachment B at 6. While the annual number of rate cases on

¹⁹ In addition, it appears that the Commission is not actively using its powers granted under Section 5 to initiate proceedings to investigate whether pipeline rates are no longer just and reasonable. But under current circumstances, pipelines have an incentive *not* to initiate rate proceedings; hence, the Commission should again avail itself of the Section 5 mechanism Congress granted it and initiate Section 5 proceedings as well as condition acceptance of new rate initiatives on an agreement to file a Section 4 rate case after a reasonable period of time.

average from 1994 through 1996 was thirteen, from 1997 through 1999, the average annual number was only six. *Id.* Indeed, a review of the time lapsed since pipelines filed their last rate case shows that 31 pipelines filed their last rate case 3 or more years ago, while only 12 have filed within the last two years. *See* Chart reproduced at 3, and in Attachment B at 7.

Finally, pipelines naturally initiate rate proceedings when they desire rate increases, or are required by previous agreements to file, and refrain from filing rate proceedings when overrecovery is occurring.²⁰ Furthermore, ongoing cost reductions provide an incentive for pipelines to refrain from filing rate cases. The increased merger activity in the past few years has the potential to further drive down costs. One of the prime goals of these consolidations is to achieve operational cost efficiencies, which are only shared with customers if a rate filing is made. Abandonment of facilities also produces cost savings that should be shared with customers. Pipelines are permitted to keep revenues associated with cost reductions between rate cases, but when the periods “between rate cases” become indefinite, pipelines may never have to share cost reductions with their customers, which is unreasonable.

The Commission should recognize that revenue crediting is not a long-term fix for pipeline rates. The Commission continually has shown a preference for cost allocation over revenue crediting and has sought other options when possible.²¹ Revenue crediting for extended

²⁰ Of 39 companies that filed a rate case from 1994 through 1999, approximately 79% requested a rate increase, 3% asked for no change in rates, and 8% asked for a rate decrease. (Information on the rate request of the remaining 10% of companies was not accessible.) The average requested rate increase was for approximately \$36 million, and the average requested rate reduction was for approximately \$7 million. (Information for 5 out of the 39 pipelines analyzed was not accessible.) Attachment B at 8.

²¹ *See, e.g., Panhandle Eastern Pipe Line Co.* (Opinion No. 404), 74 FERC ¶ 61,109 at 61,388 (1996) (“[t]he Commission’s regulations prefer rates based on projected volumes and
(Continued . . .)

or indefinite periods of time only exacerbates pipelines charging rates that are unjust and unreasonable.

Only through a requirement that a pipeline at least periodically submit a rate case can the Commission fulfill its duty to ensure meaningful cost-based rates that at least approximate a pipeline's cost-based annual revenue requirement. Given that pipelines recognize that, after having adopted seasonal rates, they stand to lose their current discount adjustment if a rate case is filed, they will be even more hesitant to file a rate case in the future than they are today. Permitting seasonal rates thus increases exponentially the need for rate review.

NGSA believes that one of the Commission's most important responsibilities and functions in monitoring gas pipelines is to closely examine Form 2 information and initiate Section 5 proceedings where such filings suggest that recovered revenues are consistently exceeding revenue requirements. Form 2 information should be revised to show clearly pipeline revenues and to enable shippers and the Commission to calculate easily pipeline costs and revenues, including returns on equity, and this information should be posted on the Commission's website.

(Continued . . .)

costs rather than on crediting”) (citing 18 C.F.R. § 284.7(d)(2) (1995)); *Panhandle Eastern Pipe Line Co.*, 74 FERC ¶ 61,102 at 61,326 (1996) (referring to “the Commission’s established policy of basing the firm rates on test-period data without revenue crediting”). For example, in implementing Order No. 636, the Commission permitted revenue crediting to accompany the introduction of interruptible transportation but required that such revenue crediting terminate once a pipeline filed a rate case after gaining sufficient experience to project volumes. *See Panhandle Eastern Pipe Line Co.*, 74 FERC at 61,385-86 (“[w]hen Panhandle files its next rate case, it will have substantial post-restructuring experience, and the Commission’s normal policy that rates be based on projected units of service, without any revenue crediting, will apply”).

NGSA is willing to work with the Commission, pipelines and shippers in formulating a rate review process for reviewing current rates (including rate design and cost allocation) that would not be as “burdensome” as prior rate reviews, but in the meantime, the industry cannot continue indefinitely with rates that lack a meaningful relationship to costs when sufficient competition has not been shown to exist. Additionally, NGSA urges the Commission to take responsibility to deliver just and reasonable rates – rather than relying on pipelines to do so. Pipelines are not altruistic and should not be expected to file when it is not in their own best interests to do so. Shippers need the Commission to intervene.

C. Over-Collections From Seasonal Rates Should Be Refunded To All Shippers.

The Commission has provided that pipelines may propose that any overcollection of revenues resulting from the implementation of seasonal rates be split fifty-fifty between pipelines and their long-term shippers. All pipeline shippers, however, should be credited with any excess revenues derived from seasonal rates.

It is appropriate to credit all shippers because, until a pipeline’s next rate proceeding, revenue crediting acts as a substitute for adopting new discount adjustments (*i.e.*, lowering maximum rates) -- which will benefit all shippers, i.e., both short-term and long-term shippers. Although the Commission states that, by giving excess revenues to long-term shippers, it “is seeking to lower the rates to long-term customers in recognition of the additional risks they take by signing long-term contracts,” Order at 105, this goal can already be achieved through term-differentiated rates and, in addition, can only be achieved under seasonal rates in the context of a Section 4 rate proceeding at which time the benefit of decreased discounting levels can be recognized.

Moreover, there is no sound justification for allowing pipelines to retain *any* excess revenues -- much less up to 50% of excess revenues -- because such overcollections are,

by definition, in excess of cost-based, just and reasonable revenue requirements. In this respect, the Order is internally inconsistent: on the one hand, it justifies seasonal rates by repeatedly proclaiming that pipelines' overall revenue recovery will be limited to their cost-based annual revenue requirements, *see* discussion *supra* at p. 23; Order at 96, 100; yet, on the other hand, the Order permits pipelines to retain as much as 50% of excess revenues. Such retention is further inappropriate in that it creates an incentive for pipelines to file for seasonal rates for the sole purpose of obtaining over-collections. Implementing seasonal rates should be a revenue neutral event.

Indeed, although, during restructuring, the Commission previously allowed pipelines to retain 10% of interruptible transportation (“IT”) revenues to provide an incentive for pipelines to provide interruptible transportation service,²² even the rationale of providing an incentive to pipelines is inapplicable here. Pipelines themselves have proposed and want seasonal rates. Nevertheless, if the Commission believes some “incentive” should be provided – notwithstanding the absence of a sound rationale for such – then the maximum percentage of excess revenue from seasonal rates that pipelines could even reasonably be permitted to retain would be 10%, similar to the incentive provided with respect to IT.

In this regard, the Commission should also not permit excess revenues to be credited to pipeline affiliates. That practice also provides pipelines with an incentive to adopt seasonal rates that result in the collection of excess revenues.²³

²² *See, e.g., Panhandle Eastern Pipe Line Co.*, 64 FERC ¶ 61,009 at 61,049 (the 10% provides “an incentive to market the service”).

²³ The Order provides little explanation as to how excess revenues will be calculated. Order at 105-106. The Commission should also clarify how such revenues will be determined.

In sum, the Order provides no basis for allowing pipelines to share in *any* excess revenues associated with seasonal rates, much less 50% of excess revenues. At a minimum, the Commission needs to explain why any sharing of excess revenues with pipelines is justified, and, if a reason is found, to limit the percentage retained by pipelines to match the purpose identified.

CONCLUSION

For the foregoing reasons, NGSА respectfully requests rehearing of the Commission's Order, and respectfully requests reconsideration of the issues identified in Attachment A of this submission.

Respectfully submitted,

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March 10, 2000

ATTACHMENT A

ATTACHMENT A

NGSA respectfully requests reconsideration or clarification of the following issues:

1) **Require consistency with GISB standards:** The Commission should clarify or specify that the pipeline tariff filings due to be filed on May 1, 2000, should follow GISB standards that have been agreed upon but not filed to date. Otherwise, gross inefficiencies will result from the filing of large numbers of inconsistent tariffs containing numerous non-standardized terms. In particular, when selecting the window of time in which shippers are to conduct imbalance trading, pipelines should be required to follow the GISB standard, rather than be permitted to impose a period of time on shippers that may not be sufficient to allow adequate imbalance trading to occur.

2) **Clarify or strengthen reporting requirements:** With respect to reporting requirements, pipelines should be required to report on a real time flow basis to the extent their existing metering equipment permits. The Commission should clarify that whatever information regarding capacity usage that a pipeline has access to should be made public for all to see and on a real time basis wherever feasible.

In particular, where operationally feasible, a pipeline should report on a real-time basis for each point on its system – and especially for constraint points or other critical points – the design capacity (*i.e.*, total available capacity before subscriptions) for that point, the capacity actually scheduled for that point, and actual physical flows through the point. Only with this information can shippers know how much of unused capacity is actually unused *but* subscribed capacity that can be taken back by firm capacity holders at either the second or third nomination cycles.

At a minimum, the Commission should at least require that pipelines post available design and scheduled capacity not only after the normal or “timely” cycle (11:30 a.m. on the day before flow day), but also after the 6 p.m. evening cycle and, where operationally feasible, after the two intra-day cycles. Reporting available capacity only after the normal cycle is of limited value because available capacity often changes substantially as a result of the evening cycle.

Such reporting information should be provided and maintained on-line in a usable format that will permit customers to download the information and examine monthly capacity trends.

3) **Priorities for capacity within a path:** The Commission should reconsider its decision not to adopt a generic policy of giving equal priority to both primary and secondary delivery points within the same constrained path. Equality should be the generic policy, and pipelines that depart from that policy should be required to justify such departure.

4) **Require master agreements:** Although the Commission established scheduling equality between capacity release shippers and others holding firm capacity, and recognized the efficacy of master agreements in achieving scheduling equality, it nonetheless did not take the next step supported by its findings and simply require use of a master agreement. In NGSAs’ view, master agreements are the *only* solution for achieving scheduling equality, and the Commission should therefore require them.

5) **Penalties:** The Commission has taken appropriate steps to limit the use of pipeline penalties; however, the Commission should go further and adopt a “no harm, no foul” policy with respect to penalties. Where an imbalance or other action by a shipper does not result in any actual harm to the pipeline or other shippers, it is inappropriate to impose a penalty. The

Commission should also require that penalty-generated revenues be credited to all shippers based on their contribution to revenue during the period resulting in the penalty, while excluding from such revenue sharing the particular shipper that caused the penalty.

6) **Wider availability of imbalance information and consistent application of penalty provisions:** The Commission should clarify that all parties that are accountable for imbalances such as OBAs and point operators will receive imbalance information. In fact, all imbalance information should be posted on the Internet, and all participants should be able to access it. Not only should pipelines give imbalance information to OBAs and point operators, but any operational flow order and penalty tariff provisions should apply consistently to point operators and OBAs in the same manner as they do to other transporters, in order to maintain system integrity.

7) **Negotiated rates versus negotiated terms and conditions:** The Commission should further clarify the distinction between negotiated rates and negotiated terms and conditions with respect to how it intends to treat capacity turnback issues.

ATTACHMENT B

Firm Transmission Capacity Under Contract for Selected Interstate Pipelines
January 2000 FERC Index of Customers
Thousand Dekatherms per Day of Transmission Capacity
Compiled by Energy and Environmental Analysis, Inc.

Pipeline	Firm Capacity Under Contract as of 1/1/2000			
	Held by Affiliates	Held by Non-Affiliates	Total**	% Held by Affiliates
Algonquin Gas Transmission Company	20	2,073	2,093	1%
ANR Pipeline Company	171	8,224	8,395	2%
CNG Transmission Corporation	1,637	3,271	4,908	33%
Colorado Interstate Gas Company	157	2,554	2,712	6%
Columbia Gas Transmission Corporation	4,751	7,254	12,005	40%
Columbia Gulf Transmission Company	737	2,572	3,309	22%
East Tennessee Natural Gas Company	0	677	677	0%
El Paso Natural Gas Company*	1,200	4,630	5,830	21%
Equitrans LP	536	205	741	72%
Florida Gas Transmission Company	31	1,568	1,599	2%
Great Lakes Gas Transmission LP	3,139	1,599	4,739	66%
High Island Offshore System, L.L.C.	0	21	21	0%
Iroquois Gas Transmission System, L.P.	20	1,038	1,058	2%
K N Interstate Gas Transmission Co.	362	525	886	41%
Kern River Gas Transmission Company	0	788	788	0%
Koch Gateway Pipeline Company	318	1,954	2,272	14%
Midwestern Gas Transmission Company	0	870	870	0%
Mississippi River Transmission Corporation	410	1,265	1,675	24%
Mojave Pipeline Company	24	376	400	6%
National Fuel Gas Supply Corporation	1,195	728	1,924	62%
Natural Gas Pipeline Company of America	379	7,183	7,562	5%
Northern Border Pipeline Company	557	2,773	3,329	17%
Northern Natural Gas Company	605	13,131	13,736	4%
Northwest Pipeline Corporation	60	4,082	4,141	1%
Panhandle Eastern Pipe Line Company	136	3,402	3,538	4%
PG&E Gas Transmission, Northwest Corp.	655	2,160	2,815	23%
Questar Pipeline Company	848	265	1,113	76%
Reliant Energy Gas Transmission Company	1,628	1,032	2,660	61%
Sea Robin Pipeline Co	0	259	259	0%
Southern Natural Gas Company	18	2,441	2,459	1%
Stingray Pipeline Company	0	54	54	0%
Tennessee Gas Pipeline Company	78	5,836	5,915	1%
Texas Eastern Transmission Corporation	116	4,970	5,086	2%
Texas Gas Transmission Corporation	33	2,211	2,243	1%
Trailblazer Pipeline Company	288	317	605	48%
Transcontinental Gas Pipeline Corporation	604	7,121	7,726	8%
Transwestern Pipeline Company	41	2,271	2,312	2%
Trunkline Gas Company	372	2,083	2,455	15%
Viking Gas Transmission Company	141	488	630	22%
Williams Gas Pipelines Central, Inc.	131	2,891	3,022	4%
Williston Basin Interstate Pipeline Company	438	468	907	48%
Wyoming Interstate Company, Ltd.	379	689	1,069	35%
Total	22,216	108,321	130,538	17%

* Adjusted to include March 1, 2000 Contract with affiliate. El Paso's January 2000, Index of Customer data did not include any firm capacity held by affiliates.

**This table is a conservative representation of the percentage of capacity held by affiliates because in many instances the segmentation of firm capacity results in a total capacity in excess of total design capacity.

NATURAL GAS SUPPLY ASSOCIATION PIPELINE O&M EXPENSES

	Pipeline:	1994	1995	1996	1997	1998
1	Algonquin Gas Transmission Company_	\$43,804,818	\$39,436,881	\$44,605,295	\$52,123,631	\$48,719,533
2	ANR Pipeline Company_	\$475,630,081	\$445,052,003	\$412,769,740	\$369,543,939	\$345,049,144
3	CNG Transmission Corporation_	\$232,552,513	\$224,667,977	\$231,896,823	\$217,841,477	\$224,300,253
4	Colorado Interstate Gas Company_	\$151,767,820	\$162,902,423	\$165,554,681	\$153,090,476	\$143,839,474
5	Columbia Gas Transmission Corporation_	\$532,229,740	\$278,450,577	\$353,660,719	\$332,583,152	\$288,837,165
6	Columbia Gulf Transmission Company_	\$149,781,871	\$81,234,542	\$84,212,940	\$79,029,111	\$65,838,645
7	East Tennessee Natural Gas Company _	\$29,333,247	\$19,374,724	\$18,110,121	\$15,268,444	\$20,147,265
8	El Paso Natural Gas Company_	\$373,766,324	\$354,215,972	\$337,873,515	\$181,360,757	\$164,209,474
9	Equitrans, L.P._	\$30,303,312	\$31,010,999	\$29,359,095	\$28,298,622	\$25,839,884
10	Florida Gas Transmission Company_	\$63,430,868	\$77,174,344	\$65,941,027	\$85,405,087	\$71,509,444
11	Great Lakes Gas Transmission Limited Ptrshp_	\$40,254,529	\$43,349,571	\$44,059,042	\$41,955,171	\$45,482,367
12	High Island Offshore System, L.L.C._	\$24,792,888	\$19,205,686	\$15,548,824	\$16,975,738	\$18,935,496
13	Iroquois Gas Trans. Sys. L.P.	\$26,583,508	/2	\$22,537,422	\$23,988,103	\$21,978,402
14	K N Interstate Gas Transmission Co._	\$33,102,770	\$35,227,924	\$30,529,864	\$28,761,882	\$31,529,554
15	Kern River Gas Transmission Company	\$24,715,501	\$23,570,802	\$25,691,589	\$23,121,915	\$24,028,378
16	Koch Gateway Pipeline Company	\$116,669,523	\$63,264,553	\$104,718,068	\$117,619,655	\$109,873,973
17	Michigan Gas Storage Company	\$11,895,607	\$11,961,343	\$11,773,918	\$11,920,264	\$12,083,438
18	Midwestern Gas Transmission Company	\$19,814,608	\$-3,648,737	\$9,395,495	\$8,126,430	\$9,144,569
19	Mississippi River Transmission Corporation _	\$90,588,032	\$33,899,863	\$38,891,991	\$29,787,016	\$21,899,584
20	Mojave Pipeline Company_	\$13,446,468	\$10,854,268	\$8,162,511	\$8,569,248	\$6,985,747
21	National Fuel Gas Supply Corporation	\$63,248,804	\$63,868,832	\$72,394,013	\$65,437,915	\$63,767,022
22	Natural Gas Pipeline Company of America_	\$723,443,181	\$608,742,393	\$565,110,367	\$501,134,411	\$284,326,865
23	Northern Border Pipeline Company_	\$27,661,651	\$25,552,600	\$26,885,853	\$28,425,317	\$29,348,718
24	Northern Natural Gas Company_	\$509,851,257	\$312,261,299	\$195,536,078	\$187,420,294	\$175,919,579
25	Northwest Pipeline Corporation	\$98,581,958	\$88,468,980	\$98,066,908	\$89,071,465	\$85,850,401
26	Overthrust Pipeline Company	\$1,083,989	\$1,083,989	\$729,646	\$992,872	\$543,613
27	Panhandle Eastern Pipe Line Company_	\$198,464,679	\$181,140,732	\$178,290,059	\$201,119,412	\$137,406,264
28	PG&E Gas Transmission, Northwest Corporation	\$85,636,813	\$101,834,838	\$84,518,698	\$58,679,726	\$49,160,388
29	Questar Pipeline Company	\$44,486,628	\$46,425,253	\$43,754,845	\$39,249,239	\$40,774,463
30	Reliant Energy Gas Transmission Company 1/	\$163,886,116	\$170,420,610	\$229,991,942	\$108,955,504	\$82,338,013
31	Sea Robin Pipeline Company	\$15,418,239	\$14,960,546	\$14,268,532	\$13,278,821	\$12,662,662
32	Southern Natural Gas Company	\$542,354,733	\$423,669,247	\$516,546,403	\$327,569,776	\$163,953,915
33	Stingray Pipeline Company	\$13,704,202	\$13,533,283	\$13,770,224	\$15,080,588	\$14,434,715
34	Tennessee Gas Pipeline Company_	\$743,072,700	\$545,410,946	\$367,612,649	\$413,344,837	\$304,220,434
35	Texas Eastern Transmission Corporation	\$382,266,215	\$445,963,773	\$448,408,866	\$460,049,850	\$394,078,571
36	Texas Gas Transmission Corporation	\$282,764,895	\$237,751,371	\$222,570,127	\$180,876,355	\$134,056,509
37	Traillblazer Pipeline Company_	\$2,406,572	\$2,386,386	\$2,306,709	\$3,073,312	\$3,282,915
38	Transcontinental Gas Pipeline Corporation	\$1,214,600,929	\$1,138,787,345	\$1,222,185,009	\$1,019,007,426	\$861,263,082
39	Transwestern Pipeline Company_	\$64,135,308	\$61,736,907	\$32,807,749	\$49,673,730	\$51,325,963
40	Trunkline Gas Company	\$269,875,360	\$84,401,486	\$105,775,478	\$75,040,893	\$74,127,353
41	U-T Offshore System	\$3,442,163	\$2,734,203	\$2,423,640	\$2,403,964	\$2,372,191
42	Viking Gas Transmission Company	\$8,754,561	\$8,811,525	\$9,139,753	\$8,934,872	\$9,880,323
43	Williams Gas Pipelines Central, Inc._	\$170,100,050	\$134,898,410	\$117,671,917	\$100,196,870	\$143,380,720
44	Williston Basin Interstate Pipeline Company	\$38,754,064	\$35,708,362	\$37,142,778	\$34,256,422	\$27,138,887
45	Wyoming Interstate Company, Ltd.	\$1,987,824	\$1,949,378	\$918,589	\$3,428,578	\$2,694,703
	Grand Total	\$8,154,446,919	\$6,703,708,409	\$6,664,119,512	\$5,812,072,567	\$4,848,540,058
	Percentage change in Grand Total from 1994 to 1998					-41%

Source: FERC Form 2

1/ Former NorAm Gas Transmission Company.

2/ Data for Iroquois Gas Transmission System, L.P. for 1995 was not available on FERC Form 2.

Attachment B

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NATURAL GAS SUPPLY ASSOCIATION

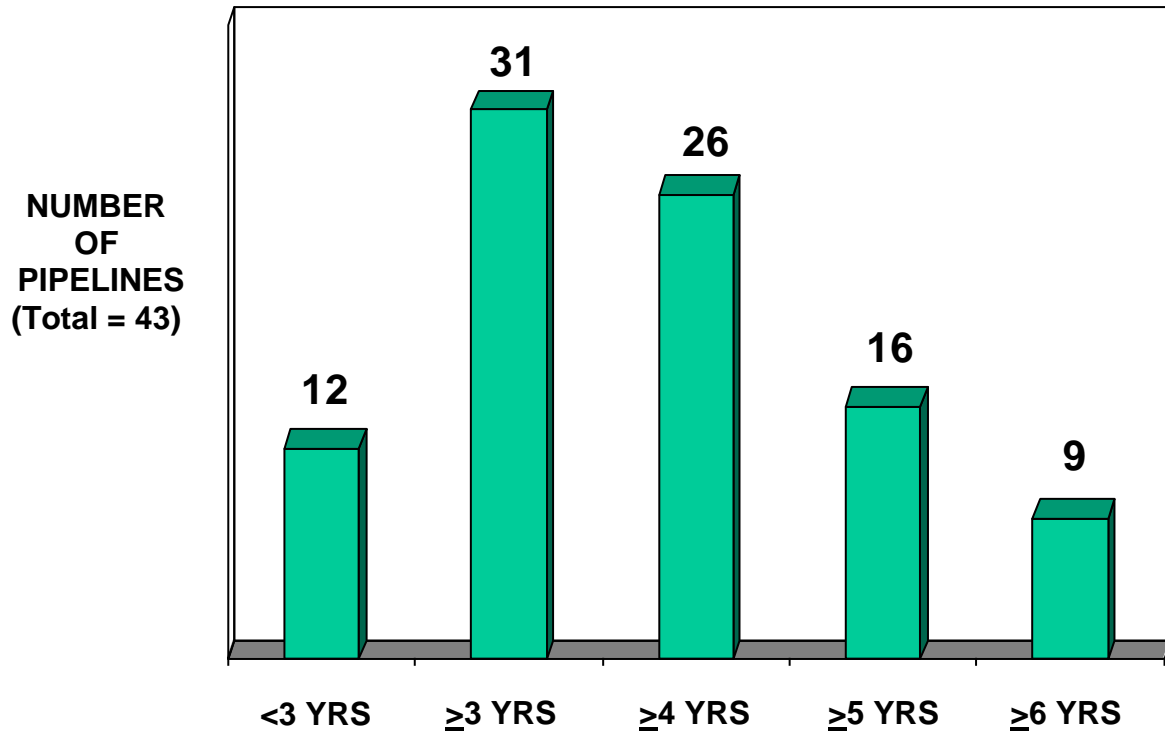
**NUMBER OF SECTION 4 RATE CASES
FILED BY MAJOR INTERSTATE PIPELINES
PER YEAR***

YEAR	NUMBER OF FILINGS
1994	13
1995	14
1996	11
1997	7
1998	5
1999	7

Source: Commission Issuance Posting System (CIPS) and the Records and Information Management System (RIMS) from FERC Energy Information Online.

*Includes multiple filings by the same pipeline where applicable.

FIGURE 1
TIME LAPSED SINCE LAST RATE CASE



Source: NGSAs Analysis of Major Interstate Pipelines
Using Commission Issuance Posting System (CIPS) and the Records
and Information Management System (RIMS) from FERC Energy
Information Online

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 10th day of March, 2000.

John H. Sharp
Vice President for Federal And State
Regulatory Affairs and General Counsel
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