# **1 Regulation of the Gas Industry § 8.05**

***Regulation of the Gas Industry* > *DIVISION I Evolution of the Gas Industry and the Regulatory Framework* > *CHAPTER 8 INTERSTATE TRANSPORTATION OF NATURAL GAS***

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**§ 8.05 Key Ratemaking Standards Pertinent to Transportation**

1. **Overview and Key Cost-based Rate Principles and Applications**

The principles underlying the standard, cost-based transportation rates were primarily developed in Order No. 436 and its implementing cases, and in the Policy Statement on Rate Design issued prior to Order No. 636. The ratemaking standards expressly imposed by the open access regulations include the following key items:[[2]](#footnote-3)1

(b) Rate objectives. Maximum rates for both peak and off-peak periods must be designed to achieve the following three objectives:

(1) Rates for service during peak periods should ration capacity;

(2) Rates for firm service during off-peak periods and for interruptible service during all periods should maximize throughput; and

(3) The pipeline’s revenue requirement allocated to firm and interruptible services should be attained by providing the projected units of service in peak and off-peak periods at the maximum rate for each service.

1. **Unbundled Rates**

Just as one of the main themes of Order No. 436 was unbundling transportation service from sales service, another was establishing properly unbundled rates. This requirement is expressed in three of the open access rate regulations requiring: (1) that the maximum firm rate recover all those costs which are allocated to the service to which the rate applies;”[[3]](#footnote-4)2 (2) that revenue requirements allocated to firm and interruptible services should be attained by providing the projected units of service in peak and off-peak periods at the maximum rate for each service;[[4]](#footnote-5)3 and (3) that each rate must separately identify cost components attributable to transportation, storage, and gathering costs.”[[5]](#footnote-6)4 The meaning of these ratemaking principles was clarified with the issuance of the Policy Statement on rate design issues in the Policy Statement on rate design,[[6]](#footnote-7)5 with Opinion No. 369,[[7]](#footnote-8)6 and subsequently in Order No. 636.[[8]](#footnote-9)7 The Commission also established economic efficiency as one of its explicit ratemaking goals, and required that all pending rate cases address that goal and the other issues raised in the Policy Statement.

1. **Firm and Interruptible Rates**

A long-contentious ratemaking issue involved the relationship of interruptible (*i.e*., subject to being interrupted by higher-priority services even when the pipeline is operating at normal capacity) and firm (*i.e*., not subject to interruption except during times of force majeure or capacity curtailment) transportation rates. Most of the early rate orders and settlements provided for an interruptible rate equivalent to the firm rate at 100 percent load factor usage, and the Commission approved that approach against complaints by numerous marketers, brokers, and producers.[[9]](#footnote-10)8 The D.C. Circuit affirmed the Commission’s approval of a 100% load factor interruptible transportation rate in *Elizabethtown Gas Co. v. FERC,*[[10]](#footnote-11)9 and the Commission has generally approved interruptible rates on that basis since Order No. 636.[[11]](#footnote-12)10 The Commission defended this policy at length in Opinion Nos. 406 and 406-A,[[12]](#footnote-13)11 where it found that the 100% load factor rate fulfilled the goals of the Rate Design Policy Statement, by rationing capacity during times of scarcity, while permitting the pipeline to maximize throughput in times of excess capacity.[[13]](#footnote-14)12 Variations in the form of lower interruptible rates have been allowed, however, including 125%[[14]](#footnote-15)13 and 175% load factor rates.[[15]](#footnote-16)14

1. **Distance-sensitive and Seasonal Rates**

The regulations require that rates “must reasonably reflect any material variation in the cost of providing the service due to” provision of the service on a peak or off-peak basis, and “the distance over which the transportation is provided.”[[16]](#footnote-17)15 The actual implementation of these principles has been less than clear-cut, however. Subsequent to Order No. 436, the Commission upheld rates that reflected traditional zoning by states,[[17]](#footnote-18)16 and rates that reduced the historical number of zones from six to two (mileage rates in the “field zone” and postage stamp rates in the “market zone”).[[18]](#footnote-19)17 Postage stamp rates have been upheld based on system operations.[[19]](#footnote-20)18 The requirement for seasonal rates has been described as merely a “goal that ought to be considered … but which [is] not absolutely required.”[[20]](#footnote-21)19 Both mileage and seasonal rate issues were prominently discussed the rate design Policy Statement, but during the subsequent period the Commission has not established firm requirements for these standards. A general disposition favoring mileage rates was reflected in an order modifying a settlement so as to require that postage stamp rates for firm service be replaced by mileage rates like those the settlement already provided for interruptible service.[[21]](#footnote-22)20 Similarly, pipelines were permitted to charge shippers the actual path rate for use of alternative receipt points.[[22]](#footnote-23)21 But a somewhat greater degree of leniency was reflected in a certificate, where the Commission, allowed it to file initial rates on a zone basis, and indicated that the pipeline’s reflection of distance in its rates would receive a more careful look after its first three years of operation.[[23]](#footnote-24)22 In applying the rate design Policy Statement to the Panhandle System in Opinion No. 369,[[24]](#footnote-25)23 the Commission required distance-sensitive rates in 100-mile increments for transportation services but not for the pipeline’s sales services.[[25]](#footnote-26)24

Following Order No. 636, the Commission addressed rate design issues relating to the propriety of zoned or mileage-based rates, expressing particularly concern to the impact of rate design upon the competitive impact of the rates on gas sales. For example, the Commission determined that one pipeline’s “zone of delivery rate” structure created an economic disincentive to receive and deliver gas solely in a downstream zone by requiring the downstream shipper to pay rates that included costs associated with transportation from upstream rate zones. The Commission ultimately directed the parties instead to develop “an appropriate mileage-sensitive rate.”[[26]](#footnote-27)25 The Commission ordered another pipeline to develop mileage based reservation charges in the field area, unless it could explain why it was appropriate to accept postage stamp reservation rates and mileage-based usage rates for that service area.[[27]](#footnote-28)26 The Commission rejected another pipeline’s restructuring proposal to use system-wide reservation rates, because that proposal was a change in rate design from the existing zone-based rates and therefore was not required by Order No. 636.[[28]](#footnote-29)27 The same pipeline was also required to provide that shippers using a downstream delivery point pay a higher reservation charge than shippers using an upstream delivery point.[[29]](#footnote-30)28 In another proceeding, the Commission found that use of a zone matrix methodology to be a form of mileage-based rates consistent with its regulations.[[30]](#footnote-31)29

More broadly, the Commission commented that postage stamp rates are inappropriate for a system with multiple market centers, *i.e.,* a web-like and multi-directional system, but it declined to impose a particular distance-sensitive rate structure, leaving the issue to be reexamined after the pipeline develops an operational history under Order No. 636.[[31]](#footnote-32)30 The Commission directed another pipeline to develop mileage-based reservation charges in the field area unless it could explain why it was appropriate to use postage stamp reservation rates and mileage-based usage rates.[[32]](#footnote-33)31 It directed another pipeline to develop distance-sensitive demand and commodity charges to avoid creating barriers to the development of market centers that were created by the pipelines’ system-wide reservation rate.[[33]](#footnote-34)32 However, the Commission approved a settlement calling for postage stamp rates finding them not to be inconsistent with Order No. 636.[[34]](#footnote-35)33 Indeed, despite the apparent tilt towards distance-based rates reflected in the Policy Statement on Rate Design and some of the restructuring cases, little change has occurred in the rate design of most major pipelines since Order No. 636. Even as of 2009, many major pipelines retained a postage-stamp rate design (often through settlements),[[35]](#footnote-36)34 and even following Order No. 636, the Commission approved Northwest Pipeline’s postage stamp rates after a fully litigated rate proceeding.[[36]](#footnote-37)35

1. **Backhaul Exchange Rates**

Pipelines are not required to offer backhaul rates,[[37]](#footnote-38)36 but the Commission has ruled on backhaul rates in a number of cases. Early during the open access era, the Commission eliminated special rate schedules (and rates) for backhaul and exchange arrangements, ruling that these services should be covered under the generally applicable tariffs, with discounting of the rate if the pipeline considers it appropriate.[[38]](#footnote-39)37 However, in the Policy Statement on rate design, the Commission ruled that its previous orders “no longer embody Commission policy.”[[39]](#footnote-40)38 The Commission later clarified that pipelines may “separately state and charge rates for backhauls and exchanges … [although such rates may be] the same as the direct haul rates provided that is justified”[[40]](#footnote-41)39 —given that, as displacement transactions, backhauls generally increase pipeline throughput capacity and do not involve physical transportation. In Opinion No. 369, the Commission ruled that backhauls on the Panhandle system created additional capacity on the pipeline and that a special backhaul rate equal to one-half the applicable forward haul rate was appropriate.[[41]](#footnote-42)40

1. **Rate Design Impact on Market Centers**

The Commission has sought to prohibit rate structures which would impair the development of market centers[[42]](#footnote-43)41 since Order No. 636. In some proceedings, the Commission simply voiced concern over whether a rate structure would affect market center development,[[43]](#footnote-44)42 and expressed its intention to monitor pipeline systems that, in its view, may produce viable market centers.[[44]](#footnote-45)43 The Commission required that one pipeline change its current zone structure to make reservation rates additive, so that a shipper pays only for the reservation charges or interruptible rates on a zone basis, in order to reduce deleterious rate impacts on the development of market centers.[[45]](#footnote-46)44

1. **Selective Discounting**

Under Part 284, pipelines have been permitted to charge rates below the maximum and above the minimum rates stated in its tariff—“selective discounting.”[[46]](#footnote-47)45 The regulations restricts discounts to marketing affiliates and the Commission has stated from the outset that the NGA §§ 4 and 5 nondiscrimination requirements still apply.[[47]](#footnote-48)46 Moreover, the requirement to offer discounts on a nondiscriminatory basis was emphasized by the affiliate rules.[[48]](#footnote-49)47 Following Order Nos. 636 and 637 the Commission did not make any changes to its policy on pipeline discount adjustments for ratemaking purposes. However the D.C. Circuit, on judicial review of Order No. 637, court stated that the Commission had deferred general broader consideration of the discounting issue for such a long time that “[s]ome of its conduct is suggestive of a shell game,” and further noted that despite having invited a broad review of issues comprehensively (including the discount adjustment) in its rulemaking proceeding leading to Order No. 637, the Commission nonetheless failed to address the issue in Order No. 637. Although the court concluded that the issue appeared best treated in a comprehensive, generic proceeding, it ultimately concluded that the Commission should be granted its choice to address the issue in yet a newer generic proceeding, noting in closing that, “[a]s time drags on, however, Commission failure to address the issue on the merits will virtually set it up for a successful claim for delay.”[[49]](#footnote-50)48 Commencing in 2004,[[50]](#footnote-51)49 the Commission undertook an inquiry into whether the discount adjustment policy should be retained. The Commission subsequently concluded that the policy was an integral and essential part of its policies supporting a competitive national gas marketplace, while still providing safeguards to protect captive consumers, and thus should be retained.[[51]](#footnote-52)50

1. **Storage Rates**

Following the commencement of open access, the Commission adopted a policy on contract storage rate design that required four rate components to reflect cost incurrence: deliverability, capacity, injection, and withdrawal.[[52]](#footnote-53)51 Fixed storage costs would be divided equally between the deliverability and capacity charges, while variable storage costs are allocated to the injection and withdrawal charges. The Commission closely adhered to this storage rate design policy, rejecting tariffs that did not contain each of the four changes and did not properly allocate costs.[[53]](#footnote-54)52

1. **The Policy Statement on Rate Design**

Although issued in 1989, the principles expressed in the Commission’s Policy Statement on rate design[[54]](#footnote-55)53 largely remain valid and that Policy Statement represents the Commission’s last comprehensive review of its rate policies. The Policy Statement was issued to guide the Administrative Law Judges and participants in rate design hearings on implementing the Commission’s Part 284 rate objectives, and it is worth reviewing both the Policy Statement and its implementation shortly after being issued, in a major rate order, to understand the Commission’s longstanding transportation rate principles.[[55]](#footnote-56)54

1. **General Considerations**

The Policy Statement reiterated and elaborated on the rate design objectives of Section 284.7(c) of the regulations that “rates for service during peak periods should ration capacity” and “rates for firm service during off-peak periods and for interruptible service during all periods should maximize throughput.”[[56]](#footnote-57)55 The Policy Statement envisioned that rates designed with those objectives will lead to allocative and productive economic efficiency. The Policy Statement made clear, however, that economic efficiency would not be the sole objective in designing just and reasonable rates for all customers.[[57]](#footnote-58)56 The Commission encouraged case-by-case development of methods that would be specifically tailored to accomplish the rate design objectives in view of the circumstances presented by each particular pipeline system. The Commission also noted that, to the extent a particular method was theoretically consistent with Commission goals but would have a harsh or inequitable result, pragmatic adjustments to counter that result should be made.[[58]](#footnote-59)57 The Policy Statement, *inter alia*, stated that there should be no cross-subsidization between sales and transportation services and that the quantity of a particular service should be reflected in the rate for that service.[[59]](#footnote-60)58 On rehearing of the Policy Statement,[[60]](#footnote-61)59 the Commission emphasized the non-mandatory nature of the Policy Statement and that it fixed no generally applicable rules. The Commission pointed out that its goal of promoting economic efficiency as set forth in the Policy Statement was merely a recasting of the Section 284.7 rate objectives into economic terms.[[61]](#footnote-62)60

The Commission stressed that it would also recognize “equitable factors and objectives in addition to economic efficiency.”[[62]](#footnote-63)61 The Policy Statement was intended to apply to open access transportation rates, transportation rates on non-open access pipelines, and the transportation component of sales rates,[[63]](#footnote-64)62 given that the same issues arise in all three contexts.[[64]](#footnote-65)63 The Commission clarified that it had not adopted value-of-service ratemaking and affirmed that pipeline’s overall revenues would be limited to an amount equal to the cost of service. The Commission, moreover, stated that value and costs are “inexorably linked through the establishment of a cost of service.”[[65]](#footnote-66)64 In 1991, the Commission implemented the Policy Statement in a fully litigated rate proceeding[[66]](#footnote-67)65 and in Order No. 636 specifically endorsed the Policy Statement—although Order No. 636 superseded some aspects of the Policy Statement, particularly regarding the use of straight fixed-variable[[67]](#footnote-68)66 rate design.[[68]](#footnote-69)67 The scope of permissible rate design further evolved under the Commission’s subsequent policy on alternative rate design and under Order No. 637.

1. **Seasonal Rates**

Uniform demand and commodity charges that are applicable throughout the year would not properly ration peak capacity or “lead to efficient use of the pipeline in periods of excess capacity.”[[69]](#footnote-70)68 Accordingly, the Commission required participants in then-pending rate design hearings to present evidence as to whether a pipeline had a sufficiently differentiated pattern of usage to justify peak and off-peak demand and commodity rates. The Commission posited assigning costs incurred to perform peak season service (for example, system storage facilities) only to the seasonal service and as signing other costs to seasonal service based on demand factors.[[70]](#footnote-71)69 On rehearing, the Commission clarified that, in analyzing the appropriateness of seasonal rates on a particular pipeline system, the Commission would consider material variations in both cost and usage.[[71]](#footnote-72)70 In its first major application of this principle, the Commission rejected the pipeline’s assumption that costs must vary with differing seasonal use[[72]](#footnote-73)71 and further found that the pipeline’s transportation costs were not seasonally differentiated.[[73]](#footnote-74)72 Seasonal pricing can be employed to ration capacity, the Commission found, but further determined that rationing was not needed based upon the facts of the system,[[74]](#footnote-75)73 although it did require an allocation of storage costs to services using storage. Because it was mandating the use of straight fixed variable rate design eliminating any assignment of fixed costs to the commodity rate, the Commission found that no seasonal revisions were needed.[[75]](#footnote-76)74 Pipelines have shown little interest in filing seasonal rates in subsequent years.

1. **Demand and Commodity Charges**

Although this aspect of the Policy Statement was rapidly overtaken by the rate design determinations of Order No. 636,[[76]](#footnote-77)75 the Commission’s rationale illustrates the issues influencing rate design. The Commission suggested that, because the merchant role of most pipelines had greatly declined, the modified fixed-variable (MFV)[[77]](#footnote-78)76 method of cost classification and allocation was likely outdated. The Commission also noted that the low-load-factor customers that it once sought to protect by means of separate demand cost allocations to D-1 (peak basis) and D-2 (annual basis) were now complaining about the method because of the D-2 re-nomination requirement. Consequently, the Commission suggested that a separate D-2 charge may no longer be warranted.[[78]](#footnote-79)77 On rehearing the Commission nonetheless cautioned that the Policy Statement was not meant to preclude the use of D-2 charges in the event that they are found “more realistic” than the current D-2 charges or to preclude “use of a D-2 concept for allocation purposes.”[[79]](#footnote-80)78 The Policy Statement defined the “central question” surrounding the issue of demand and commodity charges as whether there exists a waiting line (or “queue”) for firm capacity. In the event a waiting list did exist, the Commission suggested that the existing D-1 charge was both probably too low and not rationing capacity consistently with the goals of economic efficiency.

In contrast, if capacity were “under-booked,” it may be evidence that the D-1 charge was already too high.[[80]](#footnote-81)79 In *Opinion No. 369,* the Commission required the elimination of the pipeline’s MFV rate design even though it found that there was no need to ration firm capacity.[[81]](#footnote-82)80 Presaging the conclusions of Order No. 636, the Commission found that further reducing the level of fixed costs in the commodity charge would help the pipeline maximize throughput and promote fair competition among gas supplies transported over both the pipeline and competing pipelines. Instead, a fixed variable (“FV”) rate design, under which all fixed costs are recovered through a demand charge, was found to better allow the pipeline and other marketers of gas to compete for gas sales,[[82]](#footnote-83)81 although the Commission retained MFV cost allocation.[[83]](#footnote-84)82

1. **Capacity Adjustments**

The Commission has encouraged participants to explore contract demand adjustments, particularly through settlements and has said that these adjustments might be necessitated by the imposition of seasonal rates and demand-commodity revisions. In *Opinion No. 369,* however, the Commission declined to require that the pipeline offer its customers CD reductions or another capacity release mechanism, reasoning that if FV rate design and cost allocation had been adopted to ration firm capacity rights, capacity adjustment mechanisms would have been appropriate.[[84]](#footnote-85)83 Significantly, neither Order No. 636 nor subsequent orders required any pipeline to involuntarily permit reductions in contract entitlements as a result of rate design charges.

1. **Discounting**

In a lengthy discussion, the Policy Statement suggested that a pipeline should not be required to absorb discounts because, by doing so, it might not be able to recover its cost of service. The Commission supported this conclusion by reference to the *AGD I* decision, in light of the competitive market that had emerged in the gas industry particularly because a disincentive to discount in order to capture marginal firm and interruptible business would exist if the pipeline were expected to absorb the discounts. The Commission offered a number of different methods of setting rates so as to permit discounting and maximizing throughput, including revenue credits, surcharges, throughput adjustments, benefit sharing, and risk sharing.[[85]](#footnote-86)84 On rehearing, the Commission confirmed its twofold objective to prevent cross-subsidization in the design of future rates and to maximize throughput by discounting when necessary. The Commission described requiring maximum rates for all throughput as a “punitive measure” that it was unwilling to take. It also suggested that lower maximum interruptible rates would alleviate the difficulties associated with implementing discounting. Finally, the Commission emphasized that discounts must be given on a nondiscriminatory basis.[[86]](#footnote-87)85 As described above in § 8.05[1], the Commission comprehensively reviewed and retained the discount adjustment policy in a 2005 policy statement—largely on similar grounds to those expressed in the earlier Policy Statement.[[87]](#footnote-88)86

1. **Maximum Interruptible Rates**

As described above in § 8.05[1], the Commission has expressed a general default support for 100% load factor interruptible rates—a position consistent with the reasoning in the Policy Statement. The Commission had previously indicated its willingness to reexamine its policy requiring that the maximum interruptible rate be equivalent to the firm rate at 100-percent load factor.[[88]](#footnote-89)87 In restating the problem in the Policy Statement, the Commission asked “whether the 100 percent load factor rate yields a maximum interruptible rate which is too high to efficiently maximize throughput and is therefore an inefficient allocation of costs or revenue responsibility to interruptible service.”[[89]](#footnote-90)88 On rehearing, the Commission indicated that the role of maximum rates in allocating fixed costs had diminished since earlier cost allocation decisions.[[90]](#footnote-91)89 The Commission also pointed out that the quality of a service is a relevant factor in setting maximum rates. For example, a pipeline may justify certain differences in rates through a demonstration that it provides more receipt and delivery point flexibility for sales gas than transportation gas.[[91]](#footnote-92)90

1. **Mileage Reflection and Rates for Backhaul and Exchange Service**

One of the last issues addressed in the Policy Statement was the recognition of miles of haul in pipeline rates. At the outset, the Commission recognized that the regulations do not mandate mileage-based rates. Nonetheless, the Commission suggested that the reflection of distance may be appropriate in forward haul rates.[[92]](#footnote-93)91 On rehearing, the Commission’s example of mileage-based rates included point-to-point rates, Mcf-mile rates, and zone rates. Although the Commission considered zone rates to be mileage-based, it identified the “appropriate size of a zone” as a subsidiary issue for individual hearing.[[93]](#footnote-94)92 In *Opinion No. 369,* the Commission applied this policy and found that the pipeline’s large, historically zoned rate zones failed to reflect the cost of providing services.[[94]](#footnote-95)93 In addition, the Commission concluded that the existing zoned rates were anti-competitive, in that they encouraged the use of Panhandle’s sales service rather than supplies transported by other pipelines interconnecting downstream of Panhandle’s production zones. Therefore, the Commission affirmed an Administrative Law Judge’s finding that the rates should be designed in 100 mile increments for transportation purposes. The Commission found that this approach would also alleviate capacity constraints between the pipeline’s production zone and its major pipeline interconnection.[[95]](#footnote-96)94

1. **Unbundling of Rates and Services**

The Commission expressed a preference for fully unbundled services and directed consideration in pending cases of unbundling of storage, gathering, and other production area services as well as selling gas separately from transportation services.[[96]](#footnote-97)95 In *Opinion No. 369,* the Commission applied this rule and required that 22% of storage costs be assigned to transportation, on the grounds that transportation customers use storage on the peak basis, but only for balancing purposes.[[97]](#footnote-98)96 The Commission also required that the pipeline unbundle its gathering costs, and provide separately stated firm and interruptible gathering rates.[[98]](#footnote-99)97 The subsequent issuance of Order No. 636 did not change, but rather re-emphasized the need to unbundle rates and services.

1. **Principal Ratemaking Alternatives**

Although the regulations in 18 C.F.R. § 284.10 describe a traditional, cost-based ratemaking regime, the Commission has also developed important alternatives to cost-based rates since the inception of open access—the requirements for one of which, market-based rate submissions, is now codified at 18 C.F.R. § 284.501 *et seq*. The alternative methodologies arose in 1995, the Commission issued a “Request for Comments on Alternative Pricing Methods,”[[99]](#footnote-100)98 stating an interest in developing a framework for analyzing proposals for alternative pricing methods to the traditional cost-of-service methods. Early in 1996, the Commission issued its “Statement of Policy on Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines.”[[100]](#footnote-101)99 The Policy Statement provided for three alternatives to traditional cost-of-service rates: (1) market-based rates; (2) incentive rates; and, (3) negotiated/recourse rates. The criteria and standards for each alternative are discussed below.

1. **Market-Based Rates**

1. **Market-Based Rates Under the Policy Statement**

1. **Basis and Market Definitions**

Market-based rates are an option for achieving the flexibility and added efficiency required by the current market place in cases where an interstate pipeline can establish that it lacks market power. However, even in those cases where a pipeline is unable to establish that it lacks market power, the Policy Statement permits the Commission to authorize market-based rates, provided that the pipeline identifies certain conditions or changes that it could implement to mitigate the effects of market power and make market-based rates a viable option. Under the Policy Statement, interstate pipelines are authorized to develop market-based rate proposals that apply only to segments of the pipeline system or to specific services offered by the pipeline. The Commission evaluates each proposal separately, in case-specific settings, through use of paper hearings or settlement procedures. In adopting the criteria, the Commission rejected all challenges to its legal authority to permit market-based rates, finding that ‘light-handed regulation’ is justified when it can be shown that the goals and purposes of the statute can be accomplished without traditional regulatory oversight. Further, the Commission determined that competition in the market place would ensure that a natural gas company’s rates will remain just and reasonable in any case where the company can show that it lacks market power.

The Commission identified two key issues that it would examine in applying its criteria for market-based rates. First, the Commission will determine whether the pipeline can withhold or restrict services and, as a result, increase price by a significant amount for a significant period of time. Second, the Commission will determine whether the pipeline can discriminate unduly in price or terms and conditions. The Commission will: (1) define the relevant market; (2) measure a pipeline’s market share and concentration; and, (3) evaluate other relevant factors. The task for “market definition” is to identify the specific products or services and the suppliers of those products and services that provide “good alternatives” to the pipeline’s ability to exert market power. Under the Commission’s approach, the pipeline is required to identify the product market “fully and specifically,” and to “show how each of the substitute services is an adequate substitute to the pipeline’s services in terms of quality, price and availability.” The Commission declined to adopt a specific time period within which a product “must become available in order to be a substitute.” Timeliness therefore will depend on the specifics of the product it is replacing. Should a pipeline attempt to show that it cannot exert market power based on pipeline capacity not available immediately, that pipeline “should also show that its customers will not be committed to long-term contracts on its system within the relevant time period.”[[101]](#footnote-102)100 Further, the pipeline should give customers the option of reducing service demand levels once the alternative capacity and/or service becomes available.

The price of the alternative capacity must be low enough to effectively restrain the pipeline from increasing its own price. The Commission decided to adopt a pricing threshold of 10 percent. Accordingly, “if a company can sustain an increase in its rates in the order of 10 percent or more without losing significant market share, the company is in a position to exercise market power to the detriment of the public interest.”[[102]](#footnote-103)101 The 10 percent threshold is to be treated like a presumption, and all interested persons—the pipeline and other interested parties –are free to argue that the 10 percent threshold is either too high or too low. The alternative service must be of a quality that is “at least as high” as that of the pipeline’s service. To meet this requirement, the alternative service does not need to be the same service as that for which the pipeline seeks market-based rates. For example, a pipeline seeking market-based rates for firm transportation could show that interruptible transportation is a “good alternative” of similar “quality” by demonstrating that “an adequate amount of capacity is unsubscribed during peak periods … .”[[103]](#footnote-104)102

The relevant geographic market consists of all of the sellers of the product or service for which market-based rates are sought. In assessing whether there are “good alternatives” to the pipeline’s service or product, the Commission will identify both the origin and destination markets. The pipeline must also identify “those competitors that provide service either out of the origin market or into the destination market.”[[104]](#footnote-105)103

1. **Market Power Test**

The Commission identified two ways in which a pipeline could exercise market power. First, it could attempt to raise the price of the relevant product or service by acting alone. Second, it could attempt to do so in conjunction with others. To determine if the pipeline has the ability to raise the price by acting alone the Commission must assess the pipeline’s share of the market since “a large market share is generally a necessary condition for the exercise of market power.”[[105]](#footnote-106)104 However, this may not hold true for those markets that have “ease of entry.” Most pipeline markets will not have ease of entry, except in cases of minor facilities. To determine if the pipeline can act with others to raise the price, the Commission will examine the market’s concentration, through use of the “Herfindahl Hirschman Index” (HHI). Small HHI’s generally suggest that there are sufficient diverse sources of supply that no one firm or group acting together could profitably raise the market price. Higher HHI’s suggest that there may be a level of market concentration that would allow one firm or group of firms to raise the market price.

In the Policy Statement, the Commission announced that it will not “adopt a rigid bright-line threshold level for the HHI, below which an applicant [*i.e.,* the pipeline] would automatically qualify for market-based rates.”[[106]](#footnote-107)105 Instead, the Commission will use an 1800 HHI as an indicator. As a result, if the HHI is above an 1800, then the Commission will give the applicant closer scrutiny. Moreover, the Commission made clear that a high HHI does not automatically preclude a pipeline from qualifying for market-based rates. For example, if market entry were extremely easy, the pipeline still might not be able to exercise market power notwithstanding a high level of market concentration. “Buyer power” also will affect the evaluation of market power.

Finally, even if a pipeline has market power, the Commission still is willing to consider market-based rates as an option if “the company [is] able to identify certain conditions or changes that it could implement to mitigate the effects of market power … .”[[107]](#footnote-108)106

The Commission will continue its current policy of using declaratory orders to rule on requests for market-based rates on a case-by-case basis. Applications are required to contain specific information.[[108]](#footnote-109)107 Applications will be noticed subject to intervention and protest, and either a paper hearing or a formal evidentiary hearing. The result would be a declaratory order ruling, and if the service meets the requirements for market-based rates, the pipeline must make a prospectively effective tariff filings.[[109]](#footnote-110)108

1. **Market-based Rates for Storage**

The Commission had since 1992, under its less systematic approach to market power analysis, approved market-based rates for new or production area storage operators[[110]](#footnote-111)109 and denied market-based rates when the applicant failed to justify such treatment for the requested service.[[111]](#footnote-112)110 After the Policy Statement, the Commission continued to approve market-based rates for many new storage operators,[[112]](#footnote-113)111 and to deny them when the application was insufficient.[[113]](#footnote-114)112 The Commission as well approved market-based rates for hub services,[[114]](#footnote-115)113 Hinshaw and Section 311 intrastate pipeline storage services.[[115]](#footnote-116)114 Following the *Red Lake* proceeding, in which the project owner declined a certificate authorization that lacked market-based rate approval, and wider concerns about the need to support additional storage capacity, and related legislation, the FERC has adopted alternatives to its approach to market-based rates, as discussed below.[[116]](#footnote-117)115

1. **Market-based Rates for Pipeline Transmission Services**

The context and results when the Commission has addressed applications for market-based rates for mainline pipeline transportation have been very different than those of the storage cases. The Commission approved market-based transmission rates for KN Interstate Gas Transmission Company’s (“KN”) Buffalo Wallow pipeline transportation system, a short-haul feeder pipeline with one firm customer located exclusively in a production area.[[117]](#footnote-118)116 The Commission concluded that KN lacked market power over customers moving gas into the Buffalo Wallow system on upstream systems (*i.e.,* passthrough customers). Due to the absence of market power, the Commission also authorized the removal of the maximum rate cap on capacity released by these customers. However, the Commission rejected market-based rates for production and consuming customers locked into the Buffalo Wallow system, due to KN’s failure to demonstrate a lack of market power with respect to these customers. Subsequently, the Commission revisited its findings in the *Buffalo Wallow* case, after KN acquired additional production area capacity which constituted a “significant change” in circumstances. The Commission found that this development required the filing of a revised market power analysis.[[118]](#footnote-119)117

In 1998, the Commission issued a significant order applying its policy statement regarding alternative ratemaking for major gas pipelines, in *Koch Gateway Pipeline Co.*[[119]](#footnote-120)118 In an initial decision, the presiding ALJ found that the pipeline reasonably defined the product market as its interruptible service and the geographic market as its entire system.[[120]](#footnote-121)119 The ALJ also found that the pipeline had identified good alternatives within five miles of each receipt and delivery point and that it could not raise prices more than 10 percent for a period of more than one year. The ALJ also found that the pipeline’s market share and market concentration data showed a lack of market power, as did other factors, including heavy discounting, gas spot price differentials and the pipeline’s demand elasticity study—thus the pipeline lacked market power.

In the October 2 Order, the Commission reversed the Initial Decision in virtually every respect, and found that the pipeline had not shown that it lacked market power. The Commission first disagreed that the pipeline had adequately defined its product market, because it failed either to show that the alternative pipelines were undersubscribed during peak periods (thus providing comparable quality interruptible service), or that Koch itself was undersubscribed year-round. Koch thus failed to show that interruptible and firm services were comparable.[[121]](#footnote-122)120 The Commission also found that Koch failed adequately to define the geographic market, because the five-state regional market endorsed by the Initial Decision did not identify the sellers from whom customers could purchase service, and because services and rates differed in availability in various portions of Koch’s pipeline system. The Commission stated that, “[u]ltimately, however, the definition of the geographic market depends on the identification of good alternatives,” which Koch failed to demonstrate.[[122]](#footnote-123)121 Because Koch failed to give the names or identities of the pipelines within a five-mile radius of its receipt and delivery points, the Commission could not determine whether the pipelines were interstate or intrastate, whether their service was comparable to Koch’s and hence, whether these alternatives had sufficient quality of service to be good substitutes for Koch.[[123]](#footnote-124)122 Because the Commission had found no evidence that the pipelines were good alternatives, it rejected the market concentration (“HHI”) evidence relied upon in the Initial Decision.[[124]](#footnote-125)123 The Commission also rejected Koch’s arguments that marketers ensured competition, as being too vague and unsupported.[[125]](#footnote-126)124 For all of these reasons, the Commission found that Koch failed to meet the requirements of the Policy Statement. Finally, the Commission rejected Koch’s alternative argument that it lacked market power in the interruptible market, because it failed to show the proper price standard for judging the spot price differentials, and because the evidence indicated that at times, it might be able to exercise market power by charging a price greater than the long-run competitive transportation price.[[126]](#footnote-127)125

The market-based rate option is still available for interstate pipeline transmission services, although s of 2009 no major interstate pipeline has succeeded in obtaining authorization to use the option.

1. **Revised Standards for Market-Based Rates for Storage services**

1. **Proposed Revisions to Market Power Standards**

In 2006 the Commission significantly altered its policy and regulations governing market-based rates for storage services with the issuance of Order No. 678.[[127]](#footnote-128)126 Reconsideration of the long-standing market power requirements arose in light of the order in the *Red Lake* proceeding and other developments.[[128]](#footnote-129)127 Moreover, Congress amended Section 4 of the Natural Gas Act in Section 312 of the Energy Policy Act of 2005,[[129]](#footnote-130)128 by providing FERC with the authority to grant market-based rate authority for new storage facilities in the absence of a finding that the applicant lacked significant market power.

These two developments prompted the Commission to issue a *NOPR*.[[130]](#footnote-131)129 The proposed rules proposed both to implement EPACT of 2005 § 312, applicable to market-based rates for certain new storage facilities, and to modify the standards for all facilities “to better reflect the competitive alternatives to storage.”[[131]](#footnote-132)130 The Commission noted that the use of storage has shifted from primarily a means for LDCs to meet winter load needs to a more diverse range of uses, including meeting swiftly-shifting daily and hourly electric generation needs and to ensure liquidity at market centers. The Commission found that storage should assist in damping volatility in gas prices, and particularly that short-term storage services may be better suited to market-based rates than traditional long-term storage arrangements.[[132]](#footnote-133)131

The Commission reviewed its analytic framework for assessing market power under the Policy Statement. Under those criteria, the Commission addressed requests for authority to charge market-based rates from more than 40 storage service providers following issuance of the Policy Statement in 1996, typically resulting in Commission approval.[[133]](#footnote-134)132 In those proceedings, the Commission only considered storage alternatives in weighing whether the storage provider lacked significant market power. The *NOPR* noted that all such requests made by applicants with storage facilities in the producing areas had been granted, because of the “extensive storage infrastructure” there; in contrast, storage projects in consuming regions were typically found in markets with fewer storage alternatives, higher market concentration figures, and greater scrutiny. The NOPR proposed to broaden the non-storage products and services that would be considered in a properly-defined geographic as good alternatives to storage capable of mitigating a storage provider’s potential market power. Excluding these alternatives could result in denial of market-based rates even where constraints would exist to curb the storage provider’s market power. The Commission found that this result would harm consumers by creating a disincentive to storage development, even in areas underserved by storage services.[[134]](#footnote-135)133 Therefore, the Commission proposed to allow applicants for market-based rates for storage service to include the following alternatives in their market power presentations: available pipeline capacity, both firm and released; local gas production; or LNG terminals. The *NOPR* proposed that these additional alternatives would be considered on a case-by-case basis, must be shown to be “good alternatives,” that is practically available as alternatives. As examples, the Commission noted that released capacity might be available as an alternative to a market otherwise holding little storage capacity.[[135]](#footnote-136)134 In addition, the Commission proposed to adopt new reporting requirements for applicants for market power, including specified information to accompany market based storage filings, as well as the obligation to updated market power analyses every five years.[[136]](#footnote-137)135

The *NOPR* also proposed amending the regulations in response to § 312 of EPACT of 2005. The Commission summarized that provision as one that:

permits the Commission to allow a natural gas storage service provider placing new facilities in service to negotiate market-based rates even if it is unable to show that it lacks market power if the Commission determines that market-based rates are in the public interest and necessary to encourage the construction of the storage capacity in the area needing storage services, and that customers are adequately protected.[[137]](#footnote-138)136

To address the statute’s requirements that the Commission determine that market-based rates are “in the public interest,” and that “customers will be adequately protected from any abuses of market power by the storage provider,” the *NOPR* proposed that: (1) the applicant bear the burden of showing that market-based rates were “necessary” to encourage the construction of storage facilities, and that storage services are needed in the area;[[138]](#footnote-139)137 and (2) that the applicant show that customers would be protected (consistent with the need to balance the benefits of new, needed storage). As to the second requirement, the Commission acknowledged the difficulties in establishing a standard, but sought comments on what type of protection would be appropriate and suggested several general, potential types of protection (*e.g*., a demonstration that the applicant has not withheld capacity, or potentially a reserve price on capacity, or other rate protections.[[139]](#footnote-140)138 The new statutory provision also required the Commission to “review periodically whether the market-based rate is just, reasonable, and not unduly discriminatory or preferential.”

1. **Order No. 678**

The Commission issued Order No. 678, in June 2006 and promulgated the changes along the general lines suggested in the *NOPR.* The Commission found a need for incremental storage over the next two decades. In particular, the Commission determined that additional storage would assist in reducing price volatility. Consequently, the amended regulations were approved in large part to encourage investment in of storage infrastructure, while meeting the statutory obligation to prevent storage providers from exercising market power over their customers.[[140]](#footnote-141)139 In addition, the Commission grounded its proposed changes to the market power analysis for storage service on alterations occurring over nearly a decade in the natural gas markets, which would ensure that the analytic framework would more accurately reflect storage service alternatives.

As proposed in the *NOPR*, Order No. 678 expanded the definition used for “product market” to include substitutes for gas storage service that could be available pipeline capacity (including released capacity), local natural gas production and LNG service. As in the *NOPR*, the Commission undertook to evaluate proffered “close substitutes” on a case-by-case basis. Applicants must bear the burden to demonstrate that customers could substitute the alternatives for the applicant’s services because the substitutes would be: available soon enough; at a price low enough; and in a quality high enough;[[141]](#footnote-142)140 furthermore, that in peak demand periods, customers could use the alternative as a comparable substitute for storage under these criteria.[[142]](#footnote-143)141 Even financial instruments and similar alternatives could be proposed as part of the applicant’s case, but the applicant would need to demonstrate that the non-storage product would be adequately available and that it would meet the key criteria previously established.[[143]](#footnote-144)142

Operators of existing storage services could seek market-based rates using the new criteria;[[144]](#footnote-145)143 however, the Commission found that it would “consider in the case of existing storage all relevant facts of the applicant’s potential to exercise market power, including for example, impacts on existing customers and the applicant’s relationship with transmission service providers in the relevant market.”[[145]](#footnote-146)144

A variety of other changes to market based rate policy were proposed, but not adopted.[[146]](#footnote-147)145 As contemplated in the *NOPR*, Order No. 678 amended the regulations to require codified and standardized filing requirements for applicants seeking market-based rates,[[147]](#footnote-148)146 although the Commission declined to impose the proposed obligation to file revised market power analyses every 5 years—instead storage providers (except exempt small-market share providers) with market-based rates would be required to notify the Commission within 10 days of a significant change in circumstances affecting the basis for their authority.[[148]](#footnote-149)147 In addition, to guard against the potential for cross-subsidies, companies would need to keep separate accounts for market-based and cost-based services.[[149]](#footnote-150)148

Under the new regulations also implemented § 312 of EPACT 2005, an entity would be permitted to apply for market-based rates for facilities placed in service after enactment of EPACT 2005, even in the absence of any showing that it lacks market power, provided that the applicant demonstrates: (1) that market-based rates are in the public interest; (2) that market based rates are necessary to encourage the construction of storage capacity; (3) that the area in which the storage project is proposed needs storage services; and (4) that customers are protected against the exercise of market power. Regarding the type of facility eligible for this authority, the Commission reversed itself relative to the *NOPR*. The Commission found that the statutory use of the word “services” was ambiguous; whereas in the *NOPR*, the Commission proposed to define such “services” eligible for the new rate authority to include only new reservoirs, caverns and aquifers, Order No. 678 broadened the scope to encompass all expanded certificated services, including expansion of existing caverns and facilities. This definition, the Commission found, would be more consistent with Congressional intent and existing precedent, as well as furthering the goal of facilitating the development of new natural gas storage capacity.[[150]](#footnote-151)149

As proposed in the *NOPR*, Order No. 678 required such applicants to show that market based rates would be “necessary for the project to secure financing and move forward with the project.” Instead, the Commission expected that an existing pipeline would have greater difficulty making this showing than would an independent storage operator.[[151]](#footnote-152)150 The required “public interest” demonstration could encompass, “the risk faced by the project sponsors, the extent to which additional capacity is needed in the area of the project, and the strength of the applicant’s showing that the facilities would not be build but for market-based rate treatment.”[[152]](#footnote-153)151 The existence of need for the new capacity might be shown by a number of factors.[[153]](#footnote-154)152

Under EPACT of 2005, the Commission was required to allow such market based rates only when adequate customer protection was shown. In Order No. 678, the Commission declined to establish a particular standard. Instead, applicants would be expected to present “proposals that will operate effectively given the unique situations involved.”[[154]](#footnote-155)153 The Commission nonetheless listed some types of supporting facts.[[155]](#footnote-156)154 In addition, FERC required entities seeking authority under this approach to demonstrate compliance with a “no-withholding” requirement as to capacity (which would be mandatory) and to state whether a reserve price would be set, and, if so, how (which would be optional).[[156]](#footnote-157)155

The Commission declined to require periodic filings by storage providers under these regulations, finding instead that Staff oversight of forms and data postings would better protect customers,[[157]](#footnote-158)156 and further relied on reports submitted by storage providers must submit as well as the availability of complaints or comments upon storage operator actions.[[158]](#footnote-159)157 The Commission found that storage operators could apply for market-based pricing and clarified that applicants can seek this type of pricing for “any storage services that it proposes to provide,” rather simply for firm storage service.[[159]](#footnote-160)158

In Order No. 678-A, the Commission dismissed all requests for re-hearing and reaffirmed the regulations and policy changes implemented in Order No. 678. Numerous parties argued that the revised market power test failed to take into account the situation of storage customers subject to “Memphis clauses”[[160]](#footnote-161)159 —*i.e*., that many customers were obligated to pay the maximum rate approved by FERC for the contract’s length and thus lacked the ability to switch to other storage alternatives. In response, the Commission found that “Memphis clauses” would permit a pipeline to file to change a customer’s existing cost-based rate to a market-based rate. At the same time the Commission noted that the applicant would have the burden of showing a lack of significant market power; the issues raised by those seeking rehearing would bear on that question during the market power determination.[[161]](#footnote-162)160 Regarding requests for rehearing regarding standards for market-based rate authorizations in the absence of a market power showing, the Commission generally denied rehearing, but did provide clarification in certain respects.[[162]](#footnote-163)161

Shortly after issuance of Order No. 678, in July 2006 a pipeline filed a request for declaratory order seeking authority to charge market-based rates for new facilities in the absence of a showing that it lacked market power. The Commission granted that request in *Northern Natural*,[[163]](#footnote-164)162 finding that the applicant’s proposed expansion of capacity met the requirements for a qualifying project. The applicant also showed that the project was in the public interest and that customers were protected, on several grounds. The pipeline argued that cost uncertainties for the proposed expansion made cost-based rates unacceptably risky and thus market-based rates were needed in order to construct the facilities. Further, the Commission found that the pipeline held a transparent auction for all available capacity in which the capacity was awarded to shippers offering the highest net present value (capped at a pre-set, though non-cost-based maximum price and maximum term), which the Commission concluded was evidence of a lack of market power.[[164]](#footnote-165)163 The Commission limited the market-based rate authority to the specific expansion capacity. The Commission has granted similar requests in response to later applications by pipelines.[[165]](#footnote-166)164

1. **Policy for Incentive Rates**

In conjunction with the 1996 policy guidelines on market-based rates, the Commission announced changes to its existing policy on incentive rates. Incentive rates are intended for use by those pipelines that are in markets where market-based rates are not appropriate, *i.e.*, “where the continued existence of market power prevents the Commission from implementing light-handed regulation without harm to consumers.”[[166]](#footnote-167)165 Incentive rates were intended to foster long-term efficiency by divorcing rates from the underlying cost-of-service; by lengthening the period between rates cases; and by sharing the benefits of cost savings between consumers and stockholders on a current basis.

To spur greater interest in its incentive rate policy, the Commission removed the requirement that pipelines must quantify the benefits of the “performance-based” incentive rate. In lieu thereof, pipelines must specify the performance standards adopted; the mechanism for showing benefits with consumers; and a method for evaluating the proposal. Contrary to the Commission’s invitation, however, as of the spring of 2009, no pipeline had filed an incentive rate proposal under the revised guidelines.

1. **Negotiated Rate Policy**

1. **Requirements for Use of Negotiated Rates**

The negotiated rate option was an entirely new form of rate-setting for natural gas pipelines, and proved to be the most widely adopted of the alternatives. The Policy Statement endorsed negotiated-recourse rates as a way of achieving flexible, efficient pricing when market-based rates are not appropriate. Under a largely self-implementing framework, the shipper could choose to negotiate its rate, even to a level above the pipeline’s maximum tariff rate. A recourse rate would be established that is equal to a pipeline’s approved maximum rate. The Commission intended that the recourse rate should prevent the pipeline from exercising market power by assuring that the shipper can fall back to the tariff rate.[[167]](#footnote-168)166

The Commission clarified in *NorAm Gas Transmission Co.*[[168]](#footnote-169)167 a number of key elements and limits of a negotiated rate program, and imposed a number of conditions, including the following: (1) the pipeline must file and specify the rate or precise rate formula used to derive each negotiated rate;[[169]](#footnote-170)168 (2) the pipeline must file the negotiated rate contract or its essential elements to permit a determination of whether other shippers are similarly situated to the shipper to the negotiated agreement;[[170]](#footnote-171)169 (3) the pipeline must specifically state which rate is the recourse rate as to each service for which it has a negotiated rate;[[171]](#footnote-172)170 and (4) the pipeline must not make a discount-type adjustment to its recourse rates to account for negotiated rates in subsequent rate cases.[[172]](#footnote-173)171 Subsequent Commission orders addressing negotiated rate filings adopted the standards announced in the *NorAm* case and applied them to a number of pipelines.[[173]](#footnote-174)172 The Commission also rejected or modified negotiated rate proposals that conflicted with *NorAm* or its policies.[[174]](#footnote-175)173

Not long after the 1996 Policy Statement, the Commission elaborated on the application of its policy regarding the future rate treatment of discounted negotiated rates.[[175]](#footnote-176)174 The Commission approved Northwest Pipeline’s proposal for negotiated rates with a discount-adjustment provision. Protesters argued that Northwest’s discount adjustment mechanism would lead to recourse rate customers bearing costs shifted by negotiated rate deals. The Commission distinguished its decision to accept Northwest’s discount adjustment provision from its prior orders denying similar adjustments by finding that the proposed mechanism was advantageous to recourse customers and did not harm them. Under its proposal, Northwest would not make future discount adjustments to its demand billing determinants unless the recourse rate has already been discounted. In those instances, the discount adjustment would be based on the greater of: (1) the negotiated rate revenues received; or (2) the initial Part 284 discounted rate revenues which otherwise would have been received.[[176]](#footnote-177)175 The Commission held that under this mechanism cost shifting to recourse rate customers is less likely to occur because Northwest’s discount adjustment for negotiated rate contracts would never be more than the adjustment for the pre-existing recourse rate contracts, had those contracts not been converted. In addition, the Commission noted that the appropriateness of the discounts would be at issue in future rate proceedings, which would also protect recourse rate customers against undue cost shifting. The Commission did, however, express some continuing concerns over the impact of discount adjustments on recourse rate shippers, and required Northwest to make its discount adjustments for negotiated rates according to the Commission’s standards for affiliate discounts.[[177]](#footnote-178)176

1. **Further Delineation of the Policy Statement’s Requirements**

In related orders and decisions issued in 2001, the Commission addressed different aspects of its negotiated rate policy. In one case, the Commission considered whether a contract properly fell within the negotiated rate standards if it contained minimum pressure, rate relief and contract cancellation, or changes to primary points.[[178]](#footnote-179)177 The Commission determined that although minimum pressure seemed to implicate operational conditions of service, and hence a prohibited term and condition of service, because the tariff permitted all shippers to negotiate minimum pressures with the pipeline, the term was acceptable. The Commission also found that a provision granting rate relief in the event of a pressure failure was a rate term, and not an operational term and condition. However, the Commission found that a provision allowing a customer to reduce or terminate its contract raised “too much potential for undue discrimination.”[[179]](#footnote-180)178 Similarly, the Commission found that a provision allowing the customer to change its primary delivery point also raised the potential for undue discrimination, because bypassing the regular procedures for allocating such points could adversely affect others seeking capacity, contrary to Commission policy.

In the second order, the Commission concluded that a negotiated rate containing a clause allowing the customer to reduce its MDQ and buy out its obligations, created too much danger of undue discrimination, particularly because the right to terminate is such a valuable right, which must be granted in a nondiscriminatory manner.[[180]](#footnote-181)179 Similarly, in anther order, another clause permitting negotiation of the shipper’s MDQ was found to be unduly discriminatory.[[181]](#footnote-182)180 In so ruling, the Commission addressed at length the standards for determining whether a contract represents a material deviation from the pro form contracts, and how such non-conforming contracts were to be treated. In a concurrently issued order, the Commission applied this same analysis to conclude that certain early termination clauses in contracts of another pipeline were both material deviations from the pro forma contracts and were prohibited negotiated terms and conditions that must be offered in generally available tariffs.[[182]](#footnote-183)181

Regarding a different aspect of the policy, negotiated agreements specifying agreed-upon minimum pressures were found to constitute a material deviation from the tariff.[[183]](#footnote-184)182 In the course of addressing this question, however, the Commission had also become aware that the pipeline in question had numerous (159) contracts with non-conforming provisions. The pipeline was required to file all of those contracts. After reviewing them, and in light of the absence of protests or complaints, the Commission decided to allow them to remain in effect as long as they were re-filed and treated as non-conforming service agreements.

1. **Rates Based on Index Differentials**

In 2002, the Commission issued two orders suggesting a reappraisal of elements of the negotiated rate policy. The Commission suggested limitations to the permissible scope of pricing negotiated rates in *Transwestern Pipeline Co.*,[[184]](#footnote-185)183 which reversed an initial decision regarding the lawfulness of certain negotiated rates entered into by the pipeline with two shippers. The transportation contracts were day-to-day contracts with rollover provisions, whose prices were calculated based on index-to-index differentials of natural gas spot prices. Due to the conditions in the California and neighboring markets during the time period under review (the 2000–2001 winter), the resulting transportation rates were vastly higher than the maximum posted prices.[[185]](#footnote-186)184 In addition, the Commission found that although the shippers had voluntarily agreed to the contracts, either one of two unlawful circumstances were also true: either the capacity (which was operationally available only, and not firm) was being sold as firm service, in violation of the pipeline’s tariff; or, alternatively, the service was firm but constituted a prohibited negotiated term and condition of service. Consequently, the service was made available to the two shippers on a preferred basis, but not to others, in violation of the negotiated rate policy. As a remedy, the Commission required that the pipeline return the revenues above the maximum filed rate, with interest, but also required that other shippers denied the opportunity to receive the service, share in the refunds. Further, the Commission conditioned the pipeline’s ability to enter into negotiated rates for one year by denying it the ability to enter into contracts based on market to market pricing differentials in the spot market.

Concurrently with the *Transwestern* order, the Commission issued the “Notice of Inquiry Concerning Natural Gas Pipeline Negotiated Rate Policies and Practices,”[[186]](#footnote-187)185 in which the Commission reviewed the history of its negotiated rate policy and noted the emergence of rates based on price-index differentials that, “have raised serious concerns regarding the breadth and direction of the Commission’s negotiated rate program.”[[187]](#footnote-188)186 The Commission asked a number of specific questions for public comment, including whether the program has been successful; should the program be modified; whether the filing requirements were adequate and transparent; whether the recourse rate option did “effectively mitigate pipeline market power”; whether further mitigation measures were needed; whether negotiated rates above the maximum recourse rate should be disallowed; whether deals based hub price differentials should be disallowed; and whether limits or constraints should be placed on such hub price differentials.[[188]](#footnote-189)187

In 2003, the Commission issued the “Modification of Negotiated Rate Policy” (“Modification”),[[189]](#footnote-190)188 making modest changes to the negotiated rate standards. First, the Commission concluded that it would no longer allow the use of gas basis differentials to price negotiated rate transactions, largely because the Commission concluded that such pricing arrangements gave pipelines too much incentive to withhold capacity.[[190]](#footnote-191)189 The Commission concluded that the risk of such pipeline manipulation ran counter to the goals of Order No. 636 and outweighed the benefits of increased flexibility for the parties. In addition, the Commission tightened the filing and reporting requirements for negotiated rates.[[191]](#footnote-192)190 In particular, the Commission concluded that parties to negotiated rates had at times strayed too far from the *pro forma* service agreements, had at times not filed non-conforming agreements, or had not adequately explained the terms of the negotiated rates in their filings. Consequently, parties were directed to provide specified data in the tariff sheet summaries, and to identify in detail all departures from the pro forma tariff when filing.

On rehearing of the *Modification*, *supra*, however, the Commission reversed the prohibition against using basis differentials for negotiated rate transactions.[[192]](#footnote-193)191 The Commission noted that on related, though different grounds, it had changed its policy and allowed the use of basis differentials for discounted rates, and concluded, “that a generic policy against the use of gas basis differentials in negotiated rate transactions is overly restrictive, given the benefits such pricing mechanisms yield and the fact that there are other less restrictive means to ensure that the pipelines do not utilize market power to influence the gas commodity market.”[[193]](#footnote-194)192 Further, the Commission reasoned that, the use of basis differentials would be consistent with its goals of encouraging competition in the marketplace and in minimizing distortions in producer exploration and production decisions, as well as to more accurately inform decisions whether to construct new capacity, among other benefits.[[194]](#footnote-195)193 To prevent consumer harm, the Commission stated that several protections would apply to the use of this authority: (1) pipelines could not “hoard desired capacity” in order to widen basis differentials; (2) all negotiated rates must be filed with the Commission and subject to scrutiny; (3) these activities will be subject to market oversight and monitoring by the Commission; and (4) the new anti-manipulation law under the Energy Policy Act of 2005 and implementing regulations prohibits manipulation of natural gas markets.[[195]](#footnote-196)194 Consequently, the Commission elected to end the ban on using basis differentials while leaving to case-by-case enforcement any alleged or perceived attempts to manipulate gas markets by their use.[[196]](#footnote-197)195

The Commission continues to refine the scope and application of its negotiated rate policy through individual letter orders.

1. **Straight Fixed-variable Rate Design (“SFV”)**

1. **Uniform Adoption of SFV**

In Order No. 636, the Commission announced a sweeping change in rate design policy by mandating that all interstate pipelines file transportation rates under the SFV rate design for billing purposes.[[197]](#footnote-198)196 In doing so, the Commission followed a long tradition of changing rate design in order to promote or reflect competitive conditions in the industry.[[198]](#footnote-199)197 The Commission noted that after 1983, when the modified fixed-variable (“MFV”) rate design[[199]](#footnote-200)198 was first introduced, the level of fixed costs allocated to the commodity portion of pipeline rates was sharply reduced.[[200]](#footnote-201)199 As discussed above in § 8.05[2], the 1989 policy statement on rate design had subsequently required that rates for firm and interruptible services “should maximize throughput” on the pipeline.[[201]](#footnote-202)200 (1992). Further, in Opinion No. 369, the Commission had required the adoption of SFV to maximize a pipeline’s throughput.[[202]](#footnote-203)201 Given the changes required by Order No. 636, the Commission questioned whether MFV remained consistent with the Commission’s goals. The Commission found that it did not.[[203]](#footnote-204)202 Because MFV places differing amounts of fixed costs in the commodity component of pipeline rates, the Commission reasoned that head-to-head competition between gas sellers would be impeded. Specifically, the Commission found that where pipelines reflected differing levels of costs in the commodity rate, sales customers would make purchases on the basis of pipeline commodity rates rather than on the cost of gas. This result, the Commission concluded, inhibited the development of the national market envisioned in the Wellhead Decontrol Act. The Commission therefore found MFV to be unjust and unreasonable.[[204]](#footnote-205)203 As such, the Commission required the uniform adoption of SFV in designing rates for billing purposes.[[205]](#footnote-206)204

Two fundamental reasons supported its decision. First, the Commission found that SFV “goes hand-in-hand with the equality principle’ by permitting all gas sellers to compete in a national market on even terms.[[206]](#footnote-207)205 SFV would thus promote head-to-head, gas-on-gas competition, because the firm transportation rate structure would not be a potentially distorting factor in the competition among merchants.[[207]](#footnote-208)206 Secondly, the Commission found that SFV should maximize pipeline throughput by enhancing the degree to which changes in gas prices may reflect changes in alternative fuel costs. The Commission also responded in detail to several objections raised to SFV rate design. First, many commenters expressed concerns about the shifting of costs to low load-factor customers. The Commission recognized this possibility and required that each pipeline file reports comparing each customer class’s cost responsibility for unbundled services under the pipeline’s last approved cost classification method and with its cost responsibility under SFV. Where adopting SFV would result in a 10% or greater increase in revenue responsibility for any customer class, the Commission required a phased-in plan, to extend no more than four years. Examples of mitigation included one-part volumetric rates, seasonal contract entitlement levels or use of MFV for cost allocation and SFV for billing purposes.[[208]](#footnote-209)207

The Commission dismissed, however, any possibility that it would defer implementation of SFV due to cost-shift concerns. The Commission also declined to permit customers to reduce their contract entitlements following adoption of SFV, in light of the mitigation provisions and the capacity reallocation mechanisms being established elsewhere in the rule.[[209]](#footnote-210)208 Many parties had argued that SFV would reduce pipeline incentives to minimize cost and maximize throughput. The Commission concluded that several regulatory tools would obviate this concern. The Commission would continue its oversight to ensure prudent pipeline construction projects. Incentive ratemaking would be available as a vehicle to enhance pipeline efficiency, given the pendency of the proposed policy statement on incentive rates.[[210]](#footnote-211)209 The Commission also would defer any consideration of adjustments to pipeline return on equity to pipeline-specific analyses in individual rate cases. Finally, the Commission rejected the contention that SFV would not affect gas sales purchasing decisions because purchasers choose long-term supplies on the basis of total cost, including demand charges.[[211]](#footnote-212)210 The Commission noted that significant gas is purchased on the short-term market, for which a commodity transportation cost will be the primary cost factor. In addition, the Commission argued that calculating total cost in long-term contracts would be easier using SFV.

1. **Implementation of SFV**

Order No. 636 left open the possibility that pipelines might deviate from SFV rate design in individual restructuring cases.[[212]](#footnote-213)211 Very few pipelines, however, were able to demonstrate to the Commission sufficient need for an alternative rate design methodology. Pipeline proposals for SFV rates were nearly uniformly approved.[[213]](#footnote-214)212 The Commission’s commitment to the uniform use of SFV was illustrated in the orders rejecting proposals for alternative rates on two pipelines serving California. The Commission rejected ***Kern*** River Pipeline’s argument that MFV rate design was required for some of its shippers under its shipper contracts and certificate conditions,[[214]](#footnote-215)213 noting that the pipeline’s Part 284 blanket certificate was conditioned on compliance with all Commission regulations under the NGA, including any future regulations and that Order No. 636 required SFV.[[215]](#footnote-216)214 Although the contract restrictions prohibited ***Kern*** River from unilaterally filing a rate case, it did not limit the Commission’s right under § 5 of the NGA to find the MFV rate design condition in those contracts to be unjust and unreasonable, and to order an appropriate change in rate design.[[216]](#footnote-217)215 On judicial review, the court affirmed, relying on the presence of a “Memphis” clause[[217]](#footnote-218)216 in the parties’ contracts, and concluded that, “[o]n balance, we believe that the fundamental changes that are to occur in the natural gas industry under restructuring greatly outweigh the anticipation of the parties and the Commission when ***Kern*** River’s original certificate was being considered that the MFV methodology would not change.”[[218]](#footnote-219)217

Similarly, the Commission rejected Mojave Pipeline’s proposal to limit the implementation of SFV rates to new customers.[[219]](#footnote-220)218 In the aftermath of Order No. 636, several pipelines proposed implementing SFV rates generally, but allowing shippers to negotiate individual rates that would place more costs in the usage component of the rate. The Commission rejected these proposals, finding that they did not satisfy the goals of Order No. 636.[[220]](#footnote-221)219 At the same time, the Commission did not allow rates for individually certificated services to be changed by moving variable costs in the reservation charge to the usage charge.[[221]](#footnote-222)220

The Commission did grant limited exceptions, based on specific facts and on the conclusion that the goals of Order No. 636 would still be met.[[222]](#footnote-223)221 Where, for example, only a single customer experienced a greater than ten percent cost shift, the Commission did not require use of a general mitigation plan, but rather customer-specific mitigation steps.[[223]](#footnote-224)222 The Commission rejected a pipeline’s attempt to use a two-part reservation charge for billing purposes as means of mitigating SFV, because the proposal failed to resolve significant impacts on individual customers.[[224]](#footnote-225)223 The Commission required a pipeline to mitigate the cost increase to customers experiencing an increase of over ten percent by reducing the base tariff rates of the customers to the ten percent level and increasing the base tariff rates to other customers to offset the aggregate amount of the reductions.[[225]](#footnote-226)224 The Commission clarified that mitigation should be considered in light of the overall impact on each customer for all of the services it receives.[[226]](#footnote-227)225 The mitigation measures were required to continue until the existing service agreements terminate or the pipeline files a NGA § 4 proceeding. In addition, pipelines were permitted to file for one-part small customer rates.[[227]](#footnote-228)226

1. **Commission Relaxes the Uniform Use of SFV**

The Commission’s rigid adherence to SFV as an essential feature of restructuring was upheld on appeal, both as to Order No. 636,§ and as to an individual pipeline’s circumstances.[[228]](#footnote-229)227 Nonetheless, after the pipeline restructuring proceedings, the Commission began to relax its virtually absolute rule against variations from SFV. In the spring of 1996, the Commission authorized several pipelines to file mechanisms to enable shippers paying maximum rates to customize the pattern of payments of otherwise applicable reservation charges.[[229]](#footnote-230)228 The Commission noted that the flexible reservation charge billing mechanism could be approved for transportation on the primary market under the Commission’s Alternative Rate Policy Statement. Subsequently, in Orders issued in September 1996, the Commission declined to authorize the CRP mechanism for capacity releases.[[230]](#footnote-231)229 The ability to vary even the billing of demand charges demonstrated greater flexibility by the Commission.

In the context of negotiated rates, the Commission went further. In approving NorAm’s negotiated rate program, the Commission directly stated that rate designs other than SFV would be permitted in the context of individually negotiated rates:

[T]he Commission believes that in this instance, rigid adherence to SFV is inappropriate in that it eliminates needed flexibility for the pipeline. Rate flexibility already exists in the Commission’s regulations. In addition, only the actual customers that negotiate a rate that uses a different rate design are affected by the variation.[[231]](#footnote-232)230

The Commission emphasized the limited nature of the exception, stating, “the rate that is generally applicable throughout NorAm’s system, *i.e.,* the recourse rate, is an SFV rate.”[[232]](#footnote-233)231

The Commission took an even larger step away from its uniform SFV policy when it approved a contested settlement[[233]](#footnote-234)232 that provided that commodity charges would recover $79 million of the pipeline’s fixed costs. Rejecting some parties’ concerns that the inclusion of fixed costs in the commodity rate violated Order No. 636, would hinder competition among gas sellers and would harm the national market for natural gas,[[234]](#footnote-235)233 the Commission responded that SFV had been adopted as the best rate design to assist in creating a seamless national pipeline grid, but that the industry’s substantial evolution meant that SFV may, in some circumstances, no longer be the only rate design consistent with the Commission’s goals. The Commission noted that common business and communications standards, the growth of market centers and electronic trading, have changed the marketplace. The Commission further concluded that the development of consistent market procedures would be “the most important key to the further growth of competitive natural gas markets.” The Commission stated:

The Commission’s preference for SFV rate design was part of the complex restructuring the Commission initiated in 1992 to obtain the goal of a seamless national pipeline grid. Today the Commission believes that it can also permit variation from SFV in individual cases consistent with its goal of a national pipeline grid.[[235]](#footnote-236)234

The Commission nonetheless stated that, “as a general proposition, the SFV rate design fosters efficient use of pipeline systems.” In support of its decision in this case, the Commission stressed the facts rendering a departure on this particular pipeline appropriate and not harmful.[[236]](#footnote-237)235 In Order No. 637, the Commission has signaled a far broader willingness to consider alternative rate designs, yet in a subsequent rate proceeding it modified a proposed volumetric seasonal firm service to include both a reservation and commodity charge.[[237]](#footnote-238)236

Regulation of the Gas Industry

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**End of Document**

1. \*Mr. Barr is an attorney with the law firm of Post & Schell PC, and prepared this chapter with the assistance of Matthew J. Agen, also an attorney with the same firm. This chapter incorporates substantial material written by the prior author, Robert J. Haggerty, who was assisted by Mark K. Nasseri; it also reflects extensive assistance from Kristine Delkus, Jane Lewis-Raymond and David S. Shaffer, who were formerly associates at the firm of Morgan, Lewis and Bockius. [↑](#footnote-ref-2)
2. 118 C.F.R. § 284.10. [↑](#footnote-ref-3)
3. 218 C.F.R. § 284.7(e). [↑](#footnote-ref-4)
4. 318 C.F.R. § 284.10(b)(c). [↑](#footnote-ref-5)
5. 418 C.F.R. § 284.10(c)(1). [↑](#footnote-ref-6)
6. 5Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, *order* *on reh’g*, 48 FERC ¶ 61,122 (1989); *see* § 8.05[2]. [↑](#footnote-ref-7)
7. 6Panhandle Eastern Pipeline Co. 57 FERC ¶ 61,264 (1991), *order* *reh’g*, 51 FERC ¶ 61,244 (1992). [↑](#footnote-ref-8)
8. 7*See* § 8.05[2]. [↑](#footnote-ref-9)
9. 8*E.g.*, El Paso Natural Gas Co., 35 FERC ¶ 61,440, at 62,056 (1986); El Paso Natural Gas Co., 38 FERC ¶ 61,008, at 61,030–61,031 (1987); Texas Eastern Transmission Corp., 37 FERC ¶ 61,260, at 61,704–61,705 (1986). *See also Mobil* ***Oil*** *Corp. v. FERC*, 886 F.2d 1023, 1030 (8th Cir. 1989), *aff’g* Northern Natural Gas Co., 37 FERC ¶ 61,272 (1986), *on reh’g*, 41 FERC ¶ 61,158 (1987); *Texaco, Inc. v. FERC*, 886 F.2d 749, 753 (5th Cir. 1989), *aff’g* Texas Eastern Transmission Corp., 35 FERC ¶ 61,416 (1986), 37 FERC ¶ 61,260 (1986), *reh’g granted in part*, 41 FERC ¶ 61,015 (1987); Mobile Producing Texas & New Mexico, Inc. v. FERC, 886 F.2d 745, 747–48 (5th Cir. 1989), *aff’g* Transwestern Pipeline Co., 38 FERC ¶ 61,061, *reh’g denied*, 41 FERC ¶ 61,178 (1987). *See* Viking Gas Transmission Co., 52 FERC ¶ 61,015, at 61,103 (1990); Texas Eastern, 62 FERC at 61,091–92; Trunkline, 62 FERC at 62,417 (100% load factor rates on a peak basis but 125% load factor rates off-peak); Algonquin, 62 FERC at 61,863 [↑](#footnote-ref-10)
10. 910 F.3d at 871–72 (D.C. Cir. 1993). [↑](#footnote-ref-11)
11. 10*See* Arkla Energy Resources, Inc., 67 FERC ¶ 61,208 (1994) (“a 100 percent load factor rate, being a fully allocated rate, is the starting point for interruptible rate design”). [↑](#footnote-ref-12)
12. 11Tennessee Gas Pipeline Co., 76 FERC ¶ 61,022 (1996) (Op. No. 406), *reh’g,* 80 FERC ¶ 61,070 (1997) (Op. No. 406-A). [↑](#footnote-ref-13)
13. 12Op. No. 406-A, 80 FERC at 61,201–203. [↑](#footnote-ref-14)
14. 13Transwestern, 61 FERC at 62,227. [↑](#footnote-ref-15)
15. 14Northern Natural, 62 FERC at 61,406 (rejecting Northern’s attempt to change its load factor to 100%). [↑](#footnote-ref-16)
16. 1518 C.F.R. § 284.10(c)(3). [↑](#footnote-ref-17)
17. 16El Paso Natural Gas Co., 38 FERC ¶ 61,008, at 61,030. [↑](#footnote-ref-18)
18. 17Northern Natural Gas Co., 37 FERC ¶ 61,212, at 61,811 (1986). The change was without prejudice to trial of the issue in the pipeline’s next rate case. [↑](#footnote-ref-19)
19. 18Mobil ***Oil*** Corp. v. FERC, 886 F.2d 1023, 1032 (8th Cir. 1989), *aff’g* Northern Natural Gas Co., 37 FERC ¶ 61,272 (1986), *on reh’g*, 41 FERC ¶ 61,158 (1987). The court relied heavily, however, on the temporary nature of the rates, calling the orders a “laboratory for FERC in how open-access will or should be applied in the future.” 886 F.2d at 1028. [↑](#footnote-ref-20)
20. 19Texaco, Inc. v. FERC, 886 F.2d 749, 754 (5th Cir. 1989), *aff’g* Texas Eastern Transmission Corp., 35 FERC ¶ 61,416 (1986), 37 FERC ¶ 61,260 (1986), *reh’g granted in part,* 41 FERC ¶ 61,015 (1987). [↑](#footnote-ref-21)
21. 20United Gas Pipe Line Co., 46 FERC ¶ 61,314, at 61,948 (1989) (citing Transcontinental Gas Pipe Line Corp., 45 FERC ¶ 61,468 (1988)). [↑](#footnote-ref-22)
22. 21Northern Natural Gas Co., 52 FERC ¶ 61,296, at 62,179 (1990). [↑](#footnote-ref-23)
23. 22Wyoming-California Pipeline Co., 44 FERC ¶ 61,001, at 61,007–08 (1988). *See also* ***Kern*** River Gas Transmission Co., 50 FERC ¶ 61,069, at 61,146–61,147 (1990); Delta Pipeline Co., 52 FERC ¶ 61,004, at 61,047–48 (1990). [↑](#footnote-ref-24)
24. 23Panhandle Eastern Pipe Line Co., 57 FERC ¶ 61,264 (1991). [↑](#footnote-ref-25)
25. 24*See* § 8A.07[7]. [↑](#footnote-ref-26)
26. 25Southern Natural, 64 FERC at 62,883. [↑](#footnote-ref-27)
27. 26Northern Natural, 62 FERC at 61,403. The Commission approved, however, Northern’s existing postage stamp rate design for its market area. *Id.* at 61,404. [↑](#footnote-ref-28)
28. 27Transwestern, 61 FERC at 62,226–27. [↑](#footnote-ref-29)
29. 2861 FERC at 62,227. “Backhaul rates” involve transportation that occurs against the physical flow of the natural gas, by displacement. [↑](#footnote-ref-30)
30. 29Tennessee, 62 FERC at 62,651. Tennessee’s zone matrix methodology determines rates based on the average distance of haul from the centroid in the zone of receipt to the delivery centroid in the zone of delivery. [↑](#footnote-ref-31)
31. 30Arkla, 62 FERC at 61,462. [↑](#footnote-ref-32)
32. 31Northern Natural, 62 FERC at 61,404. The Commission approved Northern’s existing postage stamp rate design for its market area. [↑](#footnote-ref-33)
33. 32ANR, 64 FERC at 62,022. [↑](#footnote-ref-34)
34. 33East Tennessee Natural Gas Co., 64 FERC. ¶ 61,159, at 62,321 (1993). [↑](#footnote-ref-35)
35. 34*E.g.*, Columbia Gas Transmission Corporation, CNG Transmission Corporation, Northern Natural Gas Company (market area zone), National Fuel Gas Supply Corporation, and East Tennessee Natural Gas Company. [↑](#footnote-ref-36)
36. 35Northwest Natural Pipeline Corp., 82 FERC ¶ 61,158 (1998). [↑](#footnote-ref-37)
37. 36El Paso Natural Gas Co., 114 FERC ¶ 61,305 at P 297 (March 23, 2006). [↑](#footnote-ref-38)
38. 37Northern Natural Gas Co., 37 FERC ¶ 61,272, at 61,814–15 (1986); Texas Eastern Transmission Corp., 37 FERC ¶ 61,260, at 61,708–09 (1986). [↑](#footnote-ref-39)
39. 38Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, at 62,059 n.56, *on reh’g*, 48 FERC ¶ 61,122 (1989). In the Policy Statement, the Commission recognized that pipelines and shippers may concur that no fee should be charged when an exchange arrangement is producing substantially equal benefits. 47 FERC ¶ 61,295, at 62,058–62,059 (1989). Only on providing justification would a pipeline be allowed to charge the full forward-haul rates for backhauls and exchanges. In *Opinion 369,* the Commission found that a backhaul was in fact shown to create additional capacity, and therefore should be calculated at one-half of the applicable forward haul rate. Opinion No. 369, at 61,839–40; Opinion No. 369-A at 61,850–52. [↑](#footnote-ref-40)
40. 39Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, *on reh’g*, 48 FERC ¶ 61,122, at 61,451 (1989). *See* Texas Eastern Transmission Corp., 51 FERC ¶ 61,156, at 61,426 (1990) (FERC required separate rate filing to cover no-fee exchanges that were permitted to be performed under blanket certificate authority); Viking Gas Transmission Co., 52 FERC ¶ 61,015, at 61,104 (1990). [↑](#footnote-ref-41)
41. 40Panhandle Eastern Pipe Line Co., 57 FERC ¶ 61,264, at 61,839–40 (1991). [↑](#footnote-ref-42)
42. 41A market center is a point of interconnection between pipelines where traders can exchange gas and shippers can obtain a variety of services, including gas trading, wheeling, parking, loaning, storage, and transfer facilities. See Order No. 637, Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services, Order No. 637, FERC Stats. & Regs., Regulations Preambles July 1996–December 2000 ¶ 31,091, 65 F.R. 10156 at 10160 (Feb. 25, 2000). [↑](#footnote-ref-43)
43. 42Texas Eastern, 62 FERC at 61,095 (expressing concern over Texas Eastern’s Access Area boundary at Little Rock, to be reexamined with other operational issues after a year of operational experience); Southern Natural, 62 FERC at 61,950 (stating concern that the pipeline’s interconnection with Texas Eastern downstream of the proposed production area zone may discourage its development as a market center. Yet, the Commission allowed the parties to address that issue in ongoing rate proceedings). [↑](#footnote-ref-44)
44. 43Williston Basin, 62 FERC at 62,036. [↑](#footnote-ref-45)
45. 44ANR, 62 FERC at 61,541–42. [↑](#footnote-ref-46)
46. 45*See* 18 C.F.R. § 284.10(c)(5). [↑](#footnote-ref-47)
47. 46*See* El Paso Natural Gas Co., 35 FERC ¶ 61,440, at 62,057–62,058 (1968); Texas Eastern Transmission Corp., 37 FERC ¶ 61,260, at 61,682 (1986). The relevant language of NGA § 4 requires that no pipeline may “(1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.” Section 5 authorizes the Commission to prohibit unlawful rates prospectively. [↑](#footnote-ref-48)
48. 47Order No. 497, Inquiry Into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, III FERC Stats. and Regs. ¶ 30,820, 53 Fed. Reg. 22,139 (1988); Order No. 497-A, III FERC Stats. and Regs. ¶ 30,868 (1988), *on reh’g*, 49 FERC ¶ 61,344 (1988). Subsequent Commission orders have maintained affiliate rules. *E.g.*, Order No. 497-D, FERC Stats. & Regs. [Regs. Preambles 1991–1995] ¶ 30,934 (1992); Order No. 497-E, *on reh’g*, FERC Stats. & Regs. [1991–1996] ¶ 30,987 (1993); Order No. 497-F, *reh’g denied, clarification granted,* 66 FERC ¶ 61,347 (1994); and Order No. 497-G, *order extending sunset date,* FERC Stats. & Regs. [1991–1996] ¶ 30,996 (1994). [↑](#footnote-ref-49)
49. 48Interstate Natural Gas Association of America v. FERC, 285 F.3d 18 at 54–58 (D.C. Cir. 2002). [↑](#footnote-ref-50)
50. 49“Notice of Inquiry,” Policy for Selective Discounting by Natural Gas Pipelines, 109 FERC ¶ 61,202 (November 22, 2004). [↑](#footnote-ref-51)
51. 50“Order Reaffirming Discount Policy and Terminating Rulemaking Proceeding,” Policy for Selective Discounting by Natural Gas Pipelines, 111 FERC ¶ 61,309 (May 31, 2005), *order denying reh’g*, 113 FERC ¶ 61,117 (November 17, 2005). The Commission has followed this order and policy in subsequent rate proceedings. *See, e.g.*, Northern Natural Gas Company, 118 FERC P 61,053, 2007 FERC LEXIS 151 (FERC 2007) [↑](#footnote-ref-52)
52. 51*See* Equitable Gas Co., 36 FERC ¶ 61,147, at 61,366 (1986). [↑](#footnote-ref-53)
53. 52Panhandle Eastern Pipe Line Co., 53 FERC ¶ 61,227, at 61,948 (1990). [↑](#footnote-ref-54)
54. 53Interstate Natural Gas Pipeline Rate Design, Policy Statement on Rate Design, 47 FERC ¶ 61,295 (1989). [↑](#footnote-ref-55)
55. 54The Policy Statement should be read in conjunction with the regulations governing rate design issues as to open access rates, which are codified at 18 C.F.R. § 284.10(c):

    1. Except as provided in § 284.7(e), any rate filed for service subject to this section must be a one-part rate that recovers the costs allocated to the service to the extent that the projected units of that service are actually purchased and may not include a demand charge, a minimum bill or minimum take provision or any other provision that has the effect of guaranteeing revenue. Such rate must separately identify cost components attributable to transportation, storage, and gathering costs.
    2. **f service.**Any rate filed for service subject to this section must be designed to recover costs on the basis of projected units of service. The fixed costs allocated to capacity reservations, as determined in accordance with § 284.7(e), should be used along with the projected nominations accepted by the pipeline to compute the unit reservation fee. The remaining fixed costs and all variable costs should be used to determine the volumetric rate computed on the basis of projected volumes to be transported. The units projected for the service in rates filed under this section may be changed only in a subsequent rate filing under section 4 of the Natural Gas Act.
    3. **e and distance.**Any rate filed for service subject to this section must reasonably reflect any material variation in the cost of providing the service due to:
    4. Whether the service is provided during a peak or an off-peak period; and
    5. The distance over which the transportation is provided.
    6. Any maximum rate filed under this section must be designed to recover on a unit basis, solely those costs which are properly allocated to the service to which the rate applies.
    7. Any minimum rate filed under this section must be based on the average variable costs which are properly allocated to the service to which the rate applies.
    8. Any rate schedule filed under this section must state a maximum rate and a minimum rate.
    9. Except as provided in paragraph (d)(5)(ii)(B) of this section the pipeline may charge an individual customer any rate that is neither greater than the maximum rate nor less than the minimum rate on file for that service.
    10. If a pipeline does not hold a blanket certificate under Subpart G of this part, it may not charge, in a transaction involving its marketing affiliate, a rate that is lower than the highest rate it charges in any transaction not involving its marketing affiliate.
    11. The pipeline may not file a revised or new rate designed to recover costs not recovered under rates previously in effect.

    [↑](#footnote-ref-56)
56. 5547 FERC at 62,052. [↑](#footnote-ref-57)
57. 56*Id.* at 62,053. [↑](#footnote-ref-58)
58. 57*Id.* 62,052. [↑](#footnote-ref-59)
59. 58*Id.*  at 62,059. Commissioner Charles A. Trabandt concurred in a separate opinion. *Id.* at 62,060–62,066. [↑](#footnote-ref-60)
60. 5948 FERC ¶ 61,122 (1989). [↑](#footnote-ref-61)
61. 6048 FERC at 61,443, 61,446. [↑](#footnote-ref-62)
62. 6148 FERC at 61,443. This approach was adopted in CNG Transmission Corp., 50 FERC ¶ 61,006, at 61,009 (1990) (“[O]ther relevant factors” to be considered include “equity, incentives, marketability, impact on various customer and producer classes, [and] historical development of the [pipeline] system”). [↑](#footnote-ref-63)
63. 6248 FERC at 61,444. [↑](#footnote-ref-64)
64. 63The Commission was careful to point out that the substantive requirements of Part 284 (*e.g.*, the nondiscriminatory access condition) would not apply to non-open access pipelines. 48 FERC ¶ 61,122, at 61,444 (1989). [↑](#footnote-ref-65)
65. 64*Id.* at 61,446. [↑](#footnote-ref-66)
66. 65Panhandle Eastern Pipeline Co., 57 FERC ¶ 61,264 (1991) (“Opinion No. 369”), *reh’g*, 51 FERC ¶ 61,244 (1992) (“Opinion No. 369-A”). [↑](#footnote-ref-67)
67. 66Under straight fixed-variable rate design, all fixed pipeline costs are recovered through the reservation charge. [↑](#footnote-ref-68)
68. 67In Opinion No. 369-A, the Commission found that after Order No. 636, the policy statement would “not be applicable to apportioning costs between the reservation and usage charges,” but noted that it “remains operative for issues such as interruptible transportation rates, discounting and the reflection of materials variations in the cost of services.” 59 FERC at 61,838, *citing* Order No. 636, at 30,434 [↑](#footnote-ref-69)
69. 6847 FERC ¶ 61,295, at 62,054 (1989). [↑](#footnote-ref-70)
70. 69*Id.* at 62,054 n.28. [↑](#footnote-ref-71)
71. 7048 FERC ¶ 61,122, at 61,447 (1989). [↑](#footnote-ref-72)
72. 71The pipeline had sought to implement the seasonal rates based on the ratio of the average day to the peak day use of the system. Opinion No. 369, at 61,831. [↑](#footnote-ref-73)
73. 72Opinion No. 369-A at 61,844. [↑](#footnote-ref-74)
74. 73Opinion No. 369, at 61,827, 61,831. [↑](#footnote-ref-75)
75. 74*Id.* at 61,831. [↑](#footnote-ref-76)
76. 75Opinion No. 369-A at 61,838, 61,842. [↑](#footnote-ref-77)
77. 76In modified fixed-variable rate design, all fixed costs are assigned to the reservation charge except one-half of return and associated income taxes. [↑](#footnote-ref-78)
78. 7747 FERC ¶ 61,295, at 62,055 (1989). [↑](#footnote-ref-79)
79. 7848 FERC ¶ 61,122, at 61,447 n.54 (1989). [↑](#footnote-ref-80)
80. 7947 FERC ¶ 61,295, at 62,055 (1989). [↑](#footnote-ref-81)
81. 80Opinion No. 369, at 61,826–27. [↑](#footnote-ref-82)
82. 81*Id.* at 61,827–28. The Commission found that the pipeline’s underutilization suggested a need to design rates to increase throughput, and that MFV rates made it difficult for gas attached to the pipeline to compete with other gas sources, particularly Canadian gas. [↑](#footnote-ref-83)
83. 82*Id.* at 61,843–44. The imposition of SFV rates under Order No. 636 resolved this issue. [↑](#footnote-ref-84)
84. 83Opinion No. 369, at 61,842. [↑](#footnote-ref-85)
85. 8447 FERC ¶ 61,295, at 62,057 (1989). [↑](#footnote-ref-86)
86. 8548 FERC ¶ 61,122, at 61,449 (1989). [↑](#footnote-ref-87)
87. 86“Order Reaffirming Discount Policy and Terminating Rulemaking Proceeding,” Policy for Selective Discounting by Natural Gas Pipelines, 111 FERC ¶ 61,309 (May 31, 2005), *order denying reh’g*, 113 FERC ¶ 61,117 (November 17, 2005). [↑](#footnote-ref-88)
88. 87Transcontinental Gas Pipe Line Corp., 46 FERC ¶ 61,364, at 62,143 (1989). [↑](#footnote-ref-89)
89. 8847 FERC ¶ 61,295, at 62,058 (1989). [↑](#footnote-ref-90)
90. 8948 FERC ¶ 61,122, at 61,450 (1989). [↑](#footnote-ref-91)
91. 90Opinion No. 369, at 61,835. [↑](#footnote-ref-92)
92. 9147 FERC ¶ 61,295, at 62,058 (1989). [↑](#footnote-ref-93)
93. 9248 FERC ¶ 61,122, at 61,451 (1989). [↑](#footnote-ref-94)
94. 93Opinion No. 369, at 61,836; Opinion No. 369-A at 61,847–849. [↑](#footnote-ref-95)
95. 94At the same time, the Commission approved the continued use of the historic zones for sales purposes since sales gas had to travel the full length of the system in any event. Opinion No. 369, at 61,837. [↑](#footnote-ref-96)
96. 9547 FERC ¶ 61,295, at 62,059 (1989). [↑](#footnote-ref-97)
97. 96Opinion No. 369 ¶ 61,264, at 61,844–46; Opinion No. 369-A at 61,859–862 (1991). [↑](#footnote-ref-98)
98. 97*Id.* at 61,840–42; Opinion No. 369-A at 61,852–54. The Commission rejected Panhandle’s claim that it could not be compelled to charge new gathering service rates in the absence of § 7(c) certificate. *Id.* [↑](#footnote-ref-99)
99. 98Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 70 FERC ¶ 61,139 (1995). [↑](#footnote-ref-100)
100. 99Alternatives to Traditional Cost of Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, 74 FERC ¶ 61,076 (1996) (Policy Statement), *order granting clarification*, 74 FERC ¶ 61,196 (1996), *order denying requests for reh’g and clarification*, 75 FERC ¶ 61,024 (1996), *order denying reh’g*, 75 FERC ¶ 61,066 (1996), *petition for review denied sub nom.* Burlington Resources ***Oil*** & Gas Co. v. FERC, 1998 U.S. App. LEXIS 20697 (unpublished order, July 20, 1998). [↑](#footnote-ref-101)
101. 100*Id.* at 61,231 [↑](#footnote-ref-102)
102. 101*Id.* at 61,232. [↑](#footnote-ref-103)
103. 102*Id.* at 61,232–33. [↑](#footnote-ref-104)
104. 103*Id.* at 61,234. [↑](#footnote-ref-105)
105. 104*Id.* 61,234–35. [↑](#footnote-ref-106)
106. 105*Id.* at 61,235. [↑](#footnote-ref-107)
107. 106*Id.* at 61,235–36. [↑](#footnote-ref-108)
108. 107The information includes a detailed description of the services proposed for market-based rate treatment, a statement defining the relevant product and geographic markets, a showing of market share and HHI calculations, and a discussion of other relevant competitive factors. *Id.* [↑](#footnote-ref-109)
109. 108*Id.* at 61,236. [↑](#footnote-ref-110)
110. 109*E.g.*, Avoca Natural Gas Storage, 68 FERC ¶ 61,045 (1994); Bay Gas Storage Co., Ltd., 66 FERC ¶ 61,354 (1994); Ouachita River Gas Storage Co., 68 FERC ¶ 61,402 (1994). [↑](#footnote-ref-111)
111. 110*E.g.*, Cove Point LNG Ltd. P’ship, 68 FERC ¶ 61,377 (1994) (due to concerns over the role of affiliates) and Ouachita River Gas Storage Co., 68 FERC ¶ 61,402 (1994) (finding that the applicant failed to justify market-based prices for hub services). [↑](#footnote-ref-112)
112. 111*E.g.*, Steuben Gas Storage Syst., 74 FERC ¶ 61,060 (1996); Central Oklahoma ***Oil*** and Gas Corp., 80 FERC ¶ 61,250 (1997); Pontchartrain Natural Gas Syst., 80 FERC ¶ 61,279 (1997); NE Hub Partners, LP, 83 FERC ¶ 61,043 (1998), *reh’g denied*, 90 FERC ¶ 61,142 (2000); and Petal Gas Storage, L.L.C., 90 FERC ¶ 61,243 (2000); Gulf South Pipeline Co., L.P., 101 FERC ¶ 61,202 (2002) (despite the applicant’s affiliation with a major interstate pipeline, the Commission approved market-based storage rates because the production area storage market in question was unconcentrated) ; Wyckoff Gas Co., 105 FERC ¶ 61,022 (2003); Pine Prairie Energy Center LLC, 109 FERC ¶ 61,215 (2004). [↑](#footnote-ref-113)
113. 112Lee 8 Storage P’ship, 81 FERC ¶ 61,094 (1997) (denying market-based rates both for an inadequate market power analysis and concerns over affiliates); CNG Transmission Corp., 80 FERC ¶ 61,137 (1997), *reh’g denied*, 81 FERC ¶ 61,031 (1997) (rejecting proposal for market-based interruptible and parking service, for failure to show lack of market power); and Clear Creek Storage Co., LLC, 84 FERC ¶ 61,210 (1998) (rejecting market-based rate request for failure to make the showing required); Northwest Natural Gas Corp., 95 FERC ¶ 61,242 (2001) (denying request for failure to select appropriate market definition and because the evidence did not support the market power conclusions). In another order, the Commission denied a request by a pipeline for both market-based storage rates and market-based no-notice service, because the latter service combined the storage with a transportation service that would require a separate showing of lack of market power. Transok, 97 FERC ¶ 61,362 (2001). [↑](#footnote-ref-114)
114. 113Egan Hub Partners, L.P., 81 FERC ¶ 61,017 (1997). [↑](#footnote-ref-115)
115. 114New York State Elec. & Gas Corp., 81 FERC ¶ 61,020 (1997); Transok LLC, 93 FERC ¶ 61,031 (2000); EPGT Texas Pipeline, L.P., 103 FERC ¶ 61,181 (2003); Katy Storage and Transportation, L.P., 106 FERC 61,145 (2004). [↑](#footnote-ref-116)
116. 115Even prior to the legislation that prompted the revised regulations discussed below, the Commission informally contemplated changed policies toward assessing whether market based rates are appropriate for storage services. *See*, Staff Report, “Current State of and Issues Concerning Underground Natural Gas Storage,” Dkt. No. AD04-11-000, issued September 30, 2004. [↑](#footnote-ref-117)
117. 116*See* KN Interstate Gas Transmission Co., 76 FERC ¶ 61,134 (1996). [↑](#footnote-ref-118)
118. 117KN Interstate Gas Transmission Co., 82 FERC ¶ 61,009 (1998). [↑](#footnote-ref-119)
119. 11885 FERC ¶ 61,013 (1998) (October 2 Order). [↑](#footnote-ref-120)
120. 119Koch Gateway Pipeline Co., 80 FERC ¶ 63,008 (1997) (Initial Decision). [↑](#footnote-ref-121)
121. 120October 2 Order, 85 FERC at 61,041. [↑](#footnote-ref-122)
122. 121*Id.* at 61,041–42. [↑](#footnote-ref-123)
123. 122*Id.* at 61,044. [↑](#footnote-ref-124)
124. 123*Id.* at 61,044–45. [↑](#footnote-ref-125)
125. 124*Id.* at 61,045. [↑](#footnote-ref-126)
126. 125October 2 Order, 85 FERC at 61,045–46. The Commission subsequently denied rehearing, in *Koch Gateway Pipeline Co.* 89 FERC ¶ 61,046 (1999). The Commission reaffirmed the propriety of applying the policy statement on alternative rates, including its requirements for a successful market power showing, reaffirmed each element of its earlier decision, and rejected Koch’s arguments that its order had been inconsistent with the analysis used in the *Buffalo Wallow* decision. [↑](#footnote-ref-127)
127. 126Rate Regulation of Certain Natural Gas Storage Facilities, 71 Fed. Reg. 36,612 (June 27, 2006), FERC Statutes and Regulations ¶ 31,220 (2006) (“Order No. 678”), *order on clarification and reh’g*, 117 FERC ¶ 61,190 (2006) (“Order No. 678-A”). [↑](#footnote-ref-128)
128. 127In addition to the 2004 Staff Report, the Commission held a conference followed by the submission of comments by the public. *See State of the Natural Gas Industry* Conference, Docket No. PL04-17-000, October 21, 2004; *see* State of Natural Gas Industry Conference; Staff Report on Natural Gas Storage; Notice of Public Conference, 69 F.R. 59917 (Oct. 6, 2004) (summarizing the issues to be discussed at the conference). [↑](#footnote-ref-129)
129. 128Pub. L. No. 109-58, 119 Stat. 594 (2005) (“EPACT of 2005”). [↑](#footnote-ref-130)
130. 129“Notice of Proposed Rulemaking,” Rate Regulation of Certain Underground Storage Facilities, 70 FR 77079 (Dec. 22, 2005), FERC Stats. & Regs., Regulations Preambles ¶ 32,595 (Dec. 29, 2005) (NOPR). [↑](#footnote-ref-131)
131. 130NOPR, Summary. [↑](#footnote-ref-132)
132. 131*Id.* at P 7–12. [↑](#footnote-ref-133)
133. 132NOPR at P 15–18. [↑](#footnote-ref-134)
134. 133*Id.* at P 19–22. [↑](#footnote-ref-135)
135. 134*Id.* at P 23–31. [↑](#footnote-ref-136)
136. 135*Id.* at P 32–34. [↑](#footnote-ref-137)
137. 136*Id.* at P 1. [↑](#footnote-ref-138)
138. 137*Id.* at P 38–39. [↑](#footnote-ref-139)
139. 138*Id.* at P 40–45. [↑](#footnote-ref-140)
140. 139Order No. 678 at P 10. [↑](#footnote-ref-141)
141. 140*Id.* at P 27–28. [↑](#footnote-ref-142)
142. 141*Id.* at P 48. [↑](#footnote-ref-143)
143. 142*Id.* at P 50. [↑](#footnote-ref-144)
144. 143*Id.* at P 56. [↑](#footnote-ref-145)
145. 144*Id.* at P 39. [↑](#footnote-ref-146)
146. 145*Order No. 678* at 55–72. [↑](#footnote-ref-147)
147. 146*Id.* at 78–81, 198. [↑](#footnote-ref-148)
148. 147NOPR at P 90, 92. [↑](#footnote-ref-149)
149. 148*Id.* at P 98. [↑](#footnote-ref-150)
150. 149*Id.* at P 115. [↑](#footnote-ref-151)
151. 150*Id.* at P 127. [↑](#footnote-ref-152)
152. 151*Id.* at P 128. Should, for example, the applicant hold an open season based on cost-based rates and yet not obtain adequate long-term contracts, such a showing might suffice. [↑](#footnote-ref-153)
153. 152Order No. 678 at P 131. *E.g*., lack of storage in the area, full subscription of existing storage capacity; constraints on pipeline capacity, expected increases in demand, showings of customer interest; the occurrence of high natural gas prices and/or volatility; and other pertinent information [↑](#footnote-ref-154)
154. 153*Id.* at P 153. [↑](#footnote-ref-155)
155. 154*E.g*., demonstration of a fair and transparent open season in accordance with FERC policies; showing that existing customers are not subject to “additional costs, risks or degradation of services” as a result of the requested authorization; maintaining separate accounting for the costs, services and commitments; and an open access tariff showing the terms and conditions under which service is offered. P 154–158. [↑](#footnote-ref-156)
156. 155Order No. 678 at P 165. Applicants could propose a recourse rate, possibly in light of the concepts discussed in Order No. 678 with respect to the no-withholding pricing issue. [↑](#footnote-ref-157)
157. 156*Id.* at P 172. [↑](#footnote-ref-158)
158. 157*Id.* at P 173–178. [↑](#footnote-ref-159)
159. 158*Id.* at P 196–197. [↑](#footnote-ref-160)
160. 159A “Memphis Clause” permits the pipeline or storage operator to charge higher rates subject to FERC review and approval during the contract period, subject to the customer’s right to challenge such increases. [↑](#footnote-ref-161)
161. 160Order No. 678-A atP 7. [↑](#footnote-ref-162)
162. 161*Id.* at P 24. The Commission stated that applicants must provide minimum measures assuring the Commission that market-based rates would not harm existing customers. The Commission required that applicants must ensure that existing customers would not incur additional costs, risks or degradation of service, that the applicant would segregate its accounts for the costs, services and commitments provided by means of this authorization, and that the applicant would ensure use of non-discriminatory terms and conditions of tariff service. [↑](#footnote-ref-163)
163. 162*Northern Natural Gas Company*, 117 FERC ¶ 61,191 (2006) (November 16 Order), o*rder denying reh’g.*, 119 FERC ¶ 61,072 (April 20, 2007) [↑](#footnote-ref-164)
164. 163On rehearing, the Commission found that the market-based rates provided more protection than cost-based rates would have: “[i]n finding that market-based rates were in the public interest, the Commission also found that, under traditional cost-based rates, Northern’s customers would potentially be subject to rate increases through NGA section 4 filings if Northern’s cost projections were incorrect, whereas market-based rates would provide expansion shippers with rate security for the life of their contracts while the risk of rate increases falls upon Northern.” “Order Denying Rehearing” at P 12. [↑](#footnote-ref-165)
165. 164*E.g*., Columbia Gas Transmission Corp., 126 FERC ¶ 61,237 (March 19, 2009); Texas Gas Transmission, LLC, 122 FERC ¶ 61,190 (February 29, 2008). [↑](#footnote-ref-166)
166. 165KN Interstate Gas Transmission Co., 82 FERC at ¶ 61,237. [↑](#footnote-ref-167)
167. 166The Commission also established a companion docket, Docket No. RM96-7, and requested additional comments on issues concerning the negotiated terms and conditions of service and the relevant rate issues surrounding negotiated rates. Initial comments on the proposal were filed in May 1996. That question ultimately was resolved in Order No. 637. [↑](#footnote-ref-168)
168. 16775 FERC ¶ 61,091 (NorAm I), *reh’g*, 77 FERC ¶ 61,011 (1996) (NorAm II). [↑](#footnote-ref-169)
169. 168NorAm I at 61,309. [↑](#footnote-ref-170)
170. 169NorAm II at 61,037. [↑](#footnote-ref-171)
171. 170NorAm I at 61,309. [↑](#footnote-ref-172)
172. 171NorAm II at 61,036. [↑](#footnote-ref-173)
173. 172Koch Gateway Pipeline Co., 77 FERC ¶ 61,085 (1996); CNG Transmission Corp., 77 FERC ¶ 61,092 (1996); Columbia Gulf Transmission Co. and Columbia Gas Transmission Corp., 77 FERC ¶ 61,093 (1996); East Tennessee Natural Gas Co., 77 FERC ¶ 61,095 (1996); Midwestern Gas Transmission Co., 77 FERC ¶ 61,096 (1996); Transcontinental Gas Pipe Line Corp., 77 FERC ¶ 61,208 (1996); National Fuel Gas Supply Corp., 77 FERC ¶ 61,214 (1996); Tennessee Gas Pipeline Co., 77 FERC ¶ 61,215 (1996); Panhandle Eastern Pipe Line Co., 78 FERC ¶ 61,011 (1997); Trunkline Gas Co., 78 FERC ¶ 61,012 (1997); Colorado Interstate Gas Co., 81 FERC ¶ 61,037 (1997); Iroquois Gas Transmission Syst., L.P., 81 FERC ¶ 61,190 (1997). The Commission applied substantially the same terms and conditions throughout these orders. In addition to traditional transportation services, negotiated rate proposals for new parking and lending services were also approved. Koch Gateway Pipeline Co., 79 FERC ¶ 61,416 (1997); Great Lakes Gas Transmission, L.P., 86 FERC ¶ 61,234 (1999); South Georgia Natural Gas Co., 86 FERC ¶ 61,328 (1999); Southern Natural Gas Co., 86 FERC ¶ 61,317 (1999); Texas Eastern Transmission Corp., 87 FERC ¶ 61,362 (1999); ANR Pipeline Co., 87 FERC ¶ 61,241 (1999); CNG Transmission Corp., 88 FERC ¶ 61,191 (1999); and Northwest Pipeline Corp., 88 FERC ¶ 61,310 (1999); Transcontinental Gas Pipe Line Corp., 88 FERC ¶ 61,311 (1999); Tennessee Gas Pipeline Co., 89 FERC ¶ 61,033 (1999); Northern Natural Gas Co., 89 FERC ¶ 61,195 (1999); Natural Gas Pipeline Co. of Am., 89 FERC ¶ 61,098 (1999); and Koch Gateway Pipeline Co., 89 FERC ¶ 61,078 (1999). [↑](#footnote-ref-174)
174. 173NorAm Gas Transmission Corp., 85 FERC ¶ 61,039 (1998) (tariff provisions found to be in violation of the Commission’s current prohibition on negotiated terms and services for gas contracts because various contractual provisions barring discount shippers from the benefits of imbalance aggregation were held to restrict a shipper’s right to otherwise available terms and conditions of service). The Commission also scrutinized regular tariff filings for proposals that should have been submitted as negotiated rates. *E.g.*, Northern Natural Gas Co., 90 FERC ¶ 61,064 (2000), the Commission rejected a change to the pipeline’s General Terms and Conditions that would have created a new category of discounts based on published price indexes. Northern asserted that the index-based rates were expected to be a valuable marketing tool and that the discount was needed to meet competitive market conditions, and proposed to post the specific price terms of such discounts on its EBB before the commencement of gas flow or within two days of the execution of the contracts. The Commission found that the proposed discounts would in fact be negotiated rates, rather than discounted rates falling within the pipeline’s published rate minima and maxima. The Commission contrasted the proposal with the indexed discount filing by Williston Basin, in which discounts tied to a published alternate fuel price index would remain constant once the contract was commenced; Northern proposed that the indexed rate would change over time. Consequently, the Commission rejected the filing as being against Commission policy and precedent. [↑](#footnote-ref-175)
175. 174Northwest Pipeline Corp., 79 FERC ¶ 61,416 (1997). [↑](#footnote-ref-176)
176. 175*Id.* at 62,754. [↑](#footnote-ref-177)
177. 176The Commission subsequently approved many negotiated rate filings, while imposing conditions to ensure compliance with its policies. *E.g.*, NorAm Gas Transmission Co., 85 FERC ¶ 61,039 (1998) (finding that various tariff provisions violated the prohibitions against negotiated terms and conditions, especially provisions barring discount shippers from the benefits of imbalance aggregation); Tennessee Gas Pipeline Co., 84 FERC ¶ 61,340, *reh’g denied,* 85 FERC ¶ 61,441 (1998) (approving the filing but requiring that discounts be specifically limited to fall between the maximum and minimum tariff rates); Williston Basin Interstate Pipeline Co., 84 FERC ¶ 61,348, *reh’g denied,* 85 FERC ¶ 61,247 (1998) (requiring modification to remove discounts based on variances in end-use, as being impermissible in charging different rates to similarly situated shippers); Tennessee Gas Pipeline Co., 91 FERC ¶ 61,070 (2000) (requiring that a negotiated rate could provide a customer with an ROFR provision, but the pipeline must make the same right available to other, similarly situated shippers on a nondiscriminatory basis); Williams Gas Pipelines Central, Inc., 92 FERC ¶ 61,190 (2000) (establishing generic tariff discount provisions); Dominion Transmission Corp., 94 FERC ¶ 61,057 (2001) (rejecting pipeline proposal for negotiated full requirements agreements as affecting the terms of service). [↑](#footnote-ref-178)
178. 177ANR Pipeline Co., 97 F.E.R.C. ¶ 61,222 (2001). [↑](#footnote-ref-179)
179. 178*Id.* at 62,012. [↑](#footnote-ref-180)
180. 179ANR Pipeline Co., 97 FERC ¶ 61,223 (2001). [↑](#footnote-ref-181)
181. 180ANR Pipeline Co., 97 FERC ¶ 61,224 (2001). [↑](#footnote-ref-182)
182. 181Tennessee Gas Pipeline Co., 97 FERC ¶ 61,225 (2001). [↑](#footnote-ref-183)
183. 182Columbia Gas Transmission Corp., 97 FERC ¶ 61,221 (2001). [↑](#footnote-ref-184)
184. 183100 FERC ¶ 61,058 (2002). [↑](#footnote-ref-185)
185. 184The price differential was not the sole factor in this decision—the Commission also concluded that the pipeline provided advance information regarding the capacity to the shippers, in violation of its tariff. [↑](#footnote-ref-186)
186. 185100 FERC ¶ 61,061 (2002). [↑](#footnote-ref-187)
187. 186In addition to the *Transwestern* case, the Commission also cited PG&E Gas Transmission, Northwest Corp., 96 FERC ¶ 61,276 (2001). [↑](#footnote-ref-188)
188. 187The Commission continued to issue negotiated rate orders that refined and limited negotiated rates along well-established policy lines. *See, e.g.,* Horizon Pipeline Co., LLC, 101 FERC ¶ 61,259 (2002) (requiring modification of a negotiated rate purporting to limit shippers’ segmentation rights in a manner contrary to Order No. 637); ANR Pipeline Co., 101 FERC ¶ 61,094 (2002); ANR Pipeline Co., 101 FERC ¶ 61,096 (2002) (a negotiated rate may not include an essential component that is filed on a confidential basis, not open to public review); ANR Pipeline Co., 107 FERC ¶ 61,241 (2004) (accepting a negotiated rate incorporating a revenue sharing mechanism in which the pipeline would share revenues that the shipper would receive from gas sales, using the NYMEX index and basis or seasonal differentials, but capped at the revenue level the pipeline would have received had it charged maximum filed rates); ANR Pipeline Co., 108 FERC ¶ 61,028 (2004) (accepting a negotiated rate that would permit discounts subject to price indices, under stated conditions, but rejecting but rejecting ANR’s proposal to the extent that it was based on contracts with rates based on must flow conditions and “linked agreements among different contracts); Columbia Gulf Transmission Corp., 109 FERC ¶ 61,152 (2004) (rejecting a discounted rate agreement that contained a clause restricting the customers’ § 5 rights to challenge the pipelines’ rates, and requiring that the agreements be re-filed as non-conforming negotiated rates) [↑](#footnote-ref-189)
189. 188Natural Gas Pipeline Negotiated Rate Policies and Practices, 104 FERC ¶ 61,134 (2003). [↑](#footnote-ref-190)
190. 189*Id.* at 61,484–486. [↑](#footnote-ref-191)
191. 190*Id.* at 61,487. [↑](#footnote-ref-192)
192. 191Natural Gas Pipeline Negotiated Rate Policies and Practices, 114 FERC ¶ 61,042 (January 19, 2006) (“January 2006 Order”), *reh’g requests dismissed, clarification requests denied*, 114 FERC ¶ 304 (March 23, 2006). [↑](#footnote-ref-193)
193. 192January 2006 Order at P 7. [↑](#footnote-ref-194)
194. 193*Id.* at P 8. [↑](#footnote-ref-195)
195. 194*Id.* at P 10. *See* Energy Policy Act of 2005, Pub. L. No. 109-58, sections 1261 *et seq.*, 119 Stat. 594 (2005). [↑](#footnote-ref-196)
196. 195January 2006 Order at P 11. [↑](#footnote-ref-197)
197. 19618 C.F.R. § 284.8(d). (“I]f a reservation fee is charged, it must recover all fixed costs attributable to the firm transportation service, unless the Commission permits the pipeline to recover some of the fixed costs in the volumetric portion of a two-part rate.”) [↑](#footnote-ref-198)
198. 197Order No. 636, at 30,396–98. [↑](#footnote-ref-199)
199. 198Under MFV rate design, most fixed costs were allocated to the reservation component of the rate, but 50% of the return on equity and associated taxes were allocated to the commodity component, which had the effect of incenting the pipeline to maximize throughput. [↑](#footnote-ref-200)
200. 199Natural Gas Pipeline Company of America, 25 FERC ¶ 61,176 (1983), *reh’g*, 26 FERC ¶ 61,203 (1984), *aff’d in relevant part*, Northern Indiana Pub. Serv. Co. v. FERC, 782 F.2d 730 (7th Cir. 1986). [↑](#footnote-ref-201)
201. 20018 C.F.R. § 284.7(c)(2) [↑](#footnote-ref-202)
202. 201Panhandle Eastern Pipe Line Co., 57 FERC ¶ 61,264 (1991). *See* § 8A.07[2]. [↑](#footnote-ref-203)
203. 202Order No. 636 at 30,433–34. [↑](#footnote-ref-204)
204. 203*Id.* 30,434. [↑](#footnote-ref-205)
205. 204Although the Commission also stated that it “will not rigidly preclude” parties from agreeing to alternatives to SFV, Order No. 636 made it clear that acceptable departures would be rare. The Commission noted that it would only “consider giving effect to the parties’ agreement,” and that any party proposing deviation from SFV “carries a heavy burden of persuasion.” Order No. 636, at 30,434. [↑](#footnote-ref-206)
206. 205Order No. 636, at 30,434. [↑](#footnote-ref-207)
207. 206*Id.* at 30,434. [↑](#footnote-ref-208)
208. 207*Id.* at 30,435–36. [↑](#footnote-ref-209)
209. 208*Id.* at 30,436. [↑](#footnote-ref-210)
210. 209*Citing* Incentive Ratemaking For Interstate Natural Gas Pipelines, ***Oil*** Pipelines, and Electric Utilities, 58 FERC ¶ 61,287 (1992). Ultimately, that policy statement was adopted in large part, but specifically precluded the pipeline from implementing incentive rate plans as part of its compliance filings. Incentive Ratemaking for Interstate Natural Gas Pipelines, ***Oil*** Pipelines, and Electric Utilities, 61 FERC ¶ 61,168 (1992). [↑](#footnote-ref-211)
211. 210Order No. 636, at 30,437. [↑](#footnote-ref-212)
212. 211*See, e.g.,* Order No. 636-A at 30.604. [↑](#footnote-ref-213)
213. 212*See, e.g.,* Texas Eastern, 62 FERC at 61,084; Panhandle, 61 FERC at 62,402–03; Transwestern, 61 FERC at 62,225; ANR, 62 FERC. at 61,535–36; Southern Natural, 62 FERC at 61,940; Algonquin, 62 FERC at 61,856–57; National Fuel, 62 FERC at 62,440. [↑](#footnote-ref-214)
214. 213***Kern*** River Gas Transmission Co., 62 FERC ¶ 61,191, at 62,258 (1993). [↑](#footnote-ref-215)
215. 214*Id.* at 62,261. [↑](#footnote-ref-216)
216. 215Moreover, allowing two customers to retain MFV rates would be unduly discriminatory and run counter to the goals underlying uniform implementation of SFV. *Id.* at 62,258. [↑](#footnote-ref-217)
217. 216A “Memphis clause” permits the pipeline to file to raise charges to the customer during the term of the contract, subject to the customer’s right to oppose the changes before the Commission. [↑](#footnote-ref-218)
218. 217Union Pacific Fuels, Inc. v. FERC, 129 F.3d at 161–62 (D.C. Cir. 1997). [↑](#footnote-ref-219)
219. 218Mojave Pipeline Co., 62 FERC ¶ 61,195, at 62,364–66 (1993). Mojave justified the use of MFV rates for existing customers on the same grounds as ***Kern*** River, citing the underlying contracts and certificates. The Commission again rejected those arguments. Moreover, the Commission noted that Mojave competes with ***Kern*** River, hence it would be particularly anticompetitive for different shippers serving the same market to pay significantly different transportation rates. [↑](#footnote-ref-220)
220. 219Northern Natural, 62 FERC at 61,402. *See* ANR, 62 FERC at 61,535; Tennessee, 62 FERC at 62,649. [↑](#footnote-ref-221)
221. 220Texas Eastern, 62 FERC at 61,084. There were very minor, partial exceptions. Williston Basin, 62 FERC at 62,033; Colorado Interstate Gas Co., 64 FERC ¶ 61,277, at 62,955 (1993). [↑](#footnote-ref-222)
222. 221Iroquois Gas Transmission System, 62 FERC ¶ 61,167, at 62,153–54 (1993). *See* Gas Transport, Inc., 64 FERC ¶ 61,008, at 61,038 (1993) (pipeline was allowed to retain MFV rate design when its customers agreed that it could continue charging its current rates); Gasdel Pipeline System, 63 FERC ¶ 61,161, at 62,086 (1993); and Northern Border Pipeline Co., 63 FERC ¶ 61,289, at 62,954 (1993). [↑](#footnote-ref-223)
223. 222Algonquin, 62 FERC at 61,859; Tennessee, 62 FERC at 62,649–50. [↑](#footnote-ref-224)
224. 223Williston Basin, 62 FERC at 62,041 (requiring pipeline to perform a new cost shifting impact study). [↑](#footnote-ref-225)
225. 224Texas Gas Transmission Corp., 65 FERC ¶ 61,008, at 61,149 (1993). [↑](#footnote-ref-226)
226. 225Tennessee, 62 FERC at 62,650. The Commission used as an example a pipeline customer using several different services, some of which might have decreased rates and some of which might have increased rates. To the extent the increases and decreases offset one another, the Commission stated that mitigation may not be necessary. *Id.* [↑](#footnote-ref-227)
227. 226*E.g.*, Panhandle, 61 FERC at 62,407; Transwestern, 61 FERC at 62,230. [↑](#footnote-ref-228)
228. 227Union Pacific Fuels, Inc. v. FERC, 129 F.3d 157 (D.C. Cir. 1997). [↑](#footnote-ref-229)
229. 228*See* Trunkline Gas Co., 75 FERC ¶ 61,064 (1996); Texas Eastern Transmission Corp., 75 FERC ¶ 61,218 (1996); Panhandle Eastern Pipe Line Co., 75 FERC ¶ 61,230 (1996). [↑](#footnote-ref-230)
230. 229*See* Trunkline Gas Co., 76 FERC ¶ 61,316 (1996); Texas Eastern Transmission Corp., 76 FERC ¶ 61,362 (1996); Panhandle Eastern Pipeline Co., 76 FERC ¶ 61,360 (1996). Because the capacity of each of the three pipelines proposing to extend the CRP mechanism to the secondary market was fully subscribed, the Commission reasoned that replacement shippers could not request service from the pipeline so that the pipeline’s rates would serve as the recourse rate alternative to the CRP-capped released capacity rates. Without such a recourse rate alternative, the Commission reasoned, releasing shippers might be able to exercise market power. Accordingly, the Commission declined to authorize use of the CRP mechanism for secondary market (capacity release) transactions. The Commission did point out, however, that it could reconsider the issue in the context of the pending rulemaking on secondary market transactions. [↑](#footnote-ref-231)
231. 230NorAm Gas Transmission Co., 77 FERC ¶ 61,011, at 61,040 (1996) (NorAm II) (footnote omitted). [↑](#footnote-ref-232)
232. 231NorAm II at 61,040. [↑](#footnote-ref-233)
233. 232Tennessee Gas Pipeline Co., 77 FERC ¶ 61,083 (1996) (Tennessee), *reh’g denied*, 78 FERC ¶ 61,069 (1997). [↑](#footnote-ref-234)
234. 233Tennessee, 77 FERC at 61,355–56. [↑](#footnote-ref-235)
235. 234Tennessee, 77 FERC at 61,357. [↑](#footnote-ref-236)
236. 235Chiefly, that the amount of the fixed costs was not large, and that the impact on Tennessee’s commodity rates would be modest, both in absolute terms and relative to the commodity rates of competing pipelines. SFV remains the presumptive rate design, however. Columbia Gas Transmission Corp., 85 FERC ¶ 61,041 (1998), *reh’g denied,* 85 FERC ¶ 61,427 (1998) (granting summary judgment against a challenge to the pipeline’s use of SFV, where the Commission found that the party seeking a departure from SFV failed to raise other than generic, industry-wide arguments). Similarly, the Commission has mandated SFV rates for an intrastate pipeline. Michigan Consolidated Gas Co., 85 FERC ¶ 61,080 (1998). [↑](#footnote-ref-237)
237. 236Texas Gas Transmission Corp., 91 FERC ¶ 61,200 (2000). [↑](#footnote-ref-238)