

Report of the Committee on Natural Gas Rate and Accounting Regulations¹

I. COMMISSION ACTION ON PIPELINE ISSUES

A. *Accumulated Deferred Income Taxes*

In *El Paso Natural Gas Co.*,² the Commission held that when a pipeline switches from pricing its company-owned production on a cost-of-service basis to pricing under the Natural Gas Policy Act of 1978 (NGPA),³ the tax effect is neutral and, if the pipeline had been using a normalization method of reflecting income tax expense, it need not refund the deferred tax reserves. However, in this order on remand from a decision of the United States Court of Appeals for the District of Columbia Circuit,⁴ the Commission also held that the reserve is not eliminated from all rate consideration. The pipeline must credit the deferred tax reserve to its rate base. In that way, the pipeline retains the funds to pay income taxes resulting from the reversals of timing differences, and the customers will receive the benefit of the time value of the tax reserve.

B. *Affiliated Entities Test*

In *National Fuel*,⁵ the Commission clarified whether the application of the "comparable first sales" standard of the "affiliated entities" test under section 601(b)(1)(E) of the NGPA would include "market out" purchases made by competing pipelines. The Commission did not rule out the use of such purchases, but held that the resulting market-out prices did not provide "conclusive evidence" of available gas supplies since such prices are greatly affected by the particular circumstances involved in the pipeline systems exercising market-out clauses. Accordingly, the Commission found that the amounts paid by National Fuel to its affiliate did not violate the "affiliated entities" test.⁶

C. *Allocation of Capacity*

In *Transcontinental Gas Pipe Line Corp.*,⁷ the Commission approved a settlement which was contested only with respect to issues of law. Transco had requested abandonment of firm service at three points but had later been

1. The Committee's report highlights the important natural gas rate and accounting developments at the Federal Energy Regulatory Commission (FERC or Commission) and in the courts for 1988.

2. *El Paso Natural Gas Co.*, 43 F.E.R.C. ¶ 61,272 (1988).

3. Natural Gas Policy Act of 1978, 15 U.S.C. § 3301 (1982).

4. *Public Utils. Comm'n of Cal. v. FERC*, 817 F.2d 858 (D.C. Cir. 1987), *rev'g El Paso Natural Gas Co.*, 33 F.E.R.C. ¶ 61,099 (1985), *reh'g denied*, 34 F.E.R.C. ¶ 61,156 (1986).

5. Opinion No. 315, *National Fuel Gas Supply Corp.*, 44 F.E.R.C. ¶ 61,293 (1988).

6. *Id.* at 62,059.

7. *Transcontinental Gas Pipe Line Corp.*, 42 F.E.R.C. ¶ 61,131 (1988).

ordered to allow a major existing pipeline customer to convert part of its CD rights to transportation service.

Various distribution company customers claimed that, under Order No. 436, existing sales customers had a greater right to the remaining abandoned capacity than did others who requested it under the first-come first-served principle. The settlement was otherwise fully supported. Refusing to address capacity allocation questions in an abandonment proceeding, the Commission found that Transco's allocation of its freed-up capacity should be evaluated elsewhere. Moreover, it declined to disturb Transco's policy of requiring customers, who converted to transportation, to pay the same level of prudent buyout and buydown costs as if they had retained the sales service.

D. Capacity Brokering

On April 4, 1988, the FERC issued a Notice of Proposed Rulemaking which has potentially broad implications from a ratemaking standpoint.⁸ The program proposes to establish brokering of firm transportation rights on interstate pipeline systems. The brokering aspect is an outgrowth of the Commission's Order Nos. 436 and 500 open-access transportation program. The Commission proposed that a holder of rights to firm transportation or system storage on an interstate pipeline be permitted to sell or transfer those rights either at market-based rates or at price ceilings in markets determined not to be workably competitive. In a concurring statement, Commissioner Trabandt noted that the proposal raised significant issues. One particular issue was exactly how far the Commission could go under the law in substituting reliance on competition and marketing forces for traditional ratemaking approaches.

E. Contract Demand Reductions and Conversions

In *Interstate Power Co. v. Natural Gas Pipeline Co. of America*,⁹ the Commission reaffirmed on rehearing its order requiring a pre-Order No. 500 contract demand reduction to be honored by the Natural Gas Pipeline Company of America. The Commission reasoned that the court of appeals in *Associated Gas Distributors v. FERC*¹⁰ did not require the Commission to eliminate the contract demand reduction option in section 284.10(a)(1) of the regulations, but rather required the Commission to adequately support the provision. Moreover, the Commission stated that Order No. 500 eliminated the contract demand reduction option only prospectively. Thus, the Commission reasoned that granting the pre-Order No. 500 contract demand reduction to Interstate Power Company was consistent with the court's decision and Order No. 500.

In *Texas Gas Transmission Co.*,¹¹ the Commission allowed Texas Gas to modify its firm transportation (FT) tariff to provide that the minimum term

8. Notice of Proposed Rulemaking, *Brokering of Interstate Natural Gas Pipeline Capacity*, IV F.E.R.C. Stats. & Regs. ¶ 32,460, 53 Fed. Reg. 15,061 (1988).

9. *Interstate Power Co. v. Natural Gas Pipeline Co. of Am.*, 42 F.E.R.C. ¶ 61,049 (1988).

10. *Associated Gas Distribs. v. FERC*, 824 F.2d 981 (D.C. Cir. 1987).

11. *Texas Gas Transm'n Co.*, 44 F.E.R.C. ¶ 61,184 (1988).

for any FT conversions would be the remaining term of the underlying sales agreement. Citing an earlier order in *Panhandle Eastern Pipe Line Co.*,¹² the Commission noted that "a lesser term would be the functional equivalent of a contract demand reduction which section 284.10 does not require."¹³

In *Columbia Gas Transmission Corp.*,¹⁴ the Commission approved, with conditions, Columbia's request for certificate authority to revise and combine firm sales service agreements for two of its wholesale customers. The certificate combines for reduction or conversion to transportation up to thirty percent on a cumulative basis in year one, twenty percent in year two, and twenty-five percent in each of years three and four. The revised service agreement imposes a floor on contract demand for the first five years, which is lowered during the sixth through tenth years of the agreement, and provides for seasonal nominations. The Commission conditioned its acceptance of the certificate on an obligation by Columbia to negotiate with its other customers to reduce their contract demand on similar terms. The Commission also reaffirmed that it would address any rate impact of resulting abandonments in future rate proceedings under sections 4 or 5 of the Natural Gas Act (NGA).¹⁵

F. Cost Allocation and Rate Design

In *Northern Border Pipeline Co.*,¹⁶ the Commission rejected a tariff filing which would have credited revenues from interruptible transportation services to firm transportation customers based on each firm transportation customer's volume of unutilized capacity. The Commission found that the current pro rata crediting of interruptible transportation revenues should be retained because it allows a uniform reduction in the firm shipper's charges and more closely matches the result which would be required by using representative volumes for interruptible transportation services under section 284.7 of the Commission's regulations. The Commission also found that crediting of interruptible transportation revenues based on the amount of each customer's unutilized capacity would be inconsistent with traditional rate design methodologies.

In *Tennessee Gas Pipeline Co.*,¹⁷ the Commission affirmed in part and reversed in part an initial decision thereby disposing of the remnants of a prolonged section 4 rate case. The Commission, among other things, followed Opinion No. 249 and adopted a modified fixed-variable rate design with a two-part demand charge, upheld 100% load factor interruptible rates, and rejected the pipeline's policy of not rendering interruptible transportation that would displace a sale. Significantly, the Commission reversed the administrative law judge's (ALJ) determination not to allocate commodity costs associated with transmission facilities located downstream of Tennessee's storage facilities to the storage commodity charge. Rather, the Commission concluded that stor-

12. *Panhandle E. Pipe Line Co.*, 43 F.E.R.C. ¶ 61,530 (1988).

13. *Id.* at 62,318.

14. *Columbia Gas Transm'n Corp.*, 45 F.E.R.C. ¶ 61,193 (1988).

15. *Natural Gas Act*, 15 U.S.C. § 717 (1982).

16. *Northern Border Pipeline Co.*, 45 F.E.R.C. ¶ 61,534 (1988).

17. *Tennessee Gas Pipeline Co.*, 45 F.E.R.C. ¶ 61,031 (1988).

age service customers should bear those costs, since Tennessee's pipeline and compressor facilities located downstream from storage were constructed in part to provide capacity for storage services, and since these were additional costs associated with moving gas from storage to such customers.

In *Texas Eastern Transmission Corp.*,¹⁸ the Commission, on rehearing, modified its prior orders and found that the *Atlantic Seaboard* cost classification, allocation and rate design methodology was unjust and unreasonable on the Texas Eastern system. The Commission also denied rehearing of its decision to allocate production costs on a system-wide volumetric basis while retaining a mileage-based allocation of transmission costs.

In *Transcontinental Gas Pipe Line Corp.*,¹⁹ the Commission required that all non-mileage related costs classified to the D-1 component of rates (production area transmission costs, Account No. 858 costs, certain storage costs, market area administrative, and general costs) be allocated not only to nonjurisdictional customers but also to rate zones based on three-day peak deliveries rather than contract demands for service.

In *Tennessee Gas Pipeline Co.*,²⁰ the Commission retained Tennessee's long-standing, mileage-based allocation methodology where the impact of additional downstream deliveries of Canadian natural gas on the allocation methodology did not occur during the locked-in period and a new rate case was pending where the issue could be resolved.

In *CNG Transmission Corp.*²¹ and *Williston Basin Interstate Pipeline Co.*,²² the Commission conditioned its acceptance of filed rates subject to refund on the requirement that transportation rates be based on all projected units of transportation service at maximum rates, including volumes delivered under certificated transportation service agreements at discounted rates, and eliminated the related revenue credits associated with those discounted volumes. The Commission relied on the rate provisions of Order No. 436, particularly section 284.7 of the Commission's regulations.

Similarly, the Commission relied on the rate provisions of Order No. 436 in rejecting postage stamp firm transportation rates in an offer of settlement in *Transcontinental Gas Pipe Line Corp.*²³ The Commission found no support for this departure from the pipeline's mileage-based rate design for transportation services and no basis for the settlement's different treatment of firm transportation rates (postage stamp) and interruptible transportation rates (mileage-based). The Commission stated that postage stamp firm transportation rates were a departure from its policies and from the requirements of section 284.7(d)(3)(ii) of the Commission's regulations.

18. *Texas E. Transm'n Corp.*, 45 F.E.R.C. ¶ 61,396 (1988).

19. *Transcontinental Gas Pipe Line Corp.*, 45 F.E.R.C. ¶ 61,382 (1988).

20. *Tennessee Gas Pipeline Co.*, 45 F.E.R.C. ¶ 61,470 (1988).

21. *CNG Transm'n Corp.*, 45 F.E.R.C. ¶ 61,474 (1988).

22. *Williston Basin Interstate Pipeline Co.*, 45 F.E.R.C. ¶ 61,538 (1988).

23. *Transcontinental Gas Pipe Line Corp.*, 45 F.E.R.C. ¶ 61,468 (1988).

G. D-2 Nominations

In *Colorado Interstate Gas Co.*,²⁴ (CIG), the Commission issued Opinion No. 290-B which affirmed a condition imposed on CIG to accept renominations of annual gas entitlements from its sales customers for use in establishing D-2 billing determinants under a modified fixed-variable rate design. CIG's customers' last nominations of entitlements were approved by the Commission in 1985. The Commission recognized that the gas industry and the economic climate had undergone changes since then, and that customer renominations were necessary "to reflect an accurate indication of their gas supply needs."²⁵ While this may result in a short-term increase in costs to some customers, the Commission determined that such effect would be outweighed by the long-term benefits gained by giving CIG's customers an opportunity to accurately reflect their current gas supply needs.

In *Texas Eastern Transmission Corp.*,²⁶ the Commission denied rehearing requests of its decision to permit sales customers to renominate D-2 levels in this general rate case proceeding. The Commission clarified that customers' certificated entitlements would not be adversely affected by the D-2 nominations, that the unit rate of the D-2 component would be based on the D-2 nominations, and that overrun charges would accrue on takes above the D-2 nomination levels.

In *Northwest Pipeline Corp.*,²⁷ the Commission, in an order on rehearing in a section 4(e) general rate proceeding, required the pipeline to base D-2 billing determinants on annual rights to demand service rather than the pipeline's historical use of permitting nominations of D-2 levels and filing revised tariff sheets and rates to reflect these nominations.

H. Direct Billing

1. Take-or-Pay "Buyout and Buydown" Costs and Gas Costs

On January 20, 1988, in *El Paso Natural Gas Co.*,²⁸ the Commission affirmed an initial decision rejecting El Paso's attempt to collect from its customers 100% of its take-or-pay settlement costs through a fixed charge or direct bill. The Commission reaffirmed its intent to require pipelines to implement equitable sharing of such costs as described in the statement of policy in Order No. 500.²⁹

In *Pacific Offshore Pipeline Co.*³⁰ (POPCO), the Commission set for hearing POPCO's proposed passthrough of take-or-pay settlement costs as monthly gas costs. Because POPCO has a cost-of-service tariff, such treatment would permit the pipeline to directly pass through take-or-pay settle-

24. Opinion No. 290-B8, *Colorado Interstate Gas Co.*, 43 F.E.R.C. ¶ 61,485 (1988).

25. *Id.* at 62,204.

26. *Texas E. Transm'n Corp.*, 43 F.E.R.C. ¶ 61,246 (1988).

27. *Northwest Pipeline Corp.*, 43 F.E.R.C. ¶ 61,263 (1988).

28. *El Paso Natural Gas Co.*, 42 F.E.R.C. ¶ 61,024 (1988).

29. Order No. 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, III F.E.R.C. Stats. & Regs. ¶ 30,761, 52 Fed. Reg. 30,334 (1987) (to be codified at C.F.R. pts. 2, 284).

30. *Pacific Offshore Pipeline Co.*, 42 F.E.R.C. ¶ 61,058, *reh'g denied*, 42 F.E.R.C. ¶ 61,330 (1988).

ment costs without recovering the costs through the commodity component of its rates, as required by Order No. 500.

In *Northwest Pipeline Corp.*,³¹ the Commission authorized the pipeline to recover from its sales customers, by means of direct bills, each customer's share of Northwest's accrued unrecovered purchased gas costs. The amounts were to be allocated based on the ratio of each customer's purchases from Northwest to total jurisdictional sales. In authorizing this procedure, the Commission recognized that only five months earlier it had rejected a similar proposal sponsored by Northwest. The Commission found, however, that the dramatic erosion of Northwest's sales base resulting from customer conversions to firm transportation pursuant to Order No. 500 met the threshold requirement established in Order No. 483 of demonstrating that the balance in its deferred account was "extraordinary." The Commission further justified its order on the basis that Northwest did not appear to be using its PGA as a "marketing tool in anticipation of recovering the balance through direct billing."³² Finally, it held that disparate conversion of contract demand entitlements by Northwest's nine largest jurisdictional customers "would result in a substantial and inequitable shift in responsibility for deferred costs" to the pipeline's smaller customers.³³

In *Trunkline Gas Co.*,³⁴ the Commission, on remand, allowed an interstate pipeline to directly bill a lump sum refund amount, which had been paid to a former sales customer in settlement of a purchasing practices proceeding, to its sales customers on the basis of their purchases at the settlement rates. The Commission found that the sales customers directly billed for the refund had already received a benefit (\$43.8 million) which was far in excess of the anticipated settlement benefits (\$30 million) and also in excess of the amount to be directly billed to these customers (\$838,000).

2. Other Costs

In *North Penn Gas Co.*,³⁵ the Commission permitted North Penn to direct bill its customers for Order No. 473 compression allowances and liquefied natural gas (LNG) related costs on the basis of each customer's proportionate share of sales volumes during the period in which the costs were incurred on grounds that this would fairly allocate past period costs to those customers that benefitted from the incurrence of those costs. Absent direct billing, a customer which had since terminated its purchase contracts with North Penn would otherwise avoid its responsibility at the expense of other customers.

On November 1, 1988, the Commission issued its order in response to the decision in *Columbia Gas Transmission Corp. v. FERC*,³⁶ reversing the Commission's earlier order granting several pipelines the authority to directly bill

31. *Northwest Pipeline Corp.*, 45 F.E.R.C. ¶ 61,224 (1988).

32. *Id.* at 61,654.

33. *Id.* at 61,655.

34. *Trunkline Gas Co.*, 45 F.E.R.C. ¶ 61,373 (1988).

35. *North Penn Gas Co.*, 43 F.E.R.C. ¶ 61,307 (1988).

36. *Columbia Gas Transm'n Corp. v. FERC*, 831 F.2d 1134 (D.C. Cir. 1987), *modified on reh'g*, 844 F.2d 879 (1988).

retroactive amounts for gathering and compression costs. While the Court believed that the Commission's initial direct bill order constituted retroactive ratemaking, it held on rehearing that the Commission could nevertheless consider waiving the advance notice requirement of section 4(d) of the NGA to permit the direct billing tariff to be made effective on a retroactive basis. On remand, the Commission found that "good cause" existed to grant such a waiver notwithstanding the absence of customer consent.³⁷ The Commission held that "the overriding public interest in the orderliness of the nation's natural gas markets and the ultimate benefit to gas consumers which will thereby result" justified the procedure.³⁸

I. Discounted Sales Rates and Market-Based Rates

In *Distrigas of Massachusetts Corp.*³⁹ (DOMAC), the Commission rejected a request to forego recovery of \$.21 per MMBtu in commodity charges in order to honor an offer to sell a shipment of LNG at a negotiated rate below its cost-based tariff rate. The Commission found that DOMAC was not authorized to collect an alternative commodity-only tariff rate.

In *KN Energy, Inc.*,⁴⁰ the Commission reaffirmed on rehearing its rejection of KN's request to selectively discount its interruptible overrun service because the request constituted a new service, governed by section 7(c) of the NGA, rather than a rate change governed by section 4.

In *Southern Natural Gas Co.*,⁴¹ *Natural Gas Pipeline Co.*,⁴² and *CNG Transmission Corp.*,⁴³ the Commission issued certificates of public convenience and necessity authorizing interruptible sales service at discounted rates. The Commission imposed reporting requirements and conditions related to pipeline affiliate transactions and required each pipeline to provide equivalent discounts to its interruptible transportation rates if it discounted the non-gas component of the interruptible sales service rates. The rates approved for the service were flexible rates with a maximum rate equal to the 100% load factor rate and a minimum rate equal to the pipeline's weighted average cost of gas plus out-of-pocket costs. Finally, the Commission required that each interstate pipeline have a blanket, open-access transportation certificate under subpart G of part 284 and rejected minimum purchase obligations under other rate schedules as a condition to receiving service under the interruptible sales rate schedule.

In *Distrigas of Massachusetts Corporation*,⁴⁴ the Commission held that the absence of a record would not allow a finding that market-based rates are in the public convenience and necessity for an LNG sales service. The Commission authorized contractually negotiated rates with a cap on the commodity

37. Transcontinental Gas Pipe Line Corp., 45 F.E.R.C. ¶ 61,169 (1988).

38. *Id.* at 61,487.

39. *Distrigas of Mass. Corp.*, 42 F.E.R.C. ¶ 61,033 (1988).

40. *KN Energy, Inc.*, 42 F.E.R.C. ¶ 61,048 (1988).

41. *Southern Natural Gas Co.*, 45 F.E.R.C. ¶ 61,461 (1988).

42. *Natural Gas Pipeline Co.*, 45 F.E.R.C. ¶ 61,465 (1988).

43. *CNG Transm'n Corp.*, 45 F.E.R.C. ¶ 61,466 (1988).

44. *Distrigas of Mass. Corp.*, 45 F.E.R.C. ¶ 61,428 (1988).

charges and call (demand) payments for the LNG sales service equal to the higher of the commodity rates or demand charges approved by the Commission for sales service provided by competing interstate pipelines (Tennessee, Algonquin). Since these caps on prices were equivalent to rates regulated by the Commission, the Commission found that prices for the LNG sales service at or below these caps would be within the just and reasonable zone and satisfied the public convenience and necessity standard of section 7.

J. Fees

On January 14, 1988, the Commission issued Order No. 472-C,⁴⁵ clarifying the final rule and order on rehearing which established annual charges to recover from oil pipelines, electric utilities and interstate natural gas pipelines all costs of the Commission's regulatory programs not already recovered through filing fees and other charges. In Order No. 472-C, the Commission rejected the suggestion of KN Energy, Inc. that the annual charge adjustment (ACA) should not be assessed on its non-jurisdictional local distribution company sales. The Commission responded that, because the Commission incurs expenses related to the regulation of transportation of gas, all volumes are subject to the ACA charge whether or not the sale of such volumes is subject to the Commission's jurisdiction. KN's local distribution sales volumes are transported through jurisdictional facilities and therefore can be included to compute KN's annual charge.

The Commission also extended to contract storage volumes certain exemptions designed to prevent double assessment of storage volumes reported as sales or transportation and compression volumes for purposes of computing the annual charge.⁴⁶

K. Gas Inventory Charges

In *Texas Eastern Transmission Corp.*,⁴⁷ the Commission issued an order approving a contested settlement enabling Texas Eastern to implement a gas supply inventory reservation charge (GIC) to restructure sales and transportation services under new ten-year contracts with its customers, and to perform open access transportation under a blanket certificate. On October 11, 1988, Texas Eastern accepted the settlement authorization, thereby becoming the first pipeline to accept a certificate for a GIC.

The GIC provided under the settlement is a deficiency charge assessed against customers served under rate schedules CD, CDQ and GS who purchase less than sixty percent of their annual contract quantities. The charge is calculated as twenty percent of the weighted average cost of gas purchased by Texas Eastern from producers and from Texas Eastern pipeline suppliers that have inventory charges in their tariffs. Texas Eastern retains the

45. Order No. 472-C, *Annual Charges Under the Omnibus Budget Reconciliation Act of 1986*, 42 F.E.R.C. ¶ 61,013 (1988).

46. The Commission also dealt with oil pipeline and electric utility issues which are beyond the scope of this Report.

47. *Texas E. Transm'n Corp.*, 44 F.E.R.C. ¶ 61,413 (1988).

amounts collected for up to five years. During that time, Texas Eastern could use the funds to settle any future prepayments or buyouts or buydowns of gas supply contracts. Any monies not expended for these purposes would be refunded to Texas Eastern's customers through Account No. 191.

In *Transwestern Pipeline Co.*,⁴⁸ the Commission approved a GIC without a hearing, finding that only policy questions were involved. The Commission stated that lighthanded regulation which permits non-cost market forces to prevail over cost-of-service determinations is appropriate. It found that Transwestern should be permitted to charge a price for maintaining long-term inventory on hand since its anticipated sole sales customer could otherwise make short-term purchases directly from producers. The customer, Southern California Gas Company (SoCal), would be provided thirty days advance notice of Transwestern's commodity charges, and then nominate its desired annual level of sales service within a forty-five day period. In return, Transwestern was required to maintain adequate supplies and credit GIC revenues against future GIC costs. The GIC ranged from \$.42 per Dth to \$.33 per Dth depending upon the shortfall. Transwestern's PGA would be suspended while the GIC remained in effect. Although Transwestern was disallowed an exit fee if SoCal nominates zero as a result of Transwestern posting prices that are noncompetitive, pregranted abandonment would be permitted for entitlements above nominated levels.

In *Williams Natural Gas Co.*,⁴⁹ the Commission set for hearing a GIC proposal under which Williams would specify an estimated commodity charge for partial requirement sale services each October. By November 1 each customer would nominate annual purchase levels and would be required to take or pay for those volumes. If the annual nominations were less than forty percent of the annual contract entitlements, the customer would be assessed a GIC of \$.6621 per Mcf for such deficiency. Issues set for hearing included whether Williams' customers had reasonable access to alternative supplies, the validity of the charge for nominations below a certain level and the absence of conversion rights for reduced nominations in sales service. The Commission denied Williams' request for a temporary certificate to implement the GIC pending the hearing.

In *Natural Gas Pipeline Co. of America*,⁵⁰ the Commission addressed a new GIC proposed by Natural. A prior proposal of Natural's, to recover the cost of maintaining gas supply inventories to meet sales services, had been treated by the Commission as a section 7(c) certificate change, as opposed to a section 4 rate change. In its new proposal, Natural sought to meet certain of the Commission's reasons for deeming this a section 7 matter. The Commission adhered to its previous position, stating that because it is vested with discretion to docket and schedule matters before it, and because the proposal was a close analogue to discount sales proposals which always had been treated under section 7, its overriding duty to protect the public interest dictated treating the matter as a section 7 filing.

48. *Transwestern Pipeline Co.*, 43 F.E.R.C. ¶ 61,236 (1988).

49. *Williams Natural Gas Co.*, 43 F.E.R.C. ¶ 61,255 (1988).

50. *Natural Gas Pipeline Co. of Am.*, 43 F.E.R.C. ¶ 61,068 (1988).

The Commission subsequently issued an order on a contested settlement approving a GIC for Natural for one year beginning October 1, 1988.⁵¹ Under the plan, Natural can recover costs associated with the maintenance of its gas supply inventory necessary to meet sales service levels as nominated by its customers. A question arose in the proceeding regarding the competitive nature of Natural's service to a number of small municipalities. Without determining whether these markets were in fact workably competitive, the settlement severed these municipalities from the bounds of the GIC. Thus, the municipalities are not subject to either the benefits or the obligations of the settlement.

L. Gathering Rate Jurisdiction

In *Northern Natural Gas Co.*,⁵² the Commission denied an appeal from its staff's action rejecting a Northern Natural tariff sheet for not separately stating gathering rates. Northern had taken the position that the Commission had no jurisdiction over gathering rates. The Commission determined that it has jurisdiction pursuant to sections 4 and 5 of the NGA over rates, even for gathering, because gathering charges are assessed in connection with the transportation or sale of gas, and that such charges affect or pertain to jurisdictional rates. The Commission also distinguished between NGA sections 4 and 5, and section 7, stating that NGA section 1(b) only exempts gathering from the Commission's section 7 certificate jurisdiction, not from its rates jurisdiction under sections 4 and 5.

The Commission subsequently denied rehearing of its order denying the appeal of the staff action.⁵³ It reiterated its disagreement with Northern that it lacked jurisdiction under section 1(b) of the NGA over Northern's rates for its gathering service, stating that it had jurisdiction under section 4(a) of the Act over rates charged "in connection with" jurisdictional transportation. The Commission drew a distinction between price and non-price aspects of gathering, concluding that it has jurisdiction over the former, not the latter. Citing *FPC v. Louisiana Power & Light Co.*,⁵⁴ it stressed that the regulation of gathering provided in conjunction with part 284 transportation must be regulated at the federal level to prevent a regulatory gap.

In *Northwest Pipeline Corp.*,⁵⁵ the Commission denied rehearing of Opinion No. 270 and reaffirmed its rate jurisdiction over Northwest's gathering facilities. The Commission determined that it holds rate jurisdiction even if the facilities are gathering facilities otherwise exempt under NGA section 1(b) if the gathering is related to jurisdictional transportation. Commissioner Sousa dissented as he did in Opinion No. 270.⁵⁶

51. *Natural Gas Pipeline Co. of Am.*, 44 F.E.R.C. ¶ 61,163 (1988).

52. *Northern Natural Gas Co.*, 43 F.E.R.C. ¶ 61,473 (1988).

53. *Northern Natural Gas Co.*, 44 F.E.R.C. ¶ 61,384 (1988).

54. *FPC v. Louisiana Power & Light Co.*, 406 U.S. 621 (1972).

55. *Opinion No. 270-A, Northwest Pipeline Corp.*, 43 F.E.R.C. ¶ 61,491 (1988).

56. *Opinion No. 270, Northwest Pipeline Corp.*, 38 F.E.R.C. ¶ 61,302 (1988).

M. Interruptible Sales Rates and New Interruptible Sales Authority

In *Midwestern Gas Transmission Co.*,⁵⁷ the Commission held, reversing an initial decision on the issue, that the pipeline was required to include an appropriate share of purchased gas demand charges in its rates for interruptible sales. In so doing, the Commission also reaffirmed its policy of allocating transmission-related fixed costs to interruptible sales on a 100% load factor basis. The Commission noted that other allocation methods might also be appropriate, but that no reasonable alternative was justified on the record before it. The Commission ordered refunds to firm sales customers retroactively to the date *Midwestern* had decreased its interruptible sales rate by excluding all demand charges.

In *El Paso Natural Gas Co.*,⁵⁸ the Commission authorized the pipeline to make new, limited-term interruptible sales to any purchaser, either for resale or direct sale, provided that (1) *El Paso* had a surplus of gas and (2) service agreements were executed with potential customers. The Commission imposed conditions on the new interruptible service to avoid potential discrimination through discounted sales. The Commission affirmed that interruptible sales programs would be subject to the same conditions imposed in *Northern Natural Gas Co.*⁵⁹ and *Transwestern Pipeline Co.*⁶⁰

N. Liquefied Natural Gas

In *Trunkline LNG Co.*,⁶¹ the Commission resolved a long-pending rate proceeding, initiated in part by a Commission investigation and audit, involving numerous issues related to the construction and start-up of an LNG project constructed during the curtailment period of the late 1970s. Among other matters, the Commission ruled (1) that a fourteen month delay in testing the regasification plant did not justify *Trunkline's* continued accrual of its allowance for funds used during construction (AFUDC) during such period because *Trunkline* had assumed the risk of such delays; (2) the time value of deferred taxes arising during the construction period should be used to reduce AFUDC; (3) *Trunkline* was not imprudent when it elected to capitalize rather than expense certain construction-related expenditures in order to maximize its investment tax credits (ITC) since, under Commission policy at the time, pipelines were entitled to retain the benefits of ITCs; and (4) *Trunkline's* unilateral reduction of its depreciation rate during a service interruption was contrary to the Commission's initial order authorizing the project. In addition, the Commission rejected certain contentions that *Trunkline* had been imprudent in various respects in connection with the construction and start-up of the project. In one instance, however, the Commission found certain payments to *Trunkline's* affiliated shipping company to be imprudent.

57. *Midwestern Gas Transm'n Co.*, 45 F.E.R.C. ¶ 61,203 (1988).

58. *El Paso Natural Gas Co.*, 45 F.E.R.C. ¶ 61,322 (1988).

59. *Northern Natural Gas Co.*, 42 F.E.R.C. ¶ 61,303 (1988).

60. *Transwestern Pipeline Co.*, 43 F.E.R.C. ¶ 61,240 (1988).

61. Opinion No. 319, *Trunkline LNG Co.*, 45 F.E.R.C. ¶ 61,256 (1988).

O. Minimum Bills

In *Kentucky West Virginia Gas Co.*,⁶² the Commission affirmed an initial decision striking the fixed cost minimum bill of Kentucky West Virginia Gas Company. In affirming the elimination of the minimum bill, the Commission continued to utilize the standard it adopted in *Transcontinental Gas Pipe Line Corp.*,⁶³ where a fixed cost minimum bill was presumed to be unjust and unreasonable for a pipeline utilizing a modified fixed-variable rate design methodology. The Commission declined to recognize the Kentucky West Virginia system as unique.

In *Trunkline Gas Co.*,⁶⁴ the Commission upheld the ALJ's determination that Trunkline's minimum bill was unjust and unreasonable. The Commission found that Trunkline had not satisfied the *Atlantic Seaboard* criteria for retaining its minimum bill and also rejected three additional justifications proposed by Trunkline. Trunkline had argued that, because customers were currently buying gas on the spot market, the minimum bill was not anticompetitive because customers were not prevented from purchasing gas on a least-cost basis. The Commission was not persuaded that Trunkline's minimum bill was supportable as similar to the fixed charge for standby service permitted under Order No. 500. Finally, the Commission disagreed that the use of a minimum bill in a prior locked-in period required it to permit continued use of the charge by Trunkline in subsequent rate cases to guarantee recovery of take-or-pay costs.

In *Texas Eastern Transmission Corp.*,⁶⁵ the Commission issued an order directing the elimination of the minimum commodity bills in certain of the rate schedules of Texas Eastern Transmission Corporation. While predictable due to the Commission's decisions in certain prior cases, the Commission also required the elimination of the minimum commodity bill from a winter storage service performed by Texas Eastern which required Texas Eastern to purchase gas in advance for injection into storage. That aspect of the case expanded the policy against traditional minimum commodity bills.

P. NGPA Pricing of Pipeline Production

In Order No. 391-C,⁶⁶ the Commission finally disposed of all issues remaining from its issuance of the final rule in Order No. 391 which implemented the decision of the United States Supreme Court in *Public Service Commission of New York v. Mid-Louisiana Gas Co.*⁶⁷ (*Mid-La*). In *Mid-La* the Court held that the pricing provisions of title I of the NGPA are applicable to natural gas produced by pipelines. In rejecting the arguments of petitioners who questioned the Commission's view that pipeline production must be priced on a par with independent production under section 104 of the

62. *Kentucky W. Va. Gas Co.*, 43 F.E.R.C. ¶ 61,496 (1988).

63. *Transcontinental Gas Pipe Line Corp.*, 40 F.E.R.C. ¶ 61,188 (1988).

64. Opinion No. 297, *Trunkline Gas Co.*, 42 F.E.R.C. ¶ 61,201 (1988).

65. *Texas E. Transm'n Corp.*, 43 F.E.R.C. ¶ 61,076 (1988).

66. Order No. 391-C, *First Sales of Pipeline Production Under Section 2(21) of the NGPA*, 42 F.E.R.C. ¶ 61,145 (1988).

67. *Public Serv. Comm'n of N.Y. v. Mid-Louisiana Gas Co.*, 483 U.S. 319 (1983).

NGPA, the Commission reaffirmed its determination that the courts and the Congress had not intended that the price of old flowing gas charged by pipeline producers be frozen at pre-NGPA levels. The Commission nevertheless deferred answering a case-specific question whether an integrated producer-pipeline-distribution company was entitled to parity pricing.

Q. Order No. 436 and 500 Settlements and Decisions

In *Williams Natural Gas Co.*,⁶⁸ the Commission approved with several modifications a settlement agreement establishing the rates, terms and conditions under which Williams will perform open-access transportation pursuant to part 284 of the Commission's regulations. The approved settlement contained executed precedent agreements with major customers affording them adjustment rights which differed from section 284.10. The Commission approved the differences since they were freely negotiated.

In *Tennessee Gas Pipeline Co.*,⁶⁹ the Commission approved and modified a contested offer of settlement, addressing features of Tennessee's open-access transportation program, recovery and allocation of its take-or-pay buyout and buydown costs and prepayments, and the design of a charge for standby sales service.

The Commission sorted through six proposals for recovery of such costs on a cumulative deficiency basis and adopted Tennessee's proposal with modifications. Tennessee's willingness to absorb fifty percent of all past buydown, buyout and contract reformation costs isolated these costs from prudence challenges by any party agreeing to the settlement consistent with Order No. 500. Recovery was capped at \$650 million and could include only costs incurred or which Tennessee was committed to pay by the end of the current year (1988). The Commission required Tennessee to file separately to recover \$100 million in take-or-pay costs paid to affiliated producers, indicating that such costs would only be recoverable in the commodity component of sales rates. The Commission disallowed recovery of Tennessee's prepayments through the Order No. 500 mechanism because its policy is to treat such costs as rate base items not subject to any tracking mechanism.

The Commission found just and reasonable Tennessee's allocation and billing mechanism. Tennessee used two formulas in combination to allocate contract reformation costs based on purchase deficiencies of certain customer groups. The Commission held that because recovery of take-or-pay costs under a current settlement that recognizes past purchase deficiencies represents recovery of a current expense incurred for service rendered, it is not retroactive ratemaking. Finally, the Commission decided not to delay recovery under the settlement despite Tennessee's request that the Commission undertake to invalidate the contracts pursuant to section 5 of the NGA.

In response to Tennessee's willingness to provide standby sales service, provided it can recover its "supply maintenance costs," the Commission requested a new certificate application for the service, including a rate that

68. *Williams Natural Gas Co.*, 43 F.E.R.C. ¶ 61,227 (1988).

69. *Tennessee Gas Pipeline Co.*, 42 F.E.R.C. ¶ 61,175 (1988).

would recover only those costs which the pipeline incurs to stand ready to resume sales service, not variable production costs related to the displacement sale.

R. Order No. 500 "Equitable Cost-Sharing" Filings

1. Allocation of Costs

In *Tennessee Gas Pipeline Co.*,⁷⁰ the Commission on rehearing required Tennessee to follow the purchased deficiency allocation methodology established in Order No. 500 to implement its proposal to direct bill fifty percent of take-or-pay related costs while absorbing the rest, with a cap on the total dollars to be recovered. Under this methodology, a base period is selected which represents customer purchase patterns before changed circumstances resulted in decreased purchases. Customers are then allocated take-or-pay costs to the extent that their purchases were below their base period levels.

In *United Gas Pipe Line Co.*,⁷¹ the Commission made clear that a pipeline company seeking to collect take-or-pay buyout and buydown costs pursuant to Order No. 500 must allocate costs to its non-jurisdictional customers on the same deficiency basis it used to allocate those costs to its jurisdictional customers.

In *Panhandle Eastern Pipe Line Co.*,⁷² the Commission rejected challenges to the interstate pipeline's choice of 1981 as an appropriate base year under the Commission's deficiency allocation methodology. The Commission found that the fact that sales had decreased by nine percent in 1982 supported the conclusion that 1981 preceded the incurrence of take-or-pay costs and was an appropriate base year to use.

In *Texas Gas Transmission Corp.*,⁷³ the Commission denied rehearing of a prior decision and held that unauthorized sales to a customer during the base period were not a basis for reducing a customer's sales and its share of Order No. 500 costs. The Commission also refused to order a hearing to consider the propriety of the allocation methodology based on the purchasing practices of the pipeline's customers.

In a series of orders, the Commission determined that former sales customers will be liable for a share of Order No. 500 costs unless both contract termination and the issuance of any necessary, unconditional abandonment authority preceded the filing of the pipeline's cost recovery proposal.⁷⁴ However, in applying this principle, the Commission recognized the equitable necessity of allocating costs based only on what the former (or existing) customer had the right to demand. Thus, it held that where a reduction in a

70. *Tennessee Gas Pipeline Co.*, 43 F.E.R.C. ¶ 61,329 (1988).

71. *United Gas Pipe Line Co.*, 43 F.E.R.C. ¶ 61,034 (1988).

72. *Panhandle E. Pipe Line Co.*, 45 F.E.R.C. ¶ 61,432 (1988).

73. *Texas Gas Transm'n Corp.*, 45 F.E.R.C. ¶ 61,398 (1988).

74. *Transwestern Pipeline Co.*, 45 F.E.R.C. ¶ 61,427 (1988); *CNG Transm'n. Co.*, 44 F.E.R.C. ¶ 61,244, 61,855-86 (1988); *North Penn Gas Co.*, 44 F.E.R.C. ¶ 61,192, 61,692 (1988). The Commission also indicated, however, that if an abandonment order reserves, for a subsequent rate proceeding, the question of the departing customer's liability for a share of take-or-pay costs, that reservation is sufficient to impose liability on that former customer. *Trunkline Gas Co.*, 45 F.E.R.C. ¶ 61,429 (1988).

customer's contract demand occurred during a deficiency period, its Order No. 500 cost responsibility should reflect that reduction since the customer otherwise would be required to pay costs for the non-purchase of gas that it had no contractual right to demand and that the pipeline had no service obligation to provide.⁷⁵

The Commission generally denied other adjustments to the use of firm sales volumes during the deficiency period for direct billing of Order No. 500 costs. Specifically, in *Panhandle Eastern Pipe Line Co.*,⁷⁶ the Commission denied rehearing of its decision to allocate Order No. 500 take-or-pay costs only to firm sales customers. The Commission refused to allocate these costs to interruptible sales customers or to make adjustments to sales volumes during the deficiency period in order to recognize interruptible transportation volumes. The Commission held that under its purchase deficiency methodology, only sales volumes are considered.

2. Downstream Flowthrough

In *Mississippi River Transmission Corp.*,⁷⁷ the Commission rejected Mississippi River's (MRT) proposal to direct bill take-or-pay costs, charged it by upstream suppliers, on a method other than that upon which MRT is billed by those suppliers. The Commission held that downstream pipelines must use the same purchase deficiency basis for billing their customers as was used by their upstream supplier pipelines under the "as-billed" policy enunciated in Order No. 500. This policy subsequently was reaffirmed in *CNG Transmission Corp.*⁷⁸

In *Texas Eastern Transmission Corp.*,⁷⁹ the Commission granted rehearing and clarified a prior order where Texas Eastern had been authorized to recover from its customers take-or-pay buyout and buydown charges billed it by United Gas Pipe Line Company. The Commission generally followed the *Mississippi River* and *CNG* orders implementing the Order No. 500 sharing methodology on other "downstream" pipeline systems. It noted, however, that Order No. 500 did not guarantee that downstream pipelines could pass through the costs of an upstream pipeline supplier since the downstream pipeline's purchasing practices were subject to review.

In *North Penn Gas Co.*,⁸⁰ the pipeline sought to implement a direct billing mechanism to recover from its wholesale customers take-or-pay buyout and buydown costs that it incurred from two of its pipeline suppliers under Order No. 500. The Commission rejected arguments by the Public Service Commission of New York (PSCNY) that North Penn should be required to absorb

75. Transwestern Pipeline Co., 45 F.E.R.C. ¶ 61,427 (1988); United Gas Pipe Line Co., 45 F.E.R.C. ¶ 61,140, 61,416-17 (1988); and Southern Natural Gas Co., 44 F.E.R.C. ¶ 61,188, at 61,678 (1988).

76. Panhandle E. Pipe Line Co., 45 F.E.R.C. ¶ 61,433 (1988).

77. Mississippi River Transm'n Corp., 42 F.E.R.C. ¶ 61,244 (1988), *reh'g. denied*, 43 F.E.R.C. ¶ 61,282 (1988).

78. CNG Transm'n Corp., 43 F.E.R.C. ¶ 61,377 (1988).

79. Texas E. Transm'n Corp., 43 F.E.R.C. ¶ 61,488 (1988).

80. North Penn Gas Co., 44 F.E.R.C. ¶ 61,192 (1988).

some portion of such costs. Citing the *Texas Eastern*⁸¹ order, the Commission affirmed its "as-billed" approach that such costs are to be passed through by the downstream pipeline on the same basis as the costs were incurred.

Subsequently, the Commission generally required "as-billed" flowthrough of authorized Order No. 500 costs in the rates of several other downstream interstate pipeline customers.⁸² In *South Georgia Natural Gas Co.*,⁸³ the Commission rejected a departure from "as-billed" flowthrough of pipeline supplier Order No. 500 costs and precluded direct billing of these costs pending compliance with the Commission's order.

In *Trunkline Gas Co.*,⁸⁴ the Commission held that several downstream pipelines would remain subject to an allocation of Trunkline's take-or-pay settlement costs even though they had recently obtained authorization to terminate their purchases. The Commission reasoned that including the downstream pipelines in the cost allocation would achieve Order No. 500's objective of spreading the burden of the take-or-pay settlement costs as widely as possible.

3. Election Condition

In *Transwestern Pipeline Co.*,⁸⁵ the Commission on rehearing reaffirmed the requirement that, as a condition of implementing an Order No. 500 "equitable cost-sharing" mechanism, the pipeline must dismiss its pending court appeal of an earlier order denying it the right to directly bill 100% of its take-or-pay settlement costs. The rehearing order held that Transwestern could cast its lot with the courts (in the pending appeal) or with the Commission (in its equitable cost-sharing case), but not both. The order further stated that, by adopting the equitable sharing approach, Transwestern would not be precluded from seeking judicial review of the requirement that it dismiss the pending appeal.⁸⁶

4. Nonqualifying Filings

In *Texas Gas Transmission Corp.*,⁸⁷ the Commission rejected Texas Gas' proposal to collect 100% of claimed prudently incurred take-or-pay settlement costs, fifty percent through a fixed charge and fifty percent through a volumetric surcharge. The Commission ruled that gas sales should be subject to competitive market forces and that commodity charge recovery provides a reasonable opportunity to recover prudently incurred costs. It stated that, pursuant to Order No. 500, if Texas Gas proposed to absorb a portion of the

81. *Texas E. Transm'n Corp.*, 43 F.E.R.C. ¶ 61,488 (1988).

82. *Panhandle E. Pipe Line Co.*, 45 F.E.R.C. ¶ 61,433 (1988) (flowthrough of Trunkline's Order No. 500 costs); *Texas Gas Transm'n Corp.*, 45 F.E.R.C. ¶ 61,390 (1988) (flowthrough of Order No. 500 costs of United & Tennessee).

83. *South Ga. Natural Gas Co.*, 45 F.E.R.C. ¶ 61,458 (1988).

84. *Trunkline Gas Co.*, 45 F.E.R.C. ¶ 61,288 (1988).

85. *Transwestern Pipeline Co.*, 45 F.E.R.C. ¶ 61,255 (1988).

86. This condition was essentially identical to conditions imposed on two other pipelines except that Transwestern was accorded 15 days to elect while the others were accorded 30 days. See *El Paso Natural Gas Co.*, 43 F.E.R.C. ¶ 61,576 (1988); and *Natural Gas Pipeline Co. of Am.*, 43 F.E.R.C. ¶ 61,341 (1988).

87. *Texas Gas Transm'n Corp.*, 43 F.E.R.C. ¶ 61,324 (1988).

take-or-pay costs, then it would be permitted to collect an equal portion through a demand charge, but otherwise it would have to rely solely upon commodity charge recovery.

5. Order No. 500 Challenges and Imprudence Consequences

In an order on rehearing in *Southern Natural Gas Co.*,⁸⁸ the Commission clarified that customers may continue to challenge an Order No. 500 filing on issues other than prudence without becoming a contesting party subject to the risk of greater take-or-pay cost recovery.

The Commission generally held that a customer's election opportunity to contest the prudence of an interstate pipeline's Order No. 500 costs expires on or before the date for the filing of reply testimony in response to the pipeline's case-in-chief. That election may not be changed thereafter without the pipeline's concurrence and Commission approval. In *Trunkline Gas Co.*,⁸⁹ the Commission did find that a protest to an Order No. 500 filing raising prudence issues is not an irrevocable election to contest prudence in any hearing which may be ordered.

In *United Gas Pipe Line Co.*,⁹⁰ the Commission broadened the category of parties eligible to mount prudence challenges to include "state consumer advocate groups." The Commission held that in order to make their participation meaningful, such groups would have the same status as state utility commissions exercising rate setting authority over LDCs. As a result, where a state consumer advocate group challenges the prudence of a pipeline's take-or-pay settlements, the rate payable by the LDC will reflect the outcome of the litigation even though the LDC did not itself question the pipeline's prudence.

In *Columbia Gas Transmission Co.*,⁹¹ the Commission denied rehearing of an order in which the Commission rejected a proposal filed by Columbia to pass through fifty percent of its contract reformation costs. In its order the Commission stated that the Order No. 500 take-or-pay recovery mechanism could not be used to recover imprudently incurred take-or-pay buyout and buydown costs. The Commission explained that while Order No. 500 "assumes" that such costs were prudently incurred, prudence may still be contested. Here, a court already affirmed the Commission's determination that certain costs were imprudently incurred. Accordingly, the Commission would not allow these costs to be passed through.

6. Scope of Includable Costs

In *El Paso Natural Gas Co.*,⁹² the Commission accepted for filing tariff sheets submitted by El Paso to recover take-or-pay buydown costs pursuant to the "cost-sharing" mechanism of Order No. 500. While the Commission generally followed the principles adopted in other orders for the flowthrough of

88. *Southern Natural Gas Co.*, 44 F.E.R.C. ¶ 61,188, 61,675 (1988).

89. *Trunkline Gas Co.*, 45 F.E.R.C. ¶ 61,429 (1988).

90. *United Gas Pipe Line Co.*, 45 F.E.R.C. ¶ 61,335 (1988).

91. *Columbia Gas Transm'n Co.*, 43 F.E.R.C. ¶ 61,481 (1988).

92. *El Paso Natural Gas Co.*, 43 F.E.R.C. ¶ 61,576 (1988).

such charges, it recognized a "litigation exception" to the December 31, 1988, cut-off date established for the alternate demand charge flow-through treatment. For contracts that were "in litigation," the Commission allowed El Paso to pursue the litigation through judgment and final appeal or settlement. The Commission also allowed El Paso to file at the conclusion of such litigation, to recover under the Order No. 500 cost-sharing mechanism, the eligible costs resulting from any contracts in litigation on December 31, 1988.⁹³

On rehearing, the Commission clarified this policy by holding that costs associated with such litigation would continue to be eligible for recovery under the Order No. 500 recovery mechanism even if the pipeline had implemented a gas inventory charge in the meantime.⁹⁴ The Commission stated that the cut-off date for matters in litigation would be the earlier of the effective date of a GIC or the Order No. 500 sunset date.

The "litigation exception" subsequently was expanded by the Commission. In Order No. 500-F,⁹⁵ the Commission extended the deadline to March 31, 1989, for the filing of tariff sheets to recover take-or-pay buyout and buydown costs under the alternative passthrough mechanism described in Order No. 500. The Commission also authorized interstate pipelines to file tariff language permitting the pipelines to pursue litigation or arbitration of contracts and then to file to recover eligible costs (excluding punitive damages or penalties) resulting from that litigation.

Further, in *Transcontinental Gas Pipe Line Corp.*,⁹⁶ the Commission stated that the exception for contracts in litigation or arbitration on March 31, 1989, requires the interstate pipeline to identify those contracts and provide an estimate of the maximum and minimum amounts at issue in litigation. In *Panhandle Eastern Pipe Line Co.*,⁹⁷ the Commission stated that the arbitration exception was intended to cover claims which had been referred to an impartial third party for binding resolution on or before March 31, 1989, pursuant to an arbitration clause in the contract.

Finally, Order No. 500 recovery may also be authorized for known and measurable take-or-pay buyout or buydown costs incurred within nine months of the March 31, 1989 deadline. In *Tennessee Gas Pipeline Co.*,⁹⁸ the Commission found that these known and measurable costs must be costs which the pipeline must be committed, verbally or in writing, to pay as of the date of filing and that payment must commence during the nine month period.

93. *Id.* at 62,437.

94. *El Paso Natural Gas Co.*, 45 F.E.R.C. ¶ 61,250 (1988).

95. Order No. 500-F, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, III F.E.R.C. Stats. and Regs. ¶ 30,841, 53 Fed. Reg. 50,924 (1988) (to be codified at C.F.R. pt. 2). Order No. 500-F had been preceded by Order No. 500-E, where the Commission denied various requests for rehearing asserting that Order Nos. 500-C and 500-D had reduced the take-or-pay relief afforded by the interim rule promulgated in Order No. 500. The denial was grounded on the Commission's belief that no further changes to the interim rule were necessary to address the court's concerns on an interim basis. However, the Commission stated that it would treat the rehearing requests as comments to consider in developing the final rule.

96. *Transcontinental Gas Pipe Line Corp.*, 45 F.E.R.C. ¶ 61,430 (1988).

97. *Panhandle E. Pipe Line Co.*, 45 F.E.R.C. ¶ 61,432 (1988).

98. *Tennessee Gas Pipeline Co.*, 45 F.E.R.C. ¶ 61,431 (1988).

7. Volumetric Surcharge

The issue of whether exchange transportation is subject to the volumetric surcharge under Order No. 500 was addressed in *Southern Natural Gas Co.*⁹⁹ There the Commission held that if a pipeline's throughput in its most recently approved rate case included exchange transportation, then the volume-based surcharge calculated under the procedures of Order No. 500 would also include exchange volumes.¹⁰⁰

S. Purchase Gas Adjustments (PGA)

In Order No. 483-A,¹⁰¹ the Commission partially granted rehearing and clarified Order No. 483.¹⁰² In Order No. 483, issued November 11, 1987, the Commission amended the existing PGA regulations to require three quarterly updates as well as one annual PGA filing, and an annual assessment of past performance by pipelines in gas cost projections. In Order No. 483-A, addressing the area of past performance assessment, it clarified that a pipeline may use any out-of-period costs (beyond the sixty-day payment and billing cycle) relative to delayed billing transactions to explain why it exceeded the three percent margin allowed without prior approval for recoupment of under-recoveries during a test period, and may include billing adjustments as actual gas costs if the gas was purchased and received during a month. Also, the pipeline may exclude supplier demand costs subject to passthrough on an as-billed basis if the pipeline has a two-part rate structure. In addition, the sixty-day notice requirement for annual PGA filings was modified to allow for thirty-day revisions before the effective date of the annual PGA of gas cost projections. In amending Order No. 483 refund procedures, the Commission also stated that pipelines may offset (1) the refund due suppliers, (2) billing adjustments, and (3) revenue credit subaccount balance with past period debit billing adjustments subject to certain costs that cannot be offset (i.e., current deferred purchased gas costs). Waivers of the refund reporting requirements will be reviewed on an individual basis. A continual monitoring of Order Nos. 483 and 483-A actions and decisions is encouraged.

In *Northwest Central Pipeline Corp.*,¹⁰³ the Commission generally affirmed an initial decision upholding Northwest Central's filed PGA. Various parties alleged that Northwest Central had used its Account No. 191 as a marketing tool. The Commission noted that Northwest Central used a computer program to establish a gas purchasing pattern to meet a target PGA price based on the cost of competing fuel oil. When the Commission forced Northwest Central to spread an unusually high Account No. 191 credit over a twelve-month period (rather than a requested eighteen month period), Northwest Central refiled its PGA with a higher estimate of current gas costs (by

99. *Southern Natural Gas Co.*, 44 F.E.R.C. ¶ 61,188 (1988).

100. *Id.* at 61,680.

101. Order No. 483-A, *Revisions to the Purchased Gas Adjustment Regulations*, III F.E.R.C. Stats. & Regs. ¶ 30,778, 53 Fed. Reg. 7,495 (1988) (to be codified at C.F.R. pt. 154).

102. Order No. 483, *Revisions to the Purchased Gas Adjustment Regulations*, III F.E.R.C. Stats. & Regs. ¶ 30,778, 52 Fed. Reg. 43,854 (1987) (to be codified at C.F.R. pts. 154, 270, 273, 375, & 381).

103. Opinion No. 312, *Northwest Cent. Pipeline Corp.*, 44 F.E.R.C. ¶ 61,222 (1988).

approximately ten cents per Mcf) to offset the shorter amortization period, resulting in the same overall rates as if an eighteen month amortization period had been utilized for the Account No. 191 credit.

The Commission rejected arguments that Northwest Central had manipulated its Account No. 191 to make its rates competitive, finding that nothing prohibited Northwest Central from taking into consideration the balance in Account No. 191 when it estimated its purchased gas costs to meet the target price. The Commission accepted Northwest Central's use of a target price strategy as prudent, rejecting arguments that Northwest Central should be required to use a purely least-cost purchase pattern.

In *Granite State Gas Transmission, Inc.*,¹⁰⁴ the Commission approved passthrough of purchased gas costs in excess of 103% of the estimated amount for June 1988 under the assessment of past performance provisions of the Commission's revised PGA regulations. The Commission found the pipeline acted to correct the problem which occurred during that month and that a limitation on storage injection volumes under another pipeline's rate schedules was an event not within Granite State's control which justified passthrough of all costs. The Commission also identified a PGA problem with spot natural gas purchases by Granite State not matching spot natural gas deliveries by transporting pipelines to Granite State. The Commission set the issue for a technical conference.

In *CNG Transmission Corp.*,¹⁰⁵ the Commission conditioned its acceptance of filed rates to eliminate the pipeline's proposal to use its PGA to track Account No. 858 costs and standby charges and to eliminate a federal income tax tracker which CNG had proposed.

T. Pricing Status of Take-or-Pay Payments

In *ANR Pipeline Co. v. Wagner Brown*,¹⁰⁶ the Commission, for the first time, ruled that take-or-pay payments do not, under any circumstances, violate title I of the NGPA's maximum lawful prices. This case had been referred to the Commission by the affirmance of the United States Court of Appeals for the Fifth Circuit of a district court decision that this matter should be decided by the Commission under the doctrine of primary jurisdiction.¹⁰⁷ In reaching this decision, the Commission noted that under title I of the NGPA, ceiling prices apply only to first sales of natural gas that is actually delivered. Therefore, where no delivery is ever made of gas for which prepayment was made, there is no actual sale of gas.

U. Proposed Elimination of Make-Up Requirements for Prepayments

On July 14, 1988, the Commission issued a Notice of Proposed Rulemaking to eliminate the five-year prepayment make-up period requirement in pipe-

104. *Granite State Gas Transm'n, Inc.*, 45 F.E.R.C. ¶ 62,619 (1988).

105. *CNG Transm'n Corp.*, 45 F.E.R.C. ¶ 61,474 (1988).

106. *ANR Pipeline Co. v. Wagner Brown*, 44 F.E.R.C. ¶ 61,057 (1988).

107. *Wagner & Brown Co. v. ANR Pipeline Co.*, 837 F.2d 199 (5th Cir. 1988). This case is discussed in section III. G., *infra*.

line-producer gas purchase contracts.¹⁰⁸ The proposed rule would simply act to remove from the Commission's Regulations the requirement that gas sales contracts which fall under the Commission's jurisdiction must allow purchasers five years to make-up for prepayments that result from a take-or-pay clause.

V. *Prudence of Off-System Sales and Gathering Allowances*

In *National Fuel Co.*,¹⁰⁹ the Commission affirmed in part and reversed in part an initial decision where the presiding judge had found that a gathering allowance paid by National Fuel Company to local producers in Appalachia (up to \$.25 MMBtu), while not in itself improper, resulted in excessive prices when added to the base price of the gas. The Commission reversed on this issue, finding that National Fuel's payment of a gathering allowance was not excessive within the meaning of NGPA section 601, since the impact on National Fuel's weighted average cost of gas (WACOG) was less than \$.01 per MMBtu.

The Commission also determined that National Fuel's off-system sales were imprudent under section 4 of the NGA, because the off-system sales resulted in a net detriment to National Fuel's on-system customers.¹¹⁰ The Commission rejected National Fuel's argument that the proper forum for review of off-system sales is in the section 7 certificate proceeding where the pipeline requests authority to make such sales. The Commission observed that it must conduct its prudence review of certificated activities after the fact since it is impossible to know whether an applicant will act in a prudent manner before it actually exercises its section 7 authority. The Commission noted that its order granting National Fuel's off-system sale authority was predicated on the assumption that "on-system customers will be no worse off with the sale."¹¹¹

W. *Purchasing Practices*

In *Panhandle Eastern Pipe Line Co.*,¹¹² the Commission noted that Panhandle's purchases from its affiliate Trunkline must be measured against the "prudence" standard under the NGA, not the "abuse" standard of section 601 of the NGPA, because the latter test applies only to NGPA "first sales." Applying that test, the Commission found that Panhandle's purchases from Trunkline were not imprudent, notwithstanding that the record showed in part that Panhandle's purchases may have been motivated by a desire to ameliorate Trunkline's take-or-pay problems. The Commission found that Panhandle's management reasonably concluded that maintenance of a long-term contractual relationship with Trunkline was in the interest of its customers because it sustained a valuable long-term source of supply. Thus, prudent

108. Notice of Proposed Rulemaking, *Five-year Take-or-Pay Make-Up Provisions in Natural Gas Producer-Pipeline Contracts*, IV F.E.R.C. Stats. & Regs. ¶ 32,464, 53 Fed. Reg. 27,704 (1988).

109. Opinion No. 315, *National Fuel Co.*, 44 F.E.R.C. ¶ 61,293 (1988).

110. *Id.*

111. *Id.* at 62,057.

112. *Panhandle E. Pipe Line Co.*, 44 F.E.R.C. ¶ 61,246 (1988).

management could reasonably make some purchases of higher-priced Trunkline gas to assist Trunkline with its take-or-pay problems.

On January 19, 1988, in *Columbia Gas Transmission Corp.*,¹¹³ the Commission clarified available remedies for violations of section 601(c)(2) of the NGPA¹¹⁴ and section 5 of the NGA¹¹⁵ regarding abusive and imprudent gas purchasing practices by Columbia. The Commission's order was on the rehearing of a prior Commission order issued on remand following the court's review of the Commission's decision in Opinion Nos. 204 and 204-A.¹¹⁶ Although Columbia and its customers entered into a settlement limiting its refund liability for excessive payments in past periods to \$1 million, the Commission imposed an additional remedy under contracts found abusive. For PGAs filed after April 1, 1987, the Commission limited Columbia's pass-through of costs paid under contracts found abusive in its prior orders (i.e., contracts for NGPA section 107 gas with an eighty-five percent or greater take-or-pay clause) to the price of alternative fuel in Columbia's market area. Further, because the Commission found Columbia's purchasing practices and contracts to be imprudent in Opinion No. 204, it precluded Columbia from collecting, in its base tariff rates, costs other than the price paid for gas in a first sale, including costs to reform such imprudent contracts.

The Commission also held that Columbia's ratepayers should not have to pay to reform contracts that violate the NGA.¹¹⁷ The Commission declined to provide a further remedy by specifying alternative contract terms that would be appropriate, or to examine whether Columbia's cutbacks, excessive purchases, or other contract terms were imprudent. The Commission concluded that, having already found the contracts abusive in one area, it was unnecessary to examine whether the contracts were abusive or imprudent on other grounds as well.

On rehearing, the Commission further construed NGPA section 601(c)(2), determining that Columbia's contracts were abusive not because of particular take-or-pay clauses, or because of pricing provisions in combination with such clauses, but because "all of the provisions in these contracts together were likely to cause [Columbia's] costs to steadily increase at an excessive rate and were entered into when Columbia was experiencing a serious surplus."¹¹⁸ The Commission also reiterated that if a pipeline has been "abusive" under the NGPA, then the same record supporting abuse would support a lesser finding of imprudence under the NGA. The Commission provided that Columbia's passthrough of costs paid under the abusive contracts would be limited to the price of the relevant competitive alternative in Colum-

113. *Columbia Gas Transm'n Corp.*, 42 F.E.R.C. ¶ 61,021 (1988).

114. 15 U.S.C. § 3431 (1982).

115. 15 U.S.C. § 717d (1982).

116. Opinion No. 204, *Columbia Gas Transm'n Corp.*, 26 F.E.R.C. ¶ 61,034, *reh'g denied*, Opinion No. 204-A, 26 F.E.R.C. ¶ 61,334 (1984) *remanded sub nom.* Office of Consumers' Counsel v. FERC, 783 F.2d 206 (D.C. Cir. 1986).

117. In a separate order issued contemporaneously, the Commission found that Columbia could seek to recover contract reformation costs not related to the imprudent contracts and incurred after expiration of a PGA settlement on April 1, 1987. *Columbia Gas Transm'n Corp.*, 42 F.E.R.C. ¶ 61,022 (1988).

118. *Columbia Gas Transm'n Corp.*, 43 F.E.R.C. ¶ 61,482, 61,189 (1988).

bia's service areas, finding that such a price cap should be arrived at through an easily verifiable mechanical test with a different cap in each of Columbia's market areas. For contracts found abusive, the Commission disallowed recovery of *all* contract reformation costs. Commissioner Sousa dissented to this order.

In *Columbia Gas Transmission Corp.*,¹¹⁹ the Commission authorized Columbia to retain approximately \$11 million in refunds received from Chevron U.S.A. as part of a settlement arising from a contract dispute. In ruling that the \$11 million did not have to be flowed through to Columbia's customers, the Commission relied on a global settlement it approved on June 14, 1985, resolving issues relating to Columbia's purchasing practices. Article II of that settlement provided that Columbia could retain commodity refunds applicable to certain specific time periods. Although intervenors claimed that the retention of refunds would be "grossly inequitable," the Commission found that the settlement involved "mutual compromises" and should not be modified.

X. Rate Conditions Imposed on Certificates

On April 5, 1988, the Commission issued two orders, one in *Ozark Gas Transmission System*¹²⁰ and the other in *Trailblazer Pipeline Co.*,¹²¹ where the recipients of a blanket certificate, both project financed pipelines, objected to conditions which had been placed on the blanket certificates granted to them. These conditions required the pipelines to utilize a maximum interruptible rate for proposed interruptible transportation based on 100% load factor design (subject to selective discounting) and to credit all revenues received from discounted transportation to demand charges payable by existing shippers. The Commission said that the imposition of the minimum crediting condition challenged by the pipelines was necessary to prevent an over-recovery of costs since the existing demand charges covered all expenses, except return on and return of equity and related taxes. However, in reaching this conclusion, the Commission also noted that the decision of the United States Court of Appeals for the District of Columbia Circuit in *Northern Natural Gas Co.*,¹²² precluded the Commission under section 7 from using revenue crediting conditions to adjust rates previously approved by the Commission for customers not receiving the services certificated. Accordingly, the Commission vacated the blanket certificates altogether.

Y. Risk Allocation Under Optional Expedited Certificates

On July 1, 1988, the Commission issued a declaratory order in *Wyoming-California Pipeline Co.*,¹²³ regarding nonenvironmental issues stemming from an optional expedited certificate (OEC) application to build an approximately

119. *Columbia Gas Transm'n Corp.*, 43 F.E.R.C. ¶ 61,435 (1988).

120. *Ozark Gas Transm'n Sys.*, 33 F.E.R.C. ¶ 61,012 (1988).

121. *Trailblazer Pipeline Co.*, 45 F.E.R.C. ¶ 61,013 (1988).

122. *Northern Natural Gas Co. v. FERC*, 827 F.2d 779 (D.C. Cir. 1987).

123. *Wyoming-California Pipeline Co.*, 44 F.E.R.C. ¶ 61,001 (1988).

1,000 mile pipeline from Wyoming to California to serve the enhanced oil recovery (EOR) market in California. In this order, the Commission clarified that its stance on risk allocation for OEC applicants is that applicants can share the risk of the project only with new customers and not existing customers who receive no new service. The risk sharing with new customers would be through a negotiable reservation fee limited to recovery of fixed costs minus return on and return of equity and taxes. In addition, the Commission accepted, with slight modifications, Wyoming-California's (WyCal) "levelized cost of service" concept. The Commission also stated that WyCal's initial rates should be based on ninety-five percent throughput of its capacity. However, it granted WyCal, at full capacity throughput, a 16.13% return on equity and a 11.8% overall rate of return. Further, WyCal: (1) would be allowed to base rates on geographical zones; (2) could not set different peak and off-peak rates until it had operational experience; and (3) would be required at the end of three years of operations to submit cost and revenue studies to justify its rates.

On rehearing, the Commission subsequently amplified its standards for an OEC, stating that they "are so different from the conventional 7(c) standards applicable to Mojave and Kern River [two competing applicants], that an evidentiary hearing to compare WyCal with the other projects would be useless."¹²⁴ The Commission also clarified the elements necessary to satisfy the risk assumption requirements for OECs. Specifically, it declared that no risk may be allocated to existing customers, provided the customers are willing and able to engage in arms-length negotiations. The Commission amended its earlier order to require that the lowest reservation fee negotiated with any shipper be made available to all firm shippers, although individual shippers could agree, as a project-completion incentive, to pay a higher fee. To further reinforce the market basis for OECs, it ruled that OEC applicants may, if the market allows, negotiate a maximum reservation fee that includes a return on equity component. The Commission also reversed its earlier determination preventing WyCal from using its proposed seventy/thirty debt to equity ratio, on the theory that this debt to equity ratio might allow WyCal to be more competitive with other pipelines. The Commission determined that WyCal could book its firm capacity "in the order of the highest present value to it for the services requested."¹²⁵ Among those willing to pay the highest reservation fee, WyCal would have to provide nondiscriminatory service on a first-come, first-serve basis. Priorities on the WyCal system may be established, however, based on the per unit value of the reservation fee paid for capacity. WyCal was further required to include in its tariff a mechanism to allow firm shippers the right to assign their service rights so that they could compete with WyCal for sales of interruptible service.

124. Wyoming-California Pipeline Co., 45 F.E.R.C. ¶ 61,234, 61,675 (1988).

125. *Id.* at 61,679.

Z. Section 7(c) Transportation Rates

In *ANR Pipeline Co.*,¹²⁶ the Commission reaffirmed on rehearing its requirement that a pipeline may charge only its maximum interruptible transportation rate under an individual certificate issued under section 7(c) of the NGA. The Commission reiterated that it has disallowed the use of discounted rates in traditional section 7(c) transportation transactions because individual certificates lacked the same safeguards against cost-shifting as required for open-access transportation in part 284 of the Commission's regulations. The Commission further ruled that the parties' agreement to a lower rate is irrelevant, concluding that, if a pipeline sought to utilize flexible discounts, it could become an open-access transporter.

AA. Section 311(a)(1) Interstate Rates

In *Transcontinental Gas Pipe Line Corp.*,¹²⁷ the Commission rejected rate schedules which sought to establish maximum and minimum, firm and interruptible, transportation rates for service on the Mobile Bay system, constructed and operated pursuant to section 311 of the NGPA. The Commission rejected the rates because it had "fundamental concerns" concerning the use of incremental rates for a section 311 facility because a pipeline could construct individual extensions of its line under section 311 and establish incremental rates for each. In making its determination, the Commission distinguished between NGA section 7 facilities which are reviewed prior to construction (and for which the Commission has authorized incremental rates) and section 311 facilities, which receive no equivalent review. In another order issued the same day, the Commission also informed Transco that, in designing its section 311 rates, Transco and other pipelines may seek guidance from those decisions where the Commission has set section 311 rates for intrastate pipelines.¹²⁸

The Commission subsequently denied rehearing of its prior rejection of incremental rates, finding that the pipeline facilities had not been shown to be discrete from the rest of the pipeline's system and that the pipeline's proposal would allow segmentation of the pipeline's system.¹²⁹ The Commission stated that data on Transco's entire system was required and a new rate case filing was necessary prior to approving incremental rates for these facilities. The Commission also found that incremental rates were not appropriate because the pipeline extension could provide system-wide benefits.

BB. Section 311(a)(2) Intrastate Rates

In *Lear Petroleum Co.*,¹³⁰ the Commission affirmed in part and rejected

126. Opinion No. 288-A, *ANR Pipeline Co.*, 42 F.E.R.C. ¶ 61,076 (1988).

127. *Transcontinental Gas Pipe Line Corp.*, 44 F.E.R.C. ¶ 61,400 (1988).

128. *Transcontinental Gas Pipe Line Corp.*, 44 F.E.R.C. ¶ 61,403, 62,297 n.2 (1988). This is the first time the Commission has suggested that interstate pipelines should seek guidance from intrastate pipeline rate cases determined for the most part in non-evidentiary advisory staff panel proceedings (and to which Commission rule 2202 is inapplicable).

129. *Transcontinental Gas Pipe Line Corp.*, 45 F.E.R.C. ¶ 61,403 (1988).

130. Opinion No. 294, *Lear Petroleum Co.*, 42 F.E.R.C. ¶ 61,015 (1988).

in part an initial decision prescribing "fair and equitable" intrastate pipeline rates under section 311(a)(2) of the NGPA¹³¹ for two intrastate pipelines operated by Lear Petroleum Company (formerly Producer's Gas Company). The Commission affirmed the Judge's rejection of Lear's claim that the "fair and equitable" ratemaking standard under section 311 of the NGPA requires the Commission to adopt market-based rates for intrastate pipelines rather than traditional cost-based rates, such as those the Commission applies to interstate pipelines under the "just and reasonable" ratemaking standard of section 4 of the NGA.

The Commission established cost-based rates for each of Lear's Oklahoma intrastate pipelines. In reviewing Lear's costs, the Commission: (1) approved its staff's use of updated cost data for purposes of its testimony at trial; (2) excluded Lear's take-or-pay buyout or buydown costs from section 311 intrastate transportation rates; (3) affirmed amortization of the proceeds of "safe harbor" sales of accelerated cost recovery system depreciation and investment tax credits over the twenty-year useful life of the plant to which such proceeds relate; and (4) approved its staff's discounted cash-flow methodology and comparison of Lear to interstate gas transmission companies for purposes of establishing Lear's rate of return on common equity.

Furthermore, for Lear's intrastate pipeline constructed after enactment of the NGPA, the Commission reversed the Judge's use of test period actual throughput for rate design purposes and imposed rates based upon ninety percent of the pipeline's design capacity. The Commission reasoned that for such post-NGPA facilities, the risk of underutilization of the facilities must be placed on the intrastate pipeline to discourage construction of uneconomical facilities at the expense of interstate customers.¹³² For pre-NGPA intrastate pipelines, the Commission held that rates should be designed based on projected throughput based upon historical figures.

Additionally, the Commission reaffirmed its authority to provide for refunds of amounts collected in excess of fair and equitable rates under section 311 of the NGPA. The Commission also approved the Judge's ruling that refunds under section 311 must flow to the interstate customer serving as the "on behalf of" party, not a producer selling gas on a "net-back" basis, regardless of who is actually "out of pocket" as to the intrastate transportation fee in the event that the fee exceeded fair and equitable rates. However, the Commission recognized that producers may have contractual remedies to be decided by the courts.

Finally, the Commission rejected a settlement offer contested only by its staff for failure to provide sufficient information to enable the Commission to

131. 15 U.S.C. § 3371 (1982). Section 311(a)(2) of the NGPA provides that the Commission may authorize an intrastate pipeline to transport natural gas on behalf of interstate pipelines or local distribution companies served by any interstate pipeline for a rate that is "fair and equitable" and which does not exceed an amount "which is reasonably comparable to the rates and charges which interstate pipelines would be permitted to charge for providing similar transportation service." *Id.*

132. The Commission's use of 87% of a post-NGPA intrastate pipeline's capacity for rate design purposes was affirmed in *Mustang Energy Corp. v. FERC*, 859 F.2d 1,447, 1,455-57 (10th Cir. 1988). See section III.L., *infra*.

determine that the settlement rates were fair and equitable.¹³³

Following the issuance of *Lear*, in *Delhi Gas Pipeline Corp.*,¹³⁴ the Commission addressed applications filed by Delhi Gas Pipeline Corporation for approval of intrastate pipeline rates for transportation pursuant to NGPA section 311(a)(2) by Delhi's North Louisiana pipeline system.

The Commission first determined that Delhi could not include, in rate base, production-related costs in those instances where the well connection costs were incurred in connection with production. Second, the Commission found that the cost of service should be bifurcated between two systems which were non-integrated in fact, rather than on a total rolled-in basis as proposed by Delhi. Third, Delhi was directed to delete from rate base any costs associated with well connections which were in fact incurred by the producers. As for return on equity, the Commission calculated Delhi's cost of debt based on its parent company's actual cost of debt for the calendar year 1985. In determining the return on equity, the Commission found that, because the parties had not provided sufficient information, it was appropriate to establish a rate by taking official notice of the rates of interstate pipelines. In particular, the Commission noted that Delhi was a long-line pipeline with 4,500 miles of pipe located in numerous states. Therefore, the Commission determined that its rates should be based on the returns allowed comparable onshore long-line interstate pipelines.

Following the lead in *Lear*, the Commission determined that Delhi should bear the risk of under-utilization of the system. In *Lear*, the Commission had used a ninety percent load factor based on peak day design capacity which reflected the company's down time for maintenance. Although the record in *Delhi* contained no such evidence, the Commission stated that there was a better measure. Because all of Delhi's pipelines in its North Louisiana System act essentially as gathering systems, it concluded that the percentage of capacity should logically relate to the capacity output of the wells which the system was built to service. Although the record contained no specific information in this regard, the Commission noted that the average load factor for United States production in the last three calendar years was approximately eighty-seven percent. The Commission thus designed rates for Delhi's system based on eighty-seven percent of peak day design capacity, but disclaimed any intention to use the eighty-seven percent factor as precedent for any other case. Commission Sousa strongly dissented, noting that there was no record evidence for the eighty-seven percent, and it was dependent on national

133. On December 21, 1988, the Commission approved a contested settlement proposed by Lear's successor-in-interest. BP Gas Transm'n Co., 45 F.E.R.C. ¶ 61,475 (1988). The settlement allocated \$14.5 million in refunds for past periods on the basis of the amounts actually paid in excess of amounts which would have been paid by the customers at the fair and equitable rates to be charged prospectively for service. While this refund methodology would result in different rates after the refund for the intrastate pipeline's services, the Commission found this refund methodology fair and equitable and approved it where no specific alternative methodology had been presented by an interstate pipeline customer which would yield a fairer result. The settlement agreement resolved all issues which the Commission had addressed in Opinion No. 294.

134. *Delhi Gas Pipeline Corp.*, 43 F.E.R.C. ¶ 61,024 (1988).

monthly production statistics which bore no meaningful relationship to Delhi's gathering systems.

In *Louisiana Intrastate Gas Corp.*,¹³⁵ the Commission denied a request by Louisiana Intrastate (LIG) to have its NGPA section 311(a)(2) rates determined before an ALJ, not a staff panel. The Commission determined that the NGPA does not require more than informal procedures such as an opportunity for oral presentation of data, views and arguments. LIG argued that the staff panel process did not inform the company about applicable procedural and substantive standards. Summarily characterizing LIG's argument as disingenuous, the Commission spoke in general terms about how positions are defined, and noted that LIG "should already be well aware of the points of difference between it and advisory staff."¹³⁶ The Commission did not foreclose the possibility of assigning the case to an ALJ if the case became of "such a nature" to warrant the "extraordinary treatment" of referral to an ALJ. Last, the Commission determined that Commission rule 2202 (separation of functions) did not apply to staff panel proceedings.

CC. Section 311(a)(1) "On Behalf Of" Test

On July 19, 1988, the Commission issued a series of orders which served to more completely define the current Commission standard of the "on behalf of" test for transportation under section 311 of the NGPA. The most instructive was a declaratory order issued in *Hadson Gas Systems*.¹³⁷ In *Hadson* the Commission stated that while the "on behalf of" requirement can be met by an agency agreement, the primary determinative factor for determining whether a pipeline can provide transportation services to a shipper under NGPA section 311(a)(1) is the receipt by an LDC or intrastate pipeline of "some economic benefit." Throughout these orders the Commission clearly stated that receipt of "some economic benefit" is a sufficient nexus to satisfy the "on behalf of" test.¹³⁸ On rehearing, the Commission reaffirmed its prior rulings that transportation service would fall within the ambit of section 311 if an "economic," "substantial" or "tangible" benefit accrued to the LDC.¹³⁹ In addition, it reiterated that an agency agreement could provide the required nexus between the parties to a section 311 transaction.

In *Texas Eastern Transmission Corp.*,¹⁴⁰ the Commission ruled that pipelines must continue to carry gas for a shipper during the pendency of a dispute as to whether a transaction meets the "on behalf of" test.

In *Williston Basin Interstate Pipeline Co.*,¹⁴¹ the Commission rejected a proposed tariff definition of a "shipper" that would have limited section 311

135. *Louisiana Intrastate Gas Corp.*, 44 F.E.R.C. ¶ 61,397 (1988).

136. *Id.* at 62,284.

137. *Hadson Gas Sys., Inc.*, 44 F.E.R.C. ¶ 61,082 (1982).

138. See also, *Cascade Natural Gas Corp. v. Northwest Pipeline Corp.*, 44 F.E.R.C. ¶ 61,081, 61,243 (1988); *Texas E. Transm'n Corp.*, 44 F.E.R.C. ¶ 61,080, 61,242 (1988); *Southern Natural Gas Co.*, 44 F.E.R.C. ¶ 61,079, 61,237 (1988); *Algonquin Gas Transm'n Co.*, 44 F.E.R.C. ¶ 61,078, 61,230 (1988).

139. *Hadson Gas Sys.*, 45 F.E.R.C. ¶ 61,286 (1988).

140. *Texas E. Transm'n Corp.*, 45 F.E.R.C. ¶ 61,285 (1988).

141. *Williston Basin Interstate Pipeline Co.*, 45 F.E.R.C. ¶ 61,280 (1988).

service to LDCs and intrastate pipelines. The Commission ordered Williston to redefine "shipper" to include all similarly-situated shippers who act as agents for an eligible entity on whose behalf gas is being transported.

DD. *Unpaid Accruals*

In *United Gas Pipe Line Co.*,¹⁴² the Commission issued Opinion No. 298-A which denied rehearing of Commission Order No. 298.¹⁴³ The proceeding concerned the appropriate treatment of unpaid accruals included in United's PGA filings for the period from June 1972 to June 1978. The Commission determined that United could use only the rate that the producer-supplier had a legal right to charge on the effective date of its current adjustment. Likewise, for United's PGA surcharge adjustment, the Commission determined that United must use the rate its supplier had a legal right to charge, not merely their best estimates. United was required to compensate its customers for the time value of precollected monies, and to refund carrying charges collected when United had not actually expended cash.

In *Transwestern Pipeline Co.*,¹⁴⁴ the Commission decided PGA issues related to unpaid accruals based on the principles enunciated in *United Gas Pipe Line Co.*¹⁴⁵ and in the Commission's revised PGA regulations. The Commission denied recovery of unpaid accruals in excess of the rates in effect and disallowed the time value of unpaid accruals booked and collected from customers before the payments were made to the pipeline's suppliers.

II. COMMISSION ACTION ON PRODUCER ISSUES

A. *Termination of Incentive Pricing Rulemakings*

In Order No. 459-A,¹⁴⁶ the Commission denied the requests for rehearing of order No. 459, which terminated eighteen rulemaking petitions involving incentive pricing schemes for the production of gas from deep water wells under section 107 of the NGPA and proposals for take-or-pay cost recovery and similar contract reformation proposals. The Commission held that competitive market forces, individual cases, and other rulemakings were responding sufficiently to these issues.

B. *"Devonian Shale" Redefined*

In *West Virginia Department of Energy*,¹⁴⁷ the Commission issued an order granting waiver of section 272.103(e) of the regulations¹⁴⁸ defining "natural gas produced from Devonian shale," both for purposes of qualifying

142. Opinion No. 298-A, *United Gas Pipe Line Co.*, 43 F.E.R.C. ¶ 61,441 (1988).

143. Opinion No. 298, *United Gas Pipe Line Co.*, 42 F.E.R.C. ¶ 61,353 (1988).

144. *Transwestern Pipeline Co.*, 45 F.E.R.C. ¶ 61,495 (1988).

145. *United Gas Pipe Line Co.*, 42 F.E.R.C. ¶ 61,353, *reh'g denied*, 43 F.E.R.C. ¶ 61,441 (1988).

146. Order No. 459-A, *Petition for Rulemaking in the Matter of Determinations Whether Wells Drilled in More Than 500-Foot Water Depth Should be Determined to be "High Cost Gas" Under Section 107(c)(5) of the NGPA*, 42 F.E.R.C. ¶ 61,146 (1988).

147. *West Virginia Dep't of Energy*, 42 F.E.R.C. ¶ 61,052 (1988).

148. 18 C.F.R. § 272.103(e) (1988).

under the pricing provisions of section 107(c)(4) of the NGPA, and the tax credit provided by section 231 of the Crude Oil Windfall Profit Tax Act of 1980, as amended by the Economic Recovery Act of 1981,¹⁴⁹ applicable to production of fuel from non-conventional sources, including gas produced from Devonian shale. The waiver will permit more gas to qualify for the tax credit, which the Commission estimated to be \$.80 per MMBtu for 1988. The price of gas under section 107(c)(4) is deregulated. The Commission granted the waiver in response to a petition for reconsideration of an order denying rehearing of Order No. 78,¹⁵⁰ which required that for gas to qualify as Devonian shale production, the entire Devonian age stratigraphic interval encountered by the well bore must meet the standards of section 272.103(e).¹⁵¹ The Commission agreed with the West Virginia Department of Energy that because eligibility was based upon the entire Devonian interval (including nonshale rock), if the thickness of overlying Devonian rock is greater than five percent of the thickness of the Devonian interval encountered by the well bore, certain wells, particularly in the Appalachian Basin, could not possibly qualify. The waiver permitted applicants for section 107(c)(4) pricing determinations to select one continuous interval from the Devonian interval encountered by the well bore. If the interval selected is more than 200 feet thick, both the top and bottom 100 foot portions must meet the standards.

On July 21, 1988, the Commission issued Order No. 501,¹⁵² amending section 272.103(e) of the regulations consistent with the waiver granted in *West Virginia Department of Energy*. In Order No. 501, the Commission revised its definition of "Devonian Shale." Under the previous definition, the entire length of well bore that crossed through Devonian aged strata must contain no more than five percent nonshale rock. Under the amended definition, a producer is allowed to select a specific stratigraphic interval in the well bore to be tested. That interval must meet the five percent test and if the interval is greater than 200 feet, in addition to the entire section meeting the five percent test, the top and bottom 100 foot sections must meet the five percent test singularly as well.

C. Order No. 451

In *Grynberg Production Co. v. Mountain Fuel Resources, Inc.*,¹⁵³ the Commission issued an order on a complaint filed by a first seller of gas alleging that Mountain Fuel had improperly abandoned purchases of gas without first complying with the good faith negotiation procedures of section 270.201 of the Commission's regulations promulgated in Order No. 451.¹⁵⁴ Contrary to Mountain Fuel's interpretation that it could cease purchases upon rejecting an

149. 26 U.S.C. § 29 (1982) (amending 95 Stat. 172, 339 (Aug. 13, 1981)).

150. High Cost Natural Gas, 11 F.E.R.C. ¶ 61,299 (1980).

151. At least 95% of the encountered interval must have a gamma ray index of 0.7 or greater.

152. Order No. 501, *Revision of Definition for Natural Gas from Devonian Shale*, III F.E.R.C. Stats. & Regs. ¶ 30,824, 53 Fed. Reg. 28,192 (1988) (to be codified at C.F.R. pts. 272 & 274).

153. *Grynberg Production Co. v. Mountain Fuel Resources, Inc.*, 42 F.E.R.C. ¶ 61,061 (1988).

154. Order No. 451, III F.E.R.C. Stats. & Regs. ¶ 30,701, *review pending*, *Mobil Oil Exploration & Producing S.E., Inc. v. FERC*, No. 86-4940 (5th Cir. Dec. 15, 1986).

offer to nominate a price in step 1 of the good faith negotiation procedure, if the parties cannot agree on a new price in step 1, the seller has the option to cease sales of the gas governed by the nomination request. For the purchaser to cease purchases, it must first request the seller to nominate a price in step 2. The Commission found that Mountain Fuel did not request that Grynberg nominate a price in step 2 and that Mountain Fuel therefore improperly abandoned its purchases from Grynberg. The Commission ordered Mountain Fuel to renew or continue its purchases under the contracts at issue.

III. COURT ACTION ON PIPELINE ISSUES

A. *Burden of Proof*

In *Public Service Co. of North Carolina v. FERC*,¹⁵⁵ the United States Court of Appeals for the Fifth Circuit affirmed a Commission decision that transmission costs of Transcontinental Gas Pipeline Corporation (Transco) must be allocated by the Mcf-mile method, requiring Transco to forego its existing rate structure which had been based on zone rate differentials established in 1962.

Customers in Transco's zone three appealed the Commission's decision on grounds, inter alia, that the party advocating a change in present zone differentials must bear the burden of showing by substantial evidence that the existing rates are unjust and unreasonable, and that the proposed new methodology is lawful. The zone three customers contended that the burden of proof had been improperly shifted to them, rather than remaining with the party advocating the change.

The court rejected the argument that the burden of proof had been shifted, stating that the ALJ and the Commission were well aware of the proper allocation of the burden of proof,¹⁵⁶ and that substantial evidence supported the finding that distance was the primary cost factor on Transco, requiring the change in rate structure.

In *Tennessee Gas Pipeline Co. v. FERC*,¹⁵⁷ the United States Court of Appeals for the District of Columbia Circuit found that the Commission had overstepped its authority by imposing a new rate pursuant to section 5 of the NGA without affirmatively meeting its burden of showing the changed rate to be just and reasonable. At issue were Tennessee's filings of two tariff sheets to offer interruptible transportation to its small general service (GS) customers: one permitting them to satisfy their obligation to take full requirements through the substitution of interruptible transportation service, and the other requiring payment of a transportation rate higher than the otherwise generally applicable interruptible transportation rate. The Commission found Tennes-

155. *Public Serv. Co. of N.C. v. FERC*, 851 F.2d 1,538 (5th Cir. 1988).

156. The court cited an earlier Transco case where the United States Court of Appeals for the District of Columbia Circuit had reversed the Commission's cost allocation order requiring Transco to change to the Mcf-mile methodology because the Commission had failed to meet its burden of showing with substantial evidence that the existing zone rates were unjust and unreasonable. *Public Serv. Comm'n of N.Y. v. FERC*, 642 F.2d 1,335 (D.C. Cir. 1980), *cert. denied*, 454 U.S. 879 (1981).

157. *Tennessee Gas Pipeline Co. v. FERC*, 860 F.2d 446 (D.C. Cir. 1988).

see's proposal unjust and unreasonable on grounds of: (1) failing to specify maximum and minimum rates, (2) failing to identify separate transmission, storage and gathering components, and (3) discrimination in failing to reflect mileage on the same basis as used for the generally applicable interruptible rate. However, in rejecting Tennessee's proposal, the Commission accepted the tariff sheet enabling GS customers to utilize interruptible transportation services to satisfy full requirements obligations, while rejecting only that provision of the other tariff sheet identifying a separate, higher rate for such customers. In effect, the Commission authorized GS customers to utilize interruptible transportation, but through payment of the lower, generally applicable rate. Tennessee's subsequent effort to restore its full requirements obligation for such customers, as existed before its filing, was rejected by the Commission.

The *Tennessee* court held that, although the Commission's determination of Tennessee's proposed GS interruptible rate being unjust and unreasonable was supported by substantial evidence, its "decoupling" of the two proposed tariff sheets effectively imposed a rate of the Commission's own choosing, thus requiring it to bear the burden of demonstrating the new rate just and reasonable pursuant to NGA section 5. Because the record was without substantial evidence showing that the Commission had sustained this burden, the court remanded the case to the Commission for further proceedings.

B. Commission's Transportation Rate Construction

In *Tarpon Transmission Co. v. FERC*,¹⁵⁸ the United States Court of Appeals for District of Columbia Circuit held that the Commission had failed to provide a plausible basis for its interpretation of the controlling contract provisions relating to the determination of Tarpon's rate. Tarpon entered into a transportation agreement with Trunkline, its principal customer, for transportation service. Under section 10.5 of that agreement, rate adjustments based upon the entire cost of service for the entire life of the transported reserves were permitted. This contractual authorization for periodic rate adjustments was intended to reflect new information about the magnitude of the reserves. The Commission staff gave effect to the revenue-crediting portion of the disputed contract provision, but did not likewise construe it to allow any retrospective calculation of depreciation rates to account for the extension of the pipeline's useful life, contrary to Tarpon's interpretation. The Commission found that Tarpon's rate provision was reasonably susceptible only to the staff's interpretation.

On appeal, the court searched the record for possible justifications for the Commission's holdings, but found none which rose to the level of reasoned decisionmaking. It found that the Commission had overlooked the intent of the contract and ignored Tarpon's arguments that the depreciation rate was designed to replicate what would have resulted if the volume and lifetime of reserves had been known at the outset. Accordingly, the case was remanded

158. *Tarpon Transm'n Co. v. FERC*, 860 F.2d 439 (D.C. Cir. 1988).

to the Commission with instructions to provide a reasoned explanation for any outcome.

C. Discounted Rates

In *Columbia Gas Transmission Corp. v. FERC*,¹⁵⁹ the United States Court of Appeals for the District of Columbia Circuit affirmed the Commission's denial of Columbia's application for an individual certificate, authorized under section 7(c) of the NGA, to transport natural gas at a selective discount. The Commission had previously refused to authorize selective discounting under individual certificates, and determined here that permitting such a discount would lead to cost shifting. The court agreed with the Commission that Columbia could provide discounted transportation under a blanket certificate authorized by Order No. 436 and the safeguards provided by it which are crafted to permit pipelines like Columbia to selectively discount without raising the danger that captive customers subsidize the discount through higher, discriminatory rates. The court concluded that allowing Columbia to selectively discount through an individual NGA section 7(c) certificate would compromise the Commission's efforts to give pipelines the freedom to discount while at the same time protecting against discriminatory rates.

D. Federal Royalty Obligations

In *Diamond Shamrock Exploration Corp. v. Hodel*,¹⁶⁰ the United States Court of Appeals for the Fifth Circuit affirmed that federal royalty payments are not owed unless and until actual production occurs. Actual production, as defined by the court, is the actual physical severance of minerals from the earth. The court held that take-or-pay payments disbursed before gas is actually produced and taken simply cannot be a payment for a sale of gas. Rather, it reasoned, they are payments for the pipeline purchaser's failure to purchase (take) gas.¹⁶¹ Thus, no royalty is due on take-or-pay payments unless and until gas is actually produced and taken. In reaching this decision, the court took note of the Commission's rate treatment of take-or-pay payments as pre-payments for gas not taken. Until the time make-up gas is taken, the take-or-pay payment is accounted for as a pre-paid asset and may not be recovered by the pipeline from its customers as a purchased gas cost.¹⁶²

E. Filed Rate Doctrine

In *Kentucky West Virginia Gas Co. v. Pennsylvania Public Utilities Commission*,¹⁶³ the United States Court of Appeals for the Third Circuit held that the Pennsylvania Public Utility Commission's order excluding \$865,000 in wholesale gas costs from a retail distributor's rates was permissible so long as

159. *Columbia Gas Transm'n Corp. v. FERC*, 848 F.2d 250 (D.C. Cir. 1988).

160. *Diamond Shamrock Exploration Corp. v. Hodel*, 853 F.2d 1,159 (5th Cir. 1988).

161. *Id.* at 1,167.

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

163. *Kentucky W. Va. Gas Co. v. Pennsylvania Pub. Utils. Comm'n*, 862 F.2d 69 (3rd Cir. 1988).

the utility is able to recover completely those Commission-approved costs within a reasonable period of time. The court stated that the "denial to a utility of interest on Commission-imposed wholesale costs does not—without more—violate the filed rate doctrine," as articulated by the Supreme Court in *Nantahala Power & Light v. Thornburg*¹⁶⁴ and *Mississippi Power & Light v. Mississippi ex. rel. Moore*.¹⁶⁵ The court recognized that the Pennsylvania regulatory scheme reflects a state policy favoring prudent gas purchases and was designed to allow consumers to pay more accurate rates. Consequently, delay in passing through these costs does not dishonor the purposes behind the filed rate doctrine. The court specifically noted that the instant case does not address situations where the Commission might conclude that the NGA requires an immediate passthrough of wholesale costs, or situations where passthrough was delayed for an unreasonable period of time.

F. Injunctive Relief

In *City of Chanute v. Williams Natural Gas Co.*,¹⁶⁶ plaintiffs, eight municipal local distribution company customers of the defendant, sought a preliminary injunction to compel Williams Natural Gas Company (WNG) to reopen access to its interstate pipeline for transportation service. The preliminary injunction was requested pursuant to the municipalities' antitrust action which alleged that WNG violated section 2 of the Sherman Act by closing its open-access system. WNG had ceased its transportation service as a result of increased take-or-pay exposure and declining sales. The court granted the preliminary injunction, based on the following findings: (a) plaintiffs would suffer irreparable harm without the injunction, since they would stand to lose reliable, low-price natural gas supplies required to satisfy their long-term needs; (b) the potential harm of losing such supplies outweighed the minimal take-or-pay exposure of WNG; (c) it would not be in the public interest for anyone to be forced to accept gas at rates not competitive in a real world setting; and (d) with respect to the antitrust violation, plaintiffs had raised questions going to the merits "so serious, substantial, difficult and doubtful as to make them a fair ground for litigation."¹⁶⁷

G. Judicial Deference to Commission's Pricing Determination

In *Wagner & Brown v. ANR Pipeline Co.*,¹⁶⁸ the plaintiff gas producer sought damages for breach of a take-or-pay clause in its natural gas purchase contract with ANR Pipeline Company. As its defense, ANR claimed that any prepayments it made for gas not taken would raise its price for gas above the maximum lawful price, in violation of the NGPA. Along with this defense, ANR filed a motion to dismiss, asserting that the Commission has primary jurisdiction in matters of gas pricing. The district court granted the motion, and it was affirmed with directions by the United States Court of Appeals for

164. *Nantahala Power & Light v. Thornburg*, 476 U.S. 953 (1986).

165. *Mississippi Power & Light v. Mississippi ex. rel. Moore*, 108 S. Ct. 2,428 (1988).

166. *City of Chanute v. Williams Natural Gas Co.*, 573 F. Supp. 1,517 (D. Kan. 1988).

167. *Id.* at 1,534.

168. *Wagner & Brown v. ANR Pipeline Co.*, 837 F.2d 199 (5th Cir. 1988).

the Fifth Circuit. In affirming the lower court, the appellate court explained that the Commission's expertise in gas pricing and the need for uniformity in the construction of take-or-pay clauses tipped the scales in favor of deferring jurisdiction to the Commission. However, to afford the Commission an opportunity to rule on the complaint and to ensure that Wagner & Brown's rights would not be unreasonably delayed or lost, the court further ruled that the district court vacate its order of dismissal and substitute an order staying the proceedings for a period of 180 days. The district court, therefore, would adjudicate the action if a ruling by the Commission was not forthcoming within that time period, or if the district court did not grant an extension of time.

H. NGPA Dual Price Qualification

In *FERC v. Martin Exploration Management Co.*,¹⁶⁹ the United States Supreme Court held that the statutory scheme of price ceilings and deregulation established in the NGPA requires that the classification of gas not turn on contractual terms but on the provisions of the statute. Specifically, in a unanimous decision by Justice Brennan (Justice White did not participate), the Court ruled that when natural gas qualifies under more than one NGPA provision establishing maximum lawful prices, the provision under which the gas is deregulated prevails regardless of whether the regulated price is higher. In so ruling, the Court upheld the FERC's regulation interpreting section 101(b)(5) of the NGPA which provides that the applicable provision is that "which could result in the highest price." The Court stated that the word "could," as distinguished from "will," mandates use of the unregulated price since, in a pre-contract state, a provision with no price ceiling could yield higher prices than those with price ceilings. The Court further stated that the post-contract situation should not be considered to determine which provision actually results in the higher price. In addition, the decision upheld the FERC's determination that certain gas which qualifies as "new tight formation" gas under section 107(c)(5) of the NGPA is automatically qualified as deregulated "new" gas under sections 102(c) or 103. In both of these rulings the Court reversed the United States Court of Appeals for the Tenth Circuit.

I. NGPA Section 110 "Severance Tax" Treatment

In *Colorado Interstate Gas Co. v. FERC*,¹⁷⁰ the United States Court of Appeals for the District of Columbia Circuit remanded a decision in which the Commission had held Kansas' ad valorem property tax to be a "severance tax" qualifying for passthrough treatment under section 110 of the NGPA. The court did not overturn the Commission's determination that the tax was a "severance tax" as a matter of law. Rather, it held only that the Commission's rationale fell short of reasoned decisionmaking. In the court's opinion, a major infirmity with the Commission's reasoning was its decision in another

169. *FERC v. Martin Exploration Management Co.*, 108 S. Ct. 1,765 (1988).

170. *Colorado Interstate Gas Co. v. FERC*, 850 F.2d 769 (D.C. Cir. 1988).

case, decided the same day, that an "evidently identical" Texas tax was not a "severance tax" under NGPA section 110.

J. Outer Continental Shelf Lands Act (OCSLA) Jurisdiction

In *Amoco Production Co. v. Sea Robin Pipeline Co.*,¹⁷¹ the United States Court of Appeals for the Fifth Circuit affirmed the ruling of the district court finding federal jurisdiction over a dispute concerning take-or-pay obligations in a contract obligating Sea Robin to purchase, from Amoco, natural gas produced from the Outer Continental Shelf (OCS). Sea Robin invoked "force majeure" as a condition excusing "full performance" of obligations under the contract. Amoco filed suit against Sea Robin in a Louisiana state court, and Sea Robin had the action removed to the United States District Court for the Western District of Louisiana. The court of appeals found a split of authority among and within the districts of Louisiana on whether the OCSLA conferred federal jurisdiction over take-or-pay disputes concerning gas produced from the OCS. In finding federal jurisdiction in this instance, it ruled that disputes concerning take-or-pay constitute controversies "arising out of, or in connection with . . . any operation . . . which involves exploration, development, or production" within the meaning of section 1349(b)(1) of the OCSLA.¹⁷² Accordingly, the court remanded the case to the district court for a trial on the merits.

K. Remedies for Imprudence

In *Office of Consumers' Counsel of Ohio v. FERC (OCC III)*,¹⁷³ the United States Court of Appeals for the District of Columbia Circuit determined that the Commission's proposed remedies for violations of section 5 of the NGA were consistent with a prior mandate. Previously, the court had affirmed the Commission's determination that certain practices and contract clauses of Columbia Gas Transmission Corporation were imprudent under section 5 of the NGA.¹⁷⁴ The court directed the Commission to determine an appropriate remedy for the violations.

Subsequently, Associated Gas Distributors (AGD) filed a motion to enforce the mandate requiring the Commission to impose a remedy. In *Office of Consumers' Counsel of Ohio v. FERC*¹⁷⁵ (*OCC II*) the court reiterated that despite settlement negotiations the Commission was required to impose a remedy effective from the date of its finding of imprudence.

The Commission then proposed a remedy designed to correct the effects of the imprudent clauses by limiting passthrough of gas costs under the offending contracts to the price of competing fuels in the area. It also denied Columbia's application to passthrough costs incurred in reforming abusive or imprudent contracts.

171. *Amoco Production Co. v. Sea Robin Pipeline Co.*, 844 F.2d 1,202 (5th Cir. 1988).

172. *Id.* at 1,210.

173. *Office of Consumers' Counsel of Ohio v. FERC*, 842 F.2d 1,308 (D.C. Cir. 1988).

174. *Office of Consumers' Counsel of Ohio v. FERC*, 783 F.2d 206 (D.C. Cir. 1986) [hereinafter *OCC I*].

175. *Office of Consumers' Counsel of Ohio v. FERC*, 826 F.2d 1,136 (D.C. Cir. 1987).

AGD then filed this suit to renew its motion to enforce the mandate. It argued that the Commission's proposed remedy was not within the Commission's power under section 5. The Commission responded to AGD's suit by filing a motion to "enlarge" the mandate to encompass the remedy adopted. The court concluded that the remedies proposed by the Commission were "at least as effective, if not more effective than any other remedy [that the Commission] could lawfully devise."¹⁷⁶ The court found the proposed remedies to be consistent with the court's original mandate in *OCC I* and denied AGD's renewed motion to enforce the mandate.

L. Section 311(a)(2) Intrastate Pipeline Rates

In *Mustang Energy Corp. v. FERC*,¹⁷⁷ the United States Court of Appeals for the Tenth Circuit affirmed two Commission orders determining "fair and equitable" rates for firm intrastate transportation under NGPA section 311(a)(2) during two "locked-in" periods, rejecting a minimum bill provision for this transportation, and directing refunds. The orders involved rate increases filed by Mustang Energy Corporation for transportation service for El Paso Natural Gas Company. This decision represented the first appellate court scrutiny of the Commission's construction of the "fair and equitable" standard. The court found the Commission's determinations to be reasonable and supportable except for its selective use of actual cost data. The Commission had refused to use actual cost data submitted by Mustang for the second locked-in period. The court viewed this aspect of the decision as arbitrary, and directed the Commission to recalculate the rate for the second locked-in rate period using these data.

The court also upheld the Commission's conclusion that a fair and equitable cost-of-service rate was one that allowed the pipeline to recover costs and make a profit when the throughput utilized in setting the rate materialized. As a result, the intrastate pipeline bore the risk of under-utilization and the risk of financial losses resulting from any shortfall. Agreeing that section 311(a)(2) does not guarantee intrastate pipelines their recovery of transportation costs, the court affirmed the Commission's rationale to impose on intrastate pipelines the risk of under-utilization, which encourages intrastate pipelines to assess the economic viability of transportation facilities and protects interstate consumers from costs associated with the uneconomical construction of those facilities.

176. *Id.* at 1,312.

177. *Mustang Energy Corp. v. FERC*, 859 F.2d 1,447 (10th Cir. 1988).

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