COMMITTEE REPORTS

Report of the Committee on Natural Gas Rate and Accounting Regulations

The Committee's report highlights the important natural gas rate and accounting developments at the Federal Energy Regulatory Commission and in the courts during 1985.

I. Commission Action on Pipeline Issues

A. Abandonment Authority

On October 29, 1985, the Commission issued an order in *Tenneco Oil Co.*, Docket No. CI85-632-000, *et al.*, granting new abandonment and sales for resale authority through March 31, 1986, and allowing certain categories of gas to be sold on a spot basis. The so-called "limited term abandonments" issued by this order replace authority to sell gas on a spot basis that expired October 31, 1985, under the special marketing programs. The market restrictions which were a notable feature of the special marketing programs were dropped in accordance with the holding of *Maryland People's Counsel v. FERC.*[1] (See Part II, A., below). Additionally, the Commission refused to grant separate transportation authority. Instead, the Commission stated the transportation service must take place under the terms of Order No. 436. (See Section K below).

B. BTU Refunds

In Order No. 94-G, issued September 27, 1985, the Commission clarified that the term, "undisputed", in Order No. 94-F referred only to NGPA Section 110 charges purchasers had previously agreed to offset against first seller BTU refunds under Order No. 399-A, and denied petitions for rehearing in Order No. 94-F. The Commission determined that the use of the term, "undisputed", did not affect the rights of third parties to challenge Section 110 costs payments before the Production-Related Cost Board, or through other available protest procedures. Order No. 94-F was issued in light of *Interstate Natural Gas Association v. FERC.*[2]

C. Carrying Charges on Deferred Gas Cost Balance

On October 28, 1985, the FERC affirmed an initial decision in *Trunkline*

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1. 761 F.2d 768 (D.C. Cir. 1985).
2. 756 F.2d 116 (D.C. Cir. 1985).

Gas Co. Docket No. TA83-2-30-000, allowing Trunkline to amortize its Account 191 purchased gas cost balance over a thirty-six month period and to collect carrying charges for the entire period. The accumulated deferred Account 191 balance resulted primarily from LNG costs charged to Account 191. The Commission adopted the presiding Administrative Law Judge's (ALJ) conclusions that Trunkline Gas Company (Trunkline) had prudently managed its PGA, that it had not abused regulation by using PGA filings as a marketing tool and, therefore, that Trunkline was entitled to full recovery of carrying costs over a thirty-six month period as a matter of equity. The Commission emphasized that this decision was a narrow one and had no effect on any other pricing issues involved in other pending Trunkline proceedings.

D. *Cost Allocation and Rate Design*

In Opinion No. 227-A, issued May 21, 1985, the Commission granted rehearing of Opinion No. 227, which dealt with the rate treatment for transportation services provided by Sea Robin Pipeline Company (Sea Robin) to Gulf Oil Corporation (Gulf) under a fixed rate contract. In 1972, Sea Robin began transporting offshore gas to an onshore location for Gulf, charging 3.98¢/mcf and crediting transportation revenues to its cost of service. In recent rate proceedings concerning Sea Robin's other customers, Commission staff (Staff) recommended that Sea Robin drop the revenue crediting procedure and allocate costs to the Gulf transportation services in the same manner it allocated costs to other transportation services. The Staff calculated the resulting costs to be 10.01¢/mcf under this procedure.

In Opinion No. 227, the Commission had noted that the Sea Robin rate settlement, approved November 19, 1982, reserved for separate decision the "rate treatment" to be accorded the Gulf transportation service, and not "the rate to be charged" for the service, as Sea Robin had argued. By characterizing the reserved issue as the rate treatment, *i.e.*, the appropriateness of the revenue crediting approach, the Commission avoided making *Mobil-Sierra* findings that under Section 5 of the Natural Gas Act ("NGA") the fixed rate charge to Gulf was so low as to adversely affect the public interest. This characterization also allowed the Commission to make any change in rate effective as of the date Sea Robin's filed rates originally went into effect, June 1, 1980 (RP80-55), and meant that Sea Robin would owe sizable refunds to its customers, other than Gulf, if Staff's calculations prevailed. In sum, the Commission found that no reasonable justification existed for Sea Robin's allocating the Gulf transportation costs differently from the manner in which it allocated transportation costs for other customers and, therefore, the proposed rate treatment was unjust, unreasonable and unduly discriminatory. Sea Robin was ordered to refund the excess charges it had collected from its other customers as a result of undercharging Gulf.

Sea Robin's argument that the revenue crediting procedure should be left in place because it was reasonable when initiated did not sway the Commission. Noting that in a Section 4 proceeding the Commission may determine whether an entire rate structure—both existing parts and proposed parts—presently operates to ensure a just and reasonable result, the Commission found that growth in Gulf transportation volumes as a percent of Sea Robin's total volumes indicated the revenue crediting approach did not cover the cost of the Gulf transportation services. The Commission stressed that insufficient cost allocation to the Gulf transportation schedule necessarily meant that Sea Robin's other customers were subsidizing Gulf, and therefore, the Gulf schedule was integral to and could be reviewed in determining the rates to be charged. Neither Sea Robin, nor Gulf, challenged Staff's conclusion concerning subsidization of Gulf at the 3.98¢ rate, or that the 10.01¢ rate was proper based upon Sea Robin's cost allocation scheme for other transportation services.

On September 6, 1985, the presiding ALJ issued an initial decision in *Panhandle Eastern Pipe Line Co.*,[3] concluding that the Staff's modified fixed variable ("MFV") method of cost allocation and rate design should be applied to the pipeline (Panhandle). Under this MFV method all transmission and storage fixed costs were assigned to the demand component, with the exception of return on equity and related income taxes; one-half of demand costs were allocated on the basis of annual usage. The same MFV approach was adopted by the Commission in *Texas Eastern Corp.*[4] The ALJ recommended elimination of minimum bill provisions in three Panhandle rate schedules, except for the minimum bill applicable to the Annual Contracted Volume portion of the CS rate schedule because it contained no demand charge. In the same decision, the ALJ dismissed a complaint by Central Illinois Light Company in Docket No. RP82-105-000 against a Panhandle tariff provision that restricted availability of "general service" under Rate Schedule G to customers that purchased gas solely from Panhandle for resale in the areas served by Panhandle. The ALJ determined, when considered with other provisions of Panhandle's tariff, the supplier restriction provision was just, reasonable and not unduly discriminatory. However, the ALJ found Panhandle's tariff condition prohibiting Rate Schedule G customers from reselling gas purchased from another supplier in the same area where Panhandle gas was resold unduly restrictive.

E. *Direct Billing*

On September 30, 1985, the Commission permitted both Texas Eastern Transmission Corp., in Docket No. RP85-170-000,[5] and Consolidated Gas Transmission Corporation, in Docket No. RP85-179-000,[6] to directly bill customers for retroactive production-related cost allowances already paid or to be paid to the companies' natural gas suppliers. Direct billing of these costs replaced the companies' PGA method of flowing through retroactive production-related costs in their rates. The Commission found both proposals to be equitable and practical methods of allocating cost responsibility. However, the proposals were granted on the condition that all production-related cost allowances paid or collected through the direct billing procedure were subject to refund.

3. 32 F.E.R.C. ¶ 63,085 (1985).
4. 30 F.E.R.C. ¶ 61,144 (1985).
5. 32 F.E.R.C. ¶ 61,493 (1985).
6. *Id.* ¶ 61,448 (1985).

F. *Experimental Market Retention Programs*

On March 19, 1985, the Commission issued an order in *Tenneco Oil Co.*,[7] on rehearing of the generic Special Marketing Program (SMP) order issued in this proceeding September 26, 1984. The Commission concluded that transportation costs incurred when an interstate pipeline purchases SMP gas through another pipeline and pays the releasing pipeline's commodity rate for transportation is associated with gas purchased under the "ten percent" provision of the generic order. Thus, when a pipeline purchases SMP gas from another pipeline the entire delivered cost, including transmission for that purchase, may be recovered as a purchased gas cost. The Commission did require that the purchasing pipeline provide supporting information in its PGA filing to justify the separate cost component of such gas purchases under the ten percent provision of the generic SMP order.

On July 9, 1985, the FERC approved an uncontested settlement offer filed by Southern Natural Gas Company (CP84-342-000) to implement an interim, limited transportation program under Rate Schedule T-IS for one year pending hearings to resolve long term customer transportation issues. The settlement was effective July 1, 1985. Rate Schedule T-IS covers interruptible transportation at reduced rates for Southern's distribution customers acting on behalf of an industrial end-user, or end-users directly connected to Southern's system, subject to available capacity. In addition, the settlement agreement provides for a $5.2 million credit to Southern's overall cost of service. In return, Southern will retain all revenues obtained for transportation performed under the Commission's blanket certificate authorization, special marketing programs, and self-implementing programs pursuant to NGPA Section 311. Southern also agreed to a moratorium on any future rate increase prior to June 1986, except in certain circumstances.

On September 30, 1984, the Commission issued an order in *Columbia Gas Transmission Corp.*,[8] allowing Columbia's current SMP to continue until its scheduled termination on October 31, 1985. The Commission further found that Columbia's initial implementation was unduly discriminatory and in violation of its certificate. A second phase of the proceedings was initiated to determine the amount of the damages to Columbia's customers resulting from Columbia's actions. The Commission issued an order on the same day allowing Tenneco's SMP to continue until October 31, 1985.[9]

G. *Filing Fees*

On September 30, 1985, the Commission issued its Order No. 433, *Fees Applicable to Natural Gas Pipelines*, Docket Nos. RM79-63-000, et al., amending its regulations to establish the following fees for services and benefits the Commission provides to natural gas pipelines under the Natural Gas Act and the NGPA: (1) review of certificate applications under NGA Section 7(c) ($12,200); (2) review of requests for authorization to undertake routine trans-

7. 30 F.E.R.C. ¶ 61,257 (1985).
8. 32 F.E.R.C. ¶ 61,478 (1985).
9. Tenneco Oil Co., *id.* ¶ 61,525 (1985).

actions under blanket certificate notice and protest procedures ($1,700); (3) review of applications under NGPA Section 311(a) to transport gas ($12,000); (4) review of tariff filing to establish or revise a curtailment plan under Section 4 of NGA ($3,300); and (5) review of application seeking a Hinshaw exemption ($12,000). The Commission determined that the fees will also apply to all substantial amendments to pending applications and all applications to revise or amend existing authorizations or exemptions.

H. *Minimum Bills*

In *Southern Natural Gas Co.*,[10] the Commission rejected a proposed refund plan in a companion settlement agreement proposed by Southern Natural Gas Company (Southern) in resolution of disputes arising from the Commission's Opinions Nos. 222[11] and 222-A.[12] As reported in the last Committee Report, in Opinions Nos. 222 and 222-A, the Commission interpreted the minimum bill part of the tariff under which Southern Energy Company charged Southern for redelivery of vaporized LNG after deliveries of Algerian LNG ceased. Because Southern and some of its customers had entered an earlier settlement agreement regarding use of the LNG facilities after the Algerian cutoff, the Commission required Southern to submit a refund plan distributing refunds among customers who consented to the earlier settlement, to customers who did not consent and to non-consenting customers of consenting distributors. Southern's refund plan proposed refunds to the Georgia Industrial Group (a non-consenting intervenor) and to the city of Dalton, Georgia (which has a specific agreement on refunds). The companion settlement also proposed refunds to all customers of approximately $2 million. The amount was derived as fifty percent of total collections in excess of minimum bill amount ($18.6 million), or $9.3 million, less a credit for sale of LNG to an off-system customer previously flowed through to Southern's customers ($7.8 million), for a proposed principal amount of $1.5 million, plus interest. In response to comments by distributors and indirect customers, the Commission agreed that there was no basis for distinction between customers who consented to the earlier settlement and those who did not. The Commission ordered full refunds to all customers, less an appropriate credit for the off-system sale.

In *Pacific Interstate Offshore Co.*,[13] the Commission denied a request by Pacific Interstate Offshore Company (PIOC) for waiver of the Commission's minimum bill rule, as contained in Order Nos. 380 and 380-A. The Commission rejected PIOC's claim that waiver was justified because it had only one customer, was experiencing severe financial harm and might never recover take-or-pay payments if its sole customer should cease purchases. In essence, the Commission found PIOC to be in the same position as any other pipeline.

In *Northwest Central Pipeline Corp.*,[14] the Commission addressed the flowthrough by Northwest Central Pipeline Corporation (Northwest) of a fixed

10. 30 F.E.R.C. ¶ 61,080 (1985).
11. 27 F.E.R.C. ¶ 61,322 (1984).
12. 28 F.E.R.C. ¶ 61,240 (1984).
13. 31 F.E.R.C. ¶ 61,004 (1985).
14. *Id.* ¶ 61,093 (1985).

cost minimum bill payment when Northwest projected it would be unable to make up the payment. The Commission allowed Northwest to recover the $8.3 million fixed cost payment in its present rates because of Northwest's perceived inability to make up the payment and to prevent Northwest's customers from incurring unnecessary carrying charges.

On July 1, 1985, the Commission issued Opinion No. 238 in *Transwestern Pipeline Co.*, Docket No. RP81-130 which, among other things, eliminated the minimum bill provision in the pipeline's (Transwestern) sales rate schedules. The Commission set forth three factors that may justify a minimum bill: (1) protecting a pipeline from the risk of not recovering a fixed cost in the commodity component of its rates; (2) protecting full requirements customers from bearing a disproportionate share of the fixed cost resulting from swings off the pipeline system by partial requirements customers; and (3) protecting customers from take-or-pay liabilities. With respect to the first possible justification, the Commission found that only the fixed costs occasioned by depreciation and servicing of debt should be eligible for recovery. Further, the Commission found that a minimum bill "should in no way act to assure recovery of the return on equity, related income taxes and fixed production costs." These are costs, the Commission said, that "should be at risk to give the pipeline an incentive to minimize its cost." Since the Commission also approved the modified fixed variable rate designed for Transwestern, the only fixed charge the pipeline would recover would be through its monthly demand charge. Accordingly, the Commission saw no need for a continuation of a fixed cost minimum bill. The Commission did not address the second justification for a minimum bill, since all of Transwestern's customers are partial requirements customers. With respect to the third justification, the Commission stated that a minimum bill may be permissible if it ensures that the carrying cost associated with take-or-pay liabilities will be borne by the customers that caused the liabilities to be incurred. The Commission found that there was no connection between the minimum bill payments Transwestern's customers would make and the take-or-pay liabilities incurred by the company.

On September 30, 1985, the Commission issued an order in *Southern Natural Gas Co.*,[15] rejecting Southern's tariff filing to implement an interim annual minimum bill for Southern's partial requirements customers finding the tariff deficient in evidentiary support and contrary to Commission policy on imposition of minimum bill provisions. Southern requested the interim minimum bill until such time as the Commission acted to eliminate all minimum bill volume based on 95% of the average of each customer's actual gas purchases for 1980 through 1984 from Southern, not including interruptible gas purchases, and application of the fixed cost component contained in Southern's commodity rates to annual deficiency volumes below the 95% level.

I. Pipeline Purchasing Practices

On May 1, 1985, in Docket No. RM84-6, the Commission denied a request by several small producers to stay the May 3, 1985 deadline for payment

15. 32 F.E.R.C. ¶ 61,447 (1985).

to pipeline purchasers of Btu refunds in excess of any undisputed production-related costs owed to producers. The Commission rejected the producers' argument that the payment obligation should be stayed pending ruling by the U.S. Court of Appeals for the D.C. Circuit on a petition for rehearing *en banc* of the court's March 1985 order vacating Commission Order No. 399-A, which allowed producers to offset Btu refunds against production related cost payments by pipelines. The ruling is significant because it signals the Commission's willingness to mitigate the harsh impact of requiring payment of challenged assessments, despite pending court review. The Commission allowed the producers, pending ruling on the rehearing petitions, to establish escrow, on terms acceptable to pipeline purchasers, for the undisputed amounts that would be offset under Order No. 399-A. The effect of the escrow accounts is to limit interest due the pipelines to that actually earned from the escrow accounts, rather than the amount of interest that would have been earned based on the prime rate.

On June 14, 1985, the Commission, with two modifications, accepted the settlement resolving gas purchasing practice issues in *Columbia Gas Transmission Corp.*[16] The settlement generally resolved past and potentially future allegations of "fraud or abuse" or imprudence in purchasing practices for the period from March 1, 1982, through March 31, 1987. Because the settlement gave the pipeline immunity from refunds arising from past or future claims for this period, the pipeline was required: (1) to refrain from placing any new rate increase into effect for a two-year period beginning April 1, 1985; (2) to reduce its commodity rate from $4.07 to $3.60 per Dth during the two-year settlement period, subject to certain limited exceptions relating to pipeline supply rate design changes and reductions in the pipeline's commodity of gas; (3) to restrict its recovery of purchase gas costs applicable to the period before April 1, 1985, limited to a maximum of $600 million during the seven years commencing September 1, 1987, but only if its weighted average cost of gas is lower than the weighted average cost of gas of its five major pipeline suppliers; and (4) to provide unrestricted transportation during the settlement period for those wholesale customers meeting their seasonal purchase commitments. The Commission modified the settlement in two respects by: (1) deleting the provision that would have deferred until April 1, 1987, any requirement imposed by a final order in RM85-1-000 to adopt a minimum commodity bill or standby charge; and (2) deleting the provision that would have prevented any changes in rate design which may be ordered in Columbia's pending rate proceeding in RP81-83 from becoming effective before April 1, 1987.

On expedited rehearing, the Commission issued an order on June 25, 1985,[17] rescinding its second modification based on the representation of the pipeline and many customers that deferral of the rate design question was integral to the survival of the settlement. Although the Commission generally expressed disfavor with deferring implementation of any new rate design, it stated that the problem could be cured later by further remand for new record evidence if a decision could not be rendered upon the existing record.

16. 31 F.E.R.C. ¶ 61,307 (1985).
17. 30 F.E.R.C. ¶ 61,372 (1985).

J. PGA as Marketing Tool

In *Northwest Pipeline Corp.*,[18] the Commission approved, as modified, a revision to Northwest Pipeline Corporation's (Northwest) PGA clause presented in a contested settlement. The proposed revisions would have modified Northwest's PGA to provide: (1) that volumes to calculate the purchased gas cost adjustment would be estimated purchases in sales for a twelve month period beginning on the effective date of each semi-annual PGA adjustment; (2) balances in Account No. 191 would be amortized through a surchargeable credit based on twelve months of estimated sales beginning April 1 of each year; and (3) Northwest could make a midcourse correction to its Account No. 191 adjustment, if sales varied "significantly" from the twelve month estimate. The Commission deleted the midcourse correction provision because of the vagueness of the standard for the correction and otherwise approved the settlement.

On October 8, 1985, the Commission issued Opinion No. 240-B in *Tennessee Gas Pipeline Co.*[19] In this opinion the Commission affirmed earlier decisions (Opinions Nos. 240 and 240-A) which rejected a settlement entered into by the pipeline (Tennessee) and its customers. The settlement would have permitted Tennessee to lower its present PGA gas cost through an offset of refunds resulting from non-gas costs included in Tennessee's rates. The Commission reasoned that the settlement would have improperly allowed the pipeline to use its PGA filings as a marketing tool. Instead, the Commission ordered Tennessee to refund $155 million to its customers by cash or through invoice credit.

K. Rate Base and Refunds

On June 4, 1985, the Commission issued an order in *Distrigas of Massachusetts Corp.*[20] in response to the remand of the U.S. Court of Appeals for the First Circuit in *Distrigas of Massachusetts Corp. v.* FERC.[21] The Court remanded that case, in part, to enable the Commission to reconsider whether its decision that Distrigas share with its customers revenues obtained from providing "cool down" services to LNG tankers was appropriate for the period preceding the effective date of the subject rates. Because the Court also reversed the Commission's decision requiring Distrigas to reduce its rate base by the amount of the firm's deferred tax liabilities, the Commission was required also to determine whether customers should repay any refunds previously disbursed. On the cool down issue, the Commission was required also to determine whether customers should repay any refunds previously disbursed. On the cool down issue, the Commission concluded that, because it lacked authority to order refunds for the period preceding the effective date of the proposed rates, no sharing of revenues was required. However, it continued to require such sharing for the succeeding period. It also declined to order customers to repay refunds owing to the rate base reduction holding reversed by the Court. No re-

18. *Id.* ¶ 61,022 (1985).
19. 33 F.E.R.C. ¶ 61,005 (1985).
20. 31 F.E.R.C. ¶ 61,276 (1985).
21. 737 F.2d 1208 (1st Cir. 1984).

payment was required, since Distrigas' prior refunds were predicated on a refund floor set by previously effective rates. Because that refund floor exceeded the current just and reasonable rate level resulting from the rate base reversal, the Commission concluded that Distrigas was not entitled to any previously overpaid refunds.

L. *Rate of Return*

On June 18, 1985, the Commission issued two rate of return decisions endorsing a general policy of using actual, rather than hypothetical, capital structures to develop rates of return for natural gas pipelines. Although the Commission historically has relied on actual capital structures for setting rates of return in past cases, in more recent years it has departed from that practice and used a hypothetical capital structure where circumstances warranted. Thus, these decisions represent a departure from the Commission's most recent trend and a return to its more traditional practice. In both new decisions, the Commission concluded that actual capital structures were appropriate for pipelines because of: (1) changed conditions regarding competition and risk in the pipeline industry; and (2) the availability of other methods to ensure cost efficient financing for pipelines. Accordingly, in Opinion No. 235, the Commission in *Arkansas Louisnana Gas Co.*,[22] reversed an initial decision where the presiding ALJ had adopted a hypothetical capital structure for the pipeline. However, it affirmed the initial decision as to the recommended 15.4% rate of return on common equity. This opinion was reaffirmed in Opinion No. 240, issued July 22, 1985. (Docket No. RP80-97). Similarly, in Opinion No. 236, the Commission in *Midwestern Gas Transmission Co.*[23] affirmed an ALJ's initial decision which had approved use of the company's actual capital structure over Staff's position favoring adoption of a hypothetical structure. The Commission also affirmed the ALJ's adoption of a 14% rate of return on common equity.

M. *Rate Making Treatment of Interest Tax Credits*

In a Notice of Proposed Rulemaking, issued February 22, 1985,[24] the Commission announced a proposal that would prospectively amend the rate making treatment of investment tax credits by requiring pipelines to share the benefits of their credits with ratepayers. Since the severe gas shortages of the 1970's, pipelines have been allowed to retain the full benefit of the credit. The Commission, however, indicated that while such a policy was appropriate during periods of insufficient domestic supply, the present gas surplus calls for reassessment of the policy.

22. 31 F.E.R.C. ¶ 61,318 (1985).

23. *Id.* ¶ 61,317 (1985).

24. *Rate Making Treatment of Investment Tax Credits for Natural Gas Pipeline Companies*, 4 F.E.R.C. Stats. & Regs. ¶ 32,399 (1985).

N. Regulation of Natural Gas Pipelines after Partial Wellhead Deregulation—Order No. 436

On October 9, 1985, the Commission issued Order No. 436, its long awaited final rule, in *Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol.*[25] This was followed-up by the Commission's order on rehearing, Order No. 436-A, issued December 12, 1985. These orders had been preceded by the Commission's Notice of Proposed Rulemaking (NOPR), issued May 30, 1985 in the same docket.[26] The final rule accomplished the following with respect to rates.

Transportation. The final rule imposes a non-discriminatory access provision to all transportation service performed under the Commission's self-implementing programs. It allows pipelines to impose a reservation fee for firm transportation to be allocated on a "first-come, first-served" basis. In addition, it allows firm sales customers to convert firms sales entitlements to firm transportation by up to 25% annually. The rule requires transporting pipelines to charge a one-part volumetric rate design for interruptible service. Rates for firm transportation service, however, may consist of a two-part rate design. Further, the rule recognizes a pipeline's ability to impose reasonable operational conditions to be filed as part of the tariff. In addition, self-implementing transportation services must be offered unbundled and tariffed separately. However, the final rule exempts intrastate pipelines from the rate conditions of the final rule and permits them to choose whether or not to offer firm transportation service.

Take-or-Pay. The final rule deletes the NOPR's proposed safe harbor rules for take-or-pay buyouts. In addition, it provides for the review of such buyouts under the standards set forth in the policy statement issued April 10, 1985, in Docket No. PL85-1000. The April 1985 policy statement took effect immediately on this point. (See "Take-or-Pay Provisions" at Part II, S., below).

Block Billing. The Commission delayed promulgating its controversial block billing provisions specified in the NOPR. Instead, the Commission requested that additional comments be filed on November 18, 1985, and scheduled a public hearing for December 11 & 12, 1985.

O. NGPA Section 311(a)(2) Transportation Rates

On June 4, 1985, the Commission issued an order in *Mustang Fuel Corp.*, No. ST81-260-000,[27] setting fair and equitable transportation rates charged by the applicant (Mustang), an intrastate pipeline, to El Paso Natural Gas Company. In this case, the Commission opted for the approach urged by Mustang, rather than that of the Staff, in allocating costs between the intrastate customers and El Paso. To design the unit rate, Staff recommended use of throughput designated in Mustang's original 1981 petition for rate approval. Mustang advocated use of more current periods reflecting reduced throughput.

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25. 50 Fed. Reg. 42 (June 7, 1985).
26. *Id.*
27. 31 F.E.R.C. ¶ 61,265 (1985).

While acknowledging that the Commission's general policy favored Staff's method in imposing most of the risk of underutilization on intrastate customers, the Commission cautioned that such imposition of risk of underutilization on intrastate customers, typically applies to new facilities in order to encourage economically viable construction. However, where service here to El Paso would be performed largely with existing facilities, the economic goal was still achievable without full imposition of risk of underutilization on intrastate customers. Thus, the Commission concluded that use of Mustang's method, which would apportion risk of underutilization between both intrastate and interstate customers, was fair and equitable and consistent with Congress' intention in NGPA Section 311 to facilitate integration of interstate and intrastate facilities.

P. *Special Discount and Sales Rates*

On June 7, 1985, the Commission issued an order in *Southern Natural Gas Co.*[28] authorizing the pipeline to implement a Flexible Discount Rate Schedule from May 1, 1985 through October 31, 1985 to stem the pipeline's sharp decline in annual sales volumes. This discount rate proposal was unique in that, as approved, it used transmission mileage to calculate the upper limit of a range of discounted rates for each customer zone and based eligibility of the discounted rates on current contract demand, as well as past purchasing levels. All of the pipeline's jurisdictional customers were eligible for these discounted rates under the program's eligibility criteria.

On October 25, 1985, in *Northern Natural Gas Co.*,[29] the FERC denied a petition by the pipeline (Northern Natural) for authority to extend its flexible pricing option in large volume contract service rate schedules for two years beyond the October 26, 1985 deadline established by an earlier Commission order. In denying Northern Natural's petition, the Commission concluded that the discount rate program was discriminatory. It added that Order No. 436 provides an opportunity for pipelines and their customers to allocate the excess deliverability that led to the discount sales program in the first place.

On November 12, 1985, the Commission approved an offer of settlement pursuant to which Natural Gas Pipeline Company of America (Natural) obtained authorization to make sales under a rate schedule (IOS) applicable to volumes that are surplus to Natural's on-system requirements, *Natural Gas Company of America*, Docket No. CP85-57-000, Order Approving Settlement, (November 12, 1985). The volumes available for IOS sales are comprised of the excess of Natural's on-system customer entitlements over actual purchases by on-system customers. A distribution customer would be eligible to make purchases during any month in which it purchases a threshhold volume equal to a percentage of its monthly entitlement established by Natural, not to exceed 90%. The IOS rate would be no greater than the otherwise applicable commodity rate and no less than Natural's weighted average cost of gas plus 6¢/mcf. Pursuant to the settlement, IOS sales terminate on December 31, 1985. The Commission stated its belief that it was reasonable to authorize the IOS pro-

28. 31 F.E.R.C. ¶ 61,295 (1985).
29. 33 F.E.R.C. ¶ 61,066 (1985).

gram on this basis "so that Natural's customers can benefit from the program while companies and end-users begin using the programs implemented by [Order No. 436]."

Q. *Special Overriding Royalty Payments*

On September 18, 1985, the Commission approved a settlement offer submitted by El Paso Natural Gas Company (El Paso) and Union Oil Company of California (Union Oil) in *El Paso Natural Gas Co.*[30] This case resolved a dispute over the level of special overriding royalties El Paso pays to producers under Gas Lease Agreements (GLA) in which El Paso obtained large amounts of leasehold acreage in the San Juan Basin during the 1950's. Provisions in the settlement require, *inter alia*, El Paso to pay Union Oil $5 million for termination of Union Oil's special overriding royalty interests; reassign GLA properties to Union Oil; and grant market-out rights to El Paso, coupled with a right for Union Oil to terminate the gas purchase contract as to any marketed gas not subject to Section 7(b) of the NGA. The Commission determined that the settlement in price and availability of San Juan Basin natural gas for customers located within El Paso's service area was reasonable.

R. *Take-or-Pay Provisions*

In *Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations*,[31] the Commission issued a statement of policy which addressed the rate treatment of payments made by interstate pipelines to sellers of natural gas in return for waiver or reduction of a pipeline's take-or-pay minimum purchase obligations. The policy statement, at 18 C.F.R. § 2.76, provides that: (1) a producer may receive such payments without thereby receiving a price in excess of the maximum lawful prices specified in the NGPA; (2) a pipeline electing to make such payments may file to recover the payments in an NGA Section 4(e) filing, other than a filing to recover purchased gas costs; (3) the pipeline's method of cost recovery and apportionment among customers will be addressed on a case-by-case basis; and (4) when the payments are accompanied by termination of service by the seller, any necessary abandonment certificates under Section 7(b) or 7(c) of the Natural Gas Act will be granted.

At the same time, the Commission elsewhere addressed the take-or-pay issue in its rehearing order in *Columbia Gas Transmission Corp. v. Tennessee Gas Pipeline* Co.[32] (*Columbia v. Tennessee*). In a November 4, 1984 order,[33] the Commission had deleted provisions of a rate settlement that would have charged Tennessee Gas Pipeline Company's (Tennessee) customers for certain nonrecoupable take-or-pay amounts paid by Tennessee to settle disputes with its suppliers. The Commission's stated reason for the disallowance was that such payments might constitute payment of a price in excess of the maximum lawful price to purchasers. Because of its April 10, 1985 policy statement,

30. 32 F.E.R.C. ¶ 61,387 (1985).
31. 3 F.E.R.C. Stats. & Regs. ¶ 30,367 (1985).
32. 30 F.E.R.C. ¶ 61,053 (1985).
33. 29 F.E.R.C. ¶ 61,203 (1984).

above, the Commission was no longer concerned that payment by Tennessee would result in the producers receiving payment in excess of the NGPA maximum lawful price. Accordingly, on rehearing in *Columbia v. Tennessee*, the Commission modified its November 19, 1984 order. In the rehearing order, the Commission approved a billing mechanism proposed by Tennessee so long as the take-or-pay amounts were not treated as "gas costs" (under Uniform Systems of Accounts Nos. 800-803), but other gas expenses (under Account No. 813) and the prudence of reasonableness of any amounts paid were held to be open to challenge.[34]

S. *Tariff and Service Agreement Changes*

On May 21, 1985, in *Northern Natural Gas Co.*,[35] the Commission reaffirmed its jurisdiction to consider costs and revenues of any activity, facility, or service incidental to jurisdictional operations in setting jurisdictional rates, regardless of whether the Commission has independent jurisdiction of those specific activities, facilities, or services. The pipeline (Northern Natural) had been assessing an agency fee equal to 3% of the delivered cost of gas for arranging gas purchases and transportation and for providing other administrative services. While emphasizing that it wanted to encourage the provision of such agency services, the Commission rejected Northern Natural's argument that agency fees were not subject to Commission jurisdiction because they were not sales for resale or transportation in interstate commerce. The Commission found the agency services to be indistinguishable from such non-jurisdictional activities as production and gathering services, the cost of which traditionally had been considered by the Commission in setting jurisdictional rates.

On September 13, 1985, in *Texas Eastern Transmission Corp.*, Docket No. RP85-176-000, the Commission granted Texas Eastern Transmission Corporation's (TETCO) request for a limited waiver until December 31, 1985 of TETCO's "first through the meter" clause, a provision under Rate Schedule TS-1 requiring customers to take full contract quantities under the Sales Rate Schedule DCQ as a condition precedent to obtaining transportation of their own gas. TETCO requested a waiver because Public Service Electric & Gas Company (Public Service) had recently reduced its gas volumes requiring TETCO to invoke the "first through the meter" clause causing transportation services to be discontinued. Public Service's affiliate wells were shut in and potential reservoir damage was possible which could have resulted in permanent gas loss. Responding to Public Service's request to waive the tariff clause, TETCO requested limited waiver in two situations: (1) when TETCO obtains take-or-pay or minimum bill relief from gas released for transportation, or (2) when the gas is to be transported for the account of a sales customer, which certifies that the customer and seller have a long-term firm contract and that the customer is experiencing drainage, potential reservoir damage or potential loss of gas as a result of the "first through the meter clause." Brooklyn Union Gas Company's request for hearing was granted to determine whether the

34. *See also* Tennessee Gas Pipeline Co., 31 F.E.R.C. ¶ 61,052 (1985).
35. 31 F.E.R.C. ¶ 61,189 (1985).

waiver should be modified to include any transportation volumes incremental to Texas Eastern's systems or whether the "first through the meter clause" should be stricken from TETCO's tariff.

T. Transfer of Interstate Pipeline Facilities and Producing Properties

On February 13, 1985, the Commission approved a settlement proposal by which the Montana-Dakota Utilities Company transferred all of its certificated facilities and services to the Williston Basin Interstate Pipeline Company (Williston).[36] As approved, the settlement required Williston to price all company-owned production on a cost-of-service basis during the first year of operation, subject to later Commission consideration of rate of return on equity and cost allocation. Thereafter, pricing on any other lawful basis was allowed.

U. Unpaid Accruals in PGA Filings

The Commission issued three orders on September 30, 1985, determining that interstate pipelines could include accrued, but unpaid, purchased gas costs in rates so long as the company credited ratepayers the time value of the amount relating to the unpaid accruals. The Commission, by letter order, approved a settlement offer filed by El Paso Natural Gas Company (El Paso), allowing El Paso to include unpaid accruals in its rates.[37] The Commission reached the same conclusion in two orders granting rehearing of prior Commission orders that had directed Transwestern Pipeline Company (Transwestern) and K.N. Energy, Inc. (KN) to remove all unpaid accruals from Account 191 and credit Account 191 for the time value of unpaid accruals. On further review of both Transwestern's filing, Docket No. TA85-2-42-002,[38] and K.N. filing, Docket No. TA85-1-53-005,[39] the Commission determined the companies should refund the time value of the unpaid accruals.

II. COURT ACTION ON PIPELINES

A. Certificate and Marketing Programs

On May 10, 1985, the U.S. Court of Appeals for the D.C. Circuit vacated the Commission's blanket certificate transportation program and raised serious questions concerning the lawfulness of all the Commission's special marketing programs (SMP) in *Maryland People's Counsel v. FERC*[40] *(MPC I)* and *Maryland People's Counsel v. FERC*[41] *(MPC II)*. In separate opinions, the court found that the Commission had not justified its exclusion of captive, or core, market customers from the programs.

In *MPC I*, the court rejected Commission arguments that an SMP for Columbia Gas Transmission Corporation (Columbia) would benefit even ineli-

36. Williston Basin Interstate Pipeline Co., 30 F.E.R.C. ¶ 61,143 (1985).
37. 32 F.E.R.C. ¶ 61,518 (1985).
38. *Id.* ¶ 61,474 (1985).
39. *Id.* ¶ 61,475 (1985).
40. 761 F.2d 768 (D.C. Cir. 1985).
41. 761 F.2d 780 (D.C. Cir. 1985).

gible customers by spreading fixed costs over greater volumes and would assist the pipeline in avoiding take-or-pay liabilities. The court noted that the Commission had not explained why these benefits would not accrue in the absence if any limitation on eligible buyers. The court also rejected the arguments that Columbia's SMP was experimental and thus not expected to function perfectly and that comparison of the savings resulting from competitive wellhead pricing (in the absence of the SMP) with the savings from cost spreading under the SMP could be ignored because the wellhead savings could not be quantified. In the court's opinion, even experimental programs must be reasonable and not arbitrary, and the evident and significant impacts of a proposed course of action subject to the Commission's jurisdiction could not be ignored simply because they are difficult to quantify. The court ordered the Commission to show cause why its SMP order should not be vacated and remanded in light of the findings that the SMP unduly discriminated against captive customers. Neither opinion offered any guidance on the breadth of customer base the programs would have to embrace in order to gain court approval.

In MPC II, the court vacated the Commission's Order Nos. 319 and 234-B to the extent that they allow the transportation of direct-sale gas to fuel-switchable end-users without requiring pipelines to furnish the same service to local distribution companies and captive direct sale customers on non-discriminatory terms. The court expressed concern about the pipelines' insulation from full competition with alternate fuels and about the opportunities of pipelines to earn monopoly profits from such insulation. Noting that considerations of antitrust policy clearly were relevant factors to be considered under the "public convenience and necessity" standard of Section 7 of the NGA, the court remanded the blanket certificate transportation program to the Commission.

In late May the Commission issued its Notice of Proposed Rulemaking (RM85-1) responding to the court's objections (see Part I, O., above). The proposal sets forth a long range policy requirement of non-discriminatory transportation under the Commission's self-implementing programs.

In *Northern Natural Gas Co. v. FERC*,[42] the court held that the Commission may not impose a revenue crediting provision as a condition of newly certificated services, if the result is to alter previously approved rates for customers not receiving the certificated services. The ruling confirmed and expanded the Court's earlier decision in *Panhandle Eastern Pipeline Co. v. FERC*,[43] which held that the Commission may not condition a certificate for transportation revenues to resale customers. The court rejected the Commission's attempt to distinguish *Panhandle.*

B. *Cost Allocation and Rate Design*

In *ANR Pipeline Co. v. FERC*,[44] the court partly affirmed and partly reversed and remanded a contested portion of two 1983 FERC opinions deciding cost classification, cost allocation and rate design questions in rate proceed-

42. 780 F.2d 59 (D.C. Cir. 1985).
43. 613 F.2d 1120 (D.C. Cir. 1979).
44. 771 F.2d 507 (D.C. Cir. 1985).

ings of Great Lakes Transmission Company.[45] The court affirmed the Commission's decision to relocate the boundary between Great Lakes' central zone and eastern zone, but reversed and remanded the Commission's decision that Great Lakes' T-6 service, involving transportation of storage gas for ANR Pipeline Company (ANR) during summer months, should be allocated a portion of the costs of Great Lakes' original main line in addition to the incremental cost of new facilities constructed by Great Lakes to render the service to ANR. In its decision, the court emphasized the Commission's responsibility to find an existing rate unjust and unreasonable when it seeks to order a rate change not proposed in the rate change application, including an alteration to an unchanged part of a proposed higher rate. Great Lakes had sought continuation of an incremental method for allocating costs to T-6 service previously approved by the Commission. The court held that the Commission's decision respecting the T-6 rate schedule lacked record support. The court also reversed and remanded on evidentiary grounds the Commission's determination that costs of company-use gas should be treated on a rolled-in basis, rather than allocated on an incremental basis to rate schedules involving seasonal storage-related backhaul transportation provided to ANR.

C. *Curtailment Plan Compensation Schemes*

In *Texasgulf Inc. v. United Gas Pipeline Co.*,[46] the court ruled in favor of plaintiff Texasgulf, Inc. which had brought suit against United Gas Pipeline Company (United) in 1972 for breach of contract based on a failure to deliver specified contract quantities. The court specifically rejected United's defense that curtailment of deliveries was due to factors beyond its control. Rather, it found that United had failed to exercise "due diligence" imposed by its contract in managing its gas supply with necessary foresight of future demand requirements. This lack of due care was demonstrated, the court concluded, by the pipeline securing new customers with full knowledge of the continuing decline in its gas reserves. Such conduct was held not to be excused by the NGA, the pipeline's contract with Texasgulf, Inc., or its tariff provisions.

D. *Experimental Market Retention Programs (Special Marketing Programs)*

In *Maryland People's Counsel v. FERC*,[47] the court on August 6, 1985, determined that the generic Special Marketing Program (SMP) orders issued September 26, 1984,[48] and December 21, 1984, on rehearing,[49] raised the same infirmities of discrimination that were raised by earlier SMP orders, which were vacated by the same court in May 1985 due to the Commission's failure to adequately justify the exclusion of "captive customers" from eligibility to purchase cheaper SMP gas (see Part II., A., above). The court stated that the

45. *See* FERC Opinion No. 170, 24 F.E.R.C. ¶ 61,014 (1983); FERC Opinion No. 179, 25 F.E.R.C. ¶ 61,319 (1983).

46. 610 F. Supp. 1329 (D.C. Cir. 1985).

47. 768 F.2d 450 (D.C. Cir. 1985).

48. 28 F.E.R.C. ¶ 61,383 (1984).

49. 29 F.E.R.C. ¶ 61,334 (1984).

current SMP orders, in which the Commission granted limited eligibility to firm sales customers of releasing pipelines to purchase SMP gas, were slightly less discriminatory than the earlier SMP orders, yet the Commission continued to lack record support and reasoning to justify the discrimination. However, the court decided that the instant SMP orders should be allowed "to die a natural death" since they were due to expire October 31, 1985. The court determined that the vacation of the SMP orders could do "more harm than good" in the short time remaining before the expiration date.

E. Extraordinary Loss

In *Natural Gas Pipeline Co. of America v. FERC*,[50] the court had affirmed Commission Opinion No. 218, which disallowed the pipeline's (Natural) efforts to amortize $13 million expended on three non-traditional and unsuccessful gas supply projects. The court upheld the Commission's decision to disallow recovery of unsuccessful non-traditional gas supply expenditures in the pipeline's cost of service. The court found that the Commission's refusal to apply a prudence standard to the expenditures in question, as well as its different treatment of failed electric generation projects, was reasonable. The court did, however, reaffirm its opinion in *Tennessee Gas Pipeline Co. v. FERC*,[50.1] that established the principle that recovery of abandoned project expenses require two tests to be met: (1) that such expenses must be prudently incurred, and (2) that the projects abandoned must have been used and useful in providing service. None of the expenditures in the instant case resulted in projects that provided utility service.

F. Minimum Bills

In *Wisconsin Gas Co. v. FERC*,[51] the court affirmed most of the Commission's Order No. 380, *Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions*, issued May 25, 1984,[52] which barred minimum commodity bills for interstate pipelines that allowed recovery of variable costs associated with gas not purchased by customers. The court affirmed all aspects of Order No. 380, except the Commission's determination that downstream pipelines could not include fixed cost portions of upstream pipeline suppliers' minimum bills in their own minimum bills. The court remanded that issue to the Commission for further consideration. The court also upheld the Commission's Order No. 380-C issued October 24, 1984,[53] which barred minimum take provisions in interstate pipeline tariffs.

In *Mississippi River Transmission Corp. v. FERC*,[54] the court vacated and remanded a Commission decision that approved a contested settlement allowing United Gas Pipeline Company (United) to impose a minimum bill re-

50. 765 F.2d 1155 (D.C. Cir. 1984).
50.1 606 F.2d 1094 (D.C. Cir. 1979).
51. 770 F.2d 1144 (D.C. Cir. 1985).
52. 27 F.E.R.C. ¶ 61,318 (1984).
53. 29 F.E.R.C. ¶ 61,077 (1984).
54. 759 F.2d 945 (D.C. Cir. 1985).

covering fixed costs on one class of its customers. Although the Commission asserted that the minimum bill was necessary to protect United from a customer's swinging on United, *i.e.*, adjusting takes from United at the customer's discretion, the court found that the Commission had cited no substantial record evidence to support its conclusion. The court further stated that the Commission must determine, on the basis of substantial record evidence (1) that the pipeline in fact needs a minimum bill to protect against "too painful a pinch of unrestrained competition,"[55] and (2) that the particular minimum bill is narrowly designed to serve that purpose and nothing more.

In *Consolidated Gas Transmission Corp. v. FERC*,[56] the court affirmed Commission Opinion No. 202-A, *Columbia Gas Transmission Corp.*,[57] interpreting minimum bill provisions applicable to resales of liquefied natural gas (LNG) imported from Algeria and regasified at a Cove Point, Maryland facility. The minimum bill provision provided that the plant owners could recover certain operating expenses if they were unable to deliver regasified gas to their customers. LNG supplies were cut off in March 1980, but joint owners of the plant, affiliates of Consolidated Gas Transmission Corporation and Columbia Gas Transmission Corporation, did not invoke the minimum bill provisions against their customers until December 1980. The Commission concluded that the joint suppliers should have invoked the minimum bill provision on May 31, 1980, and therefore ordered refunds for amounts collected above the minimum bill levels after that date. The court held that the Commission's order was based on substantial evidence and was a rational exercise of its power to fashion discretionary relief.

G. *Producer Rates*

In *Amoco Production Co. v. FERC*,[58] the court affirmed the Commission's decision in Opinion No. 209 rejecting the producer's (Amoco) assertion of a contractually authorized right of reimbursement from its purchaser of 100 percent of all increased amounts of severance, production and excise taxes. The dispute centered on a contract amendment entered into between the gas purchaser and its subsequent repurchaser calling for an increase of the purchaser's right of reimbursement to 100 percent, rather than 75 percent, of amounts the purchaser paid to satisfy its tax reimbursement obligation to the producer. Amoco claimed that this amendment of the resale contract, as a consequence, increased its reimbursement entitlement to 100 percent, rather than the preexisting 75 percent, as called for under its contract with the purchaser. The court affirmed the Commission's refusal to so hold on behalf of the producer, accepting the Commission's reasoning that because the price received by the purchaser from its repurchaser consisted of a regulated, cost based rate already containing taxes, rather than a contract rate, the resale contract provision governing tax reimbursement was inoperative. Rather, the court agreed with the Commission that the reimbursement provision was operative only if the pur-

55. *Id.* at 950.
56. 771 F.2d 1536 (D.C. Cir. 1985).
57. 25 F.E.R.C. ¶ 61,460, *vacated*, 27 F.E.R.C. ¶ 61,089, *modified*, 28 F.E.R.C. ¶ 61,053 (1983).
58. 765 F.2d 686 (7th Cir. 1985).

chaser were to resume collection from its repurchaser of a contract based rate providing a separate increment for taxes. Absent such resumed collection, Amoco was denied any incremental tax reimbursement, since such action would allow for double recovery.

H. PGA Filings

In *Panhandle Eastern Pipe Line Co. v. FERC*,[59] the Court affirmed the Commission's decision with respect to purchase gas adjustment (PGA) filings made by Panhandle Eastern Pipeline Company (Panhandle). The case concerned an extraordinary, out of cycle, PGA filing made by Panhandle in May 1983. In response to that filing, the Commission granted Panhandle waivers of certain provisions of its tariff and applicable regulations to provide for the recovery of certain deferred purchased gas costs over a thirty-nine month period, rather than the usual six-month period. Following hearing, the Commission permitted Panhandle to recover carrying costs on the unamortized balance of the deferred account over a twelve-month period. Panhandle had requested permission to recover carrying costs for a thirty-nine month amortization period. The Commission found that an inordinately large deferred account balance reflected in Panhandle's filing—over $270 million—was attributable primarily to Panhandle's high cost of purchased gas, including, significantly, the introduction into its system supply of high cost LNG. The court found that substantial evidence supported the Commission's determination.

I. Retroactive Rate Reduction

The U.S. Supreme Court denied a petition for certiorari filed by the Arkansas-Louisiana Gas Company to review a D.C. Circuit affirmation of FERC Opinion No. 160[60] in *Arkansas-Louisiana* Gas Co. v. FERC.[61] The Commission, in Opinion No. 160, had disallowed a proposed rate increase by the pipeline (ArkLa) imposing a refund obligation on excess rate charges. Pointing to the refund floors in its last effective rate, ArkLa argued that the refund obligation was unlawful to the extent it retroactively reduced its rate below the floor level. The Commission determined that the refund floor was ArkLa's "old 1977 base tariff rate," or last FERC approved rate, which had not been changed by any of the company's interim PGA filings.

J. Royalty Payments

In *Sun Oil Company v. Wortman*,[62] the Supreme Court vacated and remanded a Kansas Supreme Court ruling which held that Sun Oil Company (Sun) was liable for interest on royalty payments to royalty owners in six states where a small amount was paid to lessors from Kansas. The Court instructed the Kansas Supreme Court to reconsider its decision in light of *Phillips Petro-*

59. 777 F.2d 739 (D.C. Cir. 1985).
60. 21 F.E.R.C. ¶ 61,125 (1983), *aff'd*, 737 F.2d 1206 (D.C. Cir. 1984).
61. 105 S. Ct. 1227 (1985).
62. 106 S. Ct. 40 (1985).

leum Co. v. Shutts.[63] In the latter case, the Court had ruled that the Kansas court exceeded its constitutional limits by applying Kansas state law to claims to recover interest on royalties which were suspended, where only a small portion of the claims in question related to royalty owners residing in Kansas. Noting the substantive differences among neighboring state laws which apply to royalty claims, including variations on how interest on the claims should be calculated, the Court remanded the *Phillips* case to the Kansas Supreme Court for further proceedings.

K. *State Regulation of Production and Pipeline Purchasing Practices*

The U.S. Supreme Court granted certiorari in *Transcontinental Gas Pipeline Corp. v. State Oil & Gas Board.*[64] In this case, Transcontinental Gas Pipeline Corp. (Transcontinental or Transco) appealed the September 1984 decision of the Mississippi Supreme Court upholding the authority of the Mississippi State Oil and Gas Board (Board) to order the pipeline (Transco) to purchase NGPA deregulated gas in ratable quantities from all producers in a common pool. The basis of the proceeding concerns Transco's refusal to purchase gas from non-contract owners, unless they agreed to a "market out" price of $5 per MMBtu, the same price offered to producers in the pool with whom Transco had gas purchase contracts. The Board ruled that Transco's refusal to purchase gas produced from the pool violated the State's ratable take rule. The Board's order was ultimately reviewed and upheld by the Mississippi Supreme Court. However, the Mississippi Supreme Court did overturn the ruling insofar as it had prohibited Transco from paying different prices to producers in the common pool, stating that the Board was without authority to regulate wellhead prices and likewise without authority to require pipelines to purchase gas without discrimination as to price. Transco appealed the Mississippi decision to the U.S. Supreme Court on the grounds of federal preemption under the supremacy clause by the NGA and NGPA and violation of the commerce clause. The Supreme Court subsequently overturned the Mississippi Supreme Court, holding that ratable taking rules applied to interstate pipelines are pre-empted under the supremacy clause.[64.1]

L. *Tax Allowance*

In *City of Charlottesville v. FERC,*[65] the court upheld Commission Opinion No. 173, which reaffirmed use of the stand-alone methodology to calculate the tax allowance included in the rates of jurisdictional companies. The court rejected the argument that the stand-alone approach was unlawful *per se.* The court generally endorsed the "benefits/burdens" theory, as applied by the Commission for allocating tax deductions for stand-alone purposes. The court agreed that pipeline customers which contributed to the expenses that created affiliated loss deductions in the consolidated tax group should receive the re-

63. 105 S. Ct. 2965 (1985).
64. 105 S. Ct. 1840 (1985).
64.1. Transcontinental Gas Pipeline Corp. v. State Oil & Gas Bd., 106 S. Ct. 709 (1986).
65. 774 F.2d 1205 (D.C. Cir. 1985).

lated tax benefits. The court accepted the Commission's conclusion that the alleged burdens borne by the ratepayers were too far removed from the tax benefits in question to justify a sharing of consolidated tax savings with ratepayers in this proceeding.

III. COMMISSION ACTION ON NGPA ISSUES

A. *Refunds*

In Final Rule RM83-53, the Commission gave pipelines the option of making refunds through billing adjustments to producers for interim collections made pending final NGPA category determinations. Under the old program, such "interim collection" refunds could be made only through lump sum payments. Addition of the "billing adjustment" option brings "interim" collection refunds in line with the Commission's general refund regulations.

The new refund procedure requires pipelines to inform producers of their intent to refund interim collections through billing adjustments or to state the amount of refund involved and the time period over which billing adjustments will be made. The pipeline must begin adjusting its bills at least 60 days before the refund becomes due.

B. *NGPA Section 110 Production-Related Costs*

In *Transcontinental Gas Pipe Line Corp.*,[66] the Commission conditionally authorized the pipeline (Transco) to bill its customers directly for an estimated $128 million in retroactive production-related cost allowances paid or to be paid to Transco's producer-suppliers. The costs would otherwise be recovered through the pipeline's PGA mechanism. The Commission determined that the direct billing of the costs would be "administratively effective and equitable" and would avoid distortion of pricing signals through the PGA mechanism due to the "influx of substantial retroactive Order 94-A costs." Under the proposal approved by the Commission, each of Transco's customers would be directly billed in proportion to its purchases during each month of the past period to which the retroactive allowances applied. The Commission directed Transco to report: (1) its actual disposition of remaining balances within thirty days after the end of the twelve-month billing period approved in the order; (2) details regarding $32.3 million previously collected through Transco's customers within fifteen days after the refunds were made; and (3) information needed to verify the accuracy of its retroactive allowance payments.

IV. COURT ACTION ON NGPA ISSUES

A. *Additional Incentive Charge for NGPA Section 311 Transportation*

In *Consolidated Edison Co. v. FERC*,[67] the Court dismissed the petition of Consolidated Edison Company (ConEd) for review of the Additional Incentive Charge (AIC) permitted by the FERC for pipelines engaging in the trans-

66. 32 F.E.R.C. ¶ 61,230 (1985).
67. 757 F.2d 1328 (D.C. Cir. 1985).

portation blanket certificate program. ConEd [joined by the Association of Gas Distributors (AGD)] petitioned the court to vacate the challenged FERC regulation insofar as the regulation provided for an incentive to transport gas for end-users only through adoption of an AIC. The petitioners also requested that end-user transportation be structured to encompass relief from minimum bill provisions and payment of demand charges. The court dismissed the petition because the AIC program was no longer operative pursuant to FERC's Order No. 319-B,[68] and because the FERC had a pending rulemaking on transportation services in its Docket No. RM85-1-000, *Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol* (see Part I., O., above).

B. Commission Authority over Producer Refunds

In *Interstate Natural Gas Assoc. v. FERC*,[69] the court directed the FERC to implement the refund procedures set forth in the latter's Order No. 399.[70] The court had previously rejected the FERC's "dry" method of measurement of the Btu content of natural gas for wellhead pricing purposes as inconsistent with the legislative purpose of the NGPA.[71] The FERC had responded in its Order No. 399 with a rule requiring "wet" measurement of Btu content and directing producers to refund the excessive charges arising from the use of the improper "dry" method of calculation.

In the Commission's rulemaking proceeding culminating in Order No. 399, various parties had advocated that refund obligations owed by pipelines to producers as "Section 110 costs" provided for in FERC Order No. 94-A,[72] should be permitted to offset whatever refund obligations were owed by producers to pipelines as a result of the improper method of Btu measurement. The FERC rejected the offset proposal in Order No. 399 as being administratively burdensome for it to monitor.[73] But on rehearing of Order No. 399, the FERC reversed its decision and authorized producers to offset Btu measurement refund obligations by deducting Section 110 refunds due them, Order No. 399-A.[74]

Associated Gas Distributors moved the court for an order for the FERC to comply with the court's mandate that producers make immediate refunds. The court construed the motion as a petition to review Order No. 399-A, the FERC arguing that the court's mandate did not extend to the offset question. The court rejected the offset provision of Order No. 399-A essentially for the same reasons which were specified by the Commission in Order No. 399. The court discussed the then pending appellate litigation concerning Section 110 costs in *Texas Eastern Transmission Corp. v. FERC*[75] (discussed below). Since the NGPA Section 110 litigation and Btu measurement orders involved different

68. 50 Fed. Reg. 3506 (1985).
69. 756 F.2d 166 (D.C. Cir. 1985).
70. 49 Fed. Reg. 37,735 (1984).
71. 716 F.2d 1 (D.C. Cir.) *cert. denied*, 104 S. Ct. 1615 (1983).
72. 48 Fed. Reg. 5152 (1983).
73. 49 Fed. Reg. 37,739 (1984).
74. *Id.* 46,353 (1984).
75. 769 F.2d 1053 (5th. Cir. 1985).

issues, the court found that unnecessary refund delays would be created if offsetting the refund obligations were permitted. The court stated that refunds are required at the earliest possible moment. The offset scheme embodied in Order No. 399-A failed to accomplish this; hence, the court prohibited offsets to be made between Section 110 costs and Order No. 399 refunds.

C. NGPA Section 110 Production-Related Costs; NGPA Title I

In *Texas Eastern Transmission Corp. v. FERC*,[76] the court issued a decision generally upholding the Commission in consolidated litigation involving three separate issues. First, the court affirmed, with minor modifications, Order No. 94-A,[77] and several related orders establishing regulations governing recovery of production-related cost allowances by first sellers of natural gas under NGPA Section 110. The court reversed and remanded the Commission's failure to provide a protest procedure allowing parties to attempt to prove that an area rate clause does not presumptively establish contractual intent to pay Section 110 delivery allowances. Second, the court affirmed a declaratory order[78] in which the Commission had ruled that the cost or value of services performed by pipeline purchasers in transporting producer-owned liquids or liquefiable hydrocarbons is not to be considered as part of the price for first sales of natural gas under Title I of the NGPA. Third, the court dismissed petitions for review of conditions attached to hundreds of pipeline certificate orders prohibiting pipeline purchasers from recovering in their rates any costs incurred in transporting producer-owned liquids and liquefiables. The court held that the latter orders were not yet ripe for review.

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76. *Id.*
77. 22 F.E.R.C. ¶ 61,055 (1983).
78. *Id.* ¶ 61,013 (1983).