Report of the Committee on Natural Gas Rate and Accounting Regulations

I. Commission Action on Pipeline Issues

A. *Account 858 Costs and Assignment of Upstream Transportation Capacity*

In *Texas Gas Transmission Corporation*,[1] the Federal Energy Regulatory Commission (Commission) approved a proposal by Texas Gas Transmission Company (Texas Gas) to track Account No. 858 costs (payments to upstream pipelines for transportation service) and to adjust its rates semiannually to account for any changes in such costs. Texas Gas originally also sought authority to direct bill its customers for the balance of any unrecovered transportation costs. In response to objections from numerous parties this provision was changed to allow recovery of the balance in Texas Gas' next rate case. In the same order, the Commission modified Texas Gas' proposal to assign its firm transportation capacity on upstream pipelines. Under its proposal, Texas Gas would not have imposed an additional charge for the use of upstream capacity. Instead the costs would be included in its rates. Thus, all Texas Gas shippers would pay the costs incurred in connection with the assigned upstream capacity, regardless of whether they used it. The Commission rejected the proposal and required that Texas Gas charge a separate rate for the use of upstream capacity and credit amounts collected against its Account No. 858 costs.

B. *Allocation of Capacity*

In *Pacific Gas Transmission Company*,[2] the Commission granted rehearing in part and concluded that Pacific Gas and Electric Company (PG&E) should have equal priority with interruptible shippers to the excess capacity of its subsidiary, Pacific Gas Transmission (PGT). In an earlier order, the Commission had determined that, because of PG&E's historical use of overrun service in meeting its customer requirements, PG&E should have the highest interruptible priority.[3] On rehearing, the Commission directed PGT to allocate the excess capacity through a competitive bidding system under which bids could not exceed PGT's Rate Schedule PL-1 rate, based on a 100 percent load factor.

C. *"At-Risk" Rate Considerations*

The Commission issued several orders in 1991 placing pipeline applicants at risk for pipeline construction costs. In Order No. 555,[4] the Commission

1. 57 F.E.R.C. ¶ 61,236 (1991).
2. 55 F.E.R.C. ¶ 61,004 (1991).
3. Pacific Gas Transmission Co., 53 F.E.R.C. ¶ 61,433 (1990).
4. *Revisions to Regulations Governing Authorizations for Construction of Natural Gas Pipeline Facilities*, III F.E.R.C. Stats. & Regs. ¶ 30,928 (1991). The Final Rule rescinded the Commission's previously-adopted OEC regulations.

adopted regulations to expedite construction of new pipeline facilities. The Final Rule sets out a variety of pipeline construction authorization options and a choice of rate options which pipelines may adopt and combine in different ways to best accommodate their own projects and customers. However, in response to numerous requests for rehearing of Order No. 555, on November 13, 1991, the Commission postponed the effective date of the Final Rule until 30 days after publication in the Federal Register of an order on rehearing.[5]

The Final Rule places pipeline applicants at risk for pipeline construction costs for capacity that may exceed customers' needs. The Final Rule maintains the traditional section 7(c) certificate and codifies the seven criteria of *Kansas Pipe Line & Gas Company*[6] at section 157.102(b) of the Commission's Regulations. However, the Final Rule relaxes the traditional supply and market evidence requirements of the *Kansas Pipe Line* standard. The new criteria only require an applicant to file a statement describing that the production areas accessed by the proposed construction project contain sufficient existing or potential gas supplies for the proposed project, and how those production areas are connected to the proposed construction. The Commission then modified the market demand standard to require an applicant to show that it has ten-year contracts in hand for 100 percent of the proposed facility's capacity as a demonstration of demand for the project. The Commission also stated that it will no longer look behind the contracts to determine if there is an actual market, but will instead accept contracts as sufficient evidence of market demand.

For pipelines that do not meet the *Kansas Pipe Line* criteria, the rule implements the "at-risk" requirement to govern the recovery of the costs of the underutilized capacity. Under this requirement, pipelines will remain at-risk for the recovery of construction costs until they can meet the *Kansas Pipe Line* standard or meet the "net benefits test" in a subsequent section 4 rate proceeding under the Natural Gas Act (NGA). The "at-risk" provisions will apply uniformly to all newly constructed pipeline facilities that do not satisfy the *Kansas Pipe Line* criteria where the pipeline proposes to charge cost-based rates for its approved sales and/or transportation services.[7]

To meet the "net benefits test," a pipeline must demonstrate that incremental revenues exceed the cost of service of the new facilities. The Final Rule does not require new facilities that are "at-risk" to remain under incremental rates. Instead, the Commission could determine that rolling the costs of new facilities into system rates would offer an "overall benefit" to the pipeline's customers and, therefore, roll-in those costs. The Commission expects to conduct the same analysis for the "overall benefits" test as it does when it

5. Order Granting Rehearing for Further Consideration and Postponing Effective Date of Order No. 555, 57 F.E.R.C. ¶ 61,195 (1991).

6. 2 F.P.C. 29 (1939).

7. The Final Rule also adopts conditions prohibiting pipelines from cost shifting, places restrictions on reservation fees, and prohibits lowering throughput volumes for integrated facilities in subsequent rate cases. The Rule also creates minimum throughput levels for designing rates: for firm transportation reservation fees and firm sales demand charges, 100 percent of the facility's daily capacity, and for firm transportation usage charges, firm sales commodity charges and interruptible volumetric rates, 90 percent (onshore facilities) and 60 percent (offshore facilities) of the facility's annual capacity.

determines whether to roll-in costs of incremental facilities into existing system-wide rates.[8]

In addition, Order No. 555 offers interstate pipelines that build under the self-implementing procedures a choice of recovery options, including a new abbreviated NGA section 4 procedure by which a pipeline may change its existing cost-based rates to recover the costs of a newly-constructed facility through either a cost-based or negotiated incremental rate.[9] Under the abbreviated rate filing, an additional rate schedule will not be necessary. The incremental rate will be separately stated within the applicable existing open-access rate schedules.

In the *Mobile Bay Pipeline Projects*,[10] the Commission placed the applicants at-risk for the costs of any capacity not supported by executed transportation contracts at the time they seek to include the costs in their rates. The Commission relied on the reasoning of Order No. 555 to support its "at-risk" condition.

In *Arkla Energy Resources*,[11] the Commission placed Arkla Energy Resources (Arkla) at-risk for the costs associated with the construction of 225 miles of pipeline facilities. Arkla constructed the pipeline facilities (Line AC) pursuant to section 311 of the Natural Gas Policy Act of 1978 (NGPA) and then sought a section 7(c) certificate to operate the facilities. In granting Arkla the certificate, the Commission noted that its policy of requiring applicants for section 7(c) construction authority to have executed firm contracts for the capacity proposed prior to construction should also apply to facilities constructed under section 311 and operated under a section 7(c) certificate. However, the Commission stepped away from a rigid adherence to the firm contract requirement and instead placed Arkla at risk by allowing it to recover only those costs associated with the capacity for which executed firm contracts existed.

In *Arkla Energy Resources*,[12] the Commission granted rehearing of its suspension order which eliminated the costs of Line AC from Arkla's rate base.[13] In the suspension order, the Commission held that exclusion of costs from the rate base was appropriate because Line AC's capacity was not fully subscribed under long-term firm contracts. The Commission permitted Arkla to include the Line AC costs in its rates subject to refund because the Commission was reviewing the "at-risk" condition in its construction rulemaking and was rehearing Arkla's certificate order. The Commission stated that the D.C. Circuit's recent decision in *ANR Pipeline Company v. FERC*[14] supported its ruling.

In authorizing ANR Pipeline Company (ANR) to construct Phase II of

8. *See* Section I, subsection J, *infra*, for recent developments on rolled-in versus incremental rates.

9. *See* Section I, subsection N, *infra*, for discussion of the negotiated rate provisions of the Final Rule.

10. 55 F.E.R.C. ¶ 61,358, *reh'g*, 57 F.E.R.C. ¶ 61,050 (1991).

11. 54 F.E.R.C. ¶ 61,033 (1991).

12. 56 F.E.R.C. ¶ 61,090 (1991).

13. 54 F.E.R.C. ¶ 61,081 (1991), *reh'g* 56 F.E.R.C. ¶ 61,090 (1991).

14. 931 F.2d 88 (D.C. Cir. 1991). *See* Section II, subsection G, *infra*.

its facilities to serve the northeastern United States, the Commission required ANR and other pipeline applicants to remain "at-risk" for any pipeline capacity for which they did not have firm transportation contracts.[15] The Commission explained that allocating the risk of capacity under-utilization to the pipelines would allow the Commission to authorize construction while continuing to protect present and future customers from unfair contributions to the cost of the new facilities. The pipelines could seek to remove the condition in subsequent section 4 rate proceedings. On rehearing, the Commission refused to remove the "at-risk" condition.[16]

On July 2, 1991, the Commission issued a preliminary determination on non-environmental issues in *Colorado Interstate Gas Company*,[17] a proceeding involving construction of 223 miles of 20-inch pipe at an approximate cost of $85 million. In this order the Commission addressed the "at-risk" condition and rolled-in rate treatment for the new facilities. Colorado Interstate Gas Company (CIG) had firm contractual commitments of no less than six years for 174,000 Mcf/d of the 178,000 Mcf/d capacity that would result from the new construction. Of that 174,000 Mcf/d commitment, however, 60,000 Mcf/d was to be reserved for CIG's system supply. Without addressing the sufficiency of the existing contracts, the Commission allowed CIG to recover only the costs associated with capacity for which it had executed firm contracts.

The Commission subjected the reserved system supply capacity and the costs associated with it to a separate "at-risk" requirement. CIG has existing contractual agreements with Questar Pipeline Company (Questar) to move the same supplies and will continue to have a demand charge obligation to Questar for that capacity after construction of its new facilities. Accordingly, the Commission required CIG to show: (1) that the new facilities are used and useful; (2) that the use of the new facilities is an economically superior alternative to the Questar service; and (3) that CIG's sales customers are not subsidizing the cost of the new facilities.

D. *Filed Rate Doctrine*

In *Kentucky West Virginia Gas Company and Columbia Gas Transmission Corporation*,[18] the Commission rejected a proposed settlement under which Columbia Gas Transmission Company (Columbia) agreed to pay Kentucky West Virginia Gas Company (Kentucky West Virginia) approximately twenty-five million dollars, which was attributable to the repricing of Kentucky West Virginia's pipeline production at applicable NGPA rates. A condition of the proposed settlement provided that the Commission would allow Columbia to pass through the settlement costs on an as-billed basis. The

15. 54 F.E.R.C. ¶ 61,032 (1991) (preliminary determination); 55 F.E.R.C. ¶ 61,415 (1991) (certificate).

16. 55 F.E.R.C. ¶ 61,415 (1991); *see also* Natural Gas Pipeline Co. of America, 55 F.E.R.C. ¶ 61,436 (1991).

17. 56 F.E.R.C. ¶ 61,015 (1991).

18. 54 F.E.R.C. ¶ 61,246 (1991).

Commission rejected the settlement as inconsistent with a previous settlement between Columbia and its customers.

The Commission reaffirmed its belief that its original orders authorizing Kentucky West Virginia to direct bill costs to Columbia "remain valid in spite of subsequent decisions [including] *Associated Gas Distributors v. FERC*,"[19] where the court overturned Commission orders authorizing retroactive direct billing of take-or-pay costs as a violation of the filed rate doctrine.[20] The Commission distinguished this case from *Associated Gas Distributors* (*AGD*) because Columbia had notice of Kentucky West Virginia's claim to NGPA prices. Further, the Commission allowed Kentucky West Virginia to recover costs through a direct bill "as a means of correcting the Commission's legal error" in denying collection of these costs in the past.[21]

In *El Paso Natural Gas Company*,[22] the Commission approved a request by El Paso Natural Gas Company (El Paso) that rates negotiated by the pipeline under its market-based gas inventory charge and filed with the Commission be kept confidential until the end of the month during which the rates are in effect. Citing its previous decision in *Natural Gas Pipeline Company of America*,[23] the Commission found that requiring El Paso to release its current actual rates to its competitors could place the pipeline at a competitive disadvantage and prevent customers from obtaining the lowest possible rates. The Commission stated that the NGA requires that the rate be on file with the Commission and does not require that the rates be available to a pipeline's competitors.

E. Fuel Use and Unaccounted-for Gas

In *CNG Transmission Corporation*,[24] the Commission reviewed CNG Transmission Company's (CNG) annual purchased gas adjustment (PGA) filing and determined that its sales customers were subsidizing the fuel use and lost and unaccounted-for gas costs associated with transportation services. Consequently, the Commission declared CNG's existing tariff provisions unjust and unreasonable and required CNG to file revised tariff language and revised PGA rates to remove the non-sales fuel use and unaccounted-for gas costs from its sales rates.

F. Gas Inventory Charge

In *Panhandle Eastern Pipeline Company*[25] and *Natural Gas Pipeline Company of America*,[26] the Commission made clear that a pipeline must be well on the way toward achieving full comparability of sales and transportation services to be eligible for a gas inventory charge (GIC) mechanism for the recov-

19. 893 F.2d 349 (D.C. Cir. 1989).
20. 54 F.E.R.C. ¶ 61,246, at 61,724.
21. *Id.*
22. 57 F.E.R.C. ¶ 61,273 (1991).
23. 55 F.E.R.C. ¶ 61,416 (1991).
24. 56 F.E.R.C. ¶ 61,345 (1991).
25. 54 F.E.R.C. ¶ 61,303 (1991).
26. 54 F.E.R.C. ¶ 61,304 (1991).

ery of gas supply costs. The Commission confirmed on rehearing that Natural Gas Pipeline Company of America (Natural) was eligible for a cost-based GIC, even though "the Commission recognizes that Natural's firm sales and transportation services are not entirely equivalent."[27] The Commission noted that Natural had offered customers an opportunity to convert 100 percent of their firm sales service to firm transportation; that converting customers were eligible for a percentage of the available storage service; and that Natural had a plan in place to allocate capacity on a system-wide, non-discriminatory basis between sales and transportation customers.

In contrast, the Commission denied Panhandle Eastern Pipeline Company's (Panhandle) application to implement a deficiency-based gas inventory charge because the proposal was "substantially deficient with respect to comparability of service."[28] The Commission noted four areas in which Panhandle's proposal was lacking. First, Panhandle "has not demonstrated that its customers were offered the option to convert 100 percent of their previous entitlements."[29] Second, "Panhandle has not offered any contract storage services for converting customers."[30] Third, "the Commmission expressed concern about the lack of a clear method to allocate mainline capacity."[31] Fourth, Panhandle's filing "does not specify how it will retain or allocate receipt-point capacity."[32]

In *El Paso Natural Gas Company*,[33] the Commission approved a market-based gas inventory charge proffered by El Paso as part of that company's global settlement. The Commission found specifically that El Paso's firm sales customers would have the right to convert up to 100 percent of their firm sales to firm transportation that would be comparable in quality to the transportation which would be provided under the GIC. The Commission also found that El Paso's sales price would be constrained by the market. Therefore, a "lightened regulatory hand" was appropriate. In making this determination, the Commission held that there were sufficient divertible supplies of gas to prevent El Paso from exercising any market power under its GIC mechanism.

In *Transcontinental Gas Pipe Line Corporation*,[34] the Commission approved two settlements which included a market-based GIC for Transcontinental Gas Pipeline Corporation (Transco). Noting that customers were not coerced to join in the settlements, the Commission concluded that "Transco's markets are sufficiently competitive to preclude it from exercising significant market power in its merchant function because . . . Transco will be providing comparable transportation service with respect to all gas supplies whether purchased from Transco or its competitors and because adequate divertible gas supplies exist."[35] Because Transco will be constrained by competition

27. *Id.* at 61,878.
28. 54 F.E.R.C. ¶ 61,303 at 61,875.
29. *Id.* at 61,873.
30. *Id.* at 61,874.
31. *Id.*
32. *Id.*
33. 54 F.E.R.C. ¶ 61,316 (1991).
34. 55 F.E.R.C. ¶ 61,446 (1991).
35. *Id.* at 62,334.

from increasing prices above market levels, such a GIC could be approved.

In *Northwest Pipeline Corporation*,[36] the Commission denied rehearing of an order[37] in which it had authorized Northwest Pipeline Company (Northwest) to implement a GIC for its larger sales customers and which denied a request of Northwest's customers that Northwest's GIC be conditioned on waiver of its right of pregranted abandonment. The Commission reaffirmed its earlier conclusion that protection through an evergreen clause is not required due to the stability of long-term contracts, potential entry by alternative pipelines, and ready access to alternative sources of gas.

The Commission clarified the priority status of firm transportation shippers when a successor contract is executed. The Commission stated that firm transportation shippers will preserve the same priority if the parties negotiate a successor contract to take effect on expiration of the preexisting contract which involves the same parties, the same volumes, and the same delivery points, and the shippers are willing to pay the maximum rate.

G. Gas Research Institute

In Opinion No. 365, *Gas Research Institute*,[38] the Commission approved the Gas Research Institute (GRI) 1992 research and development (R&D) program and GRI's 1992-1996 five-year R&D plan. As a result of this approval, in 1992 all interstate pipeline company members of GRI are permitted to recover a 1.47 cents per dekatherm (Dth) funding unit increment on all applicable sales and transportation rates.

The Commission also addressed issues on remand from *Process Gas Consumers Group v. FERC* (*PGC II*).[39] In *PGC II*, the Court remanded to the Commission for further review of GRI's funding in 1988 and 1989 of projects related to R&D on natural gas vehicles (NGVs), emission controls and industrial refrigeration. In Opinion No. 365 the Commission ruled that: (1) GRI justified previous and future funding for NGVs pursuant to recently enacted legislation in the Energy and Water Development Appropriations Bill of 1992, P.L. 102-104, which permits the Commission to approve NGV and emission controls R&D activities; (2) previous and future funding for the emission controls project was justified under both the *PGC II* "net benefits test" and P.L. 102-104; and (3) based on equitable principles, GRI is not required to decrease future R&D program funding due to past Commission-approved expenditures for industrial refrigeration R&D that cannot be justified under the "net benefits test" (GRI did not propose to fund this activity in 1992).

H. Gathering Costs in Rates

In Docket No. PL91-2,[40] the Commission announced a new policy with

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36. 56 F.E.R.C. ¶ 61,297 (1991).

37. 51 F.E.R.C. ¶ 61,179 (1990).

38. 57 F.E.R.C. ¶ 61,010 (1991).

39. 930 F.2d 926 (D.C. Cir. 1991). *See* Section II, subsection D, *infra*.

40. *Interstate Natural Gas Pipeline Rate Design, Policy Statement with Respect to the Recovery of Gathering Costs*, 56 F.E.R.C. ¶ 61,086 (1991).

regard to the recovery of gathering costs in interstate pipeline rates. Traditionally, the Commission has authorized the recovery of gathering costs only as part of the commodity charge. In the Policy Statement, the Commission determined that the jurisdictional test set out in *Farmland Industries, Incorporated*[41] will not control the rate treatment of a pipeline's production area facilities. The Commission indicated that it would continue to functionalize facilities between gathering and transmission as it has always done in order to determine the applicable depreciation rate and other elements of the cost of service. However, the Commission stated that parties should consider what rate treatment is appropriate in furthering the objectives of the Commission's rate design policies. The Policy Statement noted that any pipeline proposing to change its historical method of cost recovery should be prepared to show the impact of the change on its customers.

On July 22, 1991, the Commission approved a settlement in *Williams Natural Gas Company.*[42] In that settlement, Williams Natural Gas Company (WNG) proposed to refunctionalize certain of its gathering facilities from gathering to transmission. The Commission, over the objections of Amoco Production Company (Amoco), determined that the refunctionalization was supported by the traditional primary function criteria. Consistent with the new Statement of Policy, the Commission noted that the refunctionalization decision would not be controlling for rate purposes.

The Commission also addressed a charge by Amoco that WNG failed to credit sufficient revenues derived from processing to its cost of service. Amoco claimed that WNG had understated liquid revenues by failing to include revenues received from processing transportation gas through Oxy USA, Incorporated's Jayhawk plant. WNG replied that all extradition revenues were properly credited where it removed liquids and liquifiables as necessary to permit efficient jurisdictional operations. WNG also asserted that it would be "clearly illegal" to credit its jurisdictional cost-of-service revenues received from nonjurisdictional operations performed at facilities not owned by WNG.[43] Nevertheless, the Commission conditioned acceptance of the settlement on modification of WNG's tariff. The Commission required WNG to give shippers paying gathering and transportation rates the option to (1) pay gathering and transportation charges based on the shippers' receipt of revenues generated by the sale of products extracted from their gas (offset by the costs of such extraction), or (2) pay gathering and transportation rates without any offset but with the option to enter into separate and direct contractual arrangements with third-party plant operators.

I. Incentive and Market-Oriented Ratemaking

On December 31, 1991, the Commission rejected incentive rate mechanisms proposed in a general rate increase filing in *Viking Gas Transmission Company.*[44] One proposed mechanism, the Quarterly Rate Adjustment Mech-

41. 23 F.E.R.C. ¶ 61,063 (1983).
42. 56 F.E.R.C. ¶ 61,089 (1991).
43. *Id.* at 61,311.
44. 57 F.E.R.C. ¶ 61,417 (1991).

anism (QRAM), would have adjusted Viking Natural Gas Transmission Company's (Viking) rates each quarter to reflect the general inflation or deflation in the economy. The Commission explained that the proposal deviated from the Commission's long-standing policy of using embedded costs to determine pipeline transportation rates. In addition, the Commission rejected Viking's firm transportation (FT) bidding proposal because the suggested price caps were tantamount to market-based rates and Viking had not made even a preliminary showing that it lacked market power in firm transportation. However, the Commission accepted Viking's interruptible transportation bidding proposal and suspended it for five months, observing that the proposal was tied to a cost-based cap. Although the QRAM and FT incentive mechanisms were rejected, the Commission stated that "it is receptive to exploring the concept of incentive regulation and whether and how it can be integrated into, on a prospective basis, its approach to determining pipeline rates."[45] In the appendix to its order, the Commission set out a series of questions concerning incentive rates that the parties could address at the technical conference required by the suspension order.

In *United Gas Pipe Line Company*,[46] the Commission approved, with certain modifications, an uncontested settlement. Among other things, the settlement provided for: (1) a decrease of more than forty million dollars from United Gas Pipe Line Company's (United) previous rate levels; (2) establishment of an 18-month experimental "Market-Responsive Storage and Delivery Service" (MRSDS), with a cap on revenue recovery and a revenue sharing requirement applicable to the MRSDS; (3) suspension of United's PGA for one year; (4) establishment of gas commodity charges calculated monthly on the basis of a market price index; (5) one year "best efforts" purchase commitments by distributor customers; and (6) use of a straight fixed variable (SFV) rate design in order to lower commodity rates and maximize throughput.

When United filed the settlement on September 30, 1991, it requested that the Commission act by October 17 because: (1) MRSDS service could not be marketed unless implemented before the start of the winter heating season; and (2) citygate customers who agreed to purchase certain minimum quantities from United under the settlement had to make purchase arrangements for the month of November by October 18. The Commission's October 22nd order stated that the settlement evidenced "a disdain for the Commission's responsibilities to ensure that rates and services are consistent with the public interest . . .[and that] no one should expect such extraordinarily expedited consideration, as has been given here, to be readily given in other cases."[47]

In *Canyon Creek Compression Company*,[48] Canyon Creek Compression Company (Canyon) submitted a proposed efficiency adjustment based on reduced labor costs in a general rate increase filing. Canyon claimed that the labor cost reductions experienced since its last rate case were attributable to

45. *Id.* at 62,356.
46. 57 F.E.R.C. ¶ 61,086 (1991).
47. *Id.* at 61,311-313.
48. 55 F.E.R.C. ¶ 61,148, *reh'g. denied*, 56 F.E.R.C. ¶ 61,140 (1991).

efficiency gains and proposed that it be compensated for such efficiencies by adding seventy-five percent of such reductions to its cost-of-service in the new rate case. Asserting that Canyon's proposed efficiency adjustment did not constitute a properly structured incentive rate mechanism, the Commission rejected Canyon's proposal. The Commission stated that, "[a] properly structured incentive mechanism is prospective and intended to encourage otherwise unanticipated future actions . . . By contrast, the proposed adjustment is based on historical cost savings and actions."[49]

J. *Incremental Rates for New Facilities*

In Opinion No. 367, issued in *Great Lakes Gas Transmission Limited Partnership*,[50] the Commission considered whether to adopt incremental or rolled-in rate treatment for three of Great Lakes Transmission Ltd.'s (Great Lakes) previously authorized expansion projects. In total, the expansion projects accounted for $557 million (or 58.4 percent) of Great Lakes' rate base. The Commission noted that its review of this issue focuses on whether the pipeline operates on an integrated basis and whether the expansion will provide benefits to existing customers that are commensurate with rolled-in rate treatment. In holding that incremental rate treatment would be just and reasonable, the Commission relied on the following factors: (1) rolled-in pricing would have resulted in cross-subsidization because the benefits of the expansion do not equal or exceed the costs to existing customers — the Commission stated that rolled-in treatment would have resulted in a cost shift to existing customers of approximately $50 million; (2) the benefit of increased reliability to the entire system from mainline looping would not be commensurate with the $50 million cost shift, as there was no evidence that Great Lakes would be unable to provide reliable service, and the benefit of looping is not as significant on a system, such as Great Lakes, where the customers have more than one source to obtain gas supplies; (3) the additional capacity will not benefit existing customers by providing additional interruptible and overrun capacity; (4) the level of fuel savings resulting from the expansion is not commensurate with the increased costs; and (5) rolled-in pricing would contravene the Commission's Rate Design Policy Statement by allowing cross-subsidization, increasing costs to existing customers without providing proper pricing signals to customers requesting incremental service.

In Opinion No. 368,[51] the Commission largely reversed an ALJ's decision on three rate design issues on Great Lakes. First, the Commission held that Great Lakes must charge incremental rates prospectively for transportation service through two expansion projects. As in Opinion No. 367, the Commission held that existing customers, under rolled-in rates, would not receive systemwide benefits commensurate with the rate increase. The Commission stated that, in this case, the incremental methodology "ensures that cost responsibility follows cost incurrence and that only economically justified

49. 55 F.E.R.C. ¶ 61,148, at 61,461.

50. 57 F.E.R.C. ¶ 61,140 (1991).

51. 57 F.E.R.C. ¶ 61,141 (1991).

expansions are constructed."[52]

The Commission also reversed the ALJ's adoption of an enhanced fixed variable approach, and instead, ordered that a straight fixed variable (SFV) methodology be implemented. The Commission held that higher demand rates for Great Lakes' firm service would better ration capacity. The opinion noted that because rolled-in treatment was rejected and existing customers' rates will not reflect any cost for expansion, the SFV approach would not cause as significant a cost shift as was feared by the ALJ.

Because the Commission ordered a move to SFV in order to ration capacity, it required that Great Lakes have a capacity-releasing program in place before SFV is made effective. The Commission stated that "[h]igher demand charges without a means to respond to them would not lead to an efficient allocation of capacity."[53]

With respect to interruptible and authorized overrun service, the Commission affirmed the ALJ's finding that rates should be set at a 140 percent load factor level. The Commission found that this load factor level would help to maximize throughput and increase system efficiency consistent with the Rate Design Policy Statement. The Commission also noted that use of the 140 percent level appropriately reflects the lower quality of these services as compared to firm services.

K. Liens by Pipelines on Customer Gas

In *Algonquin Gas Transmission Company and Texas Eastern Transmission Corporation*,[54] the Commission rejected tariff sheets filed proposing to establish liens on customer-owned natural gas to secure payment of charges due for transportation, storage, or other services. Further, the Commission indicated that the provisions were vague and overly broad and the pipelines did not show that their existing tariff provisions were inadequate. The Commission added that, because there was no limitation on the proposed provisions, they appeared to apply to all bills, even those in dispute. Further, the tariff provisions did not detail any important due process procedures, such as how notice and demand would be given. The provisions would also have allowed the pipelines to suspend service. The Commission pointed out that, in past cases, it had permitted suspension of service to a shipper for nonpayment without prior Commission approval only if a pipeline incorporated in its tariff certain notice and assurance provisions similar to those imposed in *Natural Gas Pipeline Company of America*.[55]

L. Management Fee

On December 26, 1991, the Commission in *Tarpon Transmission Company*[56] authorized Tarpon Transmission Company (Tarpon) to collect a man-

52. *Id.* at 61,542.
53. *Id.* at 61,546.
54. 56 F.E.R.C. ¶ 61,267 (1991).
55. 41 F.E.R.C. ¶ 61,164 at 61,408-409 (1987).
56. 57 F.E.R.C. ¶ 61,371 (1991).

agement fee since its gas transmission plant was fully depreciated. The Commission stated that the fee is "an operator's fee to compensate Tarpon's owners for the risks of continuing to operate the pipeline and to provide incentive for efficient operations."[57] The management fee was calculated by applying the current pretax cost of capital to ten percent of the historical average rate base plus any current prepayment balance.

M. Order 636

On April 8, 1992, the Commission issued Order No. 636[58] which substantially revises the current regulation of interstate natural gas pipeline rates and services. The Commission determined that significant remedial measures were necessary in order to improve competition in the industry and to further the creation of an efficient national wellhead market for natural gas. In Order No. 636, the Commission specifically directed interstate pipelines to: (1) unbundle their sales services from their transportation services and adopt market-based pricing for their unbundled sales pursuant to new blanket sales certificates; (2) allow their current firm bundled sales customers to reduce, in whole or in part, their firm sales entitlements on the effective date of the pipeline's new blanket sales certificate; (3) offer firm and interruptible open access storage services; (4) provide open access transportation services that are equal in quality for all gas supplies, whether purchased from pipelines or from third parties; (5) offer no-notice firm transportation service whereby firm shippers may take deliveries up to their firm entitlements without incurring daily balancing or scheduling penalties; (6) provide all shippers with equal and timely access to information through the use of an electronic bulletin board; (7) not include any tariff provision that would inhibit the development of market centers; (8) allow firm transportation customers of downstream pipelines to acquire capacity on upstream pipelines held by the downstream pipeline; (9) implement a capacity releasing program (in lieu of capacity brokering) so that firm shippers can release unwanted capacity to those seeking capacity; (10) offer flexible receipt and delivery points; (11) develop transportation rates under the SFV method of cost classification, allocation, and rate design unless the Commission permits the use of a different methodology (pipelines are required to mitigate cost shifts if the use of SFV produces a ten percent or greater increase in revenue responsibility for any historic customer class); (12) eliminate pregranted abandonment for transportation contracts having a term of at least one year; and (13) develop mechanisms for the full recovery of any transition costs (e.g., Account 191 balances, gas supply realignment costs, stranded Account 858 costs) that pipelines may incur as a result of changes attributable to Order No. 636.

The Commission instituted restructuring proceedings for each interstate pipeline transporting gas under Part 284 of the Regulations and required the pipelines to initiate discussions with their customers and other interested par-

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57. *Id.* at 62,240.

58. Final Rule, *Pipeline Service Obligations and Revisions to regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol*, III F.E.R.C. Stats. and Regs. ¶ 30,939 (1992).

ties as to how to comply with the Final Rule. The Commission ordered pipelines to make restructuring compliance filings on a staggered basis beginning on October 1, 1992, for purposes of implementing the Final Rule. The Commission expects that all pipelines will be in compliance with Order No. 636 no later than November 1, 1993.

On August 3, 1992, the Commission issued Order No. 636-A[59] which, for the most part, denied rehearing of the Final Rule but did make certain changes as follows: (1) pipelines must maintain their one-part volumetric rates, computed at an existing imputed load factor, in deriving their transportation rates for small customers and must offer to sell gas to their small customers at cost-based rates for a one-year period from the effective date of a pipeline's blanket sales certificate; (2) capacity releases of less than one calendar month do not have to be posted on the electronic bulletin board for bidding purposes; (3) parties to the pipelines' restructuring proceedings may consider various ratemaking techniques to distribute revenue responsibility among customers in order to mitigate significant cost shifts resulting from the utilization of the SFV methodology; and (4) pipelines are required to recover ten percent of their gas supply realignment costs from Part 284 interruptible transportation service.

N. Negotiated Rates

Under Order No. 555,[60] pipelines building new facilities may negotiate rates for service with potential shippers. The Commission found the negotiated rates to be consistent with its just and reasonable standard where the pipeline lacks significant market power.

The Final Rule requires a pipeline to complete the competitive negotiation procedure before starting construction of its new facilities. The pipeline must file an announcement describing its proposed facilities and outlining the types of service and the terms of service that will be available. The pipeline must also hold two open seasons. First, the pipeline must hold a "builder" open season for ninety days, to permit other pipelines to state their intentions on constructing competing facilities.[61] Second, it must convene a "shipper" open season for sixty days to allow shippers to negotiate for service and terms with the pipeline.[62] To avoid discrimination, all shippers will be entitled to the lowest reservation fee that is negotiated with any individual shipper, but

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59. Order Denying Rehearing in Part, Granting Rehearing in Part, and Clarifying Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Wellhead Decontrol*, III F.E.R.C. Stats and Regs. ¶ 30,950 (1992).

60. Final Rule, *Revisions to Regulations Governing Authorizations for the Construction of Natural Gas Pipeline Facilities*, III F.E.R.C. Stats. & Regs. ¶ 30,928 (1991).

61. The Final Rule requires a competitor to file a notice of intent to file a competitive application. A complete competitive case-specific application or prior notice filing must be filed within 30 days of expiration of the intervention or protest period in order to receive contemporaneous review.

62. At the end of negotiations, a second announcement must be published if the pipeline intends to continue the project. Parties must attempt to resolve any remaining disputes within 30 days after the second announcement or the Commission will review the complaints and make its own decision within 60 days. All Commission-approved negotiated rates will be permanent, incremental rates and will not be subsequently rolled-in to the pipeline's rates or subject to change in a subsequent general rate proceeding.

the shipper can agree to pay a higher fee in order to encourage the construction of new facilities or to secure a higher priority in the service queue.

O. *"No Bump" Provisions*

In *Mississippi River Transmission Corporation,*[63] the Commission permitted the Mississippi River Transmission Corporation (MRT) to eliminate an administratively burdensome tariff provision which allowed the pipeline to interrupt transportation service during the month to an interruptible transportation shipper paying a discounted rate in order to serve another shipper offering a higher rate. The Commission did, however, order MRT to revise its tariff so that shippers paying a discount could obtain month-to-month protection against being bumped by permitting them the option of continuing to flow their gas if they would be willing to pay the maximum transportation rate being offered by another shipper.

P. *Off Peak Transportation Rates*

In *Columbia Gas Transmission Corporation,*[64] the Commission accepted and suspended tariff sheets filed by Columbia and Columbia Gulf implementing Off Peak Transportation (OPT) service. The proposed OPT service was designed to provide firm transportation service during the off-peak summer period (April 1 through October 31), while permitting Columbia/Columbia Gulf to interrupt OPT service during the winter for a maximum of either thirty or sixty days, as elected by the shipper. During the winter period, prior to expiration of the maximum period of interruption, OPT service would have receipt point priority on an equal, pro rata basis with Columbia's other "quasi-firm" services, including standby sales service.[65] After expiration of the maximum period of interruption, OPT service would have receipt point priority over and above that of Columbia's other "quasi-firm" services.[66]

Q. *Producer Demand Charges*

In *CNG Transmission Corporation,*[67] the Commission terminated a previously authorized limited term waiver[68] of the Commission's Regulations which allowed CNG to pass through to customers, on an as-billed basis, producer demand charges. Numerous parties had protested the Commission's grant of the limited term waiver. After acknowledging that it had granted the limited waivers for CNG, and previously in *Equitrans, Incorporated,*[69] primarily to gain experience with as-billed treatment of producer demand charges, the Commission responded to the numerous protests and arguments against

63. 55 F.E.R.C. ¶ 61,195 (1991).

64. 54 F.E.R.C. ¶ 61,226, *reh'g,* 55 F.E.R.C. ¶ 61,366, *reh'g,* 56 F.E.R.C. ¶ 61,182, *reh'g,* 56 F.E.R.C. ¶ 61,449, *reh'g,* 57 F.E.R.C. ¶ 61,250 (1991).

65. 57 F.E.R.C. ¶ 61,250 at 61,783.

66. *Id.*

67. 54 F.E.R.C. ¶ 61,159 (1991).

68. 18 C.F.R. § 154.305(b)(1). the regulations require a pipeline to reflect producer charges in the commodity component of two-part rates or in the volumetric rates of one-part rates.

69. 52 F.E.R.C. ¶ 61,228 (1990).

the waiver, including allegations of potential anti-competitive consequences, and terminated CNG's waiver. The Commission was persuaded that "the comparability of the pipeline's sales and transportation services must be established before a pipeline is allowed to flow through producer demand charges on an as-billed basis."[70] The Commission noted that as-billed treatment involved many of the same comparability issues as gas inventory charges.

In an order on rehearing in *Tennessee Gas Pipeline Company*,[71] the Commission adhered to its denial of as-billed treatment for producer demand charges.[72] Tennessee Gas Pipeline Company (Tennessee) had requested a waiver of section 154.305(b)(1) of the Commission's Regulations to flow through its PGA, on an as-billed basis, demand gas costs payable to a producer/supplier. The Commission concluded that a determination of comparability of Tennessee's sales and transportation services was necessary prior to approval of any such demand charge, and that the issue should be considered in connection with the comparability issues pending in other proceedings. The Commission thus reaffirmed its position that the comparability of a pipeline's sales and transportation services must be established before a pipeline is allowed to flow through producer demand charges on an as-billed basis.[73]

In *Florida Gas Transmission Company*,[74] the Commission denied a request by Florida Gas Transmission Company (Florida Gas) to pass through producer demand charges on an as-billed basis. The Commission reiterated its policy that a showing of comparability between a pipeline's sales and transportation services is a prerequisite to any Commission waiver of its PGA regulations for as-billed passthrough. The Commission determined that no such showing had been made by Florida Gas.

R. Production-Related Costs

In *Panhandle Eastern Pipe Line Company*[75] and *Trunkline Gas Company*,[76] the Commission approved settlements resolving remanded issues concerning retroactive recovery of production-related costs as implemented under the Commission's Order No. 94. Parties opposing the settlements objected that allocation of production-related costs on the basis of firm sales customers' contract demand levels as of a past date constituted retroactive ratemaking and violated the filed rate doctrine. The Commission determined the settlements were uncontested because they would bind only those parties that consented to their terms and do not apply to nonsettling parties, preserving their rights to litigate the issues.

70. 54 F.E.R.C. ¶ 61,159 at 61,492.

71. 53 F.E.R.C. ¶ 61,463 (1990), *reh'g*, 54 F.E.R.C. ¶ 61,204 (1991).

72. *See* National Fuel Gas Supply Corp., 54 F.E.R.C. ¶ 61,061 (1991); CNG Transmission Corp., 54 F.E.R.C. ¶ 61,159 (1991); Equitrans, Inc., 54 F.E.R.C. ¶ 61,161 (1991).

73. F.E.R.C. at 61,604.

74. 55 F.E.R.C. ¶ 61,146 (1991).

75. 56 F.E.R.C. ¶ 61,197 (1991).

76. 56 F.E.R.C. ¶ 61,193 (1991).

S. *Rate Design*

In one of the first litigated cases under its Rate Design Policy Statement, the Commission addressed a number of significant rate design issues in Opinion No. 369 in *Panhandle Eastern Pipe Line Company.*[77] Panhandle proposed, and an administrative law judge approved, a shift from a modified fixed variable (MFV) rate design to SFV, the elimination of a two-part demand charge, seasonal transportation and sales rates and interruptible transportation rates based on a 100 percent load factor. The administrative law judge, however, rejected Panhandle's proposals to continue its zoned transportation rates, to charge a bundled rate for gathering and transmission and to classify fixed gathering costs to the demand component.

In its decision, the Commission emphasized the importance of economic efficiency in the design of pipeline rates. Consistent with its Policy Statement, the Commission noted that rates should be designed to ration capacity during peak periods and maximize throughput during off-peak periods.

The Commission found that SFV rate design was not necessary to ration capacity on Panhandle's system. However, because Panhandle operated with substantial unused firm capacity during off-peak periods, the Commission concluded that a shift to SFV would promote increased throughput. The Commission also found that a SFV rate design would increase fair competition among gas supplies transported over Panhandle and competing pipelines by ensuring that customers purchase gas from the pipeline with the lowest delivered price.

The Commission also approved Panhandle's proposals to use a 100 percent load factor maximum rate for interruptible transportation and to eliminate its D-2 charge for rate design purposes. The Commission found that there was sufficient evidence supporting Panhandle's contention that its system was fully utilized during peak periods and that a 100 percent load factor interruptible rate is needed to ration capacity during those periods.

The Commission could find no justification, however, for Panhandle's seasonal transportation rates, transportation rate zones, or rate for backhauls. Seasonal rates would not ration capacity and did not reflect material variations in Panhandle's cost of service. Because the costs of Panhandle's sales services did vary by season, the Commission approved seasonal rates for those services. In affirming the ALJ's finding that Panhandle's transportation rate zones were unjust and unreasonable, the Commission noted that the zoned rates were cumulative (with the rates in Panhandle's market area zone being the highest) and, therefore, did not reflect the actual cost of providing certain services. The Commission adopted a uniform rate for the Field Zone and 100 mile increment rates for the remainder of the system. Finally, the Commission rejected Panhandle's proposal to charge its full forward haul rate for backhaul transportation services and reduced that rate to one-half of the forward haul rate.

The Commission affirmed the ALJ's finding that Panhandle should have a separately stated rate for gathering services. It rejected, however, the ALJ's

77. 57 F.E.R.C. ¶ 61,264 (1991).

finding that Panhandle could not recover fixed gathering costs through a demand charge. A SFV rate design is appropriate for Panhandle's firm gathering services due to the fact that the rate design treatment of production area facilities no longer depends on whether they are classified as gathering or transmission and because the Commission previously concluded that a fixed variable rate design is appropriate for Panhandle's overall system.

In *Williston Basin Interstate Pipeline Company*,[78] the Commission modified an initial decision with respect to the appropriate throughput to be used in designing Williston Basin Interstate Pipeline Company's (Williston) rates. All parties agreed, and the initial decision reflected, that the starting point for the throughput figure should be predicated on actual throughput during a recent twelve month period rather than on test period projections. The Commission reversed the initial decision on this point, finding that there were no compelling circumstances to disregard its test period. On June 21, 1991, in *Texas Eastern Transmission Corporation, et. al.*,[79] the Commission issued a rehearing order involving the Northeast Expansion Projects and adopted a SFV rate design instead of the MFV rate design methodology for Transcontinental Gas Pipe Line Corporation. The Commission's shift from MFV to SFV was based on its reconsideration of agreements between Transco and its customers providing for 100 percent demand charges. The Commission concluded that those agreements should be given "significant weight" absent a finding to do otherwise, such as the pipeline enjoying an unfair market advantage. In approving the SFV methodology, the Commission also recognized that Transco would have a lower risk because it would be able to recover its fixed costs through demand billing. Therefore, to compensate for this lower risk, the Commission adjusted Transco's rate of return on equity downward by twenty-five basis points.

T. Reservation Fees

In *Oklahoma-Arkansas Pipeline Company*,[80] the Commission granted rehearing of an order[81] in which it made a preliminary non-environmental determination issuing an optional expedited certificate (OEC) for construction of a midcontinent, transportation-only pipeline system extending from the Arkoma Basin. In its rehearing order, the Commission authorized Oklahoma-Arkansas Pipeline Company (Ok-Ark) to charge its affiliates a reservation fee for firm service capped at the lowest reservation fee being paid by a nonaffiliated firm transportation shipper. To prevent circumvention of the OEC regulations, the Commission ordered that Ok-Ark give its firm shippers certain capacity brokering rights. The Commission stated that it would amend the Part 284 blanket certificates of interstate pipeline shippers to authorize their sale of firm capacity reserved on Ok-Ark's system in its final order. The Commission also required regulated affiliates to file appropriate tariff revisions for the temporary assignment of capacity on Ok-Ark. Finally, the Commis-

78. 56 F.E.R.C. ¶ 61,103 (1991).
79. 55 F.E.R.C. ¶ 61,477 (1991).
80. 55 F.E.R.C. ¶ 61,002 (1991).
81. Oklahoma-Arkansas Pipeline Co.,53 F.E.R.C. ¶ 61,019 (1990).

sion cautioned that affiliated pipeline shippers would be required to demonstrate the prudence of any reservation charges paid to Ok-Ark.

In *Cornerstone Pipeline Company*,[82] the Commission granted final OEC authority to Cornerstone, subject to minor environmental modifications, to construct and operate a new forty-five mile transportation-only pipeline system extending from Richland Parish, Louisiana to Warren County, Mississippi. In addition, the Commission removed its earlier prohibition that would have prevented Cornerstone from assessing reservation fees in connection with transportation service it rendered for its affiliated shippers. Instead, consistent with its earlier order in *Oklahoma-Arkansas*, the Commission authorized the imposition of reservation fees capped at the lowest reservation fee negotiated with a nonaffiliated firm transportation shipper. In Order No. 555,[83] however, the Commission reversed its *Oklahoma-Arkansas* policy and stated that a pipeline may charge a reservation fee to an affiliated pipeline shipper only if that affiliated shipper establishes a separately-stated rate for its services involving the costs associated with the newly-constructed upstream facilities.[84]

U. Settlement Policy

In *El Paso Natural Gas Company*,[85] the Commission approved a global settlement among El Paso and its customers restructuring El Paso's system; establishing jurisdictional rates for each of three rate periods; resolving outstanding issues regarding take-or-pay; pipeline production, and deferred gas costs in Account No. 191, establishing a market-based gas inventory charge; and providing for the unbundling of sales and mainline transportation services. In approving the settlement largely as proposed, the Commission noted that "[i]f the Commission were issuing individual orders in each of the pending dockets, it might have resolved many of the issues differently than does the settlement. However, the Commission recognizes the considerable advantages of resolving so many dockets in a way that ends an extended period of uncertainty for all parties and, at least as to most issues, satisfies virtually all of the parties."[86] The Commission went on to note that the settlement reflects a "delicate balance" and that the Commission is "most reluctant to revise substantially a settlement which reflects significant concessions and compromises by all parties."[87] On August 14, 1991, the Commission generally denied rehearing of its order approving El Paso's global settlement.[88]

In *Transcontinental Gas Pipe Line Corporation*,[89] the Commission approved two offers of settlement involving various rate issues, Transcontinental Gas Pipe Line Corporation's (Transco) proposed service restructuring, and

82. 55 F.E.R.C. ¶ 61,023 (1991).

83. *Revisions to Regulations Governing Authorizations for Construction of Natural Gas Pipeline Facilities*, *supra* note 4.

84. *Id.* at 30,267-268.

85. 54 F.E.R.C. ¶ 61,316 (1991).

86. *Id.* at 61,915.

87. *Id.*

88. 56 F.E.R.C. ¶ 61,290 (1991).

89. 55 F.E.R.C. ¶ 61,446 (1991).

the implementation of a market-based GIC. The Commission recognized that the settlements provided for substantial unbundling of Transco's sales services from its transportation services. In addition, with respect to rate design, the Commission approved the inclusion of storage, gathering, and Account 858 costs in Transco's transportation rates.

In *CNG Transmission Corporation*,[90] the Commission approved a settlement involving the restructuring of CNG's services and reflecting a number of rate design changes including: seasonal rates; unbundling of costs related to gathering, products extraction, storage, and Account 858 from transportation rates; brokering of capacity rights; and the elimination of D-2 demand charges. Despite a lack of evidence on the record demonstrating that such rate design changes are necessary to ration peak capacity, the Commission approved the changes on the grounds that such changes are acceptable as part of a larger settlement "that achieves many of the Commission's important objectives, such as the unbundling of services and rates, the implementation of CD reductions and conversions, and capacity brokering."[91]

V. Take-or-Pay Cost Recovery

On January 31, 1991, the Commission issued Order No. 528-A,[92] generally denying rehearing of Order No. 528[93] but modifying that order in several respects. The Commission had issued Order No. 528 in response to *Associated Gas Distributors v. FERC, (AGD II)*[94] which held that Tennessee Gas Pipeline's "purchase deficiency method" for allocating a portion of its take-or-pay settlement costs violated the filed rate doctrine. Order No. 528 stayed the collection of take-or-pay fixed charges under the purchase deficiency allocation method and directed the affected pipelines to develop new recovery plans.[95] The Commission advised the affected pipelines to negotiate with their customers to develop new allocation plans based on some current measure of demand or usage and required the pipelines to file a plan for crediting, distributing, or allocating amounts previously collected in fixed charges when they file to implement a new recovery mechanism.

With respect to new allocation plans, Order No. 528-A: (1) prohibited affected pipelines from collecting through volumetric surcharges more than fifty percent of take-or-pay buyout and buydown costs included in prior Order No. 500 filings; (2) imposed a seventy-five percent cap on volumetric surcharge recovery of "new dollars"; (3) required that fifty percent of the take-or-pay settlement costs that otherwise would be allocated to small sales cus-

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90. 55 F.E.R.C. ¶ 61,189 (1991).

91. *Id.* at 61,628.

92. Order No. 528-A, *Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs*, 54 F.E.R.C. ¶ 61,095 (1991).

93. Order No. 528, *Order on Remand Staying Collection of Take-or-Pay Fixed Charges and Directing Filing of Revised Tariff Provisions*, 53 F.E.R.C. ¶ 61,163 (1990).

94. 893 F.2d 349 (D.C. Cir. 1989), *reh'g en banc denied*, 898 F.2d 809 (1989), *cert. denied*, 111 S.Ct. 277 (1990).

95. The Commission exempted from the stay those pipelines which had filed to recover take-or-pay costs through nonappealable recovery mechanisms or settlements.

tomers under the revised methodology be reallocated to other customers paying fixed charges; (4) imposed, unless the parties should agree otherwise, a true-up mechanism to prevent overrecovery of costs through a volumetric surcharge; and (5) encouraged pipelines and parties to consider establishing mileage-sensitive volumetric surcharges where appropriate. On June 6, 1991, the Commission issued Order No. 528-B[96] denying rehearing of Order No. 528-A.

In *United Gas Pipe Line Company*,[97] the Commission granted rehearing of a May 29, 1990 order in which it had approved a comprehensive take-or-pay settlement that used the purchase deficiency method.[98] In its earlier order the Commission stated that the filed rate doctrine could be waived with the consent of only the pipeline's direct customers. On rehearing, the Commission decided that the settlement could not be approved because of objections to the settlement raised by indirect customers. The Commission concluded that because indirect customers opposed the take-or-pay provisions of United's settlement and were asserting rights under the filed rate doctrine, the settlement violated *AGD II*. The Commission determined that severance of the contesting customers would not be appropriate because, in the aggregate, the contesting customers objected to approximately seventy-seven percent of the take-or-pay costs allocated under the settlement.

In *Transwestern Pipeline Company*,[99] the Commission permitted Transwestern Pipeline Company (Transwestern) to recover take-or-pay costs that it had incurred subsequent to its acceptance of a GIC certificate. The Commission justified the elimination of the so-called "exclusivity condition" on the basis that, after Transwestern had accepted its GIC, it lost the only sales customers to which it might have assessed a GIC charge. The Commission recognized that, unless it removed the exclusivity provision from its certificate, Transwestern would not be able to recover take-or-pay costs it incurred because it had no sales against which to assess a GIC and no other way to recover these costs.

II. Court Action on Pipeline Issues

A. *Cost Allocation*

In *Algonquin Gas Transmission Company v. FERC*,[100] the Court of Appeals remanded orders of the Commission requiring Algonquin Gas Transmission Company (Algonquin) to roll-in the cost of certain facilities that had been treated historically on an incremental basis. The court rejected the Commission's assertion of systemwide benefits and ruled that there was insufficient evidence under section 5 of the NGA to demonstrate that the incremental method had become unjust and unreasonable. The Court of Appeals directed

96. *Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs*, 55 F.E.R.C. ¶ 61,372 (1991).
97. 55 F.E.R.C. ¶ 61,070 (1991).
98. 51 F.E.R.C. ¶ 61,242 (1990).
99. 55 F.E.R.C. ¶ 61,157 (1991).
100. 948 F.2d 1305 (D.C. Cir. 1991).

the Commission to undertake, on remand, an analysis of the systemwide benefits flowing from each of the incremental facilities to Algonquin's customers. In addition, the court remanded the Commission's decision to roll-in Algonquin's gas costs because the Commission did not consider the cost shifting impact on the system. Finally, observing that the Commission was acting contrary to its own Order No. 436 policy favoring mileage-sensitive transportation rates, the court remanded the Commission's elimination of a particular distance-sensitive transportation rate design.

B. *Enforcement of Sole Supplier Clauses*

In *Illinois v. Panhandle Eastern Pipe Line Company*,[101] the U.S. Court of Appeals for the Seventh Circuit affirmed the district court's decision holding that Panhandle had not violated federal and state antitrust statutes by refusing to transport non-system gas for "full requirements" customers served under a tariff containing a "sole supplier" requirement. The district court found that Panhandle's reliance on the tariff's "sole supplier" condition was a lawful effort to enforce a legally valid tariff provision. The district court also held that Panhandle's refusal to negotiate a change in the tariff to allow receipt of such non-system gas by the customers served under this tariff (which was less expensive than service available under another tariff where Panhandle would allow receipt of such non-system gas) was "a lawful refusal to cut its own throat,"[102] particularly in light of the chaotic conditions in the industry.

The Seventh Circuit held that the indirect purchasers could not maintain a claim for antitrust damages since these claims were barred by the *Illinois Brick* doctrine and the Supreme Court's holding in *Kansas v. Utilicorp United, Incorporated*[103] that the "cost plus" exception to that doctrine does not permit a regulated utility's indirect customers to sue for antitrust damages. However, the court held that the parallel state law claims were not preempted by federal regulation of the gas industry and survived the application of *Illinois Brick* and *Utilicorp*. On the merits of the state law claims, the court held that Panhandle's refusal to transport non-system gas was motivated by legitimate business concerns, in that "Panhandle's exclusive dealing contract with its G tariff customers . . . was a legitimate means of ensuring that it would not be stuck holding expensive natural gas for customers who had decided to purchase unexpectedly plentiful and cheap gas from others."[104] The court found further evidence of a lack of intent by Panhandle to secure monopoly profits from the sale of this gas in the fact that Panhandle does not profit from sales, but derives its return from rendering transportation services.[105]

C. *Gas Research Institute*

In *Process Gas Consumers Group v. FERC*,[106] the Court of Appeals

101. 935 F.2d 1469 (7th Cir. 1991).
102. 730 F. Supp. 826, 833 (C.D. Ill. 1990).
103. 497 U.S. 199 (1990).
104. 935 F.2d at 1486.
105. *Id.*
106. 930 F.2d 926 (D.C. Cir. 1991).

reviewed the Commission's first application of the "net benefits test"[107] for evaluating the propriety of ratepayer funding of GRI's end use research and development (R&D) activities. The court found that the Commission's net benefits analysis for all but three of GRI's 104 end use activities in the 1988 and 1989 R&D programs was justified. However, the Commission's analysis of the natural gas vehicles (NGVs), emission controls and industrial refrigeration activities was vacated and remanded to the Commission for further review. With respect to the NGV and industrial refrigeration projects, the court ruled that the Commission improperly relied on unquantifiable "common goods" benefits, such as cleaner air, in approving the activities. Regarding emission controls R&D, the court held that the Commission incorrectly compared undiscounted R&D benefits to discounted R&D costs. As discussed in Section I, subsection G, *supra*, the Commission issued its remand order in Opinion No. 365.[108]

D. *Jurisdiction Over Gathering Rates*

In *Northern Natural Gas Company v. FERC*,[109] the Court of Appeals determined that the Commission had lawfully asserted its authority to regulate rates charged by an interstate pipeline for gathering services performed over its own lines in connection with jurisdictional interstate transportation. The court rejected arguments that section 1(b) of the NGA prevented the Commission from regulating the pipeline's gathering rates. Instead, the court reasoned that regulation of Northern Natural Gas Company's (Northern) charges for gathering performed over its facilities was essential in order to prevent discrimination against third-party gas.

E. *Return on Equity*

In *Tennessee Gas Pipeline Company v. FERC*,[110] the D.C. Circuit rejected the Commission's "regulatory lag theory" for establishing a utility's rate of return on equity. For a second time, the court remanded the proceeding to the Commission and required it to utilize the midpoint of a zone of reasonableness, unless "some reasoned basis" exists for a departure from the midpoint.

The court noted that the Commission's standard practice for establishing a utility's return on equity is to "frame a zone of reasonableness with the estimation tools of its choice. Then, in the absence of evidence that leads the Commission to prefer one estimate over the other, it sets the rate of return at the average of those boundary figures."[111] The Commission's tools were the risk premium methodology and the discounted cash flow methodology. In this case, however, the Commission relied on a "regulatory lag theory" and made certain "pragmatic adjustments" to choose a rate of return substantially below the midpoint, ostensibly because the discounted cash flow methodology

107. The net benefits test was first enunciated in Process Gas Consumers Group v. FERC, 866 F.2d 470 (D.C. Cir. 1989).

108. 57 F.E.R.C. ¶ 61,010 (1991).

109. 929 F.2d 1261 (8th Cir.), *cert. denied*, 112 S.Ct. 169 (1991).

110. 926 F.2d 1206 (D.C. Cir. 1991).

111. *Id.* at 1209.

failed to promptly reflect the decreasing interest rates for the period in question. The court found that the Commission's "regulatory lag theory" was contrary to the "cornerstone of modern investment theory."[112] The court also chastised the Commission for relying on data not in the record in the proceeding — *i.e.*, interest rates for the period after the period for which it was setting rates.

F. Summary Rejection of Rate Change Filings

In *ANR Pipeline Company v. FERC*,[113] the Court of Appeals vacated the Commission's decision to summarily reject, as part of a general rate increase filing, third-party transportation charges incurred by ANR at the request of individual customers. In the orders under review, the Commission permitted ANR to urge at a hearing that its proposal warranted a waiver of the Commission's prohibition against cost trackers. The court reasoned that, by allowing a full airing of the matter at the hearing, the Commission had implicitly acknowledged that the issue was not appropriate for summary disposition. The court stated that summary rejection is authorized only where the facts are not in dispute and where the filing contravenes explicit Commission regulations or policy.[114] However, the appellate court affirmed the Commission's summary rejection of ANR's inclusion of accrued take-or-pay prepayments in its rate base. The court agreed that such action was prohibited under the Uniform System of Accounts prescribed by the Commission because these costs were accrued, but unpaid.

G. Used and Useful Standard

In *Williston Basin Interstate Pipeline Company v. FERC*,[115] the Court of Appeals remanded Opinion No. 331 in which the Commission had denied rate base treatment for certain net storage injections made by Williston in an effort to avoid take-or-pay payments. The Commission determined that the injections, while not imprudent on Williston's part, were not "used and useful" to the pipeline's customers and therefore Williston should not be permitted to earn a return on the related costs. Williston argued that because it injected the gas to avoid take-or-pay liability, the investment is no different from take-or-pay prepayments and should be included in its rate base. The D.C. Circuit agreed with Williston. After recognizing that both stored excess gas and take-or-pay prepayments provided strikingly similar benefits for Williston's ratepayers, the court criticized the Commission for finding prepayments "used and useful," but not the injected gas. Accordingly, the court vacated and remanded Opinion Nos. 331 and 331-A and ordered the Commission to reconcile its treatment of storage injections and take-or-pay prepayments.[116]

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112. *Id.* at 1210.

113. 931 F.2d 88 (D.C. Cir. 1991).

114. *Id.* at 93.

115. 931 F.2d 948 (D.C. Cir. 1991).

116. In its subsequent remand order, the Commission determined that Williston's storage injections should receive treatment similar to that accorded a pipeline's prepayments. Williston Basin Interstate Pipeline Co., 57 F.E.R.C. ¶ 61,310 (1991).

III. Court Action on Producer Issues

A. *Area Rate Clauses*

In *South Dakota Public Utilities Com'n v. FERC*,[117] the Court of Appeals affirmed Commission orders finding that the area rate clauses contained in approximately 1,200 contracts between Northern and its producer-suppliers authorized the collection of maximum lawful prices under the NGPA. Both Northern and the producers agreed that their contracts permitted escalation to NGPA ceiling prices; petitioners contested this interpretation. Noting that the record consisted of the testimony of seventy witnesses (all testifying on behalf of either Northern or the producers) and a transcript exceeding 5,000 pages in length, the court held that there was substantial evidence to support the Commission's determination.

B. *Order No. 451*

In *Mobil Oil Exploration v. United Distribution Company*,[118] the Commission won a major court battle on January 9, 1991, when the United States Supreme Court unanimously upheld Order No. 451 —the so-called "old gas" rule which collapsed fifteen different price vintages of old gas into one classification and established a single new ceiling price — reversing an earlier decision by the Fifth Circuit.[119] In affirming the Commission, the Supreme Court ruled that: (1) the Commission's establishment of a single ceiling price in Order No. 451 was permitted under the "plain meaning" of section 104(b)(2) of the NGPA; (2) the Commission's collapsing of old gas vintages was "just and reasonable" within the meaning of the NGA; (3) the pregranted abandonment authority contained in the "good faith negotiation" procedure fully comported with the requirements set forth in section 7(b) of the NGA; and (4) the Commission had no obligation, contrary to the Fifth Circuit's view, to resolve or even address the take-or-pay problem, because the record demonstrated that approximately two-thirds of existing take-or-pay contracts did not involve old gas.

C. *Price Decontrol of Released Gas*

In *Union Pacific Resources Company v. FERC*,[120] the Court of Appeals upheld Order Nos. 523 and 523-A in which the Commission determined that the Natural Gas Wellhead Decontrol Act of 1989 deregulated gas temporarily released from a contract in effect when the Act was enacted. Congress decontrolled the price of any gas to which no contract "applied" on the date of enactment. The court accepted the Commission's interpretation of new section 121(f)(2) of the NGPA (which was added by the Decontrol Act) that the underlying contract does not apply during the release periods. The court also rejected the producers' claim of inadequate notice regarding the regulatory

117. South Dakota Public Utilities Com'n v. FERC, 934 F.2d 346, *reh'g. denied*, 941 F.2d 1233 (D.C. Cir. 1991).

118. 498 U.S. 211 (1991).

119. 885 F.2d 209 (5th Cir. 1989).

120. 936 F.2d 1310 (D.C. Cir. 1991).

status of temporarily released gas, and held that the filing of extensive comments on this issue and the opportunity for rehearing provided ample opportunity for the producers to present their views and that no remand was required.

Frank X. Kelly, Chair
James J. Hoecker, Vice Chair

Lawrence G. Acker
Christopher J. Barr
Mark L. Collins
Carl M. Fink
Michael J. Fremuth
Marvin T. Griff
Gary E. Guy
Emmitt C. House
Barbara S. Jost
John R. McDermott
James D. McKinney, Jr.
Stephen R. Melton
Richard Meyer
Luke A. Mickum
Frederick W. Peters
William D. Rapp
Randall S. Rich
Linda L. Robertson
Daniel L. Schiffer
Arthur L. Smith
Gene R. Sommers
Mary Ann Walker
Kenneth Zielonis