

# Report of the Committee on Natural Gas Rate and Accounting Regulations

## I. COMMISSION ACTION ON PIPELINE ISSUES

### A. Account No. 858 Costs

In *Northern Natural Gas Co.*,<sup>1</sup> the Commission modified a settlement in order to eliminate Northern's ability to discount Account No. 858 costs, which were allocated to sales customers.

In *Texas Gas Transmission Corp.*,<sup>2</sup> the Commission granted reconsideration of an order<sup>3</sup> that addressed Texas Gas' temporary upstream capacity assignment program. The Commission initially modified a Texas Gas settlement<sup>4</sup> in order to require the pipeline to charge assignees a separate incremental rate for their utilization of upstream capacity and to credit the incremental revenues to Account No. 858. On reconsideration, however, the Commission removed the incremental rate requirement from the settlement. It concluded that requiring Texas Gas to charge an incremental rate prior to the determination of the appropriate allocation of Account No. 858 costs, which was in Texas Gas' Order No. 636 restructuring proceeding, could result in transportation customers paying an excessive portion of such costs.<sup>5</sup> However, the Commission reaffirmed that, as a general rule, transportation customers utilizing assigned upstream capacity would be required to pay an incremental rate.<sup>6</sup>

### B. "At-Risk" Rate Considerations

The Commission approved an uncontested settlement filed by Transcontinental Gas Pipe Line Corporation.<sup>7</sup> The Commission found the proposed settlement reasonable, largely because the settlement rates placed Transco at substantial risk for the underutilization of its onshore Mobile Bay facilities. Transco's filing indicated that it had no firm contracts to transport gas on the Mobile Bay facilities.

In *Algonquin Gas Transmission Co.*,<sup>8</sup> the Commission removed an "at risk" condition, which had been imposed for want of firm transportation contracts. The Commission determined that precedent agreements committed the

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1. 59 F.E.R.C. ¶ 61,379 (1992).

2. 61 F.E.R.C. ¶ 61,090 (1992).

3. Texas Gas Transmission Corp., 59 F.E.R.C. ¶ 61,211 (1992).

4. Texas Gas Transmission Corp., 57 F.E.R.C. ¶ 61,236 (1991).

5. Texas Gas Transmission Corp., 61 F.E.R.C. ¶ 61,090, at 61,360.

6. *Id.*

7. Transcontinental Gas Pipe Line Corp., 58 F.E.R.C. ¶ 61,063 (1992). The settlement resolved the appropriate cost of service, throughput, and rate design for incremental rates charged on Transco's onshore Mobile Bay facilities and proposed rates for three periods. Period I and Period II rates used a modified fixed-variable (MFV) rate design based on 85% of capacity of 301 MMcf/d for the Mobile Bay facilities. The resulting projected throughput was over five times the actual throughput experienced on the Mobile Bay facilities for the twelve months ended June 1991. Period III rates also were designed using MFV rate design, but were based on 100% of the estimated future operating capacity of 350 MMcf/d.

8. 59 F.E.R.C. ¶ 61,254 (1992).

shippers to enter firm transportation contracts before pipeline construction, if the Commission approved the project.

In *Paiute Pipeline Co.*,<sup>9</sup> the Commission imposed an "at risk" condition because shippers could terminate service if Paiute set its initial rates at more than 120% of its estimate. However, if Paiute's initial rates did not exceed the estimate by more than 20%, the "at risk" condition would not apply.

In *Colorado Interstate Gas Co.*,<sup>10</sup> the Commission imposed an "at risk" condition on the uncommitted portion of a proposed lateral. The Commission also imposed a temporary "at risk" condition regarding CIG's planned use of the new line for services that another pipeline might have a contract right to provide. The Commission therefore held that CIG would not be assured recovery of stranded investment costs associated with the new line, which also would not be a recoverable transition cost under Order No. 636.

In *Northwest Pipeline Corp.*,<sup>11</sup> the Commission indicated that the portion of a pipeline's expansion project that was supported by long-term firm agreements, which did not in turn appear to be supported by downstream capacity, would be placed "at risk."<sup>12</sup> However, the Commission removed the "at risk" condition because most of the shippers who lacked firm downstream capacity entitlements had withdrawn from the project.<sup>13</sup>

In *ANR Pipeline Co.*,<sup>14</sup> the Commission refrained from placing the applicants' pipelines "at risk" for a joint pipeline expansion. The Commission found that ANR and Great Lakes Gas Transmission Limited Partnership had "demonstrated markets sufficient to support their proposals," and therefore found it unnecessary to place them "at risk" for under-utilization of the facilities.<sup>15</sup> It nevertheless cautioned the applicants that they would not be guaranteed cost recovery and would not necessarily be allowed to allocate the cost of the facilities to other customers unless they could show, in future rate cases, that the facilities were in fact being used for the benefit of those customers. Because a major customer had not yet received import and export authority from the Department of Energy and Canada's National Energy Board, and because the facilities might have become unnecessary in the absence of such authorization, the Commission refused to allow the pipeline to roll-in the cost of the facilities before those authorizations were obtained.

In two suspension orders,<sup>16</sup> the Commission permitted pipelines to place into effect rates that included the costs of facilities constructed, subject to "at risk" conditions. Despite protests to the contrary, the Commission neither removed the "at risk" conditions nor summarily reaffirmed the applicability of

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9. 59 F.E.R.C. ¶ 61,304 (1992).

10. 59 F.E.R.C. ¶ 61,364 (1992).

11. 58 F.E.R.C. ¶ 61,364, 61,079 (1992).

12. *Id.*

13. *Id.* at 61,273.

14. 58 F.E.R.C. ¶ 61,080 (1992).

15. *Id.* at 61,280.

16. *Transwestern Pipeline Co.*, 61 F.E.R.C. ¶ 61,305, at 62,103 (1992); *Natural Gas Pipeline Co. of America*, 61 F.E.R.C. ¶ 61,390 (1992).

the “at risk” conditions. Instead, the suspension orders called for a hearing on the issue of the continued applicability of the “at risk” conditions.

In *Natural Gas Pipeline Co.*,<sup>17</sup> the Commission denied Natural’s request for removal of an “at risk” condition originally placed on its operation of the Arkoma Lateral facilities. The Arkoma Lateral facilities were originally constructed under section 311 of the Natural Gas Policy Act of 1978 and subsequently certificated under section 7(c) of the Natural Gas Act.<sup>18</sup>

The Commission held on rehearing that, if a pipeline sought traditional section 7(c) authority to construct pipeline facilities, the applicant must execute service contracts and show supporting market data volumes equivalent to the total capacity of its proposed facilities, prior to the time it commences construction. The Commission also held that similar safeguards should routinely be applied in cases where pipelines were seeking traditional section 7(c) authority to operate facilities previously constructed under section 311. Because Natural’s application did not include the requisite market evidence, the Commission found that, while the Arkoma Lateral facilities were likely to be fully utilized, it had no assurance that the capacity would be fully contracted on a firm and long-term basis. It therefore placed Natural “at risk” for the recovery of the costs of the Arkoma Lateral facilities.

In *Arkla Energy Resources*,<sup>19</sup> the Commission authorized ANR Pipeline Company to acquire an ownership interest in certain facilities owned by Arkla Energy Resources and its affiliate, Mississippi River Transmission Corporation (MRT). The Commission imposed an “at risk” condition on ANR “for the costs associated with the newly acquired facilities in the event [that] all of [ANR’s new] capacity [was] not subscribed under firm 10-year contracts at the time it file[d] to include the costs of the facilities in its rates.”<sup>20</sup> The Commission clarified that, to the extent Arkla must remove the specific facilities from its rate base, it would be permitted to adjust the throughput underlying its rates to reflect the removal of such costs.

### C. Filed Rate Doctrine

In *Indicated Shippers v. El Paso Natural Gas Co.*,<sup>21</sup> the Commission found, among other things, a gas sales contract between El Paso and Southern California Natural Gas Company, which provided for a blended rate and which was lower than El Paso’s firm sales rate on file in its tariff, violated the filed rate doctrine as well as section 7(c) of the NGA and certain terms of El Paso’s interruptible sales certificate. The Commission deemed the contract

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17. 61 F.E.R.C. ¶ 61,297 (1992). In a February 5, 1992 order, the Commission had deferred its decision on Natural’s request for rehearing on the imposition of the “at risk” condition. *Natural Gas Pipeline Co. of America*, 58 F.E.R.C. ¶ 61,100 (1992). In *Transwestern Pipeline Co.*, 59 F.E.R.C. ¶ 61,305 (1992), the pipeline sought a section 7(c) certificate to expand the service opportunities for a facility which had already been built under NGPA section 311, but was put “at risk” because the capacity of the facility was not fully subscribed.

18. *Natural Gas Pipeline Co. of America*, 57 F.E.R.C. ¶ 61,021, at 61,084 (1991).

19. 61 F.E.R.C. ¶ 61,004, at 61,041 (1992).

20. *Id.* at 61,040.

21. 61 F.E.R.C. ¶ 61,038 (1992).

unlawful because the contract provided for an average gas cost, which for certain months was less than the rate on file with the Commission. Additionally, the contract was considered unlawful because El Paso had agreed in the contract to sell gas to SoCal for no more than the average gas cost, which at times was less than the filed rate.

#### *D. Fuel Use and Unaccounted-for Gas*

The Commission ordered that tariff sheets in three purchased gas adjustment filings be revised to include fuel use and unaccounted-for gas charges in sales rates only.<sup>22</sup> The Commission's rejection of a filing by Arkla Energy Resources was based on AER's failure to demonstrate that there would be no cross-subsidization, or potential for cross-subsidization, between sales and transportation customers for fuel use and lost and unaccounted-for gas. The Commission ordered AER to file revised tariff sheets specifically stating that its sales rates would not reflect costs associated with its non-sales service fuel use and unaccounted-for gas.<sup>23</sup>

#### *E. Gas Inventory Charges and Related Issues*

In *Texas Eastern Transmission Corp.*,<sup>24</sup> the Commission terminated a pipeline's previously-authorized gas inventory charge (GIC) over the objection of the pipeline and without regard to the timing of the pipeline's Order No. 636 restructuring program. Following the remand of Texas Eastern's GIC in *Texas Power Corp. v. FERC*,<sup>25</sup> the Commission set the issues related to the GIC for hearing.<sup>26</sup> On rehearing, the Commission ordered Texas Eastern to terminate its GIC. In the Commission's view, the continuation of the GIC "would be unfair to Texas Eastern's customers" and would avoid the realities of the restructuring required under Order No. 636."<sup>27</sup>

In *Natural Gas Pipeline Co. of America*,<sup>28</sup> the Commission approved a settlement extending Natural's GIC one year because the only alternative would be an interim return to a PGA until the effective date of Natural's compliance filing under Order No. 636.

In *Midwestern Gas Transmission Co.*,<sup>29</sup> the Commission approved an uncontested settlement establishing an interim GIC to cover upstream transportation service costs.

In *Northern Natural Gas Co.*,<sup>30</sup> the Commission approved an interim GIC pending restructuring under Order No. 636. The Commission required a

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22. *Arkla Energy Resources*, 58 F.E.R.C. ¶ 61,050 (1992).

23. *Id.* The Commission's interpretation that its rules require fuel use and unaccounted-for gas to be recovered in the PGA on sales volumes only is based on *Williams Natural Gas Co.*, 57 F.E.R.C. ¶ 61,369 (1991), citing 18 C.F.R. § 154.303(c)(2)(iii) (1991).

24. 60 F.E.R.C. ¶ 61,226 (1992).

25. 908 F.2d 998 (D.C. Cir. 1990).

26. *Texas Eastern Transmission Corp.*, 53 F.E.R.C. ¶ 61,105 (1990).

27. 60 F.E.R.C. ¶ 61,226, 61,758 (1992).

28. 59 F.E.R.C. ¶ 61,322 (1992).

29. 59 F.E.R.C. ¶ 61,358 (1992).

30. 59 F.E.R.C. ¶ 61,379 (1992).

final reconciliation, with cash refunds to those who were overcharged, and an adjustment if the pipeline understated its PGA to help its sales competition.

In *Algonquin Gas Transmission Co.*,<sup>31</sup> the Commission denied rehearing of an order that accepted and suspended the primary tariff sheets filed by Algonquin, which reflected the commodity flowthrough of Texas Eastern Transmission Corporation's GIC.<sup>32</sup> The Commission also rejected certain alternative tariff sheets, which reflected the recovery of such costs through an annualized demand charge. In light of this established rule, the Commission held that, because Algonquin had not implemented a GIC mechanism, it must place such costs in the commodity component of its rates. Moreover, the Commission rejected Algonquin's reliance on *Equitrans, Inc.*<sup>33</sup> In *Equitrans, Inc.*, the Commission allowed Equitrans to place Texas Eastern GIC costs in demand rates on an experimental basis.<sup>34</sup> However, in *Algonquin Gas Transmission Co.*,<sup>35</sup> Algonquin had not shown that its customers would incur any benefits from the inclusion of GIC costs in the demand component of Algonquin's rates, nor that such treatment would serve any purpose other than to shield Algonquin from the risk of under-recovery of GIC costs and to shift that risk to its customers.

In *Equitrans, Inc.*,<sup>36</sup> the Commission terminated its prior approval of Equitrans' proposal to flow through Texas Eastern's GIC charges in the demand component of Equitrans' PGA rate. The Commission had allowed Equitrans' demand mechanism on an experimental basis, but stated that the experiment was terminated in light of Order No. 636.<sup>37</sup>

#### F. Gas Research Institute Charges

In *Gas Research Institute*,<sup>38</sup> the Commission approved a change in the future method of collection of GRI funds from interstate pipeline customers. Historically, the amounts pipelines were authorized to collect for GRI have been collected by GRI-member pipelines through a volumetric surcharge applied generally to all units of throughput (both sales and transport) delivered by those pipelines, except those delivered by one member pipeline to another. This procedure presented few problems as pipelines were able to collect from their customers the full amounts due GRI. Recently, however, the GRI funding obligation per unit has remained relatively constant, while pipelines have been forced by market conditions to discount transportation rates in order to maintain load. Some pipelines complained that the burden of the GRI obligation had shifted away from the pipeline's customers to the pipeline's shareholders. United Gas Pipe Line Company and ANR Pipeline Com-

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31. 61 F.E.R.C. ¶ 61,299 (1992).

32. See *Algonquin Gas Transmission Co.*, 58 F.E.R.C. ¶ 61,227 (1992).

33. 61 F.E.R.C. ¶ 61,299, at 62,124 (citing *Equitrans, Inc.*, 52 F.E.R.C. ¶ 61,228 (1990)).

34. *Equitrans, Inc.*, 52 F.E.R.C. ¶ 61,228 (1990). This demand charge treatment was subsequently rejected. *Equitrans, Inc.*, 60 F.E.R.C. ¶ 61,224 (1992).

35. 61 F.E.R.C. ¶ 61,299 (1992).

36. 61 F.E.R.C. ¶ 61,308 (1992).

37. *Equitrans, Inc.*, 52 F.E.R.C. ¶ 61,228 (1992).

38. 60 F.E.R.C. ¶ 61,203 (1992), *reh'g denied*, 61 F.E.R.C. ¶ 61,121 (1992).

pany<sup>39</sup> resigned from GRI, and other pipelines were threatening to do the same. As a result, GRI proposed a revised funding mechanism for 1993. Under the revised mechanism, pipelines for the first time would recover a portion of their GRI obligation through a demand surcharge. The surcharge would be assessed on all "non-discounted" firm sales and transportation entitlements. An additional amount would be collected through the continued use of a volumetric surcharge on all "non-discounted" sales and transport throughput. With respect to the amounts formerly recovered through a volumetric surcharge on discounted transactions, each pipeline would be limited in its responsibility to 10% of its total 1991 contributions to GRI.

The Commission approved the funding plan, but denied GRI's request that the revised funding mechanism be implemented for the remainder of 1992. The Commission concluded that, because no further pipeline resignations were permitted under GRI's by-laws for the remainder of 1992, adequate funding would continue to be available through the end of the year. The Commission also stressed that the revised mechanism was being approved on only an interim basis, and ordered the appointment of a settlement judge to convene a proceeding to consider alternative funding mechanisms for 1994 and beyond.

#### G. Gathering Costs

In *Northwest Pipeline Corp.*,<sup>40</sup> the Commission granted Northwest's request to abandon certain gathering facilities by conveyance to Williams Gas Processing Company, an unregulated affiliate. In so doing, the Commission found no present need to regulate the affiliate's rates for the gathering services. However, the Commission conditioned its approval of the abandonment on the retention of authority under sections 4 and 5 of the NGA to protect the public interest and to prevent circumvention of the statutory mandates of the NGA and the NGPA.

In *Panhandle Eastern Pipe Line Co.*,<sup>41</sup> the Commission, having previously accepted and suspended Panhandle's proposed System-Wide Access Charge, finally rejected it, asserting that the change included gathering costs which all shippers would be required to pay regardless of whether they had utilized the facilities for which costs were included. The Commission required Panhandle to reinstate the Market Zone Access Charge, based on an approved

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39. See *ANR Pipeline Company*, 58 F.E.R.C. ¶ 61,228 (1992). ANR filed tariff sheets to remove the GRI Adjustment Charge from its tariff and delete all tariff references to the GRI. The Commission found that its jurisdiction to review GRI rates extended only to pipelines that were members of GRI. Therefore, the Commission held that it lacked jurisdiction to do anything other than accept ANR's proposal.

ANR reinstated its GRI tariff provisions effective May 1, 1992 after negotiating a compromise with GRI. *ANR Pipeline Co.* 59 F.E.R.C. ¶ 61,105, *reh'g denied*, 60 F.E.R.C. ¶ 61,006 (1992). The Commission concluded that ANR's authority to collect these amounts was not an issue in this case and that ANR was not required to remit the GRI surcharge on all transactions. The Commission also concluded that ANR was prevented from keeping revenues associated with the GRI surcharge, because "to the extent ANR discounts its maximum base tariff rate less than the amount of the actual GRI adjustment, [ANR must] remit to GRI that portion of any GRI surcharge actually collected above its maximum base rates." *Id.*

40. 59 F.E.R.C. ¶ 61,115 (1992).

41. 61 F.E.R.C. ¶ 61,241 (1992).

methodology.<sup>42</sup> The Commission held that Panhandle had failed to explain its departure from the required unbundling of gathering costs from transmission costs and the non-mileage transmission charge ordered in Opinion No. 369.<sup>43</sup> It concluded that Panhandle's System-Wide Access Charge amounted to rebundling.

In *Trunkline Gas Co.*,<sup>44</sup> the Commission refused to permit a pipeline to reclassify certain gathering costs as transmission costs for rate purposes. The Commission concluded that reclassification was inappropriate prior to Commission approval of the refunctionalization of the related facilities for certificate purposes. Trunkline had cited as support for its position the Commission's *Policy Statement with Respect to the Recovery of Gathering Costs*.<sup>45</sup> Trunkline argued that, in the *Policy Statement*, the Commission had specifically contemplated that gathering costs could be reclassified for rate purposes prior to the refunctionalization of the related facilities for certificate purposes. The Commission rejected Trunkline's argument, however, concluding that, because Trunkline sought to justify the reclassification based solely on its view that the related facilities performed a transmission function, the change in rate treatment could not be approved until the underlying certificate issue was resolved. The Commission did, however, permit Trunkline a second opportunity to make its case during the course of the rate proceeding.

In *Natural Gas Clearinghouse v. Panhandle Eastern Pipe Line Co.*,<sup>46</sup> the Commission held that Panhandle may not charge a gathering rate for transporting gas delivered into Panhandle's system through an interconnect on a 10-inch gathering line which was located seven feet from Panhandle's 24-inch mainline. The Commission concluded that it was unreasonable for Panhandle to charge a gathering rate for service through short segments of pipe which the Commission determined were functionally equivalent to mainline taps.<sup>47</sup> Although the Commission reversed on rehearing its factual finding that the location of the taps was merely a matter of convenience for Panhandle, it reaffirmed that Panhandle's decision to place less costly taps on its gathering system close to its mainline, rather than installing direct mainline taps, did not warrant the imposition of a gathering charge to transmission customers.<sup>48</sup>

#### H. Incremental Rates

In *Northwest Pipeline Corp.*,<sup>49</sup> the Commission permitted Northwest to roll-in the cost of a major new expansion because the evidence demonstrated substantial system-wide benefits from the expansion. However, the Commission required Northwest to demonstrate the benefits, which justified rolled-in

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42. 59 F.E.R.C. ¶ 61,246 (1992).

43. *Panhandle Eastern Pipeline Co.*, 57 F.E.R.C. ¶ 61,264 (1991), *aff'g in part and rev'g in part*, Opinion No. 369-A, 59 F.E.R.C. ¶ 61,244 (1992).

44. 60 F.E.R.C. ¶ 61,163 (1992).

45. See *Interstate Natural Gas Pipeline Rate Design*, 56 F.E.R.C. ¶ 61,086 (1991).

46. 60 F.E.R.C. ¶ 61,007 (1992).

47. *Id.* at 61,038.

48. 61 F.E.R.C. ¶ 61,102 (1992).

49. 59 F.E.R.C. ¶ 61,289 (1992).

treatment for the new facilities in its first rate case covering expansion costs.<sup>50</sup>

In *Kern River Gas Transmission Co.*,<sup>51</sup> the Commission approved rolled-in rate treatment for the cost of facilities intended to connect Kern River's mainline pipeline with supply lateral facilities. The Commission granted Kern River's request to roll the cost of the supply laterals into the total cost of its facilities for purposes of establishing transportation rates. The Commission found that (1) the supply laterals were integral to Kern River's entire system; (2) the system-wide benefits were commensurate with the small increase in rates; (3) the affected shippers reviewed the rates and did not object to them; and (4) Kern River had not yet had any real operating experience, making rolled-in rate treatment appropriate for initial rates.

In *Algonquin Gas Transmission Co.*,<sup>52</sup> the Commission on remand, authorized Algonquin to reinstate incremental rates for a past period when rolled-in rates were inappropriately required as a result of the Commission's legal error. Moreover, the Commission authorized Algonquin to implement surcharges and refunds as appropriate to correct the Commission's erroneous order and to keep Algonquin whole.<sup>53</sup>

### *I. Interruptible Sales Rates*

In *El Paso Natural Gas Co.*,<sup>54</sup> the Commission eliminated the maximum rate ceiling on El Paso's interruptible sales gas. El Paso argued that one of its direct competitors, Transwestern Pipeline Company, had no maximum rate with respect to its interruptible sales service.<sup>55</sup> The Commission agreed and found that because El Paso's sales of interruptible gas were made near the wellhead and subsequently were transported pursuant to El Paso's open access transport tariffs, El Paso would not be able to exercise any market power.

### *J. Liquefied Natural Gas (LNG)*

In *Trunkline Gas Co.*,<sup>56</sup> the Commission approved a proposal by

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50. *Id.* at 62,067. Commissioner Langdon dissented on the ground that the benefits did not match the 25 percent increase in rates due to roll-in.

51. 58 F.E.R.C. ¶ 61,073 (1992).

52. 60 F.E.R.C. ¶ 61,054 (1992).

53. The Commission concluded that a retroactive surcharge does not violate the filed rate doctrine because it corrects a legal error found by the court on review of a Commission order. *Id.* at 61,195 citing *Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066 (D.C. Cir. 1992).

54. 60 F.E.R.C. ¶ 61,230 (1992). In previous orders authorizing interruptible sales by El Paso, however, the Commission had imposed a ceiling on the gas cost component of such sales equal to El Paso's weighted average cost of gas. At the time the ceiling was imposed, the Commission explained that such a ceiling was necessary in order to prevent the exercise by El Paso of its potential market power. *El Paso Natural Gas Co.*, 45 F.E.R.C. ¶ 61,322 (1988), *reh'g granted and denied*, 47 F.E.R.C. ¶ 61,139 (1989); *El Paso Natural Gas Co.*, 52 F.E.R.C. ¶ 61,227 (1990) (amending tariff sheets to move the point of sale for ISS service from the city gate to mainline receipt points).

55. *Transwestern Pipeline Co.*, 53 F.E.R.C. ¶ 61,298 (1990), *reh'g pending*. The Commission eliminated the ceiling applicable to Transwestern's interruptible sales rates because under the terms of Transwestern's tariff and given the competitive conditions in Transwestern's sales markets, Transwestern was not able to exercise market power.

56. 60 F.E.R.C. ¶ 61,209 (1992). The minimum bill previously had been authorized by the Commission for a twenty-year term at the time the LNG facility was constructed. The long-term approval



Trunkline to terminate its previously authorized minimum bill related to its Trunkline LNG facility. Trunkline continued to collect the minimum bill even though service from the LNG facility was suspended in 1983. In exchange for the termination of the minimum bill, the Commission approved other settlement provisions which generally permitted the pipeline to recover through a direct bill to its customers the "net present value" of the debt-related portions of the remaining minimum bill payments.<sup>57</sup>

#### K. Negotiated Rates

In *Carnegie Natural Gas Co.*,<sup>58</sup> the Commission rejected, as unduly discriminatory, tariff sheets permitting Carnegie to discount bundled sales service to one customer. The Commission explained that market-based rates for sales service would be available only once Carnegie had met the requirements of Order No. 636.

In *Richfield Gas Storage System*,<sup>59</sup> the Commission granted Richfield a certificate to provide contract storage service at market-based rates, finding that Richfield (which is not a pipeline company or a gas distributor) lacked market power. The Commission declined to determine whether the negotiated rates were cost-justified or just and reasonable, but found the rates to be in the public interest. The rates were contractually fixed for the life of the service, not subject to change by Richfield or at the request of the customers. The Commission asserted jurisdiction because Order No. 636 defines transportation to include storage.

In *Northern Natural Gas Co.*,<sup>60</sup> the Commission rejected a pipeline proposal for negotiated transportation rates, there being no evidence of competing pipelines or other alternatives for shippers or customers.

In Order No. 547,<sup>61</sup> which grants limited jurisdiction blanket certificates authorizing gas sales for resale at negotiated rates, the Commission clarified the meaning of the term "negotiated rates." The Commission stated that "[a]ny sale effectuated pursuant to the marketing certificate issued by this rule is by definition a sale at a negotiated rate."<sup>62</sup> The Commission based its conclusion on the findings in Order Nos. 636 and 636-A that, after restructuring,

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of the minimum bill was necessary to assure lenders that the costs associated with debt service related to the facility would be guaranteed.

57. *Id.* at 61,709. Trunkline LNG also agreed to share with Trunkline's customers a portion of any revenues derived from future operations of the LNG facility, a portion of any operational cost savings experienced during the future operation of the facility, and a portion of any revenues realized above a certain level from any future sale of the facility to an unaffiliated entity. The Commission also approved the recovery of a portion of the payments made by Trunkline to its LNG supplier, Sonatrach, in resolution of the claims made by Sonatrach arising out of Trunkline's suspension of its LNG purchases in 1983. The settlement treated these costs essentially the same as any other take-or-pay related, buy-out costs. Trunkline was permitted to recover from its customers, 50 percent with the remaining 50 percent to be absorbed by its shareholders.

58. 60 F.E.R.C. ¶ 61,035 (1992).

59. 59 F.E.R.C. ¶ 61,316 (1992).

60. 59 F.E.R.C. ¶ 61,379 (1992).

61. Final Rule, Regulations Governing Blanket Marketer Sales Certificates, 61 F.E.R.C. ¶ 61,281 (1992); III F.E.R.C. STATS. AND REGS. ¶ 30,957 (Dec. 8, 1992).

62. *Id.*, 57 Fed. Reg at 57,957.

the sale of gas as a commodity will be sufficiently competitive so as to prevent a pipeline from gaining market power.<sup>63</sup>

*L. Order No. 636*

Order No. 636,<sup>64</sup> issued on April 8, 1992, changed the Commission's standards for natural gas pipeline rate making, both for gas sales and transportation and provided guidance on the recovery of pipeline transition costs and on the costs and rate impacts of the capacity release program established in the rule.

Provided that pipeline sales are "unbundled" from transportation services in accordance with Order No. 636, the Commission allowed interstate pipelines to offer sales service at market prices under new negotiated sales contracts. The market-based pricing approach is intended to replace the GIC and PGA mechanisms pipelines now use to recover purchase gas costs.

Under Order No. 636, each interstate pipeline must file to restructure its services by restating transportation rates based upon the Straight Fixed-Variable (SFV) method of cost allocation and rate design. According to the Commission, SFV-based rates allow competing gas merchants to compete for gas markets on an equal footing, to remove from buyers' (particularly firm customer's) gas purchase decisions the distorting effect of having to pay in their volumetric rates for pipeline fixed costs of retained capacity, and to maximize pipeline throughput by better enabling gas to compete with alternate fuels.

Under SFV, a pipeline recovers 100% of its fixed costs of service through demand or reservation fees, and its variable costs through commodity or usage charges. SFV departs from Modified Fixed-Variable (MFV) approach, under which all fixed costs except return on equity and associated taxes are recovered in demand charges. If SFV produces a 10% or greater increase in revenue responsibility for any historic customer class than would have resulted under the pipeline's previous rate methodology, Order No. 636 requires the pipeline to mitigate the effects of SFV by phasing in its SFV rates for the affected class over no greater than four years. The Commission will consider departures from SFV-based rates only if the pipeline and its customers agree to another method and if, notwithstanding such agreement, the parties can meet a heavy burden of persuasion that the change meets the objectives of Order No. 636.

Order No. 636 requires pipelines to develop new rate mechanisms for recovery of any transition costs the pipeline might incur in unbundling services under Order No. 636. The Commission identified the four types of costs: (1) unrecovered gas costs (unpaid Account 191 balances), (2) gas supply realignment (GSR) costs incurred to buy out or buy down producer contracts to track post-Order No. 636 needs, (3) costs of "stranded" capacity, including

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63. *Id.*

64. 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).

unutilized Account 858 and storage costs, and (4) new facilities or equipment needed to provide new Order No. 636 services.

The Commission permitted pipelines to direct bill customers for any unrecovered Account 191 costs accrued after July 31, 1991 and left in the PGA after the pipeline adopted market-based gas sales rates. It permitted GSR costs to be recovered through either a negotiated exit fee or a surcharge to firm transportation reservation fees.<sup>65</sup> Stranded capacity costs and costs of new equipment needed for Order No. 636 services were to be recovered in separate section 4 rate increase filings.

Finally, Order No. 636 provides that pipelines could credit the bills of firm customers who released capacity with revenues received upon resale of capacity released pursuant to the mandated capacity release program. The Commission made clear that firm customers would remain obligated to pay reservation fees if the capacity released was not resold. Further, the Commission allowed pipelines to charge firm customers a negotiable administrative fee for brokering the resale of their released capacity.

#### 1. Order No. 636-A

The Commission's order on rehearing, Order No. 636-A,<sup>66</sup> adhered to market-based sales rates and SFV rate design. However, the Commission adopted measures to mitigate the input of SFV-related rate increases, particularly on small customers.<sup>67</sup> The Commission signaled that it would consider agreements to mitigate cost-shifts by allocating costs under MFV or other methods, even though rates must still be designed under SFV. Moreover, it indicated that other ratemaking techniques for allocating revenue responsibility, including eliminating two-part reservation charges or allocating costs based upon peak-day demands, might be acceptable. Small customers are further protected under Order No. 636-A by the requirement that pipelines maintain one-part volumetric transportation rates computed at an existing load factor and gas sales service at cost-based rates for a one-year period following the effective date of a new blanket sales certificate.

Order No. 636-A also made several modifications or clarifications to transition cost recovery mechanisms. The order provided that transition costs may not be recovered until the pipeline comes into compliance with the Order No. 636 program. Only post-July 31, 1991 Account 191 costs may be direct billed, and ten percent of GSR costs must be recovered from Part 284 interruptible transportation (IT) service, not in the form of a surcharge on IT rates,

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65. Order No. 636-A, requires pipelines to recover 10% of GSR costs in their interruptible transportation rates.

66. 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 Under Part 284 of the Commission's Regulations; Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, III F.E.R.C. STATS. AND REGS. ¶ 30,950 (1992).

67. "Small customers" are those receiving that class of service as of May 18, 1992, although pipelines were encouraged to include customers receiving less than 10,000 Mcf/d. III F.E.R.C. STATS. AND REGS. ¶ 30,950, at 30,545-30,546.

but rather as an allocation of costs to that service.<sup>68</sup>

The Commission also opened the door to crediting firm customers with some portion of a pipeline's earnings from IT rates, depending upon the rate design used for developing IT rates. Because capacity releasing makes it difficult to estimate a pipeline's throughput of interruptible volumes, the Commission suggested that it may be appropriate to assign no fixed costs to IT service, and then to credit any IT revenues to firm customers.<sup>69</sup>

## 2. Order No. 636-B

The Commission's second rehearing order<sup>70</sup> provided additional guidance regarding SFV mitigation, recovery of transition costs, and IT revenue crediting. Under Order No. 636-B, a pipeline can allocate costs on the basis of both peak and annual measures of usage through the use of seasonal contract quantities or other factors, even though it cannot charge a two-part reservation fee.<sup>71</sup> The Commission declined to mandate any particular approach; however, it changed the threshold test for mitigating any cost shifts from SFV. If any individual customer's revenue responsibility (as opposed to the aggregated impact on a customer class) would be increased by 10% or more due to SFV, the impact must be mitigated.<sup>72</sup> Moreover, the Commission departed from the "bright line" test of Order No. 636 by allowing parties to adopt rate-making methodologies other than SFV for cost allocation purposes. After examining the results of an SFV-based cost allocation, parties to a restructuring proceeding were invited to first employ other cost allocation methodologies to mitigate any significant shifting of cost responsibility among customer classes. If, after such allocation, any customer still faces a ten percent or greater increase in rates, it is then entitled to a phase-in of SFV-based rates, over a period not to exceed four years.<sup>73</sup>

Order No. 636-B reaffirmed the Commission's intention to permit 100% recovery of GSR costs for prudently incurred costs, but clarified that pipelines would be at risk for recovery of GSR costs associated with providing discounted firm transportation service. It also stated that the PGA regulations will be applied in a flexible manner to permit full recovery of unrecovered purchased gas costs included in Account No. 191 and clarified that pipelines can seek waivers of the PGA regulations to ensure full cost recovery.

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68. III F.E.R.C. STATS. AND REGS. ¶ 30,950, at 30,646; *see also* Order No. 636-B, 61 F.E.R.C. ¶ 61,066, 61,272 (1992).

69. III F.E.R.C. STATS. AND REGS. ¶ 30,950, at 30,563.

70. Order Denying Rehearing and Clarifying Order Nos. 636 and 636-A, Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 61 F.E.R.C. ¶ 61,272, at 61,987 (1992).

71. 61 F.E.R.C. ¶ 61,272, at 62,014-16.

72. The Commission clarified that mitigation measures would be available for any customer facing a significant cost shift. 61 F.E.R.C. ¶ 61,272, at 62,014.

73. 61 F.E.R.C. ¶ 61,272, at 62,016.

*M. Order No. 636 Compliance Filings*

By year's end, the Commission had accepted, subject to numerous conditions, aspects of the Order No. 636 compliance plans of three pipelines, subject to submittal of conforming tariff sheets within 30 days. Many issues were made subject to the outcome of the pipelines' pending rate cases.

*1. Transwestern Pipeline Company*

In the first order on a compliance filing, the Commission accepted Transwestern's filing subject to certain modifications.<sup>74</sup> Among the rate-related modifications, the Commission accepted as complying with Order No. 636-A Transwestern's one-part volumetric rate for small customers but directed that Transwestern submit a customer-by-customer impact study to show the potential impact of the switch to SFV. The Commission rejected Transwestern's shift from zone-based to system-wide reservation charges for pre-expansion shippers, concluding that this shift would be contrary to its policy objectives to encourage mileage-sensitive or zone-based rates so as to promote the formation of pooling points and market centers. The Commission further directed that Transwestern require a shipper using a downstream delivery point to pay a higher reservation charge than a shipper using an upstream delivery point. The Commission accepted Transwestern's continued use of a 125% load factor rate for interruptible transportation service, but rejected the pipeline's proposal to charge a lower rate for higher priority interruptible service feeding firm transportation service.

*2. Panhandle Eastern Pipe Line Company*

The Commission also approved Panhandle's compliance filing subject to certain modifications.<sup>75</sup> The Commission rejected Panhandle's proposed system access charge and directed Panhandle to eliminate certain costs attributable to that charge. It accepted Panhandle's treatment of interruptible transportation, including Panhandle's retention of IT revenues, noting that Panhandle had allocated costs to IT service which therefore made appropriate its retention of the revenues. The Commission directed Panhandle to unbundle transmission and storage costs to ensure that customers using off-system storage will not have to absorb storage costs in the transmission rate. The Commission also made certain issues subject to the outcome of Panhandle's rate case in Docket No. RP92-166, including Panhandle's use of an existing special backhaul rate and possible overstatement of its rates. It ordered the company to eliminate a tariff provision that would have allowed the pipeline to use CD levels related to past periods as the basis for allocating costs in future rate filings. The Commission also rejected several features of Panhandle's GSR recovery proposal that were objectionable under Order No. 636, including a non-negotiable exit fee to recover any remaining GSR balance at the end of a three-year surcharge, and a volumetric surcharge on IT rates. Instead, it required Panhandle to allocate ten percent GSR costs to IT service.

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74. 61 F.E.R.C. ¶ 61,332 (1992).

75. 61 F.E.R.C. ¶ 61,357 (1992).

The Commission approved two tracking mechanisms to recover (1) the costs of fuel and lost, and unaccounted-for gas, and (2) the costs of Account 858 third-party transportation and Account 824 third-party storage. Finally, the Commission directed Panhandle to file a revised, customer-specific SFV cost mitigation impact study based on revised rates, reflecting the unbundling of transportation from storage service and other changes required by the order.

### 3. El Paso Natural Gas Company

The Commission accepted, subject to conditions, El Paso's compliance filings pertaining to its capacity release program.<sup>76</sup> El Paso was directed to delete a proposed \$100 fee for posting notices of released capacity on its Electronic Bulletin Board (EBB) and to credit revenues to the releasing shipper's reservation fees.

### 4. Other Compliance Cases

In separate orders, the Commission terminated the Order No. 636 restructuring proceedings of *Gas Gathering Corp.*,<sup>77</sup> *Pelican Interstate Gas System*<sup>78</sup> and *Valley Gas Transmission, Inc.*<sup>79</sup> on the ground that each of the three companies in these proceedings primarily performed nonjurisdictional gathering services. Applying the "modified primary function test" to the operations of the above companies, the Commission determined that all three systems qualified as gathering facilities and thus were exempt from NGA jurisdiction.

In *Cornerstone Pipeline Co.*,<sup>80</sup> the Commission deferred Cornerstone's obligation to comply with Order No. 636 because the pipeline did not yet have a tariff on file. In addition, the Commission required Cornerstone to make its Order No. 636 compliance filing at least 60 days before the in-service date for its pipeline facilities.

In *Wyoming Interstate Co. Ltd.*,<sup>81</sup> the Commission held that certain restructuring requirements are inapplicable to a "transportation-only" pipeline such as WIC. Those requirements include: (1) unbundling of sales and transportation; (2) equality of transportation service regardless of whether gas is purchased from the pipeline or another seller; (3) the provision of a no-notice transportation service; (4) non-discriminatory access to storage; and (5) various tariff provisions (e.g., first come, first served allocation of capacity, penalties and balancing rights and curtailment). However, the Commission ordered WIC to address other issues in its restructuring proceeding such as: (1) modifications to its existing electronic bulletin board; (2) reservation fees; (3) capacity release and capacity assignment provisions; (4) flexible receipt and delivery points, and (5) right-of-first refusal procedures. The Commission also ordered WIC to address whether its rates inhibit the development of market

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76. 61 F.E.R.C. ¶ 61,333 (1992).

77. 61 F.E.R.C. ¶ 61,028 (1992).

78. 61 F.E.R.C. ¶ 61,025 (1992).

79. 61 F.E.R.C. ¶ 61,023 (1992).

80. 60 F.E.R.C. ¶ 61,019 (1992).

81. 61 F.E.R.C. ¶ 61,017 (1992).

centers.<sup>82</sup>

In *Point Arguello Natural Gas Line Co.*,<sup>83</sup> the Commission terminated Point Arguello's Order No. 636 restructuring proceeding because, among other reasons, Point Arguello is a transportation-only pipeline with no storage facilities, no upstream firm transportation capacity or storage rights, and no shippers under its open-access rate schedules. Point Arguello provides only firm transportation service to its owners under a cost-of-service rate schedule and has only one receipt and one delivery point.<sup>84</sup>

#### *N. Payment for Construction of New Facilities*

In *Northwest Pipeline Corp.*,<sup>85</sup> the Commission addressed Northwest's proposal to amend its tariff to give customers the option of paying for construction of facilities at the time of construction or paying a monthly cost-of-service (COS) charge. The COS charge was designed to give customers an option when the proposed facilities would not meet Northwest's economic benefit test, i.e., when the incremental revenues from the facilities would not exceed the cost of construction. Northwest would finance the construction and the customer would reimburse Northwest by paying the monthly COS charge. The shipper could pay Northwest the remaining book value at any time. The Commission allowed this provision to become effective but required Northwest to be at risk for any defaults and prohibited it from seeking to recover such costs from other ratepayers.

#### *O. Policy Statement on Incentive Rates*

On October 30, 1992, the Commission issued a policy statement setting forth general principles with respect to incentive ratemaking for natural gas pipelines, oil pipelines, and electric utilities.<sup>86</sup> The policy statement was the result of the Commission's consideration of comments filed in response to its March 13, 1992, Notice of Proposed Policy Statement<sup>87</sup> regarding incentive rate regulation. The purpose of the policy statement was to provide companies that possess market power with an alternative to traditional cost-of-service ratemaking.

The goal of the Commission's incentive rate policy was to encourage companies to reduce costs and administrative burdens in an effort to achieve long-term productive efficiency in noncompetitive markets. The Commission stated that long-term productive efficiency will be accomplished in three ways: (1) by divorcing rates for service from the underlying cost of providing such

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82. See also *WestGas InterState, Inc.*, 60 F.E.R.C. ¶ 61,039 (1992).

83. 60 F.E.R.C. ¶ 61,040 (1992).

84. See also *Jupiter Energy Corp.*, 60 F.E.R.C. ¶ 61,044 (1992); *Gulf States Transmission Corp.*, 60 F.E.R.C. ¶ 61,045 (1992). In *KN Energy, Inc.*, 60 F.E.R.C. ¶ 61,042 (1992), the Commission removed cost classification, cost allocation, and rate design issues, except for issues related to gathering rates, from KN's rate case and consolidated those issues with KN's restructuring proceeding.

85. 59 F.E.R.C. ¶ 61,081 (1992).

86. Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines and Electric Utilities, Policy Statement on Incentive Regulation, 61 F.E.R.C. ¶ 61,168 (1992).

87. 58 F.E.R.C. ¶ 61,287 (1992).

service; (2) by lengthening the period of time between rate cases; and (3) through a sharing of the benefits of cost savings between the utility's shareholders and its customers.

The policy statement provided that incentive rate mechanisms should be designed to encourage utility companies to operate at optimal levels, allocate services to highest value uses, invest in new capital where warranted economically, and capture expanding markets. The Commission emphasized, however, that, initially, incentive rates will be required to conform to the Commission's traditional just and reasonable standard under the Natural Gas Act.

The policy statement sets forth five regulatory standards for the design of incentive rate mechanisms. Under the five regulatory standards, incentive rate mechanisms must (1) be implemented on a prospective basis; (2) be implemented by utility companies on a voluntary basis; (3) be understandable to all utility customers; (4) result in quantifiable benefits to consumers; and (5) demonstrate how the rates will maintain or enhance incentives to improve the quality of service.

The policy statement also sets forth five possible mechanisms that may be used to develop incentive rate proposals. The five incentive rate mechanisms include: (1) automatic rate adjustment mechanisms; (2) performance targets; (3) flexible pricing; (4) benefit sharing; and (5) consumer welfare bonuses. While the policy statement does not preclude companies from proposing other types of incentive rate mechanisms, the Commission stated that any mechanism proposed must be consistent with the five regulatory standards contained in the policy statement. The Commission promised to evaluate incentive rate proposals on a case-by-case basis.

In addition, the policy statement provides that incentive rate proposals may be discussed and formulated in the context of Order No. 636 pipeline restructuring proceedings, but must be filed in separate NGA section 4 proceedings.<sup>88</sup> Moreover, the policy statement provides that, unlike traditional section 4 rate filings, an incentive rate mechanism will not be permitted to become effective until the Commission issues an order finding that the incentive mechanism will yield just and reasonable rates. The Commission also made it clear that incentive rate proposals may be filed by intrastate pipeline companies operating under NGPA section 311.

#### *P. Post-Employment Benefits*

On December 17, 1992, the Commission issued a general policy state-

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88. The Commission's policy statement provides that there are three basic vehicles for incentive rate filings under section 4. Under the policy statement, pipelines may (1) seek to implement incentive rates by filing a new section 4 rate case; (2) base their incentive rates on rates which have been litigated and approved by the Commission within the previous 18 months (such rates will be subject to a rebuttable presumption of justness and reasonableness); or (3) base their incentive rates on rates calculated by a settlement agreement executed during the previous 18 months. In circumstances where the proposed rates are the result of a settlement agreement, the Commission stated that the utility will bear the burden of proving that such rates are just and reasonable, including the overall rate and any discrete elements of the cost-of-service supporting the rate level.



ment<sup>89</sup> concerning the rate and accounting treatment of certain post-employment benefits other than pensions (PBOPs) for employees at natural gas companies and public utilities subject to the Commission's jurisdiction. The policy statement is premised upon the requirements of Statement of Financial Accounting Standards No. 106 (FASB 106), and relates mainly to medical coverage of retirees. FASB 106, issued in December 1990, requires that for fiscal years beginning after December 15, 1992, employers must reflect in current expenses an accrual for post-retirement benefits other than pensions during the working lives of covered employees.

The Commission will recognize, as a component of jurisdictional cost-based rates of pipelines electing to comply with FASB 106, the accrual allowances for prudently-incurred costs for such benefits, provide that (1) the company agrees to make cash deposits to an irrevocable trust fund with an independent trustee equal to the annual test period allowance for the cost of such benefits, and (2) the company maximizes the use of income tax deductions for contributions to the trust fund. If tax deductions are not available for some portion of currently funded amounts, deferred income tax accounting must be followed for the tax effects of such transactions.

Each company must file within three years of its adoption of FASB 106 accounting a general rate change and seek inclusion of these costs in its rate levels. The company may defer the jurisdictional portion of the difference between the costs determined pursuant to accounting principles previously followed and FASB 106 accruals from the time it adopts FASB 106 until the company files such general rate case and places such rates into effect. The regulatory asset (or liability) thus created is to be amortized over a period not to exceed twenty years beyond the FASB 106 adoption date. Amortization of the regulatory asset (or liability) will be eligible for recovery in future rates.

#### *Q. Processing Revenues*

In *Northern Natural Gas Co.*,<sup>90</sup> the Commission clarified that Northern must revise its tariff to provide that shippers will receive a credit for benefits or revenues received by Northern for the sale or use of products extracted from a shipper's gas. Thus, shippers have the following options: (1) to enter into a contract with a processor, or (2) to receive a credit from Northern if (a) Northern processes the shipper's gas and receives revenues or uses the product, or (b) Northern contracts with a third-party or has an arrangement with an affiliate to process the shipper's gas where either generates revenues from the sale of the product.

#### *R. Purchase Gas Adjustment Issues*

In *Carnegie Natural Gas Co.*,<sup>91</sup> the Commission denied Carnegie's request

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89. Post-Employment Benefits Other Than Pensions, Statement of Policy, 61 F.E.R.C. ¶ 61,330 (1992).

90. 60 F.E.R.C. ¶ 61,074 (1992).

91. 61 F.E.R.C. ¶ 61,298 (1992).

for rehearing of a Commission suspension order<sup>92</sup> which, among other things, rejected Carnegie's request to offset its Account No. 191 balance against a refund expected from Texas Eastern Transmission Corporation. On rehearing, the Commission expressed continued concern that Carnegie's proposed offsetting of commodity costs with the Texas Eastern refund would impede an equitable distribution of refunds to Carnegie's customers. In addition, the Commission reiterated that Carnegie is not permitted to net commodity costs with demand costs under 18 C.F.R. § 154.305(i), and that such a proposal would pre-judge a matter more appropriately considered in Carnegie's Order No. 636 restructuring proceeding.

In *Pacific Gas Transmission Co.*,<sup>93</sup> the Commission denied a request for waiver of its regulations to treat the cost of line pack as a PGA cost so that it could include representative levels of line pack in its rate base. However, PGT failed to show why sales customers should bear these costs. Similarly, the Commission denied a waiver of its regulations to collect carrying charges for the difference between the cost of gas supplies purchased and the cost of supplies paid for. The Commission reasoned that a waiver would be unnecessary because PGT could seek to collect these costs when PGT accepts delivery of discrepancy volumes.

In *Northern Natural Gas Co.*,<sup>94</sup> the Commission accepted Northern's proposal to assess a termination surcharge if Northern's PGA is terminated and suspended. It accepted the filing even though Northern had no current plans to suspend or terminate its PGA, noting that such a provision provides notice to customers of potential charges so customers may take them into account when making their gas purchase decisions.

In Order No. 546,<sup>95</sup> the Commission revised its regulations to delegate to the Director of the Office of Pipeline and Producer Regulation the authority to rule on out-of-cycle PGA filings. The Commission noted in the order that the Director already had authority to rule on quarterly PGA filings, and stated that it saw no need to treat out-of-cycle PGA filings differently. To the extent that an out-of-cycle filing raises substantial policy questions (for example, proposals to alter or defer the collection of applicable surcharges or to modify accounting procedures), the Director must defer to the Commission.

#### *S. Purchase Obligations For Canadian Gas: Rate Effects*

In *Panhandle Eastern Pipe Line Co.*,<sup>96</sup> the Commission approved Panhandle's proposed settlement to resolve its obligations to purchase up to 150 Mcf/d of Canadian gas from Northwest Alaskan Pipeline Company (Northwest Alaskan) and transport such gas over the "Eastern Leg" of the Alaska Natural Gas Transportation System (ANGTS) "pre-build" facilities. Under the settlement, Panhandle will pay \$60 million to Pan-Alberta Gas Company (Pan-Alberta) for the transfers of its purchase obligations to Northwest Alas-

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92. 60 F.E.R.C. ¶ 61,225 (1992).

93. 60 F.E.R.C. ¶ 61,091 (1992).

94. 59 F.E.R.C. ¶ 61,003 (1992).

95. Order No. 546, Regulation Delegating Authority, III F.E.R.C. STATS. & REGS. ¶ 30,956 (1992).

96. 61 F.E.R.C. ¶ 61,160 (1992).

kan, and related transportation obligations on Northern Border, to Pan-Alberta's domestic marketing affiliate, Pan-Alberta Gas U.S., Inc. Panhandle will recover the \$60 million contract termination payment over a six-year period through a "Canadian resolution surcharge." The Commission's order requires Panhandle to remove from rate base \$2.2 million attributable to its rights in Northern Border's line pack, and to treat any transportation provided for PAG-US or Pan-Alberta during the settlement period at maximum rates, regardless of the provision of any discounts. The Commission determined that the ANGTS project sponsors' revenue stream would not be jeopardized by Panhandle's settlement and, therefore, the settlement would not violate section 9 of the Alaska Natural Gas Transportation Act of 1976.<sup>97</sup>

In *Panhandle Eastern Pipe Line Co.*,<sup>98</sup> the Commission applied its Rate Design Policy Statement and largely affirmed Opinion No. 369,<sup>99</sup> including: (1) Panhandle's proposal to use a straight fixed-variable rate design with a modified fixed-variable cost allocation which assigns part of the fixed costs on the basis of annual throughput; (2) Panhandle's prospective use of seasonal rates for sales service, but not for transportation services; (3) interruptible rates designed to include fixed costs on a 100% load factor basis; (4) prospective market zone rates based on 100 mile increments; (5) a prospective back haul rate set at one-half the forward haul rate; and (6) use of the three-day peak determinants to allocate costs between jurisdictional and non-jurisdictional customers and the use of contract demand (including imputed interruptible demand) to allocate D-1 costs among jurisdictional customers.

In *Northern Natural Gas Co.*,<sup>100</sup> the Commission approved a rate design in a pre-restructuring settlement that provided for tiered rates, differentiated for base load and additional load levels. The Commission, nevertheless, disapproved a special rate for transportation through the market area because the rate was lower than the rate for transportation within the market area and lacked other justification.

In *Tennessee Gas Pipeline Co.*,<sup>101</sup> the Commission approved an interim settlement demand charge on all sales, firm open access transportation, and storage services for recovery of Great Plains costs, which were subject to change in the pipeline's restructuring proceedings.

In *Stingray Pipeline Co.*,<sup>102</sup> the Commission accepted a settlement to resolve a show cause proceeding on possible over recovery. The settlement reduced transportation rates 5% to \$2.03 per dth for firm service and to 8.73

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97. 15 U.S.C. §§ 719-719(o) (1988).

98. Opinion No. 369-A, 59 F.E.R.C. 61,244 (1992). The Commission issued three companion orders applying its determinations in Opinion Nos. 369 and 369-A to rehearing on certain *Panhandle* settlement orders, 59 F.E.R.C. 61,245 (1992); the issues to be tried in a *Panhandle* general rate case, 59 F.E.R.C. ¶ 61,246 (1992); and rehearing of the suspension order in a *Panhandle* general rate case, 59 F.E.R.C. ¶ 61,247 (1992).

99. *Panhandle Eastern Pipe Line Co.*, 57 F.E.R.C. ¶ 61,264 (1991).

100. 59 F.E.R.C. ¶ 61,379 (1992).

101. 59 F.E.R.C. ¶ 61,361 (1992). The Commission likewise approved two related downstream settlements in *Midwestern Gas Transmission Co.*, 59 F.E.R.C. ¶ 61,358 (1992) and *East Tennessee Natural Gas Co.*, 59 F.E.R.C. ¶ 61,355 (1992), subject to change in restructuring proceedings.

102. 59 F.E.R.C. ¶ 61,350 (1992).

cents (based on a 100% load factor) for interruptible service. In addition, Stingray was required to credit firm service with revenues equal to 8 cents times half the interruptible transportation throughput.

### *T. Rate of Return*

In light of the increase in jurisdictional revenues of \$234 million requested by the pipeline (based in part on a pre-tax return on rate base of 18 percent), the Commission found in *Transcontinental Gas Pipe Line Corp.*,<sup>103</sup> that the use of the pipeline's capital structure was inappropriate, even though Transco had issued some long-term bonds and long-term debentures. The Commission reasoned that Transco had relied upon its parent company for cash needs in excess of the cash received from its business operations. Moreover, Transco's parent company had a 16.27% equity ratio, atypically low for the industry, and would require a rate of return on equity that is abnormally high in relation to rates of return approved by the Commission for comparable pipelines. Accordingly, the Commission developed a hypothetical capital structure based upon a comparison group of seven publicly traded pipelines which earned more than 50% of their total revenues from gas transmission (Primary Group). The zone of reasonableness based on the equity ratios for the Primary Group was between 15.62 and 65.25%. The Commission approved a hypothetical capital structure based upon the 1991 year-end average of the Primary Group, which resulted in 38.79% common equity, 3.68% preferred equity, and 57.53% long-term debt.

The Commission also reaffirmed its policy on the use of the discounted cash flow methodology (DCF) to determine a zone of reasonableness for a regulated pipeline's rate of return on equity. Although the Commission stated that the ALJ had properly rejected Transco's proposed risk-positioning methodology as unreliable and inconsistent with prior Commission precedent,<sup>104</sup> it also clarified that it remains open to the use of different methodologies for developing rates of return, including the risk positioning approach. The Commission also rejected a comparison group, including 19 gas pipelines which did not have publicly traded stock, which had been used by the Commission staff and adopted by the ALJ in developing the DCF zone of reasonableness.

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103. 60 F.E.R.C. ¶ 61,246, *reh'g*, 60 F.E.R.C. ¶ 61,085 (1992). See also *Transcontinental Gas Pipe Line Corp.* (Initial Decision), 60 F.E.R.C. ¶ 63,001 (1992). In the initial decision, the administrative law judge (ALJ) rejected Transco's filed return on equity of 36.40%. The ALJ reached numerous conclusions, including the following: (1) given that Transco's parent borrowed \$350 million by pledging Transco's assets, Transco may not argue that the parent's thin equity compels a high return on equity for the pipeline by using the parent's capital structure, and at the same time, claim a high return on its own equity from the increased risk caused by its pledge of its assets as surety for its parent's indebtedness; (2) Transco's ratepayers should not bear the economic burden resulting from the financial distress of Transco's parent, because the financial distress was caused by illegal or improper acts or losses from non-jurisdictional businesses; (3) the rate of return should be calculated based on Transco's capital structure and not the capital structure of its parent because Transco's capitalization is primarily publicly held debt and preferred stock and accurately reflects the risks Transco faces; and (4) Transco's attempt to assume an overall rate of return and then to "back out" the return on equity was inconsistent with the methodology used by the Commission and approved by the courts.

104. 60 F.E.R.C. ¶ 63,001, at 65,034.

#### *U. Recovery of Carrying Charges*

In *Tarpon Transmission Co.*,<sup>105</sup> the Commission permitted Tarpon to recover a carrying charge on certain deferred extraordinary regulatory costs equal to the charge permitted under section 157.67(c)(2)(iii) of the Commission's refund regulations.<sup>106</sup> However, the Commission held that it would not permit "in the circumstances of this case, rate base treatment of those costs."<sup>107</sup> The Commission denied rate base treatment of Tarpon's nonrecurring regulatory expenses (which were to be amortized over three years) because "they are not an investment that is used or useful in providing utility services to the public and are of no benefit to the pipeline's customers."<sup>108</sup>

#### *V. Scheduling and Balancing Penalties*

El Paso Natural Gas Company proposed to credit penalty amounts collected from shippers that took deliveries in excess of scheduled volumes to those shippers that had scheduled volumes which El Paso was unable to deliver. Subject to possible change in an Order No. 636 proceeding, the Commission agreed that the proposed crediting of penalty revenues to customers that were denied scheduled deliveries was appropriate, but that the allocation of such credits should be computed on a daily basis. Any unused credits or undistributed penalty amounts would be retained in the account until distributed in future quarters.

In *El Paso Natural Gas Co.*,<sup>109</sup> the Commission accepted, subject to conditions, El Paso's proposal to eliminate its existing daily and monthly cumulative transportation imbalance penalties and replace them with a tariff provision whereby gas imbalances existing prior to the new provision's effective date would be corrected in kind or cashed out.

The Commission rejected El Paso's method of calculating imbalances and directed it to reinstate its present method of calculating imbalance percentages. In addition, the Commission's order directed El Paso to modify its tariff to provide credit to its sales and transportation customers of any revenue received from cash-out penalties. The Commission also directed El Paso to file revised tariff sheets explaining how it will negotiate the netting of contracts on a non-discriminatory basis. The Commission stated that while it has not previously required the netting of contracts with respect to imbalances, it would require El Paso to develop tariff language in light of its expressed willingness to enter into such agreements on a non-discriminatory basis.

In *Northern Natural Gas Co.*,<sup>110</sup> the Commission rejected proposed penalty fees because the pipeline lacked necessary measurement equipment. The Commission also noted that it would not require penalty revenues to be

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105. 59 F.E.R.C. ¶ 61,241 (1992).

106. In so doing, the Commission noted (59 F.E.R.C. ¶ 61,241, at 61,820 n.15) that its authority to deny carrying charges upon reasoned grounds in situations involving extraordinary expenses is well-established under *Panhandle Eastern Pipe Line Co. v. FERC*, 777 F.2d 739 (D.C. Cir. 1985).

107. 59 F.E.R.C. ¶ 61,241, at 61,819 (1992).

108. 59 F.E.R.C. ¶ 61,241, at 61,820-21.

109. 61 F.E.R.C. ¶ 61,302 (1992).

110. 59 F.E.R.C. ¶ 61,379 (1992).

credited against other rates except for penalty revenues from the pipeline's affiliates.

### *W. Suspension Policy*

In *Columbia Gas Transmission Corp.*,<sup>111</sup> the Commission approved, subject to refund, the immediate implementation of a proposed gas cost "surcharge," rather than suspending it for the full five-month statutory period. The proposed surcharge was filed by Columbia to implement provisions of a 1985 PGA settlement,<sup>112</sup> which contemplated recovery through the surcharge of a portion of Columbia's previously unrecovered gas costs in instances where Columbia's weighted average cost of gas (WACOG) for any given calendar year, as adjusted, was below the average WACOG of its historic pipeline suppliers.

The Commission found substantial deficiencies in Columbia's calculations, noting that "the protestors have raised significant concerns regarding the propriety of the proposed WACOG surcharge. . . ."<sup>113</sup> Nevertheless, the Commission permitted Columbia to implement the proposed surcharge immediately. The Commission concluded that the shortened suspension period was appropriate because the filing was made pursuant to an approved settlement and because "Columbia has made a colorable presentation in support of its surcharge, and may be able to respond to the protestors' concerns given the opportunity to do so."<sup>114</sup>

### *X. Take-or-Pay Cost Recovery*

In *East Tennessee Natural Gas Co.*,<sup>115</sup> the Commission approved settlement provisions for direct billing and demand surcharge mechanisms for recovery of take-or-pay costs from jurisdictional customers, over the objections of non-jurisdictional direct sales customers, who were converting to jurisdictional transportation. Part of the demand surcharge costs were allocated by throughput, not contract entitlements. The demand costs included upstream pipeline demand charges, which the objecting parties wanted allocated and charged "as billed." The Commission observed that the upstream pipeline's demand charges in question were based on annual, not daily entitlements.

In *Northwest Pipeline Corp.*,<sup>116</sup> the Commission reversed its prior determination that four of Northwest's Order No. 500 take-or-pay filings were exempt from the stay of purchase deficiency-based fixed charges imposed by

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111. 60 F.E.R.C. ¶ 61,229 (1992).

112. 31 F.E.R.C. ¶ 61,307 (1985); *reh'g granted* 31 F.E.R.C. ¶ 61,372 (1985); *modified* 33 F.E.R.C. ¶ 61,344 (1985); *reh'g denied, clarification granted* 40 F.E.R.C. ¶ 61,195 (1987), *appeal dismissed*, *Process Gas Consumers Group v. FERC*, 912 F.2d 511 (D.C. Cir. 1990).

113. 60 F.E.R.C. ¶ 61,229, at 61,775.

114. 60 F.E.R.C. ¶ 61,229, at 61,775. Commissioner Langdon dissented, arguing that a longer suspension period was appropriate especially "[i]n light of the seriousness of the protestors' concerns and of the open question about refunds on Columbia under its present status." *Id.* at 61,773.

115. 59 F.E.R.C. ¶ 61,355 (1992).

116. 59 F.E.R.C. ¶ 61,145 (1992).

Order No. 528. The Commission had exempted the four filings from Order No. 528 on the ground that the use of the purchase deficiency allocation method in those proceedings was final and nonappealable. The Commission found that its initial determination that the purchase deficiency allocation method did not violate the filed rate doctrine was "so inextricably linked" to the determination of how the allocation method would be implemented that the parties could raise the first issue in a timely appeal of a Commission final order deciding the second issue. Thus, the Commission held that Northwest's four take-or-pay filings were not final and nonappealable as to the purchase deficiency method, and Northwest's flow-through of such costs "cannot be exempt from Order No. 528."<sup>117</sup>

In *Columbia Gas Transmission Corp.*,<sup>118</sup> the Commission confirmed that while fixed take-or-pay charges billed to downstream pipelines should be booked in Account No. 803, take-or-pay costs are not purchased gas costs for rate purposes and should not be included by Columbia in its WACOG calculations.<sup>119</sup>

In *El Paso Natural Gas Co.*,<sup>120</sup> the Commission issued an order resolving all but one of the outstanding non-prudence issues in El Paso's Order Nos. 500 and 528 take-or-pay cost recovery proceedings. The Commission's order resolves the issue of the recoverability by El Paso of certain take-or-pay settlement costs which the Commission had previously held could not be resolved under El Paso's global settlement in Docket Nos. RP88-44-000, et al.<sup>121</sup> The Commission's order primarily disposed of issues related to the eligibility of costs for recovery under the alternative recovery mechanisms of Order Nos. 500 and 528 in various El Paso proceedings. The Commission determined that El Paso could recover \$1 billion of the take-or-pay contract settlement costs, including cash payments to producers totalling \$658.8 million, and \$572.3 million in other take-or-pay settlement costs. The Commission disallowed recovery of amounts El Paso claimed to have paid to producer suppliers under three settlements as compensation for state severance taxes. The Commission also directed El Paso to remove costs related to a previously discovered, but uncorrected, error involving El Paso's settlement with Home Petroleum Company.

In *El Paso Natural Gas Co.*,<sup>122</sup> the Commission approved a true-up mech-

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117. 59 F.E.R.C. ¶ 61,145, at 61,541; see also *Northwest Pipeline Corp.*, 60 F.E.R.C. ¶ 61,286 (1992).

118. 59 F.E.R.C. ¶ 61,233 (1992).

119. In so holding, the Commission affirmed its prior rejection of a 20 cent-per-Dth WACOG surcharge proposed by Columbia pursuant to a 1985 PGA settlement that authorized such a surcharge when Columbia's weighted average cost of gas, minus a 22 cent-per-Dth adjustment, was below the combined average WACOG of five other specified pipelines. As further justification for the rejection, the Commission stated that "[t]o allow Columbia to collect an additional surcharge from its customers without meeting its obligation to lower its WACOG to a competitive level would provide Columbia with a windfall that it has not earned." 59 F.E.R.C. ¶ 61,233, at 61,795.

120. *El Paso Natural Gas Co.*, 61 F.E.R.C. ¶ 61,107 (1992). The single issue set for hearing involved the fair market value of property which El Paso transferred to TransAmerican Natural Gas Corporation (TransAmerican) to settle a \$602.8 million Texas state district court judgment regarding El Paso's take-or-pay liability to TransAmerican.

121. *El Paso Natural Gas Co.*, 54 F.E.R.C. ¶ 61,316 (1991).

122. 60 F.E.R.C. ¶ 61,005 (1992).

anism that required El Paso to refund any overcollection of costs collected through an Order No. 528 volumetric surcharge. The amount of overcollection, if any, was to be calculated by comparing (1) the actual collection of take-or-pay costs under the volumetric surcharge, to (2) the amount that the surcharge was designed to recover. The Commission reasoned that this true-up mechanism would prevent El Paso from overcollecting and would guarantee that El Paso would absorb the amount it agreed to absorb. Moreover, the proposed true-up mechanism was held consistent with the policy that a pipeline may not recoup the cost of past discounts either through an increase in future rates or through a shift of the cost of the discounts to other customers.

In *United Gas Pipe Line Co.*,<sup>123</sup> the Commission rejected tariff sheets (filed as a contested settlement) allocating take-or-pay costs billed to United by an upstream pipeline based on the purchase deficiency allocation method that was rejected by the court in *Associated Gas Distributors v. FERC*.<sup>124</sup>

#### Y. Unauthorized Gas Penalties

In *Panhandle Eastern Pipe Line Co.*,<sup>125</sup> the pipeline was permitted to implement the following procedure with respect to unauthorized gas. Panhandle will post a notice of such gas for 120 days on its electronic bulletin board, after attempting to give written notice to suspected owners, operators, or shippers of such gas. Valid claims after five days, but within 60 days, will be assessed a 59 cent-per-MMBtu penalty, and valid claims between 61 and 120 days will be assessed a \$1.00 per-MMBtu penalty. After 120 days, Panhandle will be entitled to retain such gas and treat it through its PGA as gas purchased at no cost.<sup>126</sup> Any benefits from retained volumes of unauthorized gas are to be refunded to both sales and transportation customers.

### II. COMMISSION ACTION ON PRODUCER ISSUES: AREA RATE CLAUSES

In *NICOR Exploration Co.*,<sup>127</sup> the Commission affirmed an Initial Decision finding that the area rate clauses in three gas sales contracts did not authorize the producer to collect the NGPA section 108 stripper well price. The Commission sustained the ALJ's conclusion that the credible record evidence showed no mutual intent to pay the highest prices allowed by law rather than cost-based rates.<sup>128</sup> The Commission rejected the producer's contention that NICOR's actions demonstrated an intent to pay the highest price allowed by law.<sup>129</sup> The Commission also refused to find that NICOR should be deemed to have agreed to pay the highest rates allowed by law, based on evidence of trade usage, commercial context, regulatory context and course of

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123. 60 F.E.R.C. ¶ 61,031 (1992).

124. 893 F.2d 349 (D.C. Cir. 1989), *cert. denied*, 498 U.S. 907 (1990).

125. 59 F.E.R.C. ¶ 61,243 (1992).

126. *Id.* at 61,832.

127. 58 F.E.R.C. ¶ 61,203 (1992).

128. 58 F.E.R.C. ¶ 61,203, at 61,632-33.

129. 58 F.E.R.C. ¶ 61,203, at 61,634. In particular, the Commission distinguished the purchaser's performance under a different contract, which contained broader area rate language than the contracts at issue.



performance.<sup>130</sup> Although the Commission found mutual intent to pay only cost-based rates under one contract, it found no mutual intent as to the other two gas sales contracts.

### III. COURT ACTION ON PIPELINE ISSUES

#### A. Remedial Authority/Filed Rate Doctrine

In *Natural Gas Clearinghouse v. FERC*,<sup>131</sup> the court, relying on *United Gas Improvement Co. v. Callery Properties, Inc.*,<sup>132</sup> upheld the Commission's remedial authority to impose retroactive surcharges on a pipeline's transportation customers in order to allow the pipeline to collect a rate that was erroneously disallowed by the Commission. In so holding, the court stated that "[w]ithout such corrective power, pipelines would be substantially and irreparably injured by FERC errors, and judicial review would be powerless to protect them from much of the losses so incurred."<sup>133</sup> The pipeline, Tarpon Transmission Company, had reduced its transportation rate from 16.88 to 4.02 cents per Mcf in compliance with a Commission order that was later reversed by the agency following a court remand. The Commission accepted Tarpon's proposal to direct bill shippers to "recoup" the 12.86 cents-per-Mcf difference between the rate ultimately found to be just and reasonable and the lower rate paid by Tarpon's shippers as a result of the Commission's error. The court found that the Commission's exercise of its remedial authority in this case did not violate the filed rate doctrine because Tarpon's shippers were "on ample notice that if Tarpon succeeded in court (and before the Commission on remand), it would be free to collect the rate differential on past shipments."<sup>134</sup>

#### B. Market-Based Rates

In *East Tennessee Natural Gas Co. v. FERC*,<sup>135</sup> the court vacated and remanded a Commission order rejecting a proposal by East Tennessee to make its interruptible authorized overrun service (AOS) more competitive by replacing a rate design based on the 100% load factor equivalent of the firm sales rates with a rate based on commodity and gas charges only. Competition from other pipelines had made the AOS service almost unmarketable. Responding to this competition, East Tennessee had proposed to replace the rate with a new, lower rate to regain some lost business. As a result of the new rate, some costs formerly collected through the 100% load factor rate were to

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130. 58 F.E.R.C. ¶ 61,203, at 61,635-36.

131. 965 F.2d 1066 (D.C. Cir. 1992).

132. 382 U.S. 223 (1965).

133. 965 F.2d at 1074-75.

134. *Id.* at 1077. Without identifying any one factor as determinative, the court based its finding of "ample notice" on (1) Tarpon's express statement of intent to seek a surcharge in the event of vindication (both on the face of its compliance tariff sheets and its transportation agreements); (2) the Commission's and Tarpon's statements that the rate for open-access transportation service was "subject to" the outcome of Tarpon's legal challenge; and (3) the Commission's authority to order retroactive collections to remedy Commission error (and the Commission's past use of that authority).

135. 953 F.2d 675 (D.C. Cir. 1992).

be absorbed by East Tennessee. East Tennessee would have paid firm demand charges to its pipeline supplier, Tennessee Gas Transmission Company. Subsequently, those charges would have flowed through East Tennessee's PGA mechanism for recovery from non-AOS customers. The Commission reversed an initial decision approving East Tennessee's proposed rate design, however, finding that (1) the revised rate resulted in an unduly discriminatory shift of Tennessee's costs to non-AOS customers, and that (2) East Tennessee had failed to establish that this cost shift would be offset by revenue gains from increased AOS service.<sup>136</sup>

The court rejected the Commission's decision on the grounds that there was "no reasoned basis to support the 'central concern' underlying the Commission's decision; therefore, [the decision lacked] any 'rational connection between the facts found and the choice made'."<sup>137</sup> The court reasoned that (1) East Tennessee's proposal did not result in impermissible discrimination of the kind found in the *Maryland People's Counsel I and II* cases;<sup>138</sup> (2) the ALJ's finding that the cost shift was not unreasonable was supported by substantial record evidence, making the Commission's unexplained rejection of the ALJ's finding "unsupported and ill-reasoned";<sup>139</sup> and (3) the Commission's past policies have never required proponents of market-based rates to demonstrate conclusively that more gas sales would ensue from market-based or incentive rates.<sup>140</sup>

### C. OCS Lands Act

In *Tennessee Gas Pipeline Co. v. FERC*,<sup>141</sup> the court of appeals remanded for further consideration the issue of whether the Commission can require a pipeline to charge a replacement shipper a different rate than was collected from the previous shipper for certificated service terminated prior to the expiration of the term of the previous shipper's underlying contract. In Order Nos. 509<sup>142</sup> and 509-A<sup>143</sup> the Commission implemented section 5 of the Outer Continental Shelf Lands Act,<sup>144</sup> in part by permitting existing shippers on OCS pipelines to terminate their contracts prior to the expiration of their term if a replacement shipper is prepared to assume the obligations of the previous shipper. In a subsequent order related to Tennessee, the Commission clarified that the services which the existing shippers could terminate also included any onshore transportation which the pipeline might be providing in conjunction with the terminated OCS transportation.<sup>145</sup>

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136. *Id.* at 679-80.

137. *Id.* at 679.

138. *Maryland People's Counsel v. FERC*, 761 F.2d 768 (D.C. Cir. 1985); *Maryland People's Counsel v. FERC*, 761 F.2d 780 (D.C. Cir. 1985).

139. 953 F.2d at 680-81.

140. *Id.* at 681.

141. 972 F.2d 376 (D.C. Cir. 1992).

142. 45 F.E.R.C. ¶ 61,406 (1988).

143. 46 F.E.R.C. ¶ 61,177 (1989).

144. 43 U.S.C. § 1334(f)(1) (1988).

145. *Tennessee Gas Pipeline Co.*, 48 F.E.R.C. ¶ 61,080 (1989). The Commission stated that, if an existing shipper sought to terminate such services, the pipeline would be required to file for abandonment of

Tennessee appealed, claiming that the Commission does not have the authority either to require a pipeline to file for the abandonment of an existing onshore transportation service prior to the expiration of the term of the underlying contract, or, more importantly, to force a change of rates in such a situation. Rather, Tennessee argued that any such change in rates can occur only after the Commission complied with the requirements of section 5 of the Natural Gas Act and finds both the existing rate unreasonable and the new rate reasonable. On appeal, the D.C. Circuit concluded that neither its own review of the Natural Gas Act nor prior judicial decision supported the Commission's decision. The court remanded the matter to the Commission "so that it may either identify the authority for or alter its rule."<sup>146</sup>

#### D. Waiver of 30-Day Notice Period

In *Consolidated Edison Co. of New York, Inc. v. FERC*,<sup>147</sup> the court of appeals affirmed a FERC letter-order accepting an out-of-cycle PGA increase which had been filed by Tennessee Gas Pipeline Company. The court found that the Commission had properly used its authority under section 4(d) of the NGA to dispense with a 30-day waiting period. Noting the Commission's frequent retrospective waiving of the 30-day period, the court held that the Commission's action had given all purchasers involved sufficient notice of the out-of-cycle increase.

In *Carnegie Natural Gas Co. v. FERC*,<sup>148</sup> the court affirmed the Commission's rejection of Carnegie's proposal "to track through" the inventory reservation charges of an upstream pipeline to those Carnegie customers who caused Carnegie to incur such charges. The court concluded that the Commission may emphasize "competing policies and approve measures that do not best match cost responsibility and causation."<sup>149</sup> In addition, the court concluded that the Commission correctly found Carnegie's proposal to have the "potential to force customers to pay imprudent costs."<sup>150</sup>

### IV. COURT ACTION ON PRODUCER ISSUES

#### A. MMS Audit Powers/Recordkeeping Requirements

In *Phillips Petroleum Co. v. Lujan*,<sup>151</sup> the court of appeals upheld the propriety of certain audit and recordkeeping requirements imposed upon lessees of federal and Indian land by the Minerals Management Service (MMS) pursuant to the Federal Oil and Gas Royalty Management Act

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the related onshore service. Thereafter, any replacement shippers would be entitled to receive service through both the pipeline's offshore and onshore facilities at the (presumably, lower) rates charged pursuant to the pipeline's Part 284 authorization, rather than at the (presumably, higher) rates charged under the agreement with the previous, incumbent shipper.

146. 972 F.2d at 383-84.

147. 958 F.2d 429 (D.C. Cir. 1992).

148. 968 F.2d 1291 (D.C. Cir. 1992).

149. *Id.* at 1294.

150. *Id.*

151. 963 F.2d 1380 (10th Cir. 1992).

(FOGRMA).<sup>152</sup> In particular, the court held that it was proper for the MMS: (1) to audit lessees on a company-wide basis, instead of a lease-by-lease basis, and to require lessees to retain all related records;<sup>153</sup> (2) to announce the initiation of an audit and thereby extend the six-year period for retaining records before commencing a review of the records related to specific leases;<sup>154</sup> and (3) to ask lessees to make changes to correct repeated royalty underpayments caused by systemic deficiencies.<sup>155</sup>

The court further held that the six-year statute of limitations on "every action for money damages brought by the United States or an officer or agency thereof which is founded upon any contract" did not apply to limit the Department of Interior's right under FOGRMA to order lessees to maintain and provide records,<sup>156</sup> and that the Paperwork Reduction Act<sup>157</sup> specifically exempts the collection of information related to the MMS's audit of lessees of federal and Indian lands under FOGRMA.<sup>158</sup>

### B. Production-Related Costs

In *Sandstone Resources, Inc. v. FERC*,<sup>159</sup> the court of appeals affirmed the Commission's determination that the costs incurred in removing liquid brine from natural gas after production were production costs and not recoverable from the purchasers of the natural gas as production-related cost additions to the maximum lawful price pursuant to section 110 of the Natural Gas Policy Act of 1978 (NGPA).<sup>160</sup>

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152. *Id.* See also 30 U.S.C. §§ 1701-1757 (1988).

153. 963 F.2d at 1385.

154. *Id.*

155. *Id.* at 1386.

156. *Id.*

157. 44 U.S.C. §§ 3501-3520 (1988).

158. *Id.* at 1386-87.

159. 973 F.2d 956 (D.C. Cir. 1992). See *Sandstone Resources Inc.*, 53 F.E.R.C. ¶ 61,340 (1990) *reh'g denied*, 55 F.E.R.C. ¶ 61,042 (1991). The Commission found that the removal of brine does not constitute the treatment or conditioning of natural gas either by its policy or industry practice. Additionally, the Commission found that the removal of brine is in no fashion similar to the removal of liquefiable hydrocarbons and its removal does not in any respect benefit gas purchasers. Likewise, the Commission rejected Sandstone's position that the point at which the cost is incurred is dispositive as to whether a cost is production-related and recoverable. Even though the costs of removing brine are incurred after the wellhead, the Commission explained that they are non-recoverable production costs because they are incurred in order to make the gas useable and in some instances in order to actually produce the gas from the well. Since gas purchasers contract to purchase natural gas, and since natural gas is not usable to the purchaser until brine is removed, it is merely a production process a producer must perform to sell its product.

160. 15 U.S.C. § 3320 (1988).

## COMMITTEE ON NATURAL GAS RATE AND ACCOUNTING REGULATION

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