Report of the Committee on Natural Gas Rate and Accounting Regulations

In 1983, several major developments occurred in general rate cases filed by interstate natural gas pipelines and in cases involving issues arising under the Natural Gas Policy Act of 1978 (NGPA). General rate cases became the principal forum for examination of pipeline purchasing practices and their impact on jurisdictional rates and pipeline rates of return. Most of these issues were resolved, at least temporarily, by settlements, leaving the purchasing practices issues to be addressed by the Commission in a series of complaint cases brought under Section 5 of the Natural Gas Act (NGA) or possibly in a general rulemaking proceeding.[1]

General rate cases also became the forum for several experiments in the allocation of pipeline fixed costs and rate design. The effect of these experiments generally was to shift more fixed costs to the demand component of pipeline jurisdictional rates; proponents intended to improve the marketability of increasingly expensive gas, especially to industrial consumers with alternative fuel capability. In a related development, parties in several cases contested the minimum bills of interstate pipeline suppliers, particularly those that included variable costs not actually incurred by those suppliers, and the Commission issued a notice of proposed rulemaking proposing to remove all such variable costs from pipeline minimum bills.

Several pipelines proposed an array of programs designed to retain industrial sales and thus to reduce load loss and corresponding rate increases. Most of these programs were adopted in rate case settlements subject to a number of conditions imposed by the Commission. These programs are short-term and experimental in nature, with the result that no clear policy was established by the Commission on these issues in 1983.

The major developments involving NGPA issues in 1983 included: (1) the Commission's issuance of final rules on production-related costs under Section 110 of the NGPA; (2) the Commission's issuance of a declaratory order determining that pipeline transportation of natural gas liquids and liquefiables did not, except under unusual circumstances, constitute a violation of the maximum lawful price ceilings established under Title I of the NGPA and the Commission's decisions regarding the appropriate allocation of the costs of liquids and liquefiables transportation; (3) the issuance of two additional rules providing incentive prices for high-cost gas produced from recompletion tight formations and production enhancement gas transported and sold in interstate markets.

The courts produced three major decisions affecting previous Commission determinations under the NGPA. Two of these decisions were by the United States Supreme Court. In one of these cases, the Court affirmed the Fifth Circuit Court of Appeals decision reversing the Commission on the issue of NGPA pricing of pipeline-owned gas production. In another case not directly related to the NGPA, the Court declared certain legislative veto provisions unconstitutional. As a result, the congressional veto of the Commission's Phase II incremental pricing rule was nullified, and the Commission proposed an indefinite stay of this rule, which would have extended incremental pricing to all non-exempt industrial uses of natural gas, including process and feedstock users. In another major decision, the U.S. Court of Appeals for the District of Columbia Circuit reversed and remanded the Commission's Btu measurement rule issued in Order 93 and declared that the

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[1]*See, e.g., Tennessee Gas Pipeline Co. v. Amoco Production Co., et al.,* Docket No. RP83-109; *Columbia Gas Transmission Corp.,* Docket No. CI83304; *Pipeline Gas Cutback Procedures,* Docket No. RP83-124; and *Inquiry Into Pipeline Gas Purchasing Practices,* Docket No. RP83-96.

Commission had exceeded its authority under the NGPA by promulgating its rule requiring that Btu content be measured on a "dry" basis regardless of the prevailing industry practice of measuring Btu content on a "wet" (saturated with water vapor) basis.

The Commission issued several other decisions during 1983 affecting natural gas rates, including particularly the Commission's first major decision on a pipeline's overall rate of return. This and other decisions involving rate base, taxes and depreciation, tracking provisions, initial rate suspension powers, and other matters will be discussed below.

I. Commission Action on Pipeline Issues

A. *Pipeline Purchasing Practices*

In a sense, the year began with Administrative Law Judge Michel Levant's initial decision in *Columbia Gas Transmission Corp.*, on December 30, 1982. Judge Levant denied the pipeline's passthrough of certain purchased gas costs, determining that certain purchasing practices by Columbia constituted an "abuse" under the NGPA Section 601(c)(2) "fraud, abuse or similar grounds" standard. 21 FERC ¶ 63,100 (1982).[2] The year ended, however, without a Commission opinion on the exceptions raised by Columbia and other parties to the initial decision.

On January 16, 1984, the Commission issued its opinion on review of the initial decision by Judge Levant. *Columbia Gas Transmission Corp.*, Opinion No. 204, 26 FERC ¶ 61,034 (1984). The Commission expanded its interpretation of the term "abuse" in Section 601(c)(2) of the NGPA. The Commission ruled that abuse exists where a pipeline's purchasing practices (1) evidenced a "reckless disregard" of the pipeline's duty to provide service at the lowest reasonable cost and (2) had a "significant adverse effect on customers." The Commission thus put aside its earlier narrower interpretation of the "fraud, abuse or similar grounds" standard of Section 601 announced in its February 1982 policy statement. The Commission held that Columbia had engaged in purchasing practices in reckless disregard of the effect of such practices on those markets on its system for which the alternate fuel was No. 6 fuel oil. The Commission, however, held that Columbia's purchasing practices during the period at issue in these proceedings (1981-1982) had not resulted in any "adverse effect" or damages to its customers. The issue of prices paid to Columbia's affiliates was remanded for further hearings along with the issue of whether Columbia's purchasing practices had caused damages to its customers in later periods.

During 1983, the Commission continued the polilcy it had announced in late 1982 of reviewing pipeline purchasing practices in rate proceedings under Sections 4 and 5 of the NGA, rather than in PGA proceedings. The first major rate case in 1983 in which the Commission ordered a review of the purchasing practices of a major pipeline under Section 4 and 5 of the NGA was a case filed by Texas Eastern Transmission Corporation on December 30, 1982. The Commission consolidated that case (Docket No. RP83-35-000) wich several other pending dockets (RP81-109-000, RP82-37 and RP74-41-016) for hearing and decision, designating Commissioner Oliver G. Richard, III as the presiding officer. On June 15, 1983, Commissioner Richard certified an uncontested partial settlement with alternatives to the Commission, which the Commission adopted on July 14, 1983. 24 FERC

[2]The initial decision was reported in the Report of the Committee on Natural Gas Rate and Accounting Regulations for 1982. 4 *Energy L.J.*, 137-38 (1983).

¶ 61,065 (1983). The settlement resolved all issues in dispute except rate design and certain related issues. The settlement provided for certain purchasing practice guidelines to be implemented by Texas Eastern and for periodic conferences between Texas Eastern and its customers to review the pipeline's adherence to the guidelines. Several other cases involving pipeline purchasing practices were the subject of similar settlements in 1983.

B. Cost Allocation and Rate Design

In several cases decided during 1983, pipeline ratemaking moved gradually away from the predominant *United* formula — the classification of fixed costs of transmission and storage facilities by assigning 25% of those fixed costs to the demand component and the remaining 75% to the commodity component of the pipelines rates — to the *Seaboard* formula — classification of fixed costs equally between the demand component and the commodity component. Towards the end of 1983, the Commission began to prescribe a "modified fixed variable" rate design. Under this approach all fixed costs except return and associated taxes are assigned to the demand component, principally in order to preserve the marketability of natural gas to users with lower cost alternative fuel capability.

On February 15, 1983, the Commission approved the use of the *Seaboard* formula in *Texas Gas Transmission Corp.* in Docket No. RP75-19-000, *Texas Eastern Transmission Corp.* in Docket No. RP74-41-000, and *Cities Service Gas Co.* (now Northwest Central) in Docket No. RP74-4-000, 22 FERC ¶¶ 61,164, 61,163, and 61,162. In these decisions, issued following a remand by the court in *Columbia Gas Transmission Corp. v. FERC,* 628 F.2d 578 (D.C. Cir. 1979), the Commission estblished that it need not demonstrate that the use of an existing cost classification formula produces unjust and unreasonable rates within the meaning of Sections 4 and 5 of the NGA before it can impose an alternative cost classification methodology. Rather, in the Commission's view, it is required to accept the current formula only as a "starting point" for analysis and to provide a "reasoned explanation" for its decision to depart from it. Once the Commission has provided a "reasoned explanation," it need only show that the cost classification methodology it chooses results in just and reasonable rates.

In *Columbia Gulf Transmission Company,* Docket No. RP81-82-000, and *Columbia Gas Transmission Corporation,* Docket No. RP81-83-000, 25 FERC ¶ 63,015 (1983), the presiding judge held that there was no basis in the evidence for a change from the modified *Seaboard* formula, which had previously been approved, to either of the fixed variable formulas proposed by Columbia and the Commission's staff. Columbia proposed an allocation of all fixed costs, including return on equity, to the demand component of its rates. The Commission staff proposed allocation of all of the fixed costs, except for return and associated taxes, to the demand component. The presiding judge concluded that the unmodified *Seaboard* methodology should continue to be applied on the Columbia system. He further expressed the view that the methodology proposed by Columbia would merely shift the responsibility for the excess costs from industrial gas customers with alterate fuel capabilities to residential consumers.

In *Natural Gas Pipeline Company of America,* Docket No. RP81-49-011, 25 FERC ¶ 61,176, the Commission on November 4, 1983, affirmed an initial decision that approved a modified fixed variable formula for allocation of the fixed transmission and storage costs proposed by the Commission staff. The formula was essentially the same as that proposed in the Columbia Gas case cited above, and the Commission approved the initial decision with limited modifications. The Commission made it clear again that only a "reasoned explanation" was required to support a change from either the *United* or the *Seaboard* methodology and affirmed the use of the modified fixed variable methodology, by which all fixed costs, with the exception of return on equity and related taxes, would be classified to the demand component of Natural's pipeline rates. Return on equity and related taxes were classified to the commodity component. The Commission affirmed the initial decision's adoption of the modified fixed variable methodology, except that the Commission classified the fixed cost of Natural's production and gathering facilities entirely to the commodity component, as recommended by Commission's staff. With respect to the allocation of costs classified to the demand component, the Commission held that half of the costs should be allocated between classes of customers and recovered from customers on the basis of daily contract quantities, and that the remaining half should be allocated on the basis of annual quantity entitlements and recovered from customers on the basis of monthly quantity entitlements through a separate demand charge.

C. *Minimum Bills*

In *United Gas Pipe Line Company*, Docket No. RP82-16-000 (Phase I), an initial decision was issued on June 29, 1983, 23 FERC ¶ 63,125, in which the presiding judge held that United's minimum commodity bill tariff applicable to its pipeline customers was unjust and unreasonable within the meaning of Section 4 of the NGA. United's tariff required its pipeline customers to pay a minimum bill in any month during which the pipelines, as a class, failed to take two-thirds of the maximum daily quantities for which they had contracted. The presiding judge found that United's minimum bill caused it to recover 75% of fixed costs and all variable costs up to two-thirds of the pipeline customers' MDQ's. The judge found that there was insufficient evidence in the record to connect load loss experienced by United with swings by its pipeline customers, nor did he find any evidence in the record to link the minimum commodity bill to United's take-or-pay obligations to producers and suppliers. Although the judge found that the minimum bill was unlawful under Section 4 of the NGA, he declined to award damages to the pipeline customers on the ground that such an award would be based on speculative reasoning.

Following the initial decision, the parties negotiated a settlement that the Commission approved on October 18, 1983, 25 FERC ¶ 61,088. Under the settlement, United agreed to waive all claims under the minimum bill and to refund with interest all payments made under the minimum bill provision. The settlement minimum bill, effective January 1, 1983, is computed on the basis of the fixed cost component of the commodity charge and does not include any variable costs. The minimum volume for each pipeline customer is an annual volume defined as a stated percentage of each customer's total sales for the year, but which cannot exceed two-thirds of its maximum daily quantity, and no change in the minimum bill will be made effective prior to January 1, 1985. The settlement also restricts pipeline customers from using United as their swing supplier. The Commission stated that it approved this aspect of the settlement despite its potential to restrict pipeline customers from obtaining gas from other suppliers at a possibly lower price because the settlement conditions serve the objective of lowering the total cost of gas to all customers.

In *Columbia Gas Transmission Corporation v. Texas Eastern Transmission Corporation*, Docket No. RP83-7-000, *et al.*, 24 FERC ¶ 61,316, the Commission, on September 21, 1983, approved a settlement of a minimum bill dispute between Columbia and Texas Eastern. Columbia notified Texas Eastern that it would be unable to purchase gas at or above the minimum bill level commencing in August 1982, claiming that the economic recession constituted an event of force majeure which excused it from Texas Eastern's minimum bill requirements. The proposed settlement provided that (1) Texas Eastern would waive as to all of its DCQ customers the minimum monthly bill for the period May 1982 through November 1984; (2) a DCQ customer which failed to purchase at the minimum bill level would continue to pay the demand charge plus: (a) a "fixed cost minimum bill" consisting of the difference between the monthly minimum commodity volume and the amount actually purchased times the fixed cost component of the applicable commodity rate, and (b) an amount which would reimburse Texas Eastern for any payments made to producer-suppliers for gas not taken (take-or-pay payments); (3) DCQ customers would be permitted to pass through to their customers the fixed cost minimum bill amounts, 50% of the take-or-pay reimbursement amounts and interest on the remaining 50% reimbursement; (4) Texas Eastern must repay to the DCQ customers all take-or-pay reimbursement amounts paid by them; (5) to the extent that any portion of any take-or-pay payment for which Texas Eastern has been reimbursed becomes nonrecoverable, Texas Eastern would be permitted to include such nonrecoverable amounts in a section 4 rate filing without prejudice to the right of any party to challenge the inclusion of such nonrecoverable amounts.

Several parties objected to the proposed settlements, particularly the provision permitting Texas Eastern to include nonrecoverable take-or-pay reimbursement amounts in a rate filing. The parties objecting to this provision argued that it could be discriminatory, resulting in the shifting of costs from customers who take less than their minimum bill level to other customers who purchased all of the gas tendered to them by Texas Eastern. The Commission rejected this objection as premature because the settlement provides that a party may challenge the inclusion of nonrecoverable amounts in any rate filing and the Commission will consider any claims of discrimination at that time. The Commission adopted the proposed settlement with a slight modification (requiring the DCQ customers to flow through to their customers 100% of the interest received by the DCQ customers.

The Commission on July 12, 1983, approved a settlement in a minimum bill dispute between Columbia and Texas Gas Transmission Corporation, also triggered by Columbia's invocation of force majeure conditions based on the economic recession. The settlement approved in Docket Nos. RP83-4-000 and RP82-37-000, 24 FERC ¶ 61,049, provides for a temporary waiver of the monthly minimum commodity bill from August 1982 through April 1, 1984. Columbia, however, will be responsible for an amount equal to the fixed cost component of the Texas Gas Zone 4 commodity rate times Columbia's monthly minimum commodity volume. In addition, Columbia will reimburse Texas Gas for producer take-or-pay payments made by Texas Gas to the extent of Columbia's deficiency under the minimum bill. All such payments by Columbia will be treated as a loan, with Texas Gas obliged to repay any take-or-pay amounts which become nonrecoverable. In order to reduce the risk of nonrecoverable payments, Columbia agrees to the minimum extent practicable not to cut its purchases from Texas Gas below the monthly minimum commodity volume by any greater percentage than it reduces total purchases from all other pipeline suppliers in the aggregate below monthly minimum commodity levels. The Commission, concerned that this provision would inhibit Columbia from pursuing a least cost gas policy, shortened the duration of the minimum bill waiver, from October 31, 1984, as proposed in the settlement, to April 1, 1984.

On July 21, 1983 the Commission adopted with some modifications a settlement to resolve a dispute between Columbia Gas and Panhandle Eastern Pipeline Company over Panhandle's 75% minimum commodity bill provision. The settlement was approved in Docket No. RP83-5-000, 24 FERC ¶ 61,090, and was nearly identical to the agreement between Columbia and Texas Gas in Docket Nos. RP83-4-000 and RP82-137-000, *supra.*

On June 17, 1983, El Paso Natural Gas Company, in Docket No. RP83-100-000, filed a revised minimum bill provision substituting a monthly minimum bill for the annual minimum bill then in effect applicable to El Paso's sales to Southern California Gas Company and Pacific Gas and Electric Company. The then effective minimum bill provision required Southern California and Pacific Gas and Electric during a calendar year to take-or-pay for a minimum annual quantity equal to 91% of their respective maximum contractual daily demand times 365. The proposed revisions would establish a minimum monthly bill equal to 75% of El Paso's total service obligation. Although the then effective provision provided for a five year make-up period for deficiency quantities paid for but not taken, El Paso's proposed revision did not provide for any make-up period. On July 15, 1983, the Commission issued an order accepting for filing and suspending the proosed tariff sheets. Several intervenors filed protests as well as requests for summary disposition, rejection or dismissal of the proposed minimum bill revisions.

By order issued September 21, 1983, the Commission granted the motions for summary disposition and rejected El Paso's June 17, 1983 minimum bill filing. In its order, the Commission stated that it was concerned that the absence of the make-up provision created a serious possibility of over-recovery of El Paso's variable costs. On September 30, 1983, El Paso filed a further minimum bill revision applicable to Southern California Gas Company and Pacific Gas & Electric Company in Docket No. RP83-139-000. The September 30 filing was similar to El Paso's rejected proposal in Docket No. RP83-100, with two exceptions. First, the later-filed minimum bill provides for recovery of only the fixed costs component of the commodity charge applicable to purchases by the affected customers. Second, the proposal provides that monthly minimum deficiency payments will be returned to the California customers by credit to subsequent billings, when in any calendar year the sum of El Paso's sales to both customers exceed 75% of the sum of the annual equivalents of El Paso's total daily service obligations to those customers, or when El Paso, through the operation of the minimum bill provision would otherwise over-recover its fixed costs. The Commission suspended the proposed filing to become effective December 17, 1983 and set the matter for hearing.

1. *Proposed Rule*

On August 25, 1983, the Commission issued a notice of proposed rulemaking in Docket No. RM83-71-000, "Elimination of Variable Costs from Certain Natural Gas Pipelines Minimum Commodity Bill Provisions." The Commission proposes to amend its rules to eliminate the portion of any minimum commodity bill provision on file which would provide for the recovery of purchased gas costs, fuel costs or other variable costs. Under the proposal, future tariffs providing for such recovery would be rejected. The Commission noted that three ratemaking functions might justify a minimum commodity bill: (1) fixed cost recovery; (2) equitable cost recovery (from partial requirements customers who have the ability to swing their purchases among the varying suppliers); (3) take-or-pay recovery (a minimum commodity bill might be used to assure recovery of such fixed costs and might be structured so as to allocate these costs equitably among customers). The Commission further pointed out that most minimum commodity provisions do not include a make-up provision, and that the absence of such a provision creates a serious possibility of over-recovery by the supplying pipeline. While requiring a make-up provision on a generic basis might be one alternative to the proposed rule, the Commission believes that removing variable costs altogether from minimum commodity bill provisions may be preferable.

The rule proposed by the Commission would apply to all minimum commodity bill provisions on file with the Commission on the effective date of the rule and would control all cases pending before the Commission to the extent that the minimum commodity bill is in issue. The Commission did not in this notice address the minimum bill provisions of transportation contracts and rate schedules, but invited comments as to whether these minimum bill provisions should also be precluded from recovery variable costs. The proposed rule would provide that any portion of any minimum commodity bill provision of any rate schedule for the sale of natural gas which provides for the recovery of purchased gas costs, fuel costs, or other variable costs, which are not incurred in providing natural gas service, would be inoperative and of no effect at law. Any rate schedule filed on or before October 30, 1983, which contained a minimum commodity bill provision providing for the recovery of purchased gas costs, fuel costs, or other variable costs, would be rejected to the extent that it provides for the recovery of costs which are not actually incurred in rendering service. Comments on the proposed rule were filed in late September, and the Commission subsequently solicited reply comments.

D. Experimental Market Retention Programs

In 1983, several pipelines experimented with various forms of market retention programs designed to retain or regain industrial sales markets which had been lost as a result of increasing gas supply costs, decreasing alternative fuel costs, and the economic recession. Most of these programs were intended particularly to reduce the commodity component of pipeline rates in order to preserve the marketability of its gas to industrial customers.

The first of these programs in 1983 was the special incentive rate proposed by Columbia Gas Transmission Corporation in Docket Nos. CP82-485-001 and CP82-485-002. Columbia proposed to sell natural gas at a special incentive rate (proposed rate schedule SSI) to existing wholesale customers for resale to consumers who would otherwise use residual fuel oil. The Commission approved a temporary certificate authorizing such service conditioned to provide that the risk of under-collection of revenues from SSI service was to be borne by Columbia's shareholders. Columbia declined to accept the temporary certificate.

On February 18, 1983, the Commission rescinded a temporary certificate issued to Northern Natural Gas Company in Docket Nos. CP83-14-003 and CP83-14-004, 22 FERC ¶ 61,173. On December 22, 1982, the Commission had issued the temporary certificate, authorizing Northern to provide six-month service under two new rate schedules, the Flexible Pricing Pipeline Option (FPO) rate schedule and the Large Volume Contract Service (LVCS) rate schedule. Both services were limited to distributor customers purchasing gas under Northern's CD rate schedule, and the rates were designed to provide gas to those consumers who would switch to fuel oil if the gas were sold under Northern's existing rate schedules. On further consideration, the Commission concluded that Northern's claims of marketr erosion by alternate fuels and the resulting detrimental effect upon its system did not provide a sufficient basis for issuance of a temporary certificate under the emergency provisions of Section 7(c)(1)(b) of the NGA. Nevertheless, the Commission set the matter of Northern's application for a permanent certificate for hearing.

On April 19, 1983, Northern filed a second application for a temporary certificate. On May 27, 1983, the Commission found that Northern had established prima facie evidence of the severity of the load loss on its system and granted the request for a temporary certificate, 23 FERC ¶ 61,295. The Commission required that the rate charged must recover the actual weighted average cost of purchased gas including any current Account No. 191 and GRI surcharges, plus any other out-of-pocket costs associated with making the sales. The Commission further required that Northern's shareholders bear the risk of any under-collection of revenues in the event that rates finally approved for these services are higher than the interim rates.

The Commission also considered the protest of Hanna Mining Company, which argued that the flexible rate services should be extended to end-users of coal as well as users of No. 6 fuel oil. The Commission concluded that Northern had demonstrated that an emergency had been created on its system by market erosion to No. 6 fuel oil but that no such showing had been made with respect to coal. On November 25, 1983, the Commission extended Northern's temporary certificate for an additional six months or until the Commission issues a final decision on Northern's request for a permanent certificate.

On April 28, 1983, the Commission approved a settlement in *Transcontinental Gas Pipe Line Corporation,* Docket No. RP83-11-000, 23 FERC ¶ 61,199, providing among other things, for an experimental Industrial Sales Program (ISP) giving producers an opportunity to sell directly to Transco's industrial markets capable of using residual fuel oil. Under the ISP, a posted price would be set by Transco each month at a level designed to enable its customers to compete with alternative fuels. Transco acted as agent to arrange the sales and to transport the gas to market. In arranging ISP sales, Transco would give first preference to dedicated supplies which, if purchased currently by Transco, would require payment of prices higher than the posted price. Because of its experimental nature, the ISP program was limited to the 1983 summer period (April through October). The settlement further provided for transportation by Transco of off-system gas supplies purchased directly by its customers. This later came to be known as the Contract Carriage Program (CCP), and volumes transported under the CCP program increased considerably during the period from June through October 1983.

On November 10, 1983, the Commission approved an amendment to the rate settlement in Transco's Docket No. RP83-11, extending the ISP and CCP programs through March 11, 1984, subject to several important conditions, 25 FERC ¶ 61,219. Those conditions included the following: (1) no gas released under the ISP or CCP programs may be sold unless the weighted average price (WACOG) is equal to or greater than the pipeline's weighted average cost of gas (the intent was to keep low cost supplies from being sold too cheaply in the ISP and CCP programs); (2) no gas could be released for sale or transported under these programs unless the producer-supplier had contractually agreed to absolve the pipeline of take-or-pay liability for any volumes of gas released, sold, or transported; (3) no gas released for sale under these programs could be sold or transported to a distribution company or an end-user traditionally served by the distribution company unless the volumes were credited against the distribution company's minimum bill obligations to the pipeline; (4) gas released or sold under these programs to distributors or end users served directly or indirectly by any other pipeline must be limited to new loads not previously served by natural gas or to requirements which would otherwise be lost to alternative fuel competition or other similar industrial sales programs, on-system or off-system. The Commission attached that final condition in order to protect competition among pipelines for "core" markets of other pipelines.

The Commission imposed similar conditions on similar sales programs proposed by Columbia Gas Transmission Corporation in Docket No. CP83-452-000, 25 FERC ¶ 61,220, and Tennessee Gas Pipeline Company in Docket No. CP83-502-000, 25 FERC ¶ 61,398; Tenneco Oil Co., *et al.*, Docket No. CI83-269-000, 25 FERC ¶ 161,234. Further, the Commission solicited comments on and held an informal conference on special marketing plans (SMP's) on March 1, 1984. "Notice of Inquiry," Docket No. RM84-7-000, 49 *Fed. Reg.* 3193 (1984).

E. Off-System Sales

On April 25, 1983, the Commission issued a general policy statement on off-system sales in Docket No. PL83-2-000, 23 FERC ¶ 61,140. On the issue of price, the Commission concluded that, where the proposed sale is between two interstate pipelines, the transaction should be priced at the higher of the selling pipeline's system average load factor rate (based upon the rates in effect at the time the transaction is proposed) or its average section 102 acquisition cost (based upon its most recent purchased gas adjustment filing). This would permit the selling pipeline to replace these supplies through additional purchases of section 102 gas. Where the purchaser is not another interstate pipeline, the selling pipeline would be free to negotiate a higher rate. On the issue of reenue treatment, the Commission stated that the pipeline should have the option of including a representative level of sales or revenues in its general rate case or crediting all revenues in excess of one cent per MMBtu to Account No. 191. The pipeline could also demonstrate that its actual out-of-pocket expenses exceeded one cent per MMBtu; if successful in that showing, the pipeline could retain the higher amount. The Commission subsequently included these price and revenue conditions in its blanket certificate regulations issued on July 20, 1983, in Order No. 319, 24 FERC ¶ 61,100, *modified,* Order No. 319-A, 25 FERC ¶ 61,194 (1983).

F. Authority to Suspend Initial Rates

On May 24, 1983, the Commission issued Order No. 303 in Docket No. RM83-21-000 interpreting the Commission's suspension authority under Section 205 of the Federal Power Act and Section 4 of the NGA to apply to initial rate schedules as well as changes in rates, 23 FERC ¶ 61,278. The Commission also asserted correlative authority to establish interim rates, if necessary, during the suspension of an initial rate and to make both the interim and initial rates subject to refund. Order No. 303 reversed the Commission's prior position that initial rates of electric utilities and natural gas companies could not be suspended. In doing so, the Commission relied upon the Supreme Court's decision in *Trans Alaska Pipeline Rate Cases,* 436 U.S. 631 (1978). The Commission concluded that its ability to ensure the reasonableness of all rates would be unduly restricted if it was without authority to suspend initial rates. The Commission observed, however, that suspension of initial rates under the NGA would probably be infrequent because of its certificate powers under section 7(e), including the power to impose rate adjustment and refund conditions.

G. Rate of Return

On June 23, 1983, the Commission issued Opinion No. 178, in *Distrigas of Massachusetts Corporation (DOMAC),* Docket Nos. RP79-23-003 and RP79-24-002, 23 FERC ¶ 61,416, *modified,* Opinion No. 178-A, 24 FERC ¶ 61,250 (1983), *appeal docketed,* No. 83-1633, *et al.*, (1st Cir. Aug. 22, 1983). The Commission approved a 16.5% rate of return on equity, based on a capital structure consisting of 68.3% equity and 31.7% debt resulting in an overall rate of return of 13.8%. This rate applied to the locked-in period of July 5, 1979 through August 1, 1981, and the Commission noted that the cost of all capital for DOMAC had increased substantially during the period in question as a result of considerably increased inflation.

In Opinion No. 180, Docket No. RP81-80-000, 24 FERC ¶ 61,046 (1983), issued on July 12, 1983, the Commission approved a 15.3% rate of return on common equity for Consolidated Gas Supply Corporation in Docket No. RP81-80-000 (Phase I), based on a hypothetical equity ratio of 45%. Consolidated advocated continued use of its parent company's capital strucute (consisting of 38.3% long-term debt, 2.3% preferred stock and 59.4% common equity, as approved by FERC Opinion No. 70, 10 FERC ¶ 61,029 (1980). The Commission reaffirmed the policy of using an imputed capital structure for a jurisdictional subsidiary whose parent provides all or part of its capital. The subsidiary's capital structure can be used if it can be shown to reasonably reflect the risks of the subsidiary, and the parent's capital structure can be used only if the business risk of the parent and subsidiary are essentially the same. In this case, the Commission held that Consolidated failed to show that its business risk was essentially the same as that of its parent on the ground that regulation insulates Consolidated from marketing risk. At the same time, the Commission found no support for the 50% debt, 10% preferred, and 40% common equity capital structure proposed by staff and adopted by Judge Nacy. While staff based its common equity ratio on a sample of electric utilities, the Commission viewed pipeline companies as more similar to gas distribution companies, whose equity ratios are closer to 48% than 40%. The Commission concluded that Consolidated's equity ratio should fall within a range of 38% (electric utilities) to 53% (major A and B pipelines) and selected 45% as the approximate mid-point of this range. The Commission concluded that a reasonable return on equity for Consolidated was in the range of 15.3% to 15.5% and selected the mid-point of that range as an adjusted reasonable rate of return based on 45% common equity.

On October 5, 1983, the Commission issued Opinion No. 190 granting a return on common equity of 15.95% to Tennessee Gas Pipeline Company in Docket Nos. RP80-97-013 and RP81-54-002 for the period from November 1, 1980 through May 31, 1982, 25 FERC ¶ 61,020 (1983). The return was granted on the capital structure of the consolidated company (Tennessee's parent is Tenneco, Inc.), agreed to by the parties, which included a common equity ratio of 51.5%.

On October 31, 1983, the Commission issued Opinion No. 196, *Alabama-Tennessee Natural Gas Company,* Docket No. RP80-2, 25 FERC ¶ 61,151 (1983), approving an 11% rate of return on a common equity ratio of 86% for the locked-in period April 3, 1980 through May 31, 1983. The Commission declined to impute a hypothetical capital structure with a 55% equity component proposed by Staff, but the Commission stated that it would re-examine the capital structure issue in the next pending rate case, Docket No. RP83-24, and impute hypothetical debt to the extent justified on the record.

H. *Taxes/Depreciation – Stand-Alone Method*

On June 22, 1983, the Commission issued two opinions upholding the use of the stand-alone method for calculating tax allowances in pipeline rate proceedings. In Opinion No. 173 the Commission affirmed the principle of computing federal income tax components of cost of service on a stand-alone basis in *Columbia Gulf Transmission Company,* Docket No. RP75-105-002 and *Columbia Gas Transmission Corporation,* Docket No. RP75-106-002, 23 FERC ¶ 61,396. The Commission's decision was issued on remand from the decision in *City of Charlottesville, Virginia v.*

FERC, 661 F.2d 945 (D.C. Cir. 1981). The Commission reaffirmed its policy originally stated in Opinions 47 and 47-A that the stand-alone policy looks beneath the single consolidated tax liability and analyzes each of the decisions used to reduce the group's liability to determine the deductions for which each service is responsible. The Commission concluded that the tax allowance, like other costs, should be based on the activities of the pipeline itself, *i.e.*, on a stand-alone basis. In a related decision, also released on June 22, 1983, the Commission upheld Southern Natural Gas Company's use of the stand-alone method in Opinion No. 174, issued in Docket Nos. RP80-102-000 and RP81-86-000, 23 FERC ¶ 61,397.

I. Gas Research Institute

On October 28, 1983, the Commission issued Opinion No. 195 approving, with minor modifications, a 1984 revised budget of $139.9 million proposed by the Gas Research Institute in Docket No. RP83-95-000 together with a 1984 funding unit of 1.25 cents per Mcf, 25 FERC ¶ 61,147 (1983). This represented a compromise from the original filing of $1.499 million and a funding unit of 1.37 cents per Mcf. The Staff contested this proposal and suggested a funding unit of 1.0 cents per Mcf in view of sales losses and revenue declines being experienced by other segments of the natural gas industry. The Commission did not accept GRI's proposal to lock-in the 1.25 cents funding unit through 1985. The Commission further ordered that the funding unit be included in rates authorized for short-term services provided by GRI interstate pipeline company members for any party other than another GRI interstate pipeline member.

II. Court Action — Pipeline Issues

A. Rate Base – Cash Working Capital

In *North Penn Gas Co. v. FERC*, 707 F.2d 763 (3d Cir. 1983), the U.S. Court of Appeals for the Third Circuit denied two arguments by North Penn, a natural gas company, on review of Commission decisions requiring it to make refunds for over-evaluating in rate base its working capital allowance for stored gas inventory. The Commission had rejected as inappropriate North Penn's valuation at the current weighted average cost of gas. The court found lawful the Commission's contrary valuation at historic actual cost, emphasizing the Commission's policy to allow pipelines to pass current gas cost increases promptly on to their customers via purchased gas cost adjustment provisions. (In the Court's view such provisions undermine the need to raise rates by increasing stored gas inventory valuations because such provisions act to finance higher-cost gas purchases over time.) North Penn also argued that the Commission lacked legal authority to order refunds under NGA Section 4. The court was persuaded instead that the working capital allowance for stored gas was an integral part of North Penn's NGA Section 4 rate case and that, therefore, refunds might be ordered under the analyses in *City of Batavia v. FERC*, 672 F.2d 64, 77 (D.C. Cir. 1982), and in *Laclede Gas Co. v. FERC*, 670 F.2d 38 (5th Cir. 1982).

B. PGA Restatements

In *South Georgia Natural Gas Co. v. FERC*, 669 F.2d 1088 (11th Cir. 1983), the U.S. Court of Appeals for the Eleventh Circuit affirmed Commission orders issued to South Georgia, a pipeline, declaring that under the PGA regulations, 18 C.F.R.

§ 154.38(d)(4)(vi)(b), the commencement date for the 36-month period within which the pipeline had to file a new base tariff rate (with a supporting cost-of-service study of both purchased gas and non-gas costs) was the day after the conclusion of the suspension period imposed by the Commission on South Georgia's NGA Section 4(e) rate filing, *i.e.*, the date the pipeline began collecting its proposed rates subject to refund.

C. Tracking Provisions

In *United Gas Pipe Line Co. v. FERC,* 707 F.2d 1507 (D.C. Cir. 1983), the U.S. Court of Appeals for the District of Columbia Circuit held that the Commission had exercised its discretion in a permissible and rational manner by rejecting a filing for a waiver of a longstanding Commission rate regulation policy against automatic, rate-adjusting "trackers." United, a pipeline, had designed its tracker to apply to all of its transportation costs and revenues in the particular context of significantly-increased transportation costs caused by deliveries of gas across the Canadian-U.S. border. The Commission had denied United's waiver application under its policy that trackers undermine the NGA concept of a just and reasonable rate based on a review of all of the pipeline's costs by automatically modifying a pipeline's rate to reflect changes in only one item of cost, thus failing to consider changes in other costs and revenues. One judge dissented on the ground that the Commission had failed to demonstrate that meaningful consideration had been given to United's arguments.

D. Access to Producer – Pipeline Contracts in PGA and NGA Section 4 Proceedings

In *Associated Gas Distrib. v. FERC,* 706 F.2d 344 (D.C. Cir. 1983), the U.S. Court of Appeals for the District of Columbia Circuit affirmed Commission orders denying a data request in a pipeline purchased gas cost adjustment proceeding. AGD, an association of pipeline customers, had sought to evaluate the pipeline's contracts with its producer-suppliers to determine whether or not contractual authority existed for the pipeline's rates. The court relied on the fact that the pipeline, as a condition for using the PGA procedure, had to submit its costs and revenues for full Commission review under NGA Section 4 at least every three years. The court held that such review provided AGD with adequate discovery and possible subsequent relief absent any evidence of, or specific allegation of, fraud or abuse.

E. Taxes/Depreciation – Tax Normalization Policy

In *Public Systems v. FERC,* 709 F.2d 73 (D.C. Cir. 1983), the U.S. Court of Appeals for the District of Columbia Circuit affirmed Commission orders adopting a general policy permitting pipelines to "normalize" in their costs of service over many years the tax deduction benefits of their expenses by spreading them over the period that their ratepayers are charged for such expenses, as opposed to flowing through the deductions currently to reduce rates only in the current year.

In *Memphis Light, Gas and Water Division v. FERC,* 707 F.2d 565 (D.C. Cir. 1983), the U.S. Court of Appeals for the District of Columbia Circuit affirmed Commission orders challenged by Memphis, a pipeline customer, as improperly approving the use of higher, historical corporate income tax rates in computing the tax component of two interstate pipelines' costs of service under the "normalization" method of accounting for accelerated depreciation. As to Memphis' challenge that the pipelines' deferred tax accounts were excessive because they were based on higher prior tax rates, the court found reasonable the Commission's method to allow the excess monies to be applied to overall deficiencies in the accounts, noting that the Commission properly can recognize taxes in ratemaking at any time, irrespective of when they are paid to the Treasury. Likewise relying on Commission discretion, the court rejected Memphis' argument that the annual increment to be paid by ratepayers under the "South Georgia" method should be decreased while the period of time for its collection remains constant. Instead the court found reasonable the Commission's continued collection of the increment at the original level under "South Georgia," but for a shorter period of time. Finally, the court affirmed the Commission's refusal to apply tax rate changes retroactively to years when earlier (higher) rates were applicable in order (as Memphis claimed necessary) to return to ratepayers excessive collections of income taxes on that portion of the pipeline's tax allowance collected under the "normalization" method that was above the pipeline's current expenses (*i.e.,* the tax-on-tax effect).

F. Taxes/Depreciation – Contract Interpretation Controlling Depreciation Rates

In *Michigan Wisconsin Pipe Line Co. v. FERC,* 717 F.2d 1027 (6th Cir. 1983), the U.S. Court of Appeals for the Sixth Circuit adopted the reasoning of two Commission orders interpreting a contract as to the depreciation rate to be used to compute the costs of Michigan Wisconsin's pipeline services to another natural gas company. The Commission had relied on its own prior decision dealing with the amount of another cost element (which the Commission found analogous to the depreciation cost element) in Michigan Wisconsin's total service charges to conclude that Michigan Wisconsin should use a lower depreciation cost.

G. Taxes/Depreciation – State Power to Prohibit Passthrough of Severance Taxes

In *Exxon Corp. v. Eagerton,* 103 S. Ct. 2296 (1983), the United States Supreme Court held that a state statute prohibiting producers from passing through to consumers an increase in the state's severance tax on gas was pre-empted by the NGA as to interstate sales, but was not pre-empted as to intrastate sales. The Court concluded that the passthrough prohibition, as it applied to sales of gas in interstate commerce, trespassed upon Commission authority to regulate such wholesale sales. As to intrastate sales, the Court first noted that the passthrough prohibition did not conflict with NGPA Section 110(a) because that NGPA provision simply provides that a seller including severance taxes in its price shall not be deemed thereby to have exceeded the NGPA price ceiling; indeed, the Court held, the provision gives no seller the affirmative right to include in its price an amount necessary to recover state severance taxes. The Court concluded that although NGPA Section 105(a) extended federal price control authority to the intrastate market, NGPA Section 602(a) provided that such extension did not deprive the states of power to establish price ceilings for intrastate producer sales at levels lower than the NGPA ceiling. The Court then reasoned that states exercising the power might impose severance taxes and forbid sellers from passing them through to their purchasers.

H. Cost Allocation

In *Texas Gas Transmission Corp. v. FERC,* No. 79-1385, issued August 8, 1983, and unreported,[3] the U.S. Court of Appeals for the District of Columbia Circuit issued

[3]This court issued no opinion, but an explanatory memorandum and order. Under the court's rules, such issuances "are not to be cited in briefs or memoranda of counsel as precedents." D.C. Cir. R. 8(f).

an order and a memorandum of motion by Texas Gas, a pipeline, to direct Commission compliance with an earlier mandate of the court. The court ordered the Commission to reinstitute a particular, historically-used method for Texas Gas to allocate costs among its customers until the Commission had acted under NGA Section 5(a) to establish another method. The court further provided that, if as a result of its clarified mandate, the Commission sought to require application of the historical method retroactively, the Commission had power to authorize refunds and surcharges to customers in order to reallocate the costs involved among the customers as a group, citing *FERC v. Triton Oil & Gas Corp.*, 712 F.2d 1450 (D.C. Cir. 1983).

III. Commission Action on NGPA Issues

A. *NGPA Section 110 Production-Related Costs*

On January 24, 1983, the Commission issued a series of orders governing the treatment of production-related costs under Section 110 of the NGPA, 22 FERC ¶¶ 61,052-56. In these orders, the Commission largely reversed the approach it had taken to production-related costs since December 1, 1978. In Order Nos. 94-A and 94-B, the Commission established a self-executing mechanism enabling first sellers to charge amounts in excess of the maximum lawful prices to the extent necessary to recover costs incurred to perform production-related activities, including compression, gathering, treating, liquefying or conditioning natural gas, or for services, other than processing, related to separation and extraction, of crude oil, liquids and liquefiables, if such services benefit the gas consumer. The Commission further required that the first seller must express contractual authority in order to be compensated for such production-related services, as evidenced by either a contract provision expressing a specific amount or a method for determining the amount to be paid. Moreover, the Commission provided that an area rate clause would provide sufficient contractual authority to recover delivery costs (compression and gathering) in connection with *interstate* gas contracts only.

The Commission permitted delivery allowances to be collected retroactively to July 25, 1980, the date of Order No. 94, in which the Commission had indicated that it would permit retroactive recovery of delivery costs upon issuance of a final rule. All other production-related costs, however, were to be collected on a prospective basis only, and the Commission provided that parties to contracts could amend them to expressly authorize recovery of production-related costs prospectively.

In Order Nos. 94-A and 94-B, the Commission departed from its prior policy on production-related costs in several major respects: (1) the Commission provided that a seller could recover the costs incurred to bring gas produced up to minimum pipeline quality standards, including any compression costs necessary to effect delivery into the pipeline's main line; (2) the Commission permitted recovery of all gathering costs, not just the costs of gathering off-lease; (3) the Commission eliminated the former requirement that a first seller apply for and justify its claims for production-related cost allowances; and (4) the Commisison eliminated the former exclusion of intrastate gas and permitted recovery of production-related costs for intrastate production on the same basis as for interstate production.

In addition to Order Nos. 94-A and 94-B, the Commission also issued three related orders on the same date. In Opinion No. 90-A, *Phillips Petroleum Co.*, CI77-410-000, 22 FERC ¶ 61,056 (1983), the Commission reaffirmed a condition imposed in producer-sales certificates requiring that pipelines seeking to recover production-related costs in their ates prove that the activities causing those costs were prudent. In a policy statement included in Order No. 94-A, the Commission provided that any production-related activity performed by an interstate pipeline would be deemed prudent for purposes of the NGA so long as the seller was not contractually obligated to perform that activity. The Commission, however, also stated that the prudence of the *amount* of any such costs incurred by a pipeline would be determined in pipeline rate or certificate proceedings under the NGA.

The Commission also issued an interim rule in Docket Nos. RM80-73-000 and RM80-74-000, 48 Fed. Reg. 5180 (1983), establishing generic allowances for the recovery of delivery (gathering and transportation) and compression costs incurred by first sellers. The Commission established certain generic allowances to apply in the absence of a lower specifically authorized contractual allowance for the services. Finally, the Commission issued an interim rule in Docket No. RM83-6-000 establishing procedures for determining the allowability of production-related costs and for any refund which may be due for overcharges.

Several parties sought rehearing of the January 24, 1983 section 110 orders, and the Commission largely denied rehearing in Order Nos. 94-C and 94-D, 23 FERC ¶ 61,279-80, issued on May 24, 1983. The Commission issued final rules on compression and delivery allowances and on enforcement and refund procedures on September 27, 1983. All of these matters are now pending before the U.S. Court of Appeals for the Fifth Circuit in *Texas Eastern Transmission Corp. v. FERC*, No. 83-4390, *et al.* (formerly No. 80-1928, *et al.*)

B. Liquids and Liquefiables

In 1983, several major decisions were issued involving the Commission's position on two major issues relating to transportation of liquids and liquefiable substances by interstate natural gas pipelines on behalf of producers: (1) whether transportation of such liquids and liquefiables at no cost or below cost constitutes a violation of the Title I NGPA ceiling prices, and (2) the proper method of allocation of the cost of such services in pipeline rate cases.

On January 17, 1983, the Commission issued a Declaratory Order, 22 FERC ¶ 61,013, in response to petitions filed by the Indicated Producers in Docket No. GP82-50-000, Associated Gas Distributors, GP82-51-000 and Texas Eastern Transmission Corporation in Docket No. GP82-52-000. The Commission held that neither the value received by producers from pipeline transportation of liquids and liquefiables, nor the cost incurred by pipelines for such transportation has any relation to Title I ceiling prices.

On May 11, 1983, the Commisison approved settlement offers submitted by ten pipelines (Tennessee Gas Pipeline Company, *et al.*, RP80-97-015, *et al.*, resolving questions involving allocation of the costs to transport and handle producer-owned liquids and liquefiables, 23 FERC ¶ 63,003. The settlement offers were virtually identical to a settlement approved by the Commission on April 21, 1983, in *Trunkline Gas Company*, Docket No. RP80-106-010, 23 FERC ¶ 61,137, because all parties had agreed to be bound by the record submitted in the Trunkline case. The settlement agreements established two sets of unit amounts deemed to constitute an allocation of cost for transportation of liquids and liquefiables and will be applied by the respective pipelines to reduce jurisdictional rates. The unit amounts differ according to well connection dates. The unit amounts were contested by certain producer intervenors, but the Commission accepted settlements over those objections.

On July 7, 1983, the Commission issued an order denying rehearing of its declaratory order on the Title I issue relating to the transportation of producer-owned liquids and liquefiables, 23 FERC ¶ 61,004. The liquids and liquefiables issues, including the cost allocation issues, are now before the U.S. Court of Appeals for the Fifth Circuit in *Texas Eastern Transmission Corp. v. FERC*, Nos. 83-4390, *et al.*

C. *Incremental Pricing*

On October 5, 1983, the Commission granted a sixty-day temporary stay of the otherwise effective date (October 15, 1983) of the Phase II rule promulgated in Order No. 80 (Docket No. RM80-10-000), which expanded the incremental pricing program to cover nearly all industrial users not exempted by Section 206 of the NGPA. The Commission's action was taken in response to court decisions that overturned the May 1980 congressional veto of the Phase II rule. In *Consumer Energy Counsel of America v. FERC*, 673 F.2d 425 (D.C. Cir. 1982), the court held that the legislative veto was severable from section 202 and unconstitutional. The court also held that the Commission's revocation of the rule was invalid because of failure to provide interested persons with adequate notice and an opportunity to comment. The D.C. Circuit's decision was summarily confirmed by the U.S. Supreme Court on July 6, 1983 in reliance on its ruling two weeks earlier that the one-house veto provision in the Immigration and Naturalization Act was contrary to constitutional requirements for bicameral legislation and presidential veto and contravened the doctrine of separation of powers. See *Immigration and Naturalization Service v. Chadha*, 103 S. Ct. 2764 (1983).

On December 1, 1983, the Commission issued a notice of proposed rulemaking in Docket No. RM80-10-002 that effectively would prevent implementation of regulations issued by the Commission in 1980, 25 FERC ¶ 61,368. The Commission simultaneously approved a separate order staying the effectiveness of the Phase II regulations until April 12, 1984, or until the Commission completes reconsideration of the regulations, whichever is earlier. The Commission proposed to issue an exemption to all industrial users of gas covered by the Phase II regulations promulgated in Order No. 80. The Commission also requested comment on other possible alternatives, including indefinite postponement of the effective date of Order No. 80 or revoking the earlier rule and issuing a new, significantly narrower Phase II rule.

D. *High-Cost Gas*

On September 26, 1983, the Commission extended the production enhancement incentive price established in Order No. 107 (Docket No. RM80-50-003) for section 105 intrastate gas to cover interstate gas subject to sections 104 and 106(a), as well as intrastate roll-over gas subject to section 106(b), 24 FERC ¶ 61,365. Order No. 107 prescribed an incentive price equal to the lesser of the "negotiated contract price" or the NGPA Section 109 maximum lawful price for "qualified production enhancement gas" covered by existing intrastate contracts and sold under NGPA Section 105. The Commisison granted rehearing of Order No. 107 on the issue of extending production enhancement procedures to sections 104 and 106 gas but denied rehearing of all other aspects of the rule, including the imposition of the negotiated contract price requirements.

On October 21, 1983, the Commission issued Order No. 345, amending the definition of "recompletion tight formation gas" that qualified for a special incentive price under Section 107(c)(5) of the NGPA, 25 FERC ¶ 61,113. The final rule, issued in Docket No. RM82-24-000, allows natural gas produced form recompletion of wells that were completed for production in designated tight formations before July 16, 1979 to qualify as recompletion tight formation gas if the recompletion produces natural gas that could not have been produced through any completion location in existence before the effective date of the rule. As in the case of other high-cost incentive price rules adopted by the Commission to date, this amended rule includes a "negotiated price requirement" specifying that the seller can collect the lesser of a negotiated contract price or the incentive price, which is equal to 200% of the applicable Section 103 maximum lawful price under the NGPA.

E. Area Rates

In Opinion No. 181, issued in *United Gas Pipe Line,* Docket No. GP80-41-000 on Jly 19, 1983, 24 FERC ¶ 61,083, the Commission affirmed the initial decision of the Chief Administrative Law Judge who found that third party protestants had produced sufficient extrinsic evidence regarding intent to pay NGPA Section 108 ceiling prices pursuant to area rate clauses to negate the contracting parties' evidence on the issue of intent. The Commission therefore sustained the protests regarding NGPA Section 108 ceiling prices but affirmed the initial decision rejecting the protests with respect to contractual authority to charge NGPA prices under all other categories.

F. Rolled-In Cost of Section 311/312 Supply

In Opinion No. 159, *United Gas Pipe Line Company,* Docket No. RP78-68-000, issued February 4, 1983, the Commission affirmed the initial decision permitting United to roll-in the cost of gas purchased from intrastate pipelines under Sections 311 and 312 of the NGPA, 22 FERC ¶ 61,126. The Commission agreed that there was insufficient evidence that the gas was earmarked only for direct sales customers and concluded that the low priority customers, both jurisdictional and nonjurisdictional, benefitted from the section 311-312 gas supply. The Commission distinguished this type of supply from emergency gas, which it had held in an earlier United decision should be priced incrementally because it had been earmarked solely for direct sale industrial customers and had conferred no benefit on United's jurisdictional customers. 8 FERC ¶ 61,051 (1979), *reh'g denied,* 8 FERC ¶ 61,127 (1979), *aff'd, United Gas Pipe Line Co. v. FERC,* 649 F.2d 110 (5th Cir. 1981). In Opinion No. 159-A issued on April 6, 1983, 23 FERC ¶ 61,029, the Commission denied rehearing of its decision in Opinion No. 159.

IV. Court Action on NGPA Issues

A. NGPA Pricing – State Regulation

In *Energy Reserves Group v. Kansas Power and Light Co.,* 103 S. Ct. 697 (1983), the United States Supreme Court rejected the constitutional claim of Energy Reserves, a Kansas intrastate gas supplier, that a 1979 Kansas statute had impaired certain indefinite price escalator provisions in its 1975 gas supply contracts with Kansas Power and Light. The Court held that Energy Reserves' contractual rights had not been substantially impaired because the parties, operating in an industry in which the price of gas was heavily regulated, expressly had recognized that their contract terms were subject to alteration by state price regulation. The Court also rejected the argument that NGPA Section 105 triggered governmental price escalator clauses in the contracts. Finally, the Court concluded, with approval of only six Justices, that the state statute was a legitimate exercise of police power to protect consumers that supplemented NGPA regulation of intrastate gas pricing, as specifically contemplated by Congerss in NGPA Section 602(a).

B. NGPA Pricing – Federal Question Jurisdiction

In *Superior Oil Co. v. Pioneer Co.,* 706 F.2d 603 (5th Cir. 1983), *cert. denied,* 104 S. Ct. 706 (1984), the U.S. Court of Appeals for the Fifth Circuit vacated the judgment of the U.S. District Court for the Northern District of Texas and dismissed a claim for breach of contract. Superior, a gas seller, had sought to increase the price for its gas by asking the district court to declare that its gas sales contract with Pioneer was an NGPA "existing contract." Instead the district court concluded that it was an NGPA "rollover contract". But the Fifth Circuit held that while the dispute pivoted on an issue of federal law (NGPA ceilings on prices in intrastate gas sales contracts) state-created contract rights propelled the lawsuit, thus depriving the courts of subject-matter jurisdiction as a question of federal law. The Fifth Circuit concluded that because NGPA price ceilings did not give the gas seller a federal right to receive a particular price for its gas (as did state-created contract law) the issue of federal-question jurisdiction was not even close.

C. Section 104 and 106 Rollover Contracts

In *Union Texas Petroleum Corp. v. FERC,* 721 F.2d 146 (5th Cir. 1983), the U.S. Court of Appeals for the Fifth Circuit affirmed Commission orders declaring that Union Texas' 1979 contract amendment, as a producer, with a pipeline was not a rollover contract under either NGPA Section 104 or 106. The court also found no abuse of discretion in the Commission's granting to Union Texas the NGA rollover rate to ensure that Union Texas did not receive a lower rate than it would have received had the NGPA not been enacted.

D. NGPA First Sale Pricing of Pipeline Production

In *Public Service Commisison of the State of New York v. Mid-Louisiana Gas Co.,* 103 S. Ct. 3024 (1983) (the *"Mid-La."* case), the United States Supreme Court, on certiorari to the U.S. Court of Appeals for the Fifth Circuit, held (generally agreeing with the Fifth Circuit, 664 F.2d 530 (5th Cir. 1981)) that the Commission's exclusion of pipeline gas production from coverage under the NGPA's pricing scheme was inconsistent with the statutory mandate. The Court then vacated and remanded the case for the Commisison to exercise its discretion as to whether NGPA "first sale" treatment should be given either to the earlier intracorporate transfer of the gas (from the pipeline-owned produciton system to the pipeline) or to the later downstream transfer of the gas (from the pipeline to its customers). The Court held that, when either transfer is treated as a first sale, the pipeline may include NGPA prices in its cost of service, just as when it acquires gas from independent producers. Repeatedly emphasizing the exhaustive and comprehensive NGPA categorization of gas production and related prices, the Court concluded that Congress would have identified any significant production source — such as pipeline production — that was intended to be excluded, but did not do so. The Court also relied on NGPA Sections 2(21)(B), 203, and 601(b)(1)(E) to find pipeline production subject to the NGPA, with no distinction to be drawn between pipeline production and affiliate produciton. Four Justices dissented to the Court's decision in a separate opinion finding the Commission's construction of the NGPA sufficiently reasonable to have been accepted by the federal courts.

E. *Btu Measurement (Wet/Dry) Under the NGPA*

In *Interstate Natural Gas Association of America v. FERC,* 716 F.2d 1 (D.C. Cir. 1983), *petition for cert. filed,* 52 U.S.L.W. 3575 (U.S. Jan. 17, 1984) (No. 83-1173), the U.S. Court of Appeals for the District of COlumbia Circuit vacated a new Commission approach to measuring the Btu content of gas for purposes of NGPA wellhead pricing.[4] When the NGPA was enacted in 1978, the Commission had been defining Btu content of gas under a laboratory-standardized, water-vapor-saturated ("wet") condition for over fifteen years. Under its new approach, in contrast, the Commission defined Btu content of gas for NGPA first sales in terms of its actual delivery ("dry") condition. Gas measured by a "dry" method, *i.e.,* absent water vapor that displaces energy-producing hydrocarbons, has a higher Btu content thatn gas measured by a "wet" method. The court concluded that Congress had fixed NGPA prices based on the "wet" method for three reasons: (1) because it was the only method with which Congress was likely to have been familiar; (2) because the "dry" method overstated the NGPA shift to MMBtu-based gas prices and distorted NGPA ceiling prices; and (3) because both the NGPA's final version (particularly Title II) and the Energy Tax Act of 1978 indicated no necessary incompatibility between NGPA Title I's shift to MMBtu measured gas and the continued use of the "wet" method.[4]

F. *Vintaging – Challenges to Commission Rules in Individual Adjudications*

In *Shell Oil Co. v. FERC,* 707 F.2d 230 (5th Cir. 1983), the U.S. Court of Appeals for the Fifth Circuit granted Shell's petition for review of a Commission order denying it, as a producer, a new, higher vintage price for onshore wells directionally redrilled, or "sidetracked," to new locations within existing proration units of gas reservoirs. The court noted that sidetracked wells are partly old and partly new, with costs incurred both initially when the well is drilled and later when the well is sidetracked, giving rise to the question whether the vintage price should be lower for the drilling date or higher for the sidetracking date. Because the general rule the Commission relied on to deny relief to Shell (*i.e.,* that sidetracked wells fail to qualify for vintaged pricing if producers are able to use existing well footage to a great degree) was unsupported by substantial evidence, both in the earlier adjudication where it had been established and in Shell's case, the court vacated the Commission's order relating to Shell and remanded for further proceedings. The court rejected the Commission's argument that Shell should have intervened in the earlier case, holding that due process of law enabled Shell to challenge the general rule from the earlier case on the facts of Shell's own case.

G. *Commission Authority Over Producer Refunds*

In *FERC v. Triton Oil & Gas Corp.,* 712 F.2d 1450 (D.C. Cir. 1983), the U.S. Court of Appeals for the District of Columbia Circuit reversed the U.S. District Court for the District of Columbia, which had entered summary judgment in favor of Triton, a producer. At issue were Triton's failures to make certain refunds to its purchasers and related refund disbursement reports to the Commission. The court concluded that the Commission possessed and had exercised the power to change producer

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[4] On January 19, 1984, the Commission initiated a "Notice of Inquiry," in Docket No. RM84-6-000, to solicit comments on appropriate refund procedures. 49 Fed. Reg. 3198 (1984).

On March 19, 1984, the United States Supreme Court denied all petitions for *certiorari.*

rates in the Southern Louisiana area retroactively and to order producers there, such as Triton, both to disburse refunds and to file reports.

Herbert J. Martin, *Chairman*
Michel Marcoux, *Vice Chairman*

Christopher T. Boland	Jeffrey M. Petrash
Patricia A. Burke	C. Frank Reifsnyder
James Choukas-Bradley	Julia Rankin Richardson
J. Paul Douglas	Gary G. Sackett
John F. Egan	John T. Stough, Jr.
Elias G. Farrah	Bryon L. Wade
James Harrison Holt	John B. Will
Kevin J. Lipson	Alan C. Wolf