Missouri Public Service Commission

Gas Purchasing / Cost Recovery

Staff Project Team Report

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Jefferson City, Missouri

ACKNOWLEDGEMENT OF PARTICIPANTS

Project Team Members

Carmen Morrissey, Policy and Planning - Team Leader
Penny Baker, General Counsel's Office
Bo Matisziw, Utility Operations
Mark Oligschlaeger, Utility Services
Ken Rademan, Utility Services
David Sommerer, Utility Services
Mike Proctor, Policy and Planning

The Project Team gratefully acknowledges all the assistance other staff members have provided.

MISSOURI PUBLIC SERVICE COMMISSION
GAS PURCHASING/COST RECOVERY PROJECT

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I.
EXECUTIVE SUMMARY

In December 1992, the Commission formed a Gas Purchasing/Cost Recovery Project Team (Team) to examine the issue of gas cost recovery in light of the Federal Energy Regulatory Commission's (FERC's) Order No. 636. The Commission instructed the Team "to determine if MoPSC rules, regulations, practices, procedures, and/or the manner of regulating natural gas utilities need to be modified to reflect the changes which have occurred to effect more open markets in the natural gas industry, augmented by the issuance of FERC's Order Nos. 636, 636-A, and 636-B. " The approved proposal for the project specifically charged the Team to: (1) Study LDCs' gas supply purchasing practices with specific emphasis on reliability and cost; (2) Review current PGA clauses, including ACA provisions and prudence reviews; (3) Review the effects of industry changes on the LDCs' obligation to serve; and (4) Address other areas as may be identified during the review process.

The opinions expressed within this report are those of the Team as a whole and do not necessarily represent the opinions of the Commission, individual Commissioners, or individual project team members. The contents of this document have been evolving in nature as Team deliberations have progressed and as a result of information gathered in its survey of other states and from workshops that were held. The first workshop consisted of discussions between the Commission Staff and Missouri LDCs on June 23-24, 1993. The second workshop was held June 27, 1994, with interested parties, including Staff, LDCs, the Office of Public Counsel, end users, marketers, and pipelines participating.

Recognizing the pressing need to implement LDC tariff modifications to effect the changes coming from Order 636, last summer and fall the Commission and its Staff focused on processing these LDC tariff filings. Now that LDCs have completed their first winter season under restructured pipeline tariffs, the Team believes it is now necessary for the Commission, its Staff, LDCs and other interested parties to concentrate on addressing the various recommendations contained in this report. The Team is making 33 recommendations which are listed at the end of this executive summary. In addition, the following items have been included to provide a picture of the suggested method(s) and schedule for implementing the Team's recommendations.

Matrix of Project Team Recommendations groups the recommendations contained in this report according to the type of action that is being suggested. Several of the recommendations have been placed in more than one category. This is because the Team believes there is some flexibility in selecting the forum in which these issues can best be resolved.

Schedule of Events for Natural Gas Proceedings presents a general time table of the major activities discussed in this report. Obviously the time lines for several of these activities overlap. Although many of the same staffers would be involved in the integrated resource planning (IRP) process, minimum filing requirements (MFR) project, actual cost adjustment (ACA) cases, and the task of reassessing the purchased gas adjustment (PGA) mechanism, the Team believes it is appropriate to keep each of these on separate tracks at this time. It seems important to do this until it becomes clear as to how the gas IRP rulemaking is going to progress and how the issues in individual ACA cases are being resolved.

Actual Cost Adjustment Schedule provides a listing of pending LDC cases in which the Project Team urges the Commission to issue orders directing Staff, LDCs and other parties to address the matters related to LDCs' obligation to serve, rate design, transition costs, and affiliate transactions. While it is important for there to be some consistency in dealing with these issues, the Team believes it is important for each LDC's situation to be reviewed and considered individually, before certain tariff changes or other requirements are prescribed for them. This is why the Team is suggesting that such issues be addressed on a case-by-case basis rather than via a generic proceeding.

The Team recognizes that the recommendations contained in this report, as well as the proposed implementation schedule are ambitious. A serious commitment by both Staff and LDCs will be necessary to work through the important issues facing us. The Team believes the viability of the PGA mechanism will depend to a large extent upon the LDCs' cooperation in supplying gas and transportation service procurement information and workable suggestions on how to modify the PGA mechanism and other regulatory procedures in light of the new circumstances Order 636 has brought to us.

It is important for the Commission to have access to LDCs' gas purchasing strategies and plans in order to evaluate initial PGA rates. The Team believes this will best be achieved through implementing gas IRP rules. However, during this interim period, i.e. until a gas IRP rule goes into effect, the most pragmatic response to these problems is for the Commission to direct LDCs to provide their gas purchasing strategies and plans, including load forecasts and gas supply and pipeline service contracts, when they file their new ACA rate in their GR-94 dockets. This information should help provide more complete and timely ACA reviews and also provide a smoother transition to implementing a gas IRP rule. It would serve to "jump start" the Commission's need to place a greater emphasis upon LDC planning functions, the evaluation of alternatives and potential results, and the continual reassessment of the environment that affects their decisions. It will convey the message that the Commission expects such processes to be performed by LDCs.

The Team wishes to point out that if the Commission desires a meaningful review of LDC supply plans in order to evaluate <u>initial</u> PGA rates, and make adjustments to those initial rates based on this review, existing PGA tariffs will likely need to be revised. Also additional staffing resources or changes in emphasis will be required since the current process is structured to make after-the-fact reviews. It is anticipated that such a shift in emphasis may actually evolve as the gas IRP process matures.

THE PROJECT TEAM RECOMMENDS: <u>Page</u>

13. *The Commission allow LDCs to recover Account 191 and GSR costs through the use of a volumetric surcharge on LDC throughput. However, an LDC should be allowed to allocate costs in such a way as to avoid double-charging the customers who may have already paid their fair share of costs at the pipeline level. The allocation of these costs is best reviewed as part of an LDC's next ACA or rate case.*
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14. *Each LDC develop and provide to the Commission its plan for long-term gas procurement strategies (and modifications to these strategies) for reliably meeting their supply responsibilities.*
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15. *Each LDC also prepare and file with the Commission an annual purchasing plan which provides specific information as to how it intends to realistically and successfully achieve the goals contained in its strategies.*
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16. *The Commission establish procedures for the review of the long-term gas procurement strategies and annual purchasing plans submitted by LDCs.*
. . . . 31

17. *LDC annual reports identify any and all affiliate entities.*
. . . . 32

18. *LDCs be required, as part of the minimum ACA filing requirements, to report any and all affiliate transactions associated with the acquisition of gas supplies or the selling of released capacity or unneeded gas supplies. Consideration should be given as to whether it is necessary to require quarterly reporting of affiliate transactions.*
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19. *That as part of their gas supply plans, LDCs be explicitly required to fully justify their decisions to purchase affiliate gas.*
. . . . 33

20. *LDCs initiate formal bidding procedures or other credible methods of documenting the selection process where transactions with affiliates are being considered.*
. . . . 33

21. *Presentations and/or workshops about hedging tools be conducted to provide information to the Commission, Staff, LDCs, and other interested parties about this complex subject. At some point, if desired, these could be used as a forum for interested parties, including the Commission and Staff, to informally convey their positions regarding price risk management and the appropriate ratemaking treatment for hedging costs.*
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22. *The Commission direct Staff, in cooperation with LDCs, to develop standard MFRs related to gas purchasing practices and the recovery of gas supply and pipeline service costs. In addition, the Commission should require Staff to report, within 120 days from the final issuance of this document, on the status of the MFR project and to indicate whether MoPSC rules should be amended to include MFRs in this area.*
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23. *The current PGA/ACA recovery mechanism be retained for the 1994-95 heating season.*
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24. *The Commission initiate a process whereby the appropriateness of the PGA/ACA mechanism is reassessed. The process used could either be in the form of another project team made up of various Staff members or a task force which would include representation from interested sectors*

MATRIX OF PROJECT TEAM RECOMMENDATIONS

COMMISSION ACTION

ISSUES	Commission Should Seek Legislation	Commission/Staff Should Deal With In The Context Of The IRP Rulemaking	Commission Should Issue Orders Directing Staff and Other Parties To Address In Each LDC's Current PGA/ACA/Rate Case	Commission Should Direct Staff To Implement	No Action Necessary
OBLIGATION TO SERVE * Service Structure			1 Establish backup sales service. 2 Transport customer choice-backup service or LDC has no sales service obligation.		
* Return to System Supply			3 Clearly defined & limited balancing. 4 Waiting period to return to system supply. 5 Require up to 12 mos. of fixed charges and notice to become backup service customer.		
* Bypass/Discounting	6 To ensure compliance with pipeline safety requirements.		7 Continue current discounting policies while encouraging LDCs to be creative in offering alternatives.		
* Contingencies & Curtailment		8 LDCs develop contingent supply arrangements as part of gas purchasing plans.	9 Prepare & update formal curtailment plans annually. 10 LDC tariffs be updated by 9/15/94 to reflect current curtailment plans. 11 Emergency exemption tariffs state conditions for temporary diversion of gas.		
RATE DESIGN			12 Rate design issues be thoroughly addressed.		
TRANSITION COSTS			13 Deal with Account 191 and GSRC recovery and allocation issues.		
SUPPLY RELIABILITY		14 LDCs develop & provide long-term gas supply strategies. 15 LDCs develop & provide annual purchasing plans. 16 Commission establish procedures for review of LDC strategies and plans.			
AFFILIATE TRANSACTIONS		19 LDCs justify the purchase of gas supplies and/or transportation from affiliates. 20 LDCs initiate formal bidding procedures or other credible selection procedures	19 LDCs justify the purchase of gas supplies and/or transportation from affiliates. 20 LDCs initiate formal bidding procedures or other credible selection procedures.	17 Ensure LDC annual reports identify all affiliates. 18 Include as part of ACA MFRs a requirement to report all affiliate transactions.	
USE OF PRICE HEDGING TOOLS				21 Presentations &/or workshops about hedging tools be conducted.	
MINIMUM FILING REQUIREMENTS (MFRs)		22 Develop MFRs to be used in PGA/ACA cases (Possibly in a separate rulemaking)	22 Develop MFRs to be used in PGA/ACA cases. (Possibly in a separate rulemaking)		
PGA MECHANISM			25 LDCs provide all gas purchasing strategy and plan documentation for GR-94 and GR-95 periods. 27 LDC gas purchasing practices be reviewed by the Commission before allowing final recovery of gas costs by LDCs. 31 Encourage development of incentive mechanisms.	24 Reassessment of PGA/ACA mechanism. 26 Annual comparison/audit of LDCs' actual purchases to planned purchases. 28 Revise ACA procedures. 29 Audit refund & ACA accounts simultaneously. 30 Analyze capacity release revenues. 32 Propose modifications, where necessary for interest to be applied to gas cost overcollections.	23 PGA/ACA mechanism be retained for the 94-95 heating season. 33 Gas IRP and gas purchasing cost recovery to proceed on separate tracks for now.

PROPOSED SCHEDULE OF EVENTS FOR NATURAL GAS PROCEEDINGS

	1993	1994				1995				1996			
	4th Quarter	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
GR-93 Dockets (92-93 PGA/ACA)		Audit		Hearing									
GR-94 Dockets (93-94 PGA/ACA) [1]	93-94 Period					Audit		Hearing					
GO-94-171 Gas IRP Rulemaking		Sect. 115 Evidence	Initial Draft & Workshops		Revised Draft Rules	Proposed Rules	Comments	Hearing	Final Rule	LDC Compliance With Rule			
93-94 Purchasing Plan Documentation				To Be Submitted									
Obligation to Serve, Rate Design, Transition Costs, Incentives				Addressed On A Case-By-Case Basis									
GR-95 Dockets (94-95 PGA/ACA)					94-95 Period					Audit		Hearing	
94-95 Purchasing Plan Documentation				To Be Submitted									
MFR Report					Review & Recommendations								
Reassessment of PGA/ACA Recovery Mechanism						Review & Comments		Recommen-dations					
GR-96 Dockets (95-96 PGA/ACA)									95-96 Period				

[1]See Actual Cost Adjustment Audit Schedule at page 8.

ACTUAL COST ADJUSTMENT AUDIT SCHEDULE

COMPANY	DOCKET NO.	ACA COMPUTATION PERIOD - 1 YEAR	ACA EFFECTIVE TARIFF DATE	RECOMMENDATION DATE
1. Union Electric	GR-94-353	Ending the March Revenue Month	May	February 95
2. St. Joseph Light & Power	GR-94-91	Ending April Revenue Month	First June Billing Cycle	March 95
3. Greeley Gas	GR-94-129	W/Billing Period, Ending 5/31	August 1	May 95
4. Missouri Gas Energy	GR-94-228[1]	W/Billing Period, Ending 6/30	First September Billing Cycle	June 95
5. Laclede Gas	GR-94-150 [1]	W/Billing Period, Ending 9/30	November 15	August 95
6. Fidelity Gas	GR-93-135	W/Billing Period, Ending 8/31	November 1	August 95
7. Associated Natural Gas.	GR-94-189	W/Billing Period, Ending 8/24	November Billing	August 95
8. Missouri Public Service	GR-94-331	W/Billing Period, Ending 8/31	November 15	August 95
9. United Cities Gas				
Hannibal/Canton	GR-94-63	W/Billing Period, Ending 5/31	January 1	September 95
Neelyville	GR-94-63	W/Billing Period, Ending 5/31	January 1	September 95
Bowling Green	GR-94-63	W/Billing Period, Ending 5/31	January 1	September 95
Palmyra	GR-94-227	W/Billing Period, Ending 5/31	January 1	September 95

[1]Other pending dockets where Obligation to Serve, Transition Costs, and/or Gas and Pipeline Service Cost Rate Design Issues could possibly be addressed:

4. Missouri Gas Energy
GO-94-318 Investigation of Certain PGA-Related Issues

9. Laclede Gas
GR-94-328 PGA Rate Design

II.
HISTORY OF
REGULATORY DEVELOPMENTS IN THE NATURAL GAS INDUSTRY

A. Federal

Federal regulation of the natural gas industry, for the most part, began with Congress' enactment of the Natural Gas Act[1] (NGA) in 1938. Prior to that time, there was very little federal regulation of natural gas. In the 1920s the U.S. Supreme Court held that individual states had no authority to regulate natural gas flowing in interstate commerce.[2]

The purpose of the NGA was for federal regulation to pick up where state regulation stopped. The NGA provided for federal regulation of interstate natural gas transportation, the interstate sale of natural gas for resale, and natural gas companies that engage in such services. Production, gathering, and local distribution of natural gas were deemed to be matters of local concern and were specifically exempted from federal purview.

The NGA created the Federal Power Commission, now the Federal Energy Regulatory Commission (FERC), to administer and enforce the NGA. The function of the FERC is to prevent abuses of monopoly power by interstate pipelines. The FERC is charged with ensuring that the services provided by interstate pipelines are required by public convenience and necessity and are sold at just and reasonable rates.

Until 1954, producers were considered to be outside the FERC's NGA jurisdiction. In 1954 the U.S. Supreme Court held that natural gas producers, like interstate pipelines, had natural monopoly power. Therefore, consumers needed the protection of a regulatory agency to ensure natural gas service at reasonable rates.[3] The Court held that producers who make sales for resale in interstate commerce are natural gas companies and therefore were subject to the FERC's jurisdiction.

Following the Phillips decision, the FERC embarked on a 25-year odyssey of producer pricing regulation. Initially, the FERC attempted to review the jurisdictional rates of every producer, just as it did with interstate pipelines. Because of the multitude of producers, this was an overwhelming task. To counter this, the FERC began establishing area rates in 1960.

Area rates were based on historical costs and were applied generically for all wellhead sales from seven different production regions, with separate ceiling rates for "old" and "new" gas. Artificially low area rates reduced interstate supply, while "vintaging"[4] and "rolled-in pricing"[5] increased interstate demand.

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[1] 15 U.S.C. § § 717-717w (1988).

[2] Missouri v. Kansas Natural Gas Co., 265 U.S. 298 (1924) and Public Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927).

[3] Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954).

[4] "Vintaging" - Originally, a term used for a pricing scheme in which gas is priced at different

(continued...)

When demand exceeded supply, pipelines and local distribution companies (LDCs) rationed the gas among consumers according to curtailment plans.

In the early 1970s, the FERC replaced area rates with national rates but it continued to allow rolled-in pricing. Although incentive prices were built into the national rate scheme to encourage interstate production, price distortions remained. Regulated prices for interstate gas were still lower than in the unregulated intrastate market and rose to meet demand. Therefore, producers still preferred to supply intrastate markets while consumers' demand for interstate gas grew. As a result, by the late 70s shortages of interstate supplies grew more severe.

To resolve these shortages and other perceived problems in the industry and the country (for example, dependence on foreign oil), Congress passed and the President signed into law a series of five energy acts:

1. Natural Gas Policy Act[6] of 1978 (NGPA);
2. Public Utility Regulatory Policies Act[7] of 1978 (PURPA);
3. Powerplant and Industrial Fuel Use Act[8] of 1978 (PIFUA);
4. Energy Tax Act[9] of 1978 (ETA);
5. National Energy Conservation Policy Act[10] of 1978 (NECPA).

Of these, the most significant to the gas industry was the NGPA. The NGPA mandated phased deregulation of wellhead prices for new gas sources (those sources discovered after April 1977). The NGPA's proponents argued that permitting the price of gas in the interstate market to rise would encourage producers to supply more gas to the interstate market. The NGPA did not remove price controls on previously-discovered gas supplies, but it did permit the price to rise with inflation.

Between 1978 and 1985, FERC issued a series of orders and instituted a set of programs to implement the NGPA. The orders and programs were intended to open the wellhead market to many sellers and

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(...continued)
levels on the basis of age (date of its initial production). More recently, the term refers to a pricing scheme in which prices are based on categories which are only loosely related to age or date of initial production.

5 "Rolled-in-pricing" represented the pipelines practice of selling the various vintages of gas supply they had purchased at the weighted average cost of gas.

6 15 U.S.C.A. § § 3301-3342 (West Supp. 1990).

7 16 U.S.C. Section 2601 et seq.

8 Pub. L. No. 95-620, 92 Stat. 3289 (contained in Sections 15, 42, 45 and 49 U.S.C.), repealed 1987, Pub. L. No. 100-42, 101 Stat. 310 (1987).

9 Pub. L. No. 95-618 92 Stat. 3174 (1978).

10 Pub. L. No. 95-619 92 Stat. 3206 (1978).

buyers, extend the markets for gas beyond traditional geographic boundaries and promote freer access to transportation on interstate pipelines.

The implementation of the NGPA caused both prices and supply to increase dramatically. Prices hit their peak in 1983. An excess supply of gas (called the gas "bubble") began to appear. Contributing factors to this bubble were: (1) As higher prices were causing more gas to be found and produced, those higher prices were also causing consumption to drop off. (2) Large customers capable of switching fuels did so; oil prices were dropping significantly during this period--ultimately setting all-time lows. (3)The PIFUA discouraged gas use for electric power generation.[11]

In an effort to bring supply and demand into balance in the gas marketplace the FERC issued four major orders between 1984 and 1989 designed to introduce competition into the pipeline industry. Issued in May 1984, Order 380[12] prohibited pipelines from including minimum bills as gas costs to their customers. Before Order 380, many pipelines required customers to pay for a minimum amount of gas every month, even if the customer did not consume any gas that month. After Order 380, pipeline tariffs could no longer recover costs associated with gas not actually taken by a pipeline's customers. Order 436[13], issued in October 1985, provided for non-discriminatory, open-access transportation on pipeline systems. Its purpose was to permit LDCs and other downstream gas users to buy gas directly from producers or other gas sellers, and to transport that gas over interstate pipelines. Since Order 436 did not address the problem of mounting pipeline "take-or-pay" liabilities, the Courts returned this to the FERC for resolution. In response, the FERC issued Order 500[14] in August 1987 (with numerous rehearing orders issued through 1989), which retained most of the open-access transportation provisions of Order 436 and included provisions for pipeline recovery of past and prospective "take-or-pay" costs. Order 451[15], issued in June 1986, allowed producers to seek higher prices for old gas by allowing them to institute good faith negotiations with pipelines holding contracts for this gas. A pipeline could retain its rights to this gas if it was willing to pay the maximum lawful price for that gas in the future. If a pipeline was unwilling to pay the maximum lawful price, the producer could terminate the contract and sell the gas to others.

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[11] The PIFUA was eventually repealed in 1987 because of pressure from the electric industry, concerns about air quality, and slumping gas sales. Pub. L. No. 100-42, 101 Stat. 310 (1987).

[12] Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, Order No. 380, 49 Fed. Reg. 22,778 (1984).

[13] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 50 Fed. Reg. 42,408 (1985), vacated and remanded, Associated Gas Distrib. v. FERC, 824 F.2d 981 (D.C. Cir. 1987), readopted on an interim basis, Order No. 500, 52 Fed. Reg. 30,334 (1987), remanded, American Gas Ass'n v. FERC, 888 F.2d 136 (D.C. Cir. 1989), readopted, Order No. 500-H, 54 Fed. Reg. 52,344 (1989), reh'g granted in part and denied in part, Order No. 500-I, 55 Fed. Reg. 6605 (1990), aff'd in part and remanded in part, American Gas Ass'n v. FERC, 912 F.2d 1496 (D.C. Cir. 1990), cert. denied, 111 S.Ct. 957 (1991).

[14] Regulation of Natural Gas Pipelines After Wellhead Decontrol Order No. 500; Interim Rule and Statement of Policy, 52 Fed. Reg. 30,334 (1987).

[15] Ceiling Prices; Old Gas Pricing Structure Order No. 451, 51 Fed. Reg. 22168 (1986).

Congress deregulated the last vestiges of "old" gas and placed it on equal footing with new gas when it passed the Wellhead Decontrol Act[16] of 1989. This legislation provided for complete deregulation of wellhead prices by January 1, 1993. Congress "determined that gas sales at the wellhead, or in the field, are sufficiently competitive to justify decontrol of all first sales of gas supplies."[17] In addition, the related House Committee Report urged the FERC "to retain and <u>improve</u> this competitive structure in order to maximize the benefits of decontrol."[18]

In following through on this legislative mandate, FERC realized that the transportation service offered by interstate pipelines was inferior in nature to the transportation service embedded in the pipelines' sales service and proposed the MegaNOPR, which culminated in the issuance of Order Nos. 636 (April 8, 1992), 636-A (August 3, 1992), and 636-B (November 27, 1992).[19] In these orders, FERC required interstate natural gas pipelines to implement a number of significant changes to the structure of their services by the 1993-94 heating season. FERC indicated that the purpose of the required changes was to improve the access of gas buyers to a variety of gas sellers by requiring pipelines to provide transportation service equal in quality for all gas supplies, whether the customer purchases the gas from the pipeline or from another supplier. Following is a summary of the provisions contained in the Order No. 636 series:

- Pipelines must unbundle transportation from their sale of gas.

- Allows pipelines, upon compliance with other aspects of Order 636, to sell gas at market-based rates similar to the way unregulated companies sell gas. Historically, pipeline sales gas prices have been set to reflect the pipelines' actual gas costs. Pipeline gas sales will now be at negotiated prices, so pipelines can include a profit.

- Order 636-A requires pipelines to continue to sell gas to small customers (10,000 Mcf/day or less) under bundled cost-based sales rates for up to one year after the pipeline's compliance filing has been approved. Small customers are also entitled to receive unbundled transportation service under a one-part volumetric rate.

- Pipelines that currently make sales for resale are required to offer a new "no-notice" service. If customers choose this no-notice service option, they will be permitted to take gas above nomination levels (but still below contract demand levels). The offering of this service is

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[16] Pub. L. No. 101-60, 103 Stat. 157 (1989).

[17] FERC Order No. 636, III FERC Stats & Regs. ¶ 30,939 at 30,439 (1992) citing S. Rep. No. 39, 101st Cong., 1st Sess., at p. 3 (1989).

[18] H.R. Rep. No. 29, 101st Cong., 1st Sess., at p. 6 (1989) (emphasis added).

[19] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, III FERC Stats & Regs. ¶ 30,939 (April 8, 1992), <u>reh'g granted and denied in part and clarifying</u>, Order No. 636-A, III FERC Stats. & Regs. ¶ 30,950 (August 3, 1992), <u>order denying reh'g and clarifying</u>, Order No. 636-B, 61 FERC ¶ 61272 (November 27, 1992).

supposed to ensure that pipeline customers will continue to receive an adequate and reliable pipeline service to meet their needs for peak service.

- Pipelines must provide customers open access to storage on a contract basis.

- Pipelines are required to provide, on an equal quality basis, open-access transportation and storage services for all gas supplies whether purchased from the pipeline or another seller. Pipelines will be required to use electronic bulletin boards (EBBs) to provide all shippers with equal and timely access to information.

- Pregranted abandonment of short-term transportation (service contracted for one year or less) is established. A pipeline will have no obligation to serve customers at the end of a short-term transportation contract. Service under transportation contracts with a term of greater than one year may be abandoned only if the existing customer fails to exercise a right-of-first-refusal by declining to match the terms (price and duration) of an offer for the capacity by another potential customer.

- Downstream pipelines are authorized and required to assign firm capacity held on an upstream pipeline to any of its firm shippers who request the upstream capacity. (Any upstream firm capacity which is either not retained by the downstream pipeline or assigned to the downstream pipeline's shippers would be bought out and treated as a transition cost.)

- A new mechanism for reassigning pipeline capacity is established. Pipeline customers holding firm rights to capacity will be permitted to release unwanted capacity, on a temporary or permanent basis, to those desiring capacity. Release and reallocation of firm capacity is to take place through an auctioning process held on pipeline EBBs.

- Pipelines are required to use straight fixed variable (SFV) cost classification and rate design. Under SFV, all pipeline fixed costs are placed in demand charges and the commodity charge includes only variable costs. The FERC, in applying this aspect of the Order(s), is requiring mitigation of any cost shifts resulting from a pipeline's adoption of SFV, where costs to a particular customer are increased by 10% or more. The resulting rate increase and mitigation measures will be accomplished by phasing in the costs over a four-year period.

- Policies are established allowing pipelines recovery of 100% of transition costs prudently incurred by them in complying with Order 636. Transition cost recovery will be permitted only after the pipeline has been found to be in compliance with Order 636. Types of transition costs and the established recovery methods are: (1) Unrecovered balances in pipeline purchased gas accounts (Account 191) will be direct-billed to those sales customers served by pipelines prior to converting to market-based pricing for sales. (2) Gas supply realignment costs may be recovered through a demand surcharge on firm transportation. Order 636-A requires pipelines to allocate 10% of these costs to interruptible transportation services. (3) Stranded costs (costs associated with unneeded upstream transportation, etc.) and (4) New facility costs (e.g., additional telemetry and computerization of pipeline operations) will be reviewed and allocated in general rate cases to be filed by the pipelines.

Obviously, federal regulation and oversight has been greatly reduced. Upon implementation of Order 636, Missouri's nine LDCs[20] will have to choose from a menu of various pipeline services and be totally responsible for obtaining all of their gas supplies. Although FERC will continue to regulate the costs and rates associated with interstate pipeline storage and transportation services, the prices LDCs pay for gas supplies will not be reviewed or approved by FERC. With complete deregulation of wellhead prices being achieved on January 1, 1993, and the evolving FERC policies to allow customers to take advantage of wellhead competition, the Missouri Public Service Commission's (MoPSC or Commission) responsibility to ensure that the citizens of the State of Missouri are charged reasonable rates for reliable gas service becomes larger and more difficult.

B. State

For many years, the wholesale gas purchasing practices of LDCs have been quite extensively controlled through the choices and options made available to them by the interstate pipelines. The rates, terms and conditions under which interstate pipeline company services were offered to LDCs were regulated by the FERC.

Since Missouri was not a producing state and all the natural gas in interstate commerce fell under FERC's administrative control, federal review, approval and preemption played a significant role in the way LDCs' wholesale gas purchases were treated at the state level. The FERC reviewed the costs and conditions of service, performed prudence reviews and issued wholesale rates which the FERC declared as being "just and reasonable". In consideration of the aforementioned constraints, the MoPSC typically insured only that the FERC approved wholesale rate was passed on to the retail customers.

Since the pipelines' wholesale gas costs were officially tariffed (consequently making it very easy to verify the charges), the LDCs could identify and isolate the costs attributable to gas purchases from all other expenses. The ability to do this was crucial in demonstrating that no other costs would be affected by making changes to the wholesale gas costs. As time went along, LDCs adjusted for changes in wholesale gas costs through traditional rate case type filings until Laclede Gas Company (Laclede) requested and received permission for an automatic adjustment provision known as the Purchased Gas Adjustment (PGA) clause.

The PGA clause has been a part of Missouri LDCs tariffs since November 2, 1962 when the MoPSC approved the use of a PGA mechanism for Laclede.[21] In approving Laclede's PGA clause, the Commission noted that the fixing of wholesale gas rates was a matter over which the company and the Commission had virtually no control. It also found the PGA clause did not affect the rate of return of the

[20] Associated Natural Gas Company, A Division of Arkansas Western Gas Co., (Associated); Fidelity Natural Gas, Inc. (Fidelity); Greeley Gas Company, A Division of Atmos Energy Corporation, (Greeley); Western Resources, Inc., d/b/a Gas Service (Gas Service), which as a result of a sale on 2/1/94 became Missouri Gas Energy (MGE), a Division of Southern Union Company; Laclede Gas Company (Laclede); Missouri Public Service (MPS), a Division of Utilicorp United Inc.; St. Joseph Light & Power Company; Union Electric Company; and United Cities Gas Company.

[21] Re: Laclede Gas Co., 46 PUR 3d 277 (1962).

company because increases or decreases in wholesale costs were offset by corresponding increases or decreases in retail rates.

Although the Missouri Supreme Court held that the Commission had no statutory authority to approve a fuel adjustment clause (FAC) for use in the rate schedules of electric companies,[22] a challenge of the PGA clause has not been ajudicated and the use of PGA clauses by gas companies has continued.

A typical PGA clause outlines the items covered and the methods used in determining the amount of change (increase or decrease) which may occur as a result of a wholesale supplier's change in rates. It also contains provisions for the administration of refunds and an annual reconciliation of gas costs. This annual reconciliation is referred to in Missouri as the Actual Cost Adjustment (ACA). The purpose of the ACA is to insure that only wholesale gas costs are flowed through on a dollar for dollar basis.

The initial PGAs contained only references to specific tariffed wholesale costs (pegged to specific pipeline suppliers' rates and tariffs). In the late 1980s, changes brought a host of concerns regarding the appropriateness of automatic recovery mechanisms. These changes included: a movement toward the deregulation of wellhead gas pricing; the appearance of "open access" transportation options; and, a desire by the FERC for a more market driven interstate gas industry. The number of FERC regulated wholesale transactions was diminishing and the list of market based choices for LDCs was growing. Since the FERC was moving itself away from the regulatory arena, the MoPSC's reliance on FERC reviews and approvals could no longer be counted on to assure fair and reasonable rates.

These concerns of less FERC oversight and greater LDC freedom and opportunity in purchasing gas from unregulated sources caused MoPSC Staff to pose basic questions about the continued use of the existing recovery mechanisms in MoPSC Case Nos. GO-85-264[23], and GO-87-74[24]. Since those dockets, many significant changes and opportunities have developed, not the least of which is Order 636. This FERC initiative proposes to completely restructure the relationship between the LDCs and their suppliers. Additionally, regulatory responsibility of the state regulators in terms of the review of purchased gas costs is greatly increased.

Attachment 1 shows the major components reflected in the bill of a typical residential customer who uses 120 Mcf of natural gas annually. The components, including demand costs, gas costs, transportation costs, pipeline margin, storage costs and LDC margin and fuel loss are shown for three of the major LDCs regulated by the MoPSC. The two sets of tables show the shift in the federally regulated portion of the major cost components as a result of the changes in FERC policy. For example, before Order 436 open

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[22] In State ex rel. Util. Consumers Council of Missouri, Inc. v. P.S.C., 585 S.W.2d 41 (Mo. banc 1979), the Court found that utilization of a FAC was illegal because it permitted the Commission to consider one factor to the exclusion of all others in determining whether or not a rate and overall revenue level is to be changed.

[23] In the Matter of the Investigation of Developments in the Natural Gas Transportation Industry and Their Relevance to the Regulation of Natural Gas Corporations in Missouri.

[24] In the Matter of the Investigation of Alternatives to the Present Purchased Gas Adjustment Clause Mechanism for Regulated and Unregulated Wholesale Natural Gas Purchases.

access and the implementation of Order 636, the majority of Gas Service's sales rate (66.74%) has been regulated by FERC with the remaining 33.26% being actively regulated by the MoPSC. The second set of tables shows the shift to what is anticipated after the implementation of Order 636. It shows that 39.45% of Gas Service's total rate will no longer be regulated by FERC.

Of all the reasons cited earlier as rationale for having an automatic adjustment mechanism, the following will no longer be present: federal preemption arguments; approved specific wholesale gas prices; regulated wellhead prices; and a concentrated prior review of costs by FERC to meet the "just and reasonable" standard.

III.
ISSUES/ITEMS REQUIRING INVESTIGATION

The Commission has instructed the Gas Purchasing/Cost Recovery Project Team (Team) "to determine if MoPSC rules, regulations, practices, procedures, and/or the manner of regulating natural gas utilities need to be modified to reflect the changes which have occurred to effect more open markets in the natural gas industry, augmented by the issuance of FERC's Order Nos. 636, 636-A, and 636-B." The approved proposal for the project specifically charged the Team to: (1) study LDCs' gas supply purchasing practices with specific emphasis on reliability and cost; (2) review current PGA clauses, including ACA provisions and prudence reviews; (3) review the effects of industry changes on the LDCs' obligation to serve; and (4) address other areas as may be identified during the review process.

Obviously, a major focus of the Team has centered on evaluating the appropriateness of continued use of LDC PGA clauses. The Team's analysis and discussion regarding the recovery method for gas purchase costs is contained in Chapter IV. However, the Team has also identified several other issues the MoPSC will be facing in the future, no matter what action is ultimately taken in regard to the LDCs' PGA mechanisms. A discussion of these other issues confronting Missouri's LDCs and this Commission follows along with the Team's recommendations as to how these issues should be resolved.

A. LDC Obligation To Serve

1. LDC Service Structure

Attachment 2 summarizes the various types of services currently offered by Missouri LDCs.

Obviously, all Missouri LDCs offer firm sales service. Where there are large customers with alternate fuel capability, interruptible sales service is offered. To the extent any LDC has customers who are truly willing to be interrupted from system supply, the LDCs have provided and should be expected to continue to offer such service.

Once open access transportation became available on interstate pipelines, all Missouri LDCs (except Greeley, which is Missouri's smallest LDC) filed transportation service tariffs. In order to make the LDCs financially indifferent as to which service the end-use customer wanted, the rates for transportation services were initially set to provide the LDC with the same amount of margin as the sales rates.

As more customers become interested in firm transportation, it also becomes more important for LDC tariffs to be explicit as to what obligations the LDC and firm transport customer will have. A firm transportation customer should be required to either (1) subscribe to firm backup sales service or (2) agree that the LDC has no obligation to provide sales service to that customer's facilities.

Currently there are few if any capacity constraints on Missouri LDC distribution systems; therefore all transportation is firm in nature. To the extent capacity constraints do exist or develop on an LDC's system, the LDC should consider establishing an interruptible transportation service. As with interruptible sales service, only customers who are willing and able to be interrupted should be permitted to sign up for interruptible transportation service.

A number of LDCs offer backup sales service to their transportation customers. However, backup services are not always identified as separate services in LDC tariffs. Rather, some are merely provisions within the LDC's transportation tariffs. This type of service is needed by those end-use transportation customers, such as schools, nursing homes, and hospitals, which have no alternate fuel source and which must have reliable firm service. These "human needs" customers would need to have the LDC ready and able to serve them if their gas supply fails. It appears that some of these types of customers are speculating that service will not be curtailed and are, therefore, buying interruptible rather than firm service. It may be necessary to require "human needs" end users, who should be the last curtailed, to purchase firm backup service or to certify that they have a viable alternative and intend to use that alternative if needed. (Curtailment plans are discussed further in Section III. A. 5. of this report.)

As smaller, less sophisticated customers become interested in transportation service, the offering of backup service by the LDC and the taking of this service by these smaller customers will also be necessary. Even though it is difficult and expensive for the LDC to line up gas supplies to be available on short notice for only a few days out of the year, any costs associated with this backup service should be allocated to the customers using this service.

While some may wonder if LDCs should be required to unbundle transportation and storage services, like interstate pipelines are now being required to do, this doesnot seem to be a critical item for this Commission to consider at this time. This is because only one LDC, Laclede, has its own storage facilities. Since Laclede's load is extremely weather sensitive, the control and operation of that storage by Laclede is crucial to providing reliable service to its customers. Therefore, it currently doesnot appear operationally or administratively feasible to require Laclede to offer a separate contract storage service.

THE PROJECT TEAM RECOMMENDS:

1. *LDCs establish a backup sales service if they currently do not offer such a service.*

2. *LDC transportation tariffs clearly indicate that a transportation customer is required to either (1) subscribe to firm backup service or (2) agree the LDC has no obligation to provide sales service.*

2. Minimum Volume Eligibility Requirements For Transportation

The question of how large or small a customer needs to be in order to qualify for gas transportation on an LDC's system has always been a topic of discussion. In GO-85-264[25] it was generally agreed that LDCs would individually establish reasonable minimum volume eligibility requirements. Even though this was left to the individual LDC's discretion, most initially set their volumetric eligibility levels at or near 3,000 Mcf per month.

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[25] Case No. GO-85-264 Investigation of Developments in Natural Gas Transportation Industry and Relevance to Regulation

Because end-user transportation at the time was a new service, with neither the pipelines nor the LDCs having much experience (and the potential downstream transportation customers having even less), the best strategy seemed to be to limit the transporter group to a manageable number of the larger end-users. The belief was that as the national system began to adjust to transportation and as more experience was obtained, the eligibility requirements of customers could change based on the LDC's pipeline situation, experience and customer demand.

As familiarity in the system developed and circumstances changed, LDCs have been willing to modify their eligibility requirements. Refer to **Attachment 2** for current eligibility requirements.

Given the many changes and opportunities that came with open access, LDCs have had to make numerous decisions concerning the purchase and transportation of gas for their system supply. This LDC participation in the transportation market has allowed many of the smaller customers who were previously prevented from directly participating in the transportation market to indirectly benefit from the options and opportunities resulting from open access. Many customers continue to rely on the LDC to buy and arrange their gas deliveries, since the LDC is equipped to do so and since this arrangement keeps the customer from having to deal with the administrative burdens associated with lining up one's own gas supplies.

Even though transportation and sales services were initially priced in a manner so as to make the LDC financially indifferent as to which service the end-user chose, it now seems important for the rates and charges for transportation services to signal to the end-user the true cost of the service being provided. With the implementation of Order 636, most end-use transporters will have to have electronic gas metering (EGM) with associated communications equipment. While EGM and other associated costs will presently prohibit many smaller customers from transporting, EGM capabilities will no doubt become more sophisticated and possibly less costly in the future. Therefore transportation may become more economically feasible for smaller customers.

Some may argue that volumetric eligibility requirements should be reduced and mandated on an industry-wide basis. Since LDCs have in the past willingly adjusted these volumes and requirements and dealt with other transportation problems creatively, it is expected this attitude will continue into the future. Questions concerning such things as conjunctive billing[26] provisions will continue to be raised. However, LDCs are in the best position to evaluate the needs of their customers and propose adjustments to the service they provide when circumstances require; therefore, there is no need to establish uniform eligibility requirements among Missouri LDCs.

3. Transportation Customers Wishing To Return To LDC System Supply

LDCs are not the only customers who have greater flexibility under the variety of services being

[26] Conjunctive billing is where the LDC is willing to combine a number of different delivery points and consider them as one for billing purposes. For example, a school district may want to transport gas and have it delivered to its various facilities. While monthly deliveries at each of those points may be too small to meet the requirement for minimum transportation volumes, the school district could qualify if the LDC is willing to view the deliveries collectively.

offered by the pipelines. Large and not-so-large customers of LDCs will also have more options. One aspect of this new-found flexibility which needs to be addressed is to define the obligation an LDC has for supplying gas to an existing customer who currently chooses to transport, but may in the future want to return to LDC system supply. To require an LDC to serve this customer on demand is not equitable to the other LDC customers or the LDC.

In Case No. GO-85-264 the Commission approved a joint recommendation filed by the parties. Regarding the LDC's obligation to serve, the joint recommendation stated the following:

> Any customer switching to transportation service without reserving backup service should be required to assume the risk that sales service will be unavailable to it for purposes of replacing the transportation volumes. Under such circumstances the local distribution company should be relieved of its obligation to maintain or procure gas supplies on behalf of the transporting customer.

This appears to continue to be an appropriate statement with regard to the LDC's obligation to serve. In fact, an LDC's firm transportation tariff should clearly state this.

In general, there are three reasons a transport customer would be using system supply gas: (1) for routine load balancing, i.e. the customer takes delivery of more gas than was dropped at the LDC's city gate, (2) the customer wishes to take the LDC's sales gas when it costs less than the price the customer can get elsewhere, or (3) the customer's supply fails and it still needs to take delivery of gas.

Following are several methods to limit the exposure of the LDC's system supply to unreasonable transport customer demands without unduly restricting open access competition.

Clearly defined and limited balancing provisions should be instituted to keep the transportation customer in balance. An imbalance occurs anytime there is a difference between what the customer uses during a month and the transportation gas the LDC receives for the customer's account at the city-gate. If the customer uses more gas than the gas received by the LDC, a "negative imbalance" is created. This negative imbalance has traditionally (though there are exceptions) been resolved by selling the customer system supply gas in the amount of the excess gas consumed. If the customer used less gas than the gas received by the LDC, a "positive imbalance" is created. This positive imbalance has not been consistently treated by Missouri LDC's. In some situations the LDC would simply carry the imbalance for the customer and attempt to require the customer to keep the imbalance at a low level. In other cases the LDC might levy a storage charge to recognize that the customer was in essence "leaving gas on the system".

A key factor in this whole discussion is how the interstate pipeline treats the end-use customer behind the LDC's city gate. If the interstate pipeline allows intra-month nomination changes to give its customers the flexibility to meet unexpected demand fluctuations or offers balancing services, then the customer has an effective tool for keeping imbalances on the LDC system to a minimum.

A possible solution is to require the customer to "cash-out" any overages or underages between the amount used and the amount transported. A "cash-out" system works by requiring the customer to pay for any use greater than the transportation gas received by the LDC and requiring the LDC to pay the customer for any gas left on the system that is greater than the customer's actual use. The rates applicable to such transactions should be set at levels, possibly increasing as the variances get larger, so differences between receipts and deliveries are discouraged.

A transportation customer should not be permitted to access the LDC's system supply gas on a daily basis merely because the LDC's rate on any given day is lower than what the customer can get elsewhere. There are several different ways to discourage this type of behavior.

First, as noted previously, graduated charges for negative imbalances should penalize transport customers when the imbalances result from something other than mere load balancing and represent "unauthorized" takes by the customer.

Second, the LDC may want to establish a short term sales service with a spot market type price where "price shopping" customers would be allowed to swing on and off on a monthly basis. If such a service were offered by the LDC, gas supply costs associated with it would need to be accounted for separate from system supply gas costs. (This is similar to the noncore market portfolio California has required its LDCs to offer.) Since there are currently a number of marketers willing to provide this type of service, it is not something which needs to be mandated by this Commission.[27]

Circumstances may be such that a transportation customer (one who has chosen to not subscribe to firm backup service) wishes to return to system supply. In this situation, the LDC should be entitled to receive up to a full year's notice before a transport customer can return to system supply. This gives the LDC a reasonable amount of time to realign its gas supply portfolio and obtain the necessary pipeline capacity. If the LDC is able to acquire additional supply for the customer in less time, the LDC may require an upfront reimbursement of fixed reservation or demand charges. An example of this arrangement can currently be found in Laclede's tariffs, where the customer pays the company 12 months' worth of pipeline demand and gas cost charges which would have been applicable to the customer had the customer been a firm backup customer.

LDC tariffs for transportation and backup services must contain provisions which allow transport customers reasonable flexibility yet preclude the taking of system supply gas without notice and proper payment.

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[27] During the June 1994 workshop, several LDCs discussed the possibility of selling excess or available supply at market prices to on-system or off-system customers. While the Team recognizes that this type of program may have some merit, it also believes such a proposal would need to be carefully structured so that it does not operate at the expense of captive customers. If an LDC believes it should offer this type of service, it seems entirely appropriate for the LDC to present for Commission consideration, proposed tariffs to implement such a service.

If a transporter cannot effectively operate under such conditions, back-up sales service should be made available. Such a service would allow the customer to still have a choice of suppliers, while enabling the customer to rely on the LDC as a safety net.

THE PROJECT TEAM RECOMMENDS:

3. *Clearly defined and limited balancing provisions be instituted to keep transportation customers in balance.*

4. *A waiting period with a notice requirement be instituted for a transportation customer to return to system supply, and/or the LDC be allowed to pre-condition the approval of the return of the customer to firm status upon the LDC's ability to obtain sufficient gas supplies and pipeline capacity.*

5. *An LDC be allowed to require up to 12 months' worth of fixed reservation or demand charges and notice before a transporter can become a firm backup customer. The required payment of demand charges would represent the charges which would have been applicable had the customer been a firm backup customer all along.*

4. Bypass And Discounting

With the changes and developments in the energy industry (oil and natural gas) over the past 15 years, large industrial and commercial customers with alternate fuel capabilities have been able to benefit greatly. These customers no longer have to rely upon the gas provided by the LDC or the pipeline. These customers have a variety of supply alternatives and have generally demonstrated a willingness to exercise those alternatives when it was to their economic benefit.

These alternatives have forced pipelines and LDCs to reevaluate the way in which they price their products to customers with fuel switching capabilities. Since LDC rates are based on embedded costs and are developed from averages, larger customers with alternative fuel capabilities and with load factors significantly better than the system load factor on which they are served, are looking for the best deal they can get at any time.

For those customers which float between the best deals on a monthly basis, it is important the LDC be able to serve as much of these customers' load as possible. A fixed rate makes it difficult for the LDC to compete, since it allows the LDC little flexibility to cope with changing prices and circumstances. Consequently, giving the LDC the ability to discount on its margin allows the LDC to continue to keep the customer on its system instead of losing the customer (temporarily) to oil, propane or some other fuel. **Attachment 2** reflects which LDCs currently have flex rate tariff provisions.

To the extent an LDC discounts, it has been the philosophy of the MoPSC Staff to have the LDC absorb the discounted margin amount until the issue can be debated in a rate case proceeding. The thought here is that the utility is the only entity which knows exactly what the situation is and since it is making the decision at the moment, it should be held at risk. Certainly, if the basic rate set by the MoPSC is high enough to cause the LDC to continually discount in order to retain the customer, the basic rate needs to be corrected. Also, just because an LDC discounts and absorbs the discounted amount does not necessarily mean that it would not have an opportunity in the future to have the situation rectified. It is in everyone's best interest to treat all customers fairly and encourage efficient utilization of the system.

In those instances where these larger end-users are close to transmission lines or where there is a corporate commitment to bypass the LDC and connect to a nearby pipeline directly, a slightly different approach has been suggested. This involves the use of special contracts with these customers. Special contracts are beneficial in that they are tailored to the specific circumstances of the customer and allow the LDC to develop a cost effective rate in continuing to provide service. This allows the customer to stay in the service area and use the system of the LDC and contribute to the overall revenues of the LDC.

It should be noted that when large customers make the decision to bypass an LDC, any obligation for the LDC to provide service is removed as well. A utility's obligation to serve continues as long as there is a reciprocal obligation on the customer's part to use the system. The ultimate decision to bypass is with the customer, however when a customer evaluates the feasibility of bypass, that customer must realize that the rates paid to the LDC do not include only the cost of the pipe network and some meter reading and billing expense. The customer must realize that the cost of maintaining, repairing, and monitoring the safe operation of the line is also included as well, along with the responsibility to do whatever is necessary to protect the public from the uncontrolled release of natural gas.

Bypassing customers certainly have the right to find the best price and service for their facilities, but they do not have the right to expose the general public to danger in the process of taking advantage of the economics of the situation. Since these customers will be operating their facilities at significantly greater elevated pressures than LDCs, it would be reasonable to hold them to the same level of responsibility as LDCs. A customer which considers bypass needs to understand that public safety is critically important and that the bypass operator must operate and maintain the facilities in a manner consistent with existing pipeline safety rules and regulations. Therefore, federal and state pipeline safety agencies need to be notified of the pending bypass construction. This allows the safety staffs to initiate contacts with the direct operator in order to make sure that all pipeline safety procedures are followed and that the line is operated in a safe manner.

The decision to bypass or stay on an LDC's system is one which sophisticated customers clearly must make on their own. In addition to continuing the use of discounting and special contracts, LDCs should be encouraged to develop economic alternatives for keeping these types of customers on their systems. The Team's comments and recommendations related to bypass should not be construed as an endorsement of bypass activities or as an indication of Staff's position regarding the legality or propriety of any particular bypass arrangement.

THE PROJECT TEAM RECOMMENDS:

6. *The MoPSC seek the legislation necessary to ensure compliance with pipeline safety requirements by customers constructing and maintaining lines directly connected to pipelines.*

7. *The MoPSC continue its current discounting/special contract policies while encouraging LDCs to be creative in developing and offering economic alternatives to sophisticated customers who have legitimate alternatives for LDC services.*

5. Contingency And Curtailment Plans

Currently there are a variety of individual LDC tariff provisions outlining curtailment procedures. (See **Attachment 2**.) The variations range from LDC tariffs containing no mention of a curtailment plan to somewhat specific curtailment plan tariffs with provisions for exemptions to those plans in customer emergencies. Some tariffed LDC curtailment plans apply to only supply deficiencies while others are very general and could be interpreted to apply to both capacity and supply curtailments. Many are overly broad and general; many are patterned after old style curtailment plans from the late 1970s; and, most do not acknowledge or deal with the curtailment of transportation customers.

Several of the more detailed LDC curtailment plans identify various service priorities similar to the NGPA Title IV end use categories used by interstate pipelines.[28] Uses identified as nonessential would be the first services eliminated, while customers needing service to protect human life and other basic needs would be the last to have service curtailed in an emergency. However, FERC has consistently held that Title IV applies to only supply curtailments and not to capacity curtailments.[29]

Although the NGPA is not directly applicable to LDC deliveries, it is expected that questions and arguments about whether curtailment plans should apply to capacity as well as supply curtailments will also be raised here at the state level. With little or no pipeline sales gas being carried by interstate pipelines, the end use service priorities which have been used at the pipeline level will have very little, if any impact on the rationing of gas supplies. It is conceivable that in the event of extreme weather conditions where various wellhead supplies may be unavailable, that the gas supply an industrial customer has lined up may be available while a portion of the LDC's system supply may not get delivered to the city gate. The question is, if an LDC's system supply is not sufficient to meet system demands, can the LDC "temporarily divert" a transporting customer's gas being delivered to the city gate?

The Team believes it is important for an LDC to have a contingency plan for such emergencies. This would be a critical element of an LDC's gas supply plan. The contingency plan would outline the method by which the LDC would obtain gas supply coverage in times of emergencies. This may or may not involve separate contracts for emergency supplies with some of its end users or other firm shippers on the LDC's upstream pipeline(s).

An LDC's curtailment plan would be activated only as a last resort. As part of the preparation (and annual review) of its curtailment plan, an LDC should document and determine the minimum levels of service its various customers need to protect human life, protect plant

[28] See 18 CFR Part 281.

[29] See curtailment discussion in Order No. 636-A at pp. 30,586-30,593.

facilities, and maintain basic needs services. This includes obtaining information regarding the absolute minimum service levels needed by its industrial and large commercial sales and transportation customers.

Curtailment plans for both supply and capacity shortage situations should be prepared in advance and reflected in an LDC's tariff. Curtailment tariffs should set out with some degree of specificity which customers will be curtailed and the sequence and circumstance of their curtailment. This is extremely critical since some customers which would have been curtailed previously during an emergency may have enhanced their position through transportation arrangements and now view their circumstances differently than when they were served on a sales basis by the LDC. An LDC's curtailment plan should factor in transportation customers and clearly spell out what will happen, to whom and when. Not only is this type of knowledge important to the LDC and its sales customers but to the customers transporting on the LDC's system as well. An LDC's tariff should also contain emergency exemption provisions which explicitly state the circumstances under which an LDC transport customer may temporarily use LDC system supply gas and under which the LDC may temporarily divert transport customer gas.

THE PROJECT TEAM RECOMMENDS:

8. *Each LDC develop, as part of its annual gas purchasing plan, contingent supply arrangements.*

9. *Each LDC prepare formal curtailment plans for both supply and capacity shortage situations, review these plans annually, and update them as circumstances warrant. As part of this process, the LDC should document and determine the minimum service levels needed by its various customers.*

10. *Each LDC review and update by September 15, 1994, its existing tariffs to reflect its current curtailment plans and any emergency exemption provisions it intends to include. If an LDC believes no update to its current tariff is necessary, it should submit a letter to the Commission by September 15, 1994, stating this to be the case.*

11. *Emergency exemption tariff provisions explicitly state the circumstances under which transport customers and LDCs may temporarily divert gas from one another.*

B. LDC Rate Design For Purchased Gas Costs

Purchased gas costs include both the LDC's gas supply portfolio as well as its pipeline service portfolio. In the past, purchased gas costs have been a straightforward application of FERC tariffs. These tariffs had demand and commodity components, and rate design amounted to a determination of which classes of service were responsible for each. With open access, rate design was complicated somewhat by having to determine how transportation customers fit into these cost allocations, but this did not require a major overhaul of the existing PGA rate structure. With the advent of Order 636, there are major changes related to both gas supply costs and pipeline services costs. Class cost responsibility is becoming much more complicated, requiring major changes in the design of rates for purchased gas costs. Understanding the basic structure of both elements of purchased gas costs, as well as their interrelationship, is essential to understanding the determination of class responsibility for purchased gas costs .

Gas supply costs are more complex.

Prior to Order 636, gas supply costs were included almost exclusively in the commodity portion of the FERC rate. Upon implementation of Order 636, LDCs will contract for their own gas supplies. Their portfolios will include gas purchases of varying degrees of firmness and swing. LDCs may have contracts for the same amount of gas day in and day out, i.e., base load gas. During the non-winter period, a portion of base load gas may be injected into storage for use during the winter peaking season. There may be contracts for gas supply that can go from no takes to full takes on short notice, i.e., swing load gas. The LDC may also arrange for gas supplies that have high variable costs (e.g., propane injection or special peaking contracts) which are only used to meet the additional loads occurring on extremely cold days, i.e., peak load gas. Each of these gas supply options will have varying forms and levels of fixed and variable costs.

While gas supplies will be purchased to meet system loads, it is clear that simplistic allocation formulas (such as fixed costs allocated on class contribution to peak and variable costs allocated on class contribution to annual volumes) are not likely to be reflective of the factors which go into the overall LDC strategy for gas supply mix (contracts for base, swing, storage and peaking gas). As is currently the case for electric rate design, the greater number of supply options, the more complex the gas supply acquisition strategy becomes and the more likely that rate design for gas supply costs will be subject to a variety of positions on cost allocation.

Pipeline service costs are more involved.

Prior to Order 636, pipeline service costs were bundled in either the demand or commodity portion of the FERC rate. Now an LDC will contract for and be charged for each of the various pipeline transportation and storage services it uses. The major change occurs in that the LDC must plan for the level of basic pipeline transmission capacity which is available every day of the year on a firm basis, as well as the amount and type of storage it will need.

There will be a direct relationship between the LDC's demand level for base load gas and the amount of basic pipeline transmission capacity it will need. While it is somewhat of an oversimplification, the LDC will target for a constant level of day-to-day usage of its basic pipeline transmission capacity. When demand is below that level, the transmission capacity can be used to transport gas for injection into downstream storage. If demand is above that level, the full level of capacity will be used to meet a portion of that demand, while the remainder of the demand will be met from storage and peak shaving sources.

Pipeline storage services can also be quite complicated. For example, on the Panhandle system, the LDC can contract for winter storage which is located in both the field and market areas, peaking storage which is located only in the market area, and in/out (balancing) storage. All three types of storage require annual fixed payments for deliverability and capacity, as well as variable payments for injections and withdrawals.

Both winter and peaking storage require transmission line capacity to ship the gas from storage to the city gate. Peaking storage on Panhandle is located in Michigan. During the non-winter period, gas is shipped from the field to the city gate via the LDC's basic transportation contract, but additional pipeline transmission capacity is used to ship from the city gate to the storage field. Then, in the winter season, that same pipeline transmission capacity is required to ship from the storage field back to the city gate. For winter storage in the field area, the LDC must pay a field zone transmission charge during the non-winter period, and a market area transmission charge to ship the gas to the city gate during the winter period.

Gas supply and pipeline services are interrelated.

In order to meet system demand requirements, the LDC must have both gas supply and deliverability of that supply integrated into a total system that will be able to meet customer demands on a reliable basis. Since system requirements are a function of weather, they are subject to a great deal of uncertainty on a day-to-day basis. Reliable supply and deliverability is not solely a function of being able to meet peak day demands. For example, while the LDC may have planned for enough pipeline transmission capacity and storage deliverability to meet its forecast of peak day requirements, an extended period of very cold weather can reduce its storage capacity to a level where there is no gas left in storage to deliver. From an overall cost standpoint, if the LDC contracts for enough storage capacity to meet a worst possible winter scenario, it will almost always be left with excess gas in storage at the end of the winter, thereby incurring not only high capacity costs for storage, but also high carrying charges for gas inventory.

Propane injection or peak shaving sources can be used not only to help meet peak day requirements, but also by using these sources on non-peak days, excess storage capacity and inventories can be reduced. Thus, the LDC must carefully design its integrated system of gas supply and pipeline services with its local storage and propane mixing facilities.

Allocating integrated system costs is difficult.

Prior to open access transportation, the FERC had used various formulas for rate design which were aimed at an equitable split of fixed pipeline cost between the demand and commodity components of the rate. In Missouri, rate design was simply a matter of determining which of these components should be allocated between firm and interruptible service customers. Since interruptible customers can be interrupted during peak periods, in theory the LDCs were able to reduce the amount of their reservation demands by the same levels. Thus, interruptible customers were not allocated any of the demand component of pipeline costs.

With the advent of open access, Missouri LDC transportation and sales services were priced so as to make the LDC financially indifferent as to which service the end user chose. Many of the LDC's large customers chose to transport gas rather than to purchase that gas from the LDC. This raised the difficult question of whether or not the LDC still had a service obligation to those customers if and when they decided to return as LDC sales customers. This service obligation had an effect on the allocation of gas supply and pipeline service costs. If the customer had the option to return, then the LDC would not be able to reduce its demands; therefore, the fixed costs associated with maintaining firm gas supply for those customers needed to be reflected in their rates.

While these simple allocation schemes worked well under a bundled pipeline rate, they are no longer valid with unbundled gas supply and pipeline services. While the question of cost responsibility remains the same, the answer is much more complex. With an LDC acquiring assorted pipeline services and varying types of gas supplies, there needs to be a thorough review and understanding of the costs associated with these activities; so the rates and charges for each of the LDC's services are representative of the costs associated with providing each service. Such a review would involve answering questions, like: If interruption only occurs on peak days when there are deliverability restrictions, to what extent does this allow the LDC to reduce its storage costs? Moreover, storage has both a deliverability and capacity component, and customers who are interrupted only because of peak day deliverability will certainly benefit from storage capacity on non-peak winter days. And while it is normally assumed that customers are interrupted whenever propane is being injected, is that assumption still valid if these injections are used to reduce storage capacity and inventory carrying costs?

This leads to a broadening of the scope of what constitutes an integrated system. For example, should LDCs offer various levels of interruptibility based on the avoided costs for gas supply, pipeline services and local facilities? How do other load management and conservation programs affect the total costs, and should the LDCs offer such programs when the cost of the program is less than the avoided supply-side costs?

It may prove that all interests can come to agreement on how to design rates under the new world of Order 636, but the Commission cannot and should not depend on that happening. This new world will be a quantum more complex than the "old" one of pipeline merchants with FERC approved bundled rates. It will even be more complicated than the "recent" world of open access because of the move from simply buying cheaper spot market gas to putting together an integrated plan for reliably meeting customer needs.

It is possible to get by in the near term with "definitional changes" or "fix ups" to existing rate designs. However, the Commission has an obligation to ensure that rates are based as closely as possible on the cost to serve customers while maintaining equity. As part of a PGA rate design review, an analysis of each gas supply and pipeline service cost component needs to be done to determine which classes of sales and transportation customers benefit from these costs. Since the kinds of costs and service situations differ among LDCs, these PGA rate design reviews need to be performed on an LDC-specific basis.

THE PROJECT TEAM RECOMMENDS:

12. *Rate design issues associated with an LDC's gas supply and pipeline service costs be thoroughly addressed in each LDC's next ACA or rate case.*

C. Treatment Of Order 636 Transition Costs[30]

FERC is allowing pipelines 100% recovery of transition costs prudently incurred by them in complying with Order 636. Arguably, this Commission is preempted from denying the recovery by an LDC of its payment of pipeline rates approved by the FERC. This conclusion was recognized by the Commission when it faced the issue of whether or not LDCs should absorb any of the Order 500/528 take-or-pay

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[30] The general categories of transition costs are: Account 191 costs, gas supply realignment (GSR) costs, stranded costs, and new facility costs. (Refer to Section II.A. p. 13 for a description of each of these.)

(TOP) costs.[31] The same conclusion appears to be applicable to the passthrough of Order 636 transition costs by LDCs.

Although 100% recovery of these costs by LDCs appears to take away any financial incentive for them to be vigilant in monitoring the prudence of pipeline gas supply realignment (GSR) costs, if an LDC is found to have been "negligently" apathetic in its oversight responsibilities, it seems entirely appropriate for the Commission to reduce accordingly the amount to be recovered by the LDC.

As with Order 500/528 costs, the MoPSC will be confronted with and does have the authority to decide how transition costs are to be allocated among LDC customers and how those costs will be charged. There is much similarity between what the FERC has characterized as transition costs and TOP costs. Most Missouri LDCs have tariff provisions which provide for a volumetric surcharge recovery of TOP from all classes of customers. In approving this recovery mechanism, the Commission indicated LDC transport customers as well as sales customers should bear these costs since they both shared in the responsibility for the incurrence of TOP and in the benefits coming from Order 436. This policy is just as pertinent for transition costs as it was for Order 500/528 costs. However, there are several factors associated with transition costs which make this policy more difficult to apply. These complications center around the facts that there is a wider variety of Order 636 transition costs, it is more difficult to ascertain which customers caused these costs, and it will be more confusing as to what extent LDC customers will have already paid some of these costs at the pipeline level.

FERC has clearly mandated how Account 191 and GSR costs are to be allocated among pipeline customers and the type of charge to be applied by the pipelines. These two types of transition costs are also the ones which LDCs, their customers and state commissions will encounter first.

Pipelines will be direct billing remaining Account 191 balances to its former firm sales customers. Since this is the same type of recovery mechanism as Order 500/528 costs, it is tempting to respond that the LDC's recovery should also mirror what has been done with TOP costs, i.e. volumetrically surcharge all LDC throughput. However, LDC transport customers will quickly point out that had the pipelines continued to be a merchant, the Account 191 (unrecovered gas costs) would have been charged to pipeline sales customers and accordingly would have been passed through to only an LDC's sales customers. (This same argument could also have been made about TOP costs.) So the "fix" for this kind of cost is not easy to determine.

GSR costs are by nature most like TOP costs. However FERC's recovery mechanism for GSR costs is unlike the TOP direct bill method. Ninety percent (90%) of GSR costs are being allocated to firm transportation customers and collected in the form of a demand surcharge. The remaining ten percent (10%) of the costs are to be allocated to interruptible transportation customers and will be built into the tariffed ITS rate, i.e. no separate surcharge will be evident. LDC transport customers will argue they have paid their share of GSR costs at the pipeline level and an LDC surcharge for GSR costs would in effect amount to a double charge for them. That may be true in some situations, but if the transporter has

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[31] Case No. GC-89-85 and No. GR-89-136 American-National Can Co., et al. v. Laclede Gas Co., Report and Order dated October 19, 1989; and Case No. GR-89-104 Missouri Public Service Co., Report and Order dated October 19, 1989.

received any kind of discounted pipeline rate it will be difficult to determine what, if any, GSR costs they have truly paid. Thus, the "fix" for GSR costs is also no simple matter.

In Order 636, FERC stated stranded costs were to be recovered by pipelines making Section 4 (rate case) type filings. However, FERC has not generically prescribed a specific recovery or allocation method for stranded costs. For now, FERC appears to be handling this on a case-by-case basis. The FERC has stated in several restructuring dockets that "stranded costs will become part of the cost of service used to design rates." In at least one instance FERC has also indicated that such costs may be allocated based on firm customers' maximum daily quantities. Nevertheless, it is still not clear whether these costs will end up being direct billed, surcharged, or buried in transportation rates. Accordingly, one cannot ascertain how much of these costs will be paid at the pipeline level by the LDC end use transporters. Therefore, at this time the Team makes no recommendations concerning the treatment of these costs at the state level.

New facility costs will appear as gas plant additions in pipeline rate cases. These would show up as depreciation costs and therefore be considered fixed costs. With FERC's mandated SFV cost allocation and rate design,[32] these costs would be paid primarily by the pipeline's firm transporters with limited contributions by interruptible shippers as they use the system. Therefore the Team believes these costs will be buried in pipeline transportation rates and therefore cannot be "allocated" by the Missouri Commission.

Also, various stipulations and agreements in individual pipeline rate cases may make the cost causation and cost responsibilities for transition costs at the pipeline level even more complicated. So to develop a solution to the knotty problem of allocations, it becomes necessary to step away from all of these complexities and come back to the general circumstances surrounding Order 636 transition costs.

Since all customers are to receive benefits from the implementation of Order 636, it is reasonable to expect all customers to pay their share of these transition costs. Therefore, it seems logical to segregate Account 191 and GSR costs and apply a volumetric surcharge to all LDC throughput for these costs. If, however, LDC shippers are able to show they have in fact paid "their fair share" of the costs at the pipeline level, the Commission should allow LDCs to make modifications to the volumetric surcharge policy. This should be reviewed on a case-by-case basis. If shippers believe the tailoring of the volumetric surcharge is inappropriate, this issue should be taken up in an LDC's next rate case or ACA proceeding.

THE PROJECT TEAM RECOMMENDS:

13. The Commission allow LDCs to recover Account 191 and GSR costs through the use of a volumetric surcharge on LDC throughput. However, an LDC should be allowed to allocate costs in such a way as to avoid double-charging the customers who may have already paid their fair share of costs at the pipeline level. The allocation of these costs is best reviewed as part of an LDC's next ACA or rate case.

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[32] Refer to Section II.A. p. 13 for an explanation of SFV.

D. Monitoring Of Supply Reliability

Having enough gas delivered to satisfy the needs of firm customers on the coldest winter day has always been the industry's single biggest mission. Low cost gas supplies are not a bargain if they are undeliverable or unavailable when needed the most. With so many customers depending greatly on natural gas in their daily lives, supply reliability is of paramount importance.

In the past, pipelines had the responsibility of securing and arranging for the delivery of adequate quantities of natural gas to satisfy the firm needs of their customers. In large part they did this by building relationships with many producers and by developing supply and delivery strategies. Now, this service will no longer be available in the traditional sense and LDCs will have the ultimate responsibility to acquire reliable supplies for their customers.

In order for LDCs to succeed in this , they will need to have a good understanding of the national and regional supply situations, the many available delivery options and an understanding of the costs and the attendant risks associated with different supply options. They must also have good insight and understanding of what their customers want and when they will need it. Since individual LDCs will be smaller players in the purchasing field than their pipeline counterparts, knowledge of the marketplace will be more critical now than ever before to effectively participate and serve their customers.

Issues of price versus security/reliability, long term versus short term supplies, what percentage of the total supply to reasonably place on the spot market without jeopardizing the delivery needs of its customers are some of the central issues that will have to be dealt with. Before much can be done, however, a plan needs to be developed from which to operate. LDCs need to develop methods for evaluating and assessing reliability and the various factors involved.

LDCs do not have the luxury of relying on the pipelines' safety nets, the kindness of strangers, or pure luck to get them by. They must realize they are in a competitive business and need to buy smart and have a realistic strategy. Also, they must be able to implement this strategy in a flexible yet accountable way. To do this, a recovery mechanism or approach needs to be developed and implemented which works to encourage adequate supplies at reasonable and fair prices.

THE PROJECT TEAM RECOMMENDS:

14. *Each LDC develop and provide to the Commission its plan for long-term gas procurement strategies (and modifications to these strategies) for reliably meeting their supply responsibilities.*

15. *Each LDC also prepare and file with the Commission an annual purchasing plan which provides specific information as to how it intends to realistically and successfully achieve the goals contained in its strategies.*

16. *The Commission establish procedures for the review of the long-term gas procurement strategies and annual purchasing plans submitted by LDCs.*

E. Affiliate Transactions

The Team is aware that five of Missouri's nine LDCs have gas exploration, development, gathering, storage, and/or marketing affiliates.[33] Several Missouri LDCs have engaged in purchases of gas from affiliated companies and one LDC has purchased a significant portion of its gas supplies from an affiliate. With the increased LDC flexibility and responsibilities for gas supplies resulting from Order 636, the number and size of these kinds of transactions are likely to increase.

Affiliate transactions are always a concern to regulators, because transactions between regulated and unregulated affiliates may not be of an arms-length nature, and because the corporate enterprise has an incentive to maximize the profits of an unregulated activity at the expense of a regulated entity (cross-subsidization). It may do so by: (1) the unregulated entity charging the regulated one (the LDC) more for goods and services than the LDC would have to pay in the open market, or (2) the LDC selling, for example, released pipeline capacity or unneeded gas supplies to its affiliate at a bargain price subsidized by the LDC's customers.

Because of the susceptibility of these types of transactions to manipulation, the question arises as to whether the enhanced regulatory scrutiny which affiliated transactions necessitate should lead to special mechanisms being established for LDCs to report affiliated transactions. For example, an audit trail dealing with affiliated transactions should be created contemporaneously with those transactions. Also, an LDC might be required to report every month or every quarter the affiliated gas purchases that cumulatively exceed a preset dollar limit. Such special reporting will allow the purchased gas auditors to accumulate a data base concerning affiliated purchases in advance of an ACA audit or rate case, and would also allow the auditors to initiate an immediate investigation of such transactions if the circumstances warranted. In addition, rules could be established requiring LDCs to justify their decisions to purchase gas from affiliates through mandatory formal bidding procedures or other documentation requirements. This justification should include an LDC's documentation of the specific pricing terms and reliability analyses for the non-affiliated alternatives for gas purchases it relied upon to make the decision to utilize affiliated entities for gas purchases.

THE PROJECT TEAM RECOMMENDS:

17. *LDC annual reports identify any and all affiliate entities.*

18. *LDCs be required, as part of the minimum ACA filing requirements, to report any and all affiliate transactions associated with the acquisition of gas supplies or the selling of released capacity or unneeded gas supplies. Consideration should be given as to whether it is necessary to require quarterly reporting of affiliate transactions.*

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[33] Gas Service, Laclede, MPS, and United Cities provided the names of affiliated companies and the nature of those companies' business in their 1992 Annual Reports filed with the MoPSC. Although Associated's 1992 Annual Report (filed by its parent, Arkansas Western Gas Company) lacks this information, there are companies related to Associated which are involved in various natural gas activities.

19. *That as part of their gas supply plans, LDCs be explicitly required to fully justify their decisions to purchase affiliate gas.*

20. *LDCs initiate formal bidding procedures or other credible methods of documenting the selection process where transactions with affiliates are being considered.*

F. Use Of Derivatives[34] To Mitigate Price Risk

Organized futures markets for natural gas (trading in futures contracts as well as options on such contracts) provide several legitimate and viable risk management tools (hedging) to all participants in the industry (producers, marketers, pipelines, LDCs, and end users). There are important limits, however, to the degree and type of risk protection that can be obtained through the use of these tools. First, they can only insure against the risks associated with price volatility. Second, for the strategies that are likely to be most attractive to LDCs, the future time horizon over which such protection can be obtained is one year and under.[35] Third, the range of price variation over which certain kinds of "price insurance" is available at any point in time is limited (usually plus or minus $0.25/MMbtu from the previous day's closing price).

Like most kinds of insurance, the use of futures markets to avoid price risk is not cost-free. Whether LDCs will choose to incur the cost of an active hedging program will depend on how price risk is allocated between shareholders and ratepayers, and how hedging costs are treated in the ratemaking process. If price risks are borne primarily by ratepayers through the PGA, and hedging costs are treated inconsistently or excluded from recovery, the LDC will have a strong incentive not to hedge against price risk. Conversely, if the PGA were eliminated, or if gas costs eligible for recovery through the PGA were pegged to hedge positions that were available in the market, the LDC would have an extremely powerful incentive to engage in hedging.

An important question is whether legitimate hedging activities can be permitted and encouraged while irresponsible speculation is prevented. The answer is that it is possible, but it requires policies and procedures that are well designed, clearly documented, rigidly enforced, and regularly audited. The most fundamental determinant of what constitutes legitimate hedging is that the size, direction, and timing of market positions must be appropriately correlated with the ownership and movement of the physical commodity.

Direct participation in derivatives markets is not the only way that LDCs can obtain the price risk protection that these markets offer. Marketers who have the necessary expertise in derivatives can provide LDCs with supply arrangements that incorporate the benefits of these risk management strategies. Of course, the price of these brokered arrangements will reflect the costs of futures trading, as well as a

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[34] Derivatives are financial instruments/transactions used to manage risks in unstable markets. As used here they include both regulated (New York Mercantile Exchange - NYMEX) and unregulated (over-the-counter - OTC) instruments. Futures and options are exchange transactions while various forms of energy swaps, collars, etc., are off-exchange transactions.

[35] Currently, exchange instruments with up to 18 month terms can be traded, while off-exchange transactions can generally be put together to cover from 1-10 years.

return to the expertise and management supplied by the marketer. Nevertheless, this avenue may be less costly for some LDCs than developing an in-house hedging program.

Prudent management of the financial risk associated with gas price volatility is vital. Although direct participation by the LDC in futures markets is one way of managing price risk, it is not the only way, and may not be the best way for a particular utility. Consequently, the Commission should not require all LDCs to use futures markets to hedge against price risk.

THE PROJECT TEAM RECOMMENDS:

21. *Presentations and/or workshops about hedging tools be conducted to provide information to the Commission, Staff, LDCs, and other interested parties about this complex subject. At some point, if desired, these could be used as a forum for interested parties, including the Commission and Staff, to informally convey their positions regarding price risk management and the appropriate ratemaking treatment for hedging costs.*

G. Minimum Filing Requirements

Under its rules, the Commission has instituted mandatory minimum filing requirement (MFR) submissions by utilities associated with rate case filings. No formal MFRs have been set up in relation to the ACA audits.

Recently, several LDCs, including Western Resources and Missouri Public Service, have agreed to implement informal MFR submissions for ACA audits. MFRs of some sort for the ACA audits were needed (1) because of the need to obtain standardized data from each LDC at the beginning of the ACA audit, without waiting for responses to data requests; and (2) to ensure that data the auditors need would be presented in an easily understandable and comprehensive format. The Team believes these efforts should be expanded upon and extended to the remaining LDCs as soon as possible.

Generally, the Team believes it is appropriate for Staff to be provided information related to: (1) gas supply and pipeline service planning, forecasting, and contract evaluations, (2) capacity release, (3) price hedging, and (4) worksheets presenting a complete trail from an LDC's filed gas costs to underlying invoices. As a starting point for discussions concerning formal filing requirements in Missouri, the Team is including **Attachment 3** - Proposed Minimum Filing Requirements.

THE PROJECT TEAM RECOMMENDS:

22. *The Commission direct Staff, in cooperation with LDCs, to develop standard MFRs related to gas purchasing practices and the recovery of gas supply and pipeline service costs. In addition, the Commission should require Staff to report, within 120 days from the final issuance of this document, on the status of the MFR project and to indicate whether MoPSC rules should be amended to include MFRs in this area.*