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December 20, 2002

Dale Hardy Roberts
Secretary/Chief Regulatory Law Judge
Missouri Public Service Commission
200 Madison Street, Suite 100
P.O. Box 360
Jefferson City, Missouri 65102

RE: *Atmos Energy Corporation*
Case Nos. GR-2001-396 and GR-2001-397

Dear Mr. Roberts:

Enclosed for filing in the above-referenced matter is the Direct Testimony of John Hack being filed on behalf of Atmos Energy Corporation.

Thank you for your attention to this matter.

Sincerely,

James M. Fischer

James M. Fischer

/jr
Enclosures

cc: Doug Micheel, Office of the Public Counsel
Denny Frey, General Counsel's office

Exhibit No.: ____
Issue: Purchasing Practices and
Other ACA Issues
Witness: John Hack
Type of Exhibit: Direct Testimony
Sponsoring Party: Atmos Energy Corporation
Case Nos.: GR-2001-396/GR-2001-397
Date Testimony Prepared: December 23, 2002

DIRECT TESTIMONY

OF

JOHN HACK

ON BEHALF OF

ATMOS ENERGY CORPORATION

DECEMBER 23, 2002

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Atmos Energy Corporation's Purchased Gas Adjustment Factors to be Reviewed in Its 2000-2001 Actual Cost Adjustment.	))))	Case No. GR-2001-396
In the matter of United Cities Gas Company's Purchased Gas Adjustment Tariff Revisions to be Reviewed in Its 2000-2001 Actual Cost Adjustment.	))))	Case No. GR-2001-397

County of)
State of Texas)

AFFIDAVIT OF

JOHN HACK

John Hack, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying testimony entitled "Direct Testimony of John Hack"; that said testimony and schedules attached thereto was prepared by him and/or under his direction and supervision; that if inquiries were made as to the facts in said testimony and schedules, he would respond as therein set forth; and that the aforesaid testimony and schedules are true and correct to the best of his knowledge, information and belief.

ETHEL Z TAYLOR
Notary Public
State of Texas
My Commission Expires
August 13, 2006

John Hack
John Hack

Subscribed and sworn to before me this 19th day of December, 2002.

Ethel Z. Taylor
Notary Public

My Commission expires 8-13-2006

DIRECT TESTIMONY OF JOHN HACK

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Hack. My business address is Atmos Energy Corporation, Suite 160, Three Lincoln Center, 5430 LBJ Freeway, Dallas, Texas 75240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Atmos Energy Corporation as Director, Gas Supply Planning. In this proceeding, I am testifying on behalf of Atmos Energy Corporation ("Atmos" or "Company") Mid States division (formerly known as United Cities Gas Company), a division of Atmos Energy Corporation.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Arts Degree in Business Administration from Kentucky Wesleyan College. I have been employed by Atmos and its predecessor since 1969 and have held numerous positions both with Atmos and Atmos' Kentucky division. During the time at Atmos' Kentucky division (July 1969 through October 1990), I held positions of Gas Controller, Supervisor of Gas Control, Supervisor of Gas Control and Rates, Manager of Gas Rates, and Manager of Gas Supply Administration. Since transferring to Atmos, I have held the positions of Director of Gas Supply Kentucky, Director of Interstate Gas Supply, Director of

Gas Supply Operations and my current position as Director of Gas Supply Planning.

Q. PLEASE DESCRIBE THE NATURE OF YOUR DUTIES.

A. One of my principal duties is gas supply management for Atmos' Mid States division which includes the State of Missouri. I am responsible for all gas supply and system supply transportation arrangements involving the interstate and intrastate pipelines which deliver gas to the Mid States system. This includes pipeline capacity arrangements, gas supply acquisition planning, contract negotiations and day-to-day administration. I supervise five professional employees who assist me in assuring that Atmos' Mid States division is provided an economical and reliable supply of natural gas for its customers. These employees are comprised of a gas supply administrator and four gas supply analysts.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the recommendation filed by the Staff ("Staff") of the Missouri Public Service Commission ("Commission") in the Actual Cost Adjustment ("ACA") cases (Case No. GR-2001-396 and Case No. GR-2001-397) for Atmos' Mid States division for the 2000-2001 ACA period. Case No. GR-2001-396 involves the former service area of Associated Natural Gas Company and Case No. GR-2001-397 involves the Atmos service territory formerly served by Atmos under the name United Cities Gas Company. My testimony will demonstrate that: 1) the Purchasing Practices recommendation made by the Staff is unreasonable and should not be adopted by the Commission; and 2) other disputed items of the Staff's recommendations should be examined further.

Q. WHAT ACA PERIOD IS INVOLVED IN THIS PROCEEDING?

A. The ACA periods in this proceeding are September 1, 2000 to August 31, 2001 in Case No. GR 2001-396 and June 1, 2000 to May 31, 2001 in Case No. GR 2001-397. It therefore involves principally the winter season of 2000-2001.

DESCRIPTION OF SERVICE AREAS

Q. IDENTIFY THE SERVICE AREAS THAT ARE THE SUBJECT OF THESE CASES.

A. Case No. GR-2001-396 includes the service areas of Kirksville and Butler. In addition, the towns of Piedmont and Jackson, plus the Southeast Missouri Integrated system, comprise the "SEMO" rate division which is subject to this case.

Case No. GR-2001-397 includes the service areas in the cities of Hannibal/ Canton/Palmyra/ Bowling Green and Neeleyville.

Q. FURTHER DESCRIBE THE SYSTEMS INCLUDED IN GR-2001-396.

A. Until June 1, 2000, these systems were owned and operated by Associated Natural Gas (ANG). As a result of the acquisition of the ANG Missouri properties, Atmos Energy Corporation took over operations on that date. The various rate divisions are as follows.

- **The Kirksville system** is located in Schuyler, Adair, and Macon counties. There are over 5,800 customers in this service area, of which 4,960 are residential customers. The Company's load requirements are very heat sensitive due to the residential core customer base and, therefore, are very challenging to predict and manage on a daily basis. The ANR Pipeline provides supply to this area.
- **The Butler system** is located in Cass, Bates, Henry, and St. Clair counties. There are 3,700 customers on this system. The majority of the customers are also residential. Again, this area is very heat sensitive and is also difficult to predict and manage daily requirements. Panhandle Eastern is the pipeline serving this area.
- **SEMO Rate Division:**
  - **The Piedmont system** has 960 customers and is located in Wayne County.
  - **The Jackson system** is served by Natural Gas Pipeline and is scattered through Ripley, Stoddard, and Cape Girardeau counties. This area consists of 4,995 customers. Heat sensitivity is a challenge in these areas as well.

- **The Southeast Missouri Integrated system,** unlike the previously described typical service areas served by a single pipeline, is a much more complex system than those discussed above. Supply is delivered to this area by two pipelines, Texas Eastern Transmission Company (TETCO) and Arkansas Western Pipeline (AWP), an extension of Ozark Transmission Company (Ozark). Currently, Ozark Transmission Company has absorbed this section of pipeline (previously identified as AWP). The Southeast Missouri Integrated service area is also "integrated" with the system retained by ANG to serve the State of Arkansas.

The Southeast Missouri Integrated system consists of over 35,000 customers, of which 30,750 are residential customers. This service area's load requirements are very heat sensitive due to the residential core customer base and, therefore, are also very difficult to predict and manage on a daily basis.

The Texas Eastern storage (SS-1) is a unique storage service in relation to the Southeast Integrated system. The Ozark firm transportation (FT) and the Texas Eastern firm transportation (CDS- Comprehensive Delivery Service) are integrated and the SS-1 storage is a balancing tool for both pipelines. The three contracts necessary to operate the Southeast Missouri Integrated System at the time of acquisition from ANG on June 1, 2000 were bifurcated between ANG and Atmos.

The supply received from Ozark and TETCO are balanced daily with the Atmos system. In addition to Atmos' system supply for Missouri, transporters' gas is also received and then delivered to points within Missouri and/or at the southern Missouri state line in Dunklin or Pemiscot Counties. Nominations often do not equal actual volumes received and delivered. The TETCO storage is utilized daily to balance the Atmos system. Associated Natural Gas (ANG), a transporter on the Atmos system, also maintains a TETCO SS-1 contract for balancing purposes with this system. Nominations are made by Atmos' Gas Control Department to both TETCO storage contracts for the daily imbalances of both Atmos and ANG.

Q. FURTHER DESCRIBE THE SYSTEMS INCLUDED IN GR-2001-397.

A. **<u>Hannibal/Canton/Palmyra/Bowling Green System</u>** – This system is located near the Mississippi River in Northeast Missouri. The towns are located in Pike, Marion, Ralls and Lewis Counties. The system serves over 14,000 customers of which approximately 13,000 are residential customers. This system is served by Panhandle Eastern Pipeline. For Bowling Green, flowing supplies and IOS (In and Out Storage) are transported on a Firm SCT (Small Customer Transportation) contract. For the other towns, flowing supplies and three pipeline storage contracts are transported on three Firm EFT (Enhanced Firm Transportation) contracts.

<u>Neeleyville</u> – Atmos serves approximately 600 customers in the town of Neeleyville, MO. This service area is served by two interstate pipelines, Natural Gas Pipeline of America ("NGPL") and Texas Eastern Transmission ("TETCO").

Supplies delivered at NGPL are provided by Firm Transportation (FT) and Firm No-Notice Storage contracts. Supplies delivered at TETCO are provided under a one-part, Firm Small Customer Transport, inclusive of Storage service. This combination ensures both reliable and reasonably priced supply.

STAFF'S PROPOSED GAS PURCHASING RECOMMENDATIONS

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE RECOMMENDATIONS SUBMITTED BY THE STAFF REGARDING ATMOS' PURCHASING PRACTICES.

A. The Staff believes that it was reasonable to expect Atmos to hedge a minimum level of its natural gas purchases for the winter months of the ACA period. The Staff believes 30% of normal requirements, as a minimum level of hedging for each month during the period of November 2000 through March 2001, is reasonable and that financial hedges are appropriate vehicles.

Normal requirements are the amount of storage withdrawals and purchases the Company needs to make on a monthly basis in order to meet its demand based upon normal weather. A financial hedge is an instrument, usually a future or option contract that is traded on an exchange or an over the counter market, the price of which is directly dependent upon the value of the underlying commodity, in this case natural gas. By contrast, a fixed forward contract hedge is settled by the physical delivery of natural gas at an agreed, fixed price.

In addition, Staff asserts that Atmos did not prudently use its storage service during this ACA period. Staff believes that Atmos should have purchased less flowing gas in January, 2001 and alternatively utilized more storage withdrawals during January.

Q. PLEASE EXPLAIN MORE SPECIFICALLY YOUR UNDERSTANDING OF THE HEDGING STANDARD PROPOSED BY STAFF.

A. Based on my review of the Staff workpapers and my understanding of Staff's recommendation, the Staff's hedge recommendation contains the following elements:

(1) A minimum hedge volume (including storage and other hedging methods) equal to 30% of normal requirements.

(2) The use of financial hedges is presumed.

(3) Hedged volume purchases are layered in during the five months (June-October) preceding the winter season.

(4) Available hedge pricing for each winter month is based on a simple average of NYMEX (New York Mercantile Exchange) daily closing prices during the months the hedge purchases are made.

Q. DID YOU REVIEW ADDITIONAL INFORMATION FROM THE STAFF REGARDING THEIR PROPOSED ADJUSTMENTS?

A. Yes. **GR-2001-396:** With regard to the Southeast Missouri Integrated system, the Company has reviewed the workpapers provided by Staff and the Staff calculated an amount of $1,309,540 reduction to gas cost as a result of Atmos' decisions regarding flowing gas and storage withdrawals. Staff subsequently revised their worksheets reducing the disallowance to $1,149,451.

GR-2001-397: In regard to the Hannibal/Canton/Palmyra/Bowling Green system, the Company has reviewed the workpapers provided by Staff and the Staff calculated a $105,326 reduction to gas cost as a result of Atmos' variance from a detailed theoretical hedging program proposed by Staff. Another reduction of $454,763 was proposed by Staff as a result of Atmos' decisions regarding flowing gas and storage withdrawals. In addition, Staff proposes a reduction of $15,875 to gas cost for the Neeleyville District as a result of Atmos' variance from a Staff proposed hedging program.

Q. DO YOU AGREE WITH THE STAFF'S PROPOSED PURCHASING PRACTICES ADJUSTMENTS?

A. No. The Company strongly disagrees with the Staff's proposed disallowance on purchasing practices. Atmos' purchasing practices in this ACA period were consistent with the prevailing custom and practices used throughout the LDC industry at the time they were made. With regard to hedging activities, at the time that the Company made its purchasing decisions for the ACA period in this proceeding, LDC's throughout the United States relied principally upon contracts that were based on index pricing rather than financial instruments or other hedging techniques. This had been the historic approach throughout the industry and it was widely accepted by regulators. The Company also believes that its use of storage during the winter of 2000-2001 was prudent and reasonable.

Q. WHY IS THE PROPOSED STAFF DISALLOWNCE ON HEDGING INAPPROPRIATE AND UNREASONABLE?

A. The proposed hedging allowance is inappropriate because Staff has adopted a hedging prudence standard that is based on hindsight and ignores the information that was available at the time the decisions were made. The proposed disallowance is unreasonable because Staff has failed to adequately consider the information available to the Company at the time Staff would have had the Company establish a hedging program. In addition, the proposed Neelyville hedging disallowance is unreasonable because Staff fails to adequately consider the physical and administrative difficulties involved in hedging for a very small load. Further, the Staff has never proposed a disallowance of this nature on any past ACA review involving these systems and it is unreasonable to propose it based solely on hindsight in such an unusual year.

Q. DURING THE WINTER OF 2000-2001, DID ANYTHING UNUSUAL OR EXTRAORDINARY OCCUR WITH REGARD TO NATURAL GAS PRICES?

A. Absolutely. During the winter of 2000-2001, natural gas wholesale prices skyrocketed to unprecedented levels. The wellhead price of natural gas had been relatively low with an average of around $2/Mcf since this price was deregulated in the 1980s. The commodity price of natural gas began to rise above historic highs in the summer of 2000 when it went above $4/Mcf in June, $5/Mcf in September, and then in November it went over $6/Mcf. At the end of 2000, after two months of extraordinarily cold weather and continued reports of extreme storage withdrawals, the commodity price of natural gas spiked to near $10/Mcf in late December. (Schedule No. JH-1—Final Report of the Missouri Public Service Commission's Natural Gas Commodity Price Task Force, pp. 63-70)("Task Force Report"). As explained in the Commission's Task Force Report, "[t]he increase in commodity cost was due to a number of factors but the primary factor was the record cold in November and December 2000 that affected most of the states east of the Rockies. This record cold occurred when the commodity price had already eclipsed $5/Mcf and led to the first sustained increase in space heating demand for natural gas nationally in five years. This increased demand caused nine weeks of sustained or increasing commodity prices from $4.50/Mcf the last week in October 2000 to $9.98/Mcf the last week of December 2000." (Schedule No. 1, p. 70)

Q. DID ATMOS HAVE ANY REASON TO BELIEVE THAT THE NATURAL GAS PRICES WOULD SKYROCKET TO RECORD LEVELS DURING THE WINTER OF 2000-2001?

A. No. Until the winter of 2000-2001, there had been relatively little volatility in the natural gas commodity markets. As I have already explained, in the winter of 2000-2001, natural gas prices for the first time exhibited a much greater degree of volatility. Based upon the information that was available at the time the purchasing decisions were being made for the winter of 2000-2001, there was no reason to expect that extraordinary measures needed to be taken to protect the Company's customers from price volatility. Unfortunately, as explained earlier, the market prices for natural gas continued to exhibit price volatility throughout the winter of 2000-2001. This volatility was not anticipated by the Company or the rest of the natural gas industry, prior to the winter heating season of 2000-2001. (Ironically, during the Winter of 2001-2002 when considerably more hedging has occurred throughout the LDC industry, natural gas prices returned to more historical levels.)

Q. PRIOR TO THE WINTER OF 2000-2001, WHAT WAS YOUR UNDERSTANDING OF THE MISSOURI PUBLIC SERVICE COMMISSION'S STANDARD REGARDING HEDGING?

A. Before the winter of 2000-2001, I am not aware that any Commission standard or other policy statement existed that indicated an expected or required hedging percentage or specific storage utilization guidelines for regulated local distribution companies in Missouri.

Q. PRIOR TO THE WINTER OF 2000-2001, DID THE STAFF SPECIFY FOR THE UPCOMING WINTER THAT ATMOS SHOULD HEDGE THIRTY PERCENT (30%) OF ITS LOAD DURING THIS ACA PERIOD?

A. No. Sometime during the Fall of 2000, I discussed the wisdom of hedging supply with David Sommerer of the Staff in a brief telephone call. He suggested that the various LDCs might consider locking in prices for the upcoming winter.

There was no discussion of a specific hedging standard to be used by LDCs in Missouri during this conversation, nor at any other time, prior to the 2000-2001 winter. In addition, it is my understanding that the Staff refused to "pre-approve" any specific level of hedging when requested to do so by larger LDCs in Missouri.

The Staff certainly did not inform Atmos personnel that they believed that it was imprudent if the Company did not hedge thirty percent (30%) of its Missouri requirements. In fact, until the Company received the Staff's recommendation in these cases, the Company was not aware of what level of hedging, if any, the Staff believed to be appropriate or otherwise prudent for these service areas.

It appears that Staff's recommendation in this case calls for hedging of 30% of normal requirements. Atmos believes that this recommendation was developed after the winter of 2000-2001 had concluded, without specific knowledge of the pricing and weather data available to Atmos at the time it made its purchasing decisions. Unfortunately, Atmos believes that the Staff's approach in this case is result oriented, or at the very least is based soley upon hindsight considerations.

Q. DO YOU HAVE INFORMATION REGARDING THE HEDGING POLICIES OF OTHER STATE COMMISSIONS?

A. The National Association of Regulatory Utility Commissioners (NARUC), in a survey conducted during the summer of 2001, asked state PUCs how they responded to the high gas prices during the winter of 2000-2001 and whether hedging and other gas utility risk-management activities had been or will be considered. The responses (which came from twenty-eight states) indicated that most states allow, but do not require, the use of hedging with financial instruments by gas utilities. (See Schedule No. JH-2).

Q. WHAT HAVE YOU CONCLUDED REGARDING THE "HEDGING STANDARD" THAT WAS IN EFFECT IN MISSOURI AND MOST OTHER STATES PRIOR TO THE WINTER OF 2000-2001?

A. I have concluded that Missouri, like the vast majority of other states, did not have a specific hedging standard that had been clearly articulated by the Commission or its Staff, prior to the winter of 2000-2001. In the past, the Commission has utilized a "prudence" standard for reviewing gas purchasing practices.

Q. IS THE USE OF HINDSIGHT APPROPRIATE WHEN REVIEWING A PUBLIC UTILITY'S PURCHASING PRACTICES FOR PRUDENCE?

A. No. In its recent Report and Order, in *Re Missouri Gas Energy's Gas Cost Adjustment Tariff Revisions to be Reviewed In its 1996-1997 Annual Reconciliation Adjustment Account,* Case No. GR-96-450 (issued March 12, 2002), the Commission rejected an adjustment proposed by the Staff related to MGE's gas purchasing practices, and stated that the use of hindsight is inappropriate for judging the purchasing practices of LDCs. The Commission stated that the following legal standard should be used in ACA cases:

> . . . ***the company's conduct should be judged by asking whether the conduct was reasonable at the time***, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company (emphasis added).[1[28]]

Based on this standard, articulated by the Commission, the Staff's proposed disallowances should be rejected.

[1[28]] Id. at 22, citing Union Electric, 27 Mo.P.S.C (N.S.) 183, 194, quoting Consolidated Edison Company of New York, Inc., 45 P.U.R. 4th 331 (1982).

Q. PLEASE PROVIDE AN EXAMPLE OF INDUSTRY OPINION ON EX-POST HEDGING PRUDENCY REVIEW.

A. In his February 2002 paper, Regulatory Questions On Hedging: The Case of Natural Gas (attached as Schedule JH-3), Ken Costello, Senior Institute Economist, National Regulatory Research Institute (Costello) advises on page 11:

> "The reasonableness of a hedging strategy should be evaluated ***before*** a program is actually implemented. If regulators decide to perform *ex post* reviews, they run the risk of creating unrealistic or inefficient performance standards, or both. The success of a hedging strategy should not be evaluated strictly on how things turn out." (emphasis added)

In their May 2001 research report published by The National Regulatory Research Institute, Costello and John Cita, Ph.D (Costello and Cita) write on page 37:

> "If the LDC's expectations are evaluated as part of the regulatory review process, the LDC may be particularly vulnerable to being second-guessed...Regulatory risk may certainly discourage LDCs from even proposing hedging programs. If so, regulators should consider the use of an 'up-front, approval process. The LDC's expectations should be evaluated within the context of the overall hedging proposal; but if the proposal is subsequently approved for implementation, that should arguably also 'close the book' on the prudence question, regardless of where prices end up going."

Q. DOES COSTELLO HAVE ANY FURTHER COMMENTS REGARDING REGULATORY REVIEW OF HEDGING?

A. Yes. On page 15 of his paper Costello expands on his thesis:

> "Commissions should establish guidelines up-front. These guidelines can act as general policy statements on different aspects of hedging, including cost recovery, what constitutes a prudent decision on the part of the utility, and the elements of an acceptable hedging strategy. In hedging with financial derivatives, utilities need to know from their regulators what they should be doing and the 'rules of the game'."

In the following paragraph of his paper (page 15), Costello continues:

> "State commissions need to strike a proper balance between 'signing off' on a hedging strategy but not micro-managing the execution of the plan. Commissions lack the necessary information to direct a utility's hedging activities on a daily basis or to advise a utility on every decision. This does not preclude a commission from evaluating the execution of a hedging strategy. But as an overall policy, it would be preferable for commissions to convey, ***prospectively*** clarity to utilities than to partake in costly and contentious hindsight reviews that frequently turn into 'Monday morning quarterbacking'." (emphasis added).

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF STAFF'S PROPOSED HEDGE ADJUSTMENTS OF $15,875.00 FOR THE NEELYVILLE SERVICE AREA AND $105,326 FOR THE HANNIBAL/BOWLING GREEN SERVICE AREA.

A. Based upon my review of Staff's workpapers, it appears that Staff is suggesting that it was imprudent for the Company to utilize only index pricing contracts[2] to purchase its Neeleyville gas supplies during this ACA period, despite the fact that index pricing contracts were the principal method used in the LDC industry during this period throughout Missouri and the rest of the country. It further appears that Staff has determined that the Company should have implemented a specific hedging program for Neeleyville and Hannibal/Bowling Green to avoid prudence disallowances. Staff's recommended purchasing practices standard is inappropriate and unreasonable, given circumstances and the available information at the time that the Company made its purchasing decisions.

[2] Index pricing contracts include provisions that tie the price of the natural gas to be supplied to a national index (i.e. NYMEX futures or other location specific indexes). This method of pricing has been the standard method used by the natural gas industry for years, and has been widely accepted by regulatory agencies.

Q. YOU STATED EARLIER THAT THE PROPOSED NEELEYVILLE AND HANNIBAL/BOWLING GREEN HEDGE DISALLOWANCES ARE UNREASONABLE BECAUSE STAFF HAS FAILED TO ADEQUATELY CONSIDER THE INFORMATION AVAILABLE TO THE COMPANY AT THE TIME IT MADE ITS DECISIONS. WHAT INFORMATION GUIDED ATMOS' DEVELOPMENT OF SUPPLY PLANS FOR THE PERIOD IN QUESTION.

A. In order to implement a hedging program similar to one outlined in Staff's recommendation, Atmos would have had to rely on information available prior to June 1, 2000, the beginning date of Staff's proposed hedge acquisition period. At that time, the Company was unaware of any surveys or of guidance from the Staff or the Commission regarding their desire for price risk management for its Missouri customers.

The price trend for the three months preceding June 2000 offered little indication that gas prices would reach historic levels during the upcoming winter. In fact, prices did not support a portfolio strategy that would differ dramatically from existing industry practice or historic plans. The January 2001 NYMEX natural gas contract, for example, ranged between $3.105 and $3.205 during March 2000 and between $3.124 and $3.365 during April 2000, with neither month establishing a trend. The January 2001 contract rose to $4.553 on May 31, 2000, a substantial increase but still resulting in only one month of significantly rising prices. In fact, by July 24, 2000 the January contract had fallen back to $3.890. In light of these factors, there was simply no indication that the Company should embark on a strategy that differed significantly from what it had done in the past.

Q. YOU STATED EARLIER THAT THE PROPOSED NEELEYVILLE HEDGING DISALLOWANCE IS UNREASONABLE BECAUSE STAFF FAILS TO ADEQUATELY CONSIDER THE PHYSICAL AND ADMINISTRATRIVE DIFFICULTIES INVOLVED IN HEDGING A VERY SMALL LOAD. PLEASE DESCRIBE THE DIFFICULTIES YOU MENTION.

A. As of December 2001, Atmos served approximately 600 customers in Neeleyville of which approximately 515 were residential customers. Due to the small size of the Neeleyville service area, it is simply not practical to fix a physical forward price or otherwise hedge a substantial portion of Neeleyville's load because of its small daily requirements and variable load characteristics. To fix a daily quantity requires that an LDC take that quantity each day of the month. That is simply not practical with a system the size of Neeleyville. Compounding the operational problems is the fact that Neeleyville is served by two pipelines, TETCO and NGPL. Consequently, two very small fixed forward supply streams would need to be purchased and administered.

NYMEX traded futures and options are designated in quantities of 10,000 MMBtu minimum per contract. If one contract had been purchased for any winter month for the Neeleyville system, it would have hedged more than

100% of the net purchases for that month, inclusive of storage. This is simply not realistic, given the size of the Neeleyville system.

Q. NOTWITHSTANDING THE DIFFICULTIES OF HEDGING RELATED TO NEELEYVILLE'S SMALL SIZE IN MISSOURI, IS IT OTHERWISE REASONABLE TO ADOPT AN ADJUSTMENT THAT PRESUMES AFTER-THE-FACT THAT THE COMPANY SHOULD HAVE HEDGED THIRTY PERCENT (30%) OF ITS MISSOURI LOAD?

A. No. As mentioned earlier, Atmos' purchasing practices in this ACA period were consistent with the prevailing custom and practices used throughout the industry at that time. At the time that the Company made its purchasing decisions in the ACA period in this proceeding, the industry had relied principally upon contracts that were based upon index pricing rather than financial instruments or other hedging techniques. As stated earlier in my testimony, those practices were widely approved by regulators, including this Commission. It is not fair or reasonable to look back on events of this ACA period, with the hindsight knowledge that natural gas prices increased to record levels during the winter of 2000-2001, and after-the-fact conclude that the Company should have hedged thirty percent (30%) of its Missouri system needs. Such an approach is arbitrary and unreasonable.

Q. PLEASE EXPLAIN WHY INDEX PRICING CONTRACTS HAVE TRADITIONALLY BEEN THE METHOD USED TO SECURE NATURAL GAS SUPPLIES.

A. The index price represents the market (or the price for which gas is bought and sold.) Traditionally, LDCs have bought gas tied to a first-of-month index for quantities nominated the first of the month to flow at a consistent level each day of the month. Typically, a gas daily index publication is used to price intra-month or incremental purchases. Supply contracts utilizing the index pricing assured the LDC that purchases would be at the current market price when utilized.

Q. PLEASE STATE YOUR CONCLUSIONS REGARDING THE STAFF'S PROPOSED DISALLOWANCE BASED UPON A THIRTY (30%) PERCENT HEDGING REQUIREMENT.

A. The Staff's proposed disallowance based upon a thirty percent (30%) hedging requirement should not be adopted by the Commission. It is simply not fair or reasonable to look back on events of this ACA period, with the knowledge that natural gas prices increased to record levels during the winter of 2000-2001, and conclude based soley on hindsight that the Company should have hedged thirty percent (30%) of its Missouri system needs. Further, it is unreasonable to make a substantial purchasing practices disallowance based upon a purchasing standard that had not been previously articulated or adopted by the Commission and that was not widely used within the industry at the time the Company was making its purchasing decisions.

Q. DID THE COMPANY UTILIZE HEDGING TECHNIQUES IN THE WINTER OF 2000-2001?

A. Yes. The Company had not developed financial hedging techniques prior to the winter of 2000-2001. Atmos, however, covered a portion (981,500 MMBtu) of its Missouri Winter 2000-2001 requirements with fixed forward contracts for the period of November 2000 through March 2001.

Q. HAS THE COMPANY BEEN UTILIZING FINANCIAL INSTRUMENTS AND HEDGING TECHNIQUES SINCE THE WINTER OF 2000-2001?

A. Yes. The Company reviews all viable options in developing its supply portfolio, including financial instruments and hedging techniques. Since the winter of 2000-2001, Atmos has utilized several techniques for mitigating price volatility.

Q. PLEASE SUMMARIZE THE EXISTING HEDGING PROGRAMS UTILIZED BY ATMOS IN MISSOURI.

A. For the winter of 2002-2003, the Company has in place a program to hedge expected gas purchases utilizing a combination of storage, futures contracts and option contracts. The purpose of the hedge program is price stabilization. The program is designed to hedge approximately 50% of expected winter gas purchase quantities on a statewide basis. Any benefits/costs would be allocated among the various Atmos operating divisions in Missouri. Gas purchase quantities are what remains after deducting estimated storage withdrawals from estimated sales requirements. The strategy allows the remaining purchase gas requirements to benefit from market declines, if any.

Q. UNDER THE CIRCUMSTANCES THAT EXIST IN THE NATURAL GAS MARKETPLACE TODAY, DO YOU BELIEVE THAT THE ATMOS HEDGING PROGRAM IS REASONABLE AND PRUDENT?

A. Yes. Given the circumstances that face the Company today, Atmos believes it is reasonable and prudent to utilize hedging programs today and in the future.

STAFF'S STORAGE ADJUSTMENTS

Q. PLEASE DESCRIBE YOUR UNDERSTANDING THE STAFF'S PROPOSED ADJUSTMENTS RELATED TO THE COMPANY'S USE OF STORAGE FACILITIES DURING THE WINTER OF 2000-01.

A. Staff believes that Atmos should have purchased more flowing gas in November and December of 2000 and less flowing gas supplies in January through March of 2001. Based on this recommendation, this would have changed the amount of natural gas pulled from storage for each of these months. Staff originally recommended a gas cost reduction of $ 1,309,540 for the Southeast Missouri integrated system, and a gas cost reduction of $ 454,763 for the Hannibal/Canton/Palmyra/Bowling Green systems. It is my understanding that Staff has revised its proposed disallowance to $1,149,451 for the Southeast Missouri integrated system.

Q. DO YOU AGREE WITH STAFF'S PROPOSED ADJUSTMENT RELATED TO THE COMPANY'S USE OF STORAGE FACILITIES?

A. Absolutely not. I believe that Atmos' actions were reasonable based upon the market and weather conditions that existed at the time the decisions were made. The Staff's proposed adjustments regarding storage utilization rely on the use of hindsight and fail to adequately recognize operational and reliability issues involved in day-to-day system operations. The Staff disregards the market intelligence and other information that Atmos and other LDCs had available during the volatile months of the 2000-2001 winter.

Q. GENERALLY DESCRIBE THE COMPANY'S SUPPLY MANAGEMENT.

A. Based on historical data for normal weather, a baseload volume is nominated for the first day of each month and is usually priced at the appropriate First-of-the-Month (FOM) index. This volume is maintained each day throughout the month. Typically during the winter season, baseload supply is relied upon first, followed by storage withdrawals, and finally swing supply is increased as needed to meet daily requirements. Swing supply is normally purchased at a daily price as published in Platt's Gas Daily for the appropriate pipeline and geographical location on that pipeline. Firm capacity, over and above that used for baseload and storage withdrawals, is available for daily swing volume. Storage inventory levels are monitored throughout the process to assure reliability and compliance with all applicable contractual parameters. The weather has a significant impact on the amount of gas that may be withdrawn or injected during the course of a month. As the storage level is depleted, Company is required to make necessary adjustments based on remaining levels to maintain adequate peaking capabilities throughout the entire winter heating season.

Q. WERE THERE ADDITIONAL FACTORS THAT AFFECTED THE COMPANY STRATEGY FOR MANAGING GAS SUPPLY AND STORAGE DURING THE REMAINDER OF THE 2000-2001 WINTER?

Yes. The Company continually reviewed information in the trade press and other market intelligence throughout the winter. For example, the excerpts from Gas Daily included in my testimony below were instrumental in developing the Company's strategy for January, 2001.

As noted, prices were expected to continue their upward trend throughout January, February, and March of 2001. In light of this information and the facts that the storage services are primarily used for operational balancing, and the Company experienced significantly colder than normal November and December periods, thereby resulting in heavier than anticipated withdrawals from storage, an operational decision was made to purchase additional flowing gas for the system during January. Further, the weather for the first week of January was forecasted to be at or colder than normal and the trend was expected to continue for a colder than normal January and February. Based upon these projections, the Company made a prudent operational decision in late December to purchase additional flowing gas to meet expected January demand in an effort to protect from further erosion of existing storage levels.

As it turned out, the weather for January was near normal, and the Company's operational decision to purchase additional flowing gas, allowed it to mitigate the risk of inadequate storage to meet future peaking conditions on the system in February and March. In addition to the storage inventory concern stated above, the Company was concerned that the price increases that occurred in late 2000 would not stop at the $10 per Dth price with a colder than normal January. Therefore, the Company was concerned that prices would continue to increase for any incremental supply that would have been required if flowing supplies would have had to been added during the month of January.

Q. DESCRIBE IN MORE DETAIL THE REFERENCE TO "MARKET INTELLIGENCE AND OTHER INFORMATION AVAILABLE TO THE LDCs" DISCUSSED ABOVE.

A. During November and December, daily prices were escalating steadily. A random sampling of Gas Daily price ranges for incremental supply during these months is as follows:

Friday, November 3, 2000	\$4.20-\$4.45
Monday, November 6	\$4.40-\$4.65
Tuesday, November 7	\$4.40-\$4.60
Monday, November 13	\$5.00-\$5.25
Thursday, November 16	\$5.50-\$5.95
Monday, November 20	\$5.40-\$5.65
Monday, November 27	\$6.00-\$6.30

Thursday, November 30	\$5.60-\$5.95
Monday, December 4	\$6.25-\$6.60
Tuesday, December 5	\$7.25-\$7.50
Wednesday, December 6	\$7.85-\$8.05
Monday, December 11	\$7.85-\$8.05
Wednesday, December 13	\$8.10-\$8.70
Wednesday, December 20	\$8.85-\$9.15
Tuesday, December 26	\$10.00-\$10.50
Tuesday, January 2, 2001	\$10.15-\$10.70

During this period, the Company was monitoring the NYMEX prices throughout each day. In addition, it monitored Gas Daily, a daily publication, each day. This publication is instrumental in keeping abreast of daily news in the natural gas industry. Gas Daily contains hedging reports, storage levels, industry announcements, regulatory news, and other market intelligence which are vital in making daily decisions in a volatile market. As I have emphasized throughout my testimony, the months of November and December were extremely volatile and uncertain on a daily basis. Prices were going up, storage levels were down, the weather was colder than normal and the weather trend was expected to continue. As a result, prices were expected to continue to escalate. The following excerpts from Gas Daily are indicative of the information received, analyzed, and acted upon each day by the Company during this uncertain period.

<u>Gas Daily, December 2000:</u>

December 5: The headline was "Futures Skyrockets; California Jumps Over $23."

December 13: The Senate Energy and Natural Resources Committee hearing was reported upon. "At a Senate hearing yesterday on the anniversary of the (National Petroleum Council) report, consensus had it that a costly winter lies ahead and no immediate relief is in sight. And in testimony before the Senate Energy and Natural Resources Committee, representatives of the industry and government agencies warned that the current price environment may last well beyond the current heating season. In opening the hearing, Committee Chairman Frank Murkowski, R-Alaska, said that the country has 'grossly underestimated the demand pressures on natural gas.'" "Addressing a question to Mark Mazur, acting director of the EIA, Murkowski asked to know how long the current high price environment would last. "My philosophy is that, if things are bad, they're going to get worse. The question is, how much worse?' Mazur answered that EIA now forecasts that it will take between 12 and 18 months for supply to catch up with demand. As Mazur explained in his testimony, the market has since late May seen an 'unprecedented run-up in prices, unprecedented in length.'"

Also, December 13: "The NYMEX trading was shut down for an hour when the contract gained the 75 cent limit, but the brief time-outs did little to cool prices. NYMEX continues to raise natural gas margins to keep track with the rocketing prices." The previous Thursday saw an increase during the day of $1.101.

December 26: Steve Bergstrom, then president and CEO of Dynegy, was quoted. "On the supply side, everything is gas-fired in power plants, adding to demand significantly. And now we have a November that was 20% colder than normal, and a December that's 30% colder than normal," a trend predicted to continue." In the same article, Mark Easterbrook of Dain Rauscher Wessels was also quoted. "'A lot of it had to do with what was going on in power markets.' Easterbrook expects gas prices to stay volatile through February, then return to 'some level of reasonable pricing' in March."

Q. DOES ATMOS HAVE A PLANNED STORAGE WITHDRAWAL SCHEDULE FOR ITS VARIOUS SERVICE AREAS DURING THE WINTER?

A. Yes. Atmos typically plans to withdraw approximately 10% of its Maximum Storage Quantity (MSQ) in the months of November and March, approximately 25% during the months of December and February, and approximately 30%

during the month of January. Later in this testimony, I will describe the specific plans for the various service areas of the Company for the winter of 2000-01.

Q. ARE THERE FACTORS THAT COULD ARISE THAT WOULD MAKE IT PRUDENT FOR ATMOS TO DEVIATE FROM THIS PLAN?

A. Yes. The plan discussed above provides a guideline for the gas scheduler to follow, assuming normal weather conditions. However, during periods of colder weather, natural gas is in higher demand, thereby increasing the need for additional supplies. Storage enhances reliability by providing a ready source of supply. When the weather is colder than normal, the economics of pricing in the market come into play. Typically, colder weather results in higher daily gas prices as a result of increased demand. By withdrawing from storage, Atmos is able to delay incremental daily purchases and avoid the higher daily gas prices. However, the Company believes storage should be used principally to ensure that necessary supplies are available to ensure the reliability of the service to consumers in the event of a late winter peak demand period.

Q. PLEASE PROVIDE THE PLANNED STORAGE WITHDRAWALS FOR NOVEMBER, 2000 ASSUMING NORMAL WEATHER CONDITIONS FOR THE SOUTHEAST MISSOURI INTEGRATED SYSTEM.

A. The planned storage withdrawal for November was 71,600 Dth, assuming normal weather.

Q. PLEASE PROVIDE ACTUAL STORAGE WITHDRAWALS FOR THE SAME PERIOD.

A. During November, 98,077 Dth (13% of MSQ) were withdrawn compared to the planned 71,600 Dth. Although November, as a whole, was 19% colder than normal, the first six days of the month were warmer than expected. This actually resulted in injections to storage early in the month. However, on November 15 through the end of November, due to cold weather, flowing supply was increased to meet system requirements and to slow storage withdrawals. The storage balance on November 30 was 557,870 Dth. Staff has recommended a storage level of 578,079 Dth for November 30. As discussed later in my testimony, Texas Eastern expected the Company's storage level to be at 723,810 Dth.

Q. PLEASE PROVIDE THE PLANNED STORAGE WITHDRAWALS FOR THE SOUTHEAST MISSOURI INTEGRATED SYSTEM IN DECEMBER, 2000 ASSUMING NORMAL WEATHER CONDITIONS.

A. The Planned storage withdrawal for December was 179,000 Dth, assuming normal weather.

Q. PLEASE PROVIDE THE ACTUAL STORAGE WITHDRAWALS FOR THE SAME PERIOD.

A. During December, 176,084 Dth (23% of MSQ) were withdrawn. December was 40% colder than normal. At December 31, the storage balance was 381,184 Dth, approximately 50% full, rather than the planned 60% inventory level anticipated in the Company's storage withdrawal schedule. Staff has recommended a December 31 storage inventory of 424,372 Dth.

Q. PLEASE PROVIDE THE PLANNED STORAGE WITHDRAWALS FOR THE SOUTHEAST MISSOURI INTEGRATED SYSTEM FOR JANUARY, 2001 UNDER NORMAL WEATHER CONDITIONS AND STATE WHETHER THE COMPANY REVISED THE STORAGE PLAN FOR JANUARY, 2001.

A. Planned storage withdrawals for January had originally been 215,000 Dth (28% of MSQ) assuming normal weather conditions. However as noted in my previous response, the storage balance at December 31 was 381,184 Dth, approximately 50% of capacity rather than the planned 60% of capacity. As discussed previously in my testimony, during the period Atmos was evaluating baseload volumes for the month of January, prices were expected to continue escalating and the forecasted weather was for the colder-than-normal trend of November and December to continue. Therefore, the Company was concerned that without increasing flowing supply and thereby slowing storage withdrawals, the operational reliability of its system for the remaining winter months might be compromised in the event of an extended cold period or late February peak conditions. Therefore, the Company increased flowing baseload gas to bring storage levels in line with its February 1 planned storage levels in an effort to protect the integrity of the system.

Texas Eastern Storage Withdrawal Plan

Q. WHAT OUTSIDE FORCE CAME INTO PLAY DURING JANUARY, 2001 THAT REINFORCED THE COMPANY'S DECISION TO INCREASE FLOWING BASELOAD SUPPLY FOR THE SOUTHEAST MISSOURI INTEGRATED SYSTEM?

A. On January 8, Texas Eastern issued an Operational Flow Order (OFO) to be in effect until further notice.

Supposedly, on November 6, 2000, Texas Eastern sent a letter to all of its storage customers concerning its Storage Withdrawal Plan for the SS-1 contracts. The letter was addressed only to "Dear Storage Customer." It did not identify a person or department within the Company to receive the letter. A customer-specific plan was attached. There is no record of the Company's receipt of this letter.

On Monday, January 8, 2001, the Company received another letter from Texas Eastern advising the Company of the immediate issuance of an Operational Flow Order (OFO), with potential $25/Dth consequences for noncompliance by the Company. A copy of that letter is attached. (Schedule No. JH-4)

The Company, without knowledge of TETCO's imminent OFO, had already taken action to increase planned flowing gas to reduce withdrawals and ensure reliability for the remaining winter months.

The OFO was cancelled on February 6, 2001, without the Company incurring $25/Dth penalties. A copy of that letter is attached. (Schedule No. JH-5)

Q. PLEASE PROVIDE ACTUAL STORAGE ACTIVITY FOR JANUARY 2001 FOR THE SOUTHEAST MISSOURI INTEGRATED SYSTEM.

A. During January 2001, 29,060 Dth (3% of MSQ) were injected. No withdrawals were made in January. The storage balance on January 31 was 412,055 Dth, or 54% full. January weather was normal.

The TETCO Storage Withdrawal Plan for January 31, 2001 was 410,244 Dth, also approximately 54% full. The Company was still subject to the OFO enforcing the TETCO storage plan levels.

The Staff has recommended a January 31 storage inventory of 233,625 Dth, or 31% full which is significantly below the pipeline's OFO level.

Q. PLEASE PROVIDE THE PLANNED STORAGE WITHDRAWALS FOR FEBRUARY, 2001 ASSUMING NORMAL WEATHER CONDITIONS FOR THE SOUTHEAST MISSOURI INTEGRATED SYSTEM.

A. The original planned storage withdrawal for February was 179,000 Dth (24% of MSQ), assuming normal weather conditions.

Q. PLEASE PROVIDE ACTUAL FEBRUARY 2001 STORAGE WITHDRAWALS.

A. During February, 123,723 Dth (16% of MSQ) were withdrawn. February was 20% warmer than normal. At February 28, the storage level was at 286,065 Dth, or 38% full, rather than 15% as originally planned, as a result of warmer than normal February weather. Staff has recommended that the Company have a February 28 storage level of 102,123 Dth, or 14% full.

As I stated earlier in my testimony, the Texas Eastern OFO was lifted on February 6. Although no longer under a storage OFO, the storage balance at February 28 was in excess of the TETCO Storage Withdrawal Plan of 218,651 Dth, or 29% full. No penalty was assessed by Texas Eastern.

Q. PLEASE PROVIDE THE PLANNED STORAGE WITHDRAWALS FOR MARCH, 2001, ASSUMING NORMAL WEATHER CONDITIONS FOR THE SOUTHEAST MISSOURI INTEGRATED SYSTEM AND STATE WHETHER THE COMPANY REVISED THE STORAGE PLAN FOR MARCH, 2001?

A. The originally planned storage withdrawal for March was 71,600 Dth (9% of MSQ) for normal weather. Due to the warmer than normal February weather, March withdrawals were increased beyond the planned withdrawal levels to prepare for the injection period.

Q. PLEASE PROVIDE ACTUAL STORAGE WITHDRAWALS FOR THE SAME PERIOD FOR THE SOUTHEAST MISSOURI INTEGRATED SYSTEM.

A. During March, 119,207 Dth (15% of MSQ) were withdrawn. March was 19% colder than normal. In spite of the colder-than-normal weather in March, the storage balance on March 31 was 166,565 Dth. The TETCO Storage Plan expected the Company to have a balance on this date of 59,672. No penalty was assessed by Texas Eastern.

Q. DESCRIBE HOW THE WEATHER PATTERN DESCRIBED EARLIER IN THIS TESTIMONY IMPACTED THE WITHDRAWALS FROM STORAGE IN THE HANNIBAL/CANTON/PALMYRA/BOWLING GREEN SYSTEM.

A. The impact of the weather on storage withdrawals in the Hannibal/Canton/Palmyra/Bowling Green system was very similar to its impact on the Southeastern Missouri integrated system. As noted earlier in my testimony November and December 2000 were among the coldest in history in the Midwest. In the Hannibal service area, November was 22% colder than normal and December was 35% colder than normal. Obviously, the cold weather created significant demand for space heating loads. Throughout the country storage levels declined rapidly as utilities struggled to meet demand during this period and prices climbed in response to the increased demand. Missouri was not an exception to these forces.

Q. DESCRIBE STORAGE ACTIVITY IN THE HANNIBAL SYSTEM FOR NOVEMBER AND DECEMBER.

A. Schedule No. JH-6 contains a summary of the Hannibal/Bowling Green area storage activity for the November 2000 through March 2001 period. November 2000 storage withdrawals of the four Hannibal System storage sources (In-Out IOS 141794, In-Out IOS 141661, Winter Storage WS 11597, and Flexible Storage FS 14088) are summarized on page 2 of 2, in the column titled "Net Inj/(WD)" of the exhibit. The summary shows net November withdrawals for the four storage sources totaling 103,000 MCF, leaving a total storage balance of 78% on November 30. Because it was early in the heating season, this level of storage at the end of November, although near the low end of the comfortable range, caused the Company no particular concern. However, as the cold weather trend continued into December, it became clear that storage levels might become a concern. In fact, December withdrawals of 170,000 left the total storage balance at 55% on December 31. The FS storage, which has the highest deliverability (9,511 MCF/D), was down to 36% of MSQ by the end of December.

Q. WHAT STEPS DID THE COMPANY TAKE TO ADDRESS THE CONCERNS REGARDING THE STORAGE LEVEL ISSUE?

A. Atmos was concerned that the system's ability to respond to a late season cold snap and the corresponding increase in demand might be impacted by the remaining available storage capacity. As I stated earlier, industry information and weather forecasts available in December did not point to a reversal of the continuing trend of extremely cold weather, high natural gas demand and upward pressure on prices. In response to these factors, Atmos made the decision to purchase an additional 8,000 MMBtu/Day of supplemental gas beginning on December 21, 2000.

Q. DID THE COMPANY TAKE ANY OTHER STEPS TO ADDRESS STORAGE DELIVERABILITY?

A. Yes. In January 2001, 50,000 MMBtu were transferred from the IOS (In and Out Storage) storage to the higher deliverability FS storage. A similar transfer of 25,000 MMBtu from IOS to FS storage occurred in March 2001. These transfers were made at no cost but enhanced the deliverability of Company's storage resources.

Q. DESCRIBE THE HANNIBAL SYSTEM STORAGE ACTIVITY DURING THE JANUARY 2001 THROUGH MARCH 2001 PERIOD.

A. The January through March period experienced more normal weather than November and December. Heating degree days for January were 99% of normal, for February 101% of normal and for March, 105% of normal. January withdrawals totaled 14,000 MMBtu leaving a level of 53% on January 31. February withdrawals were 118,000 reducing the level to 36% on February 28 and March withdrawals of 121,312 left a total storage balance 19% on March 31.

Q. DID THE COMPANY MAKE ADJUSTMENTS TO STORAGE OPERATIONS IN RECOGNITION OF THE CHANGES IN THE WEATHER TREND?

A. Yes, as temperatures began to moderate in January, Atmos reduced the supplemental deliveries from 8,000 Dth/D to 7,000 Dth/Day on January 2, 2001. Supplemental deliveries were reduced further to 4,000 Dth/Day on January 17 and were cut to zero on January 22, 2001.

Q, WOULD IT HAVE BEEN REASONABLE AND PRUDENT FOR ATMOS TO HAVE ORDERED A HIGHER LEVEL OF FLOWING GAS FOR THE MONTH OF NOVEMBER AND DECEMBER 2000, AS SUGGESTED BY THE STAFF?

A. No. Atmos acted prudently, based upon the information available at that time. Atmos disagrees that it would have been prudent to use more flowing gas during November and December.

Q. PLEASE ELABORATE UPON THE REASONS THAT STAFF'S SUGGESTED APPROACH DID NOT MAKE SENSE TO ATMOS WITH THE INFORMATION IT HAD AVAILABLE AT THE TIME THE DECISIONS WERE BEING MADE?

A. Staff's suggested approach does not adequately consider operational aspects of managing a gas supply system.

Q. HOW DID OPERATIONAL ASPECTS FACTOR INTO THE DECISION MAKING PROCESS?

A. The extremely cold December 2000 weather created high demand from customers in the Hannibal/Bowling Green system. Greater than normal storage withdrawals were required to meet demand. In conjunction with storage withdrawals Atmos was flowing purchased gas at very high levels to satisfy demand. Schedule No. JH-7 summarizes the daily levels of purchased gas compared to its transportation contract MDQs. The table shows that after the first four days of December Atmos purchased daily 92% to 102% of the available contract maximums for baseload and swing gas for the remainder of the month. In short, Atmos was guided by customer demand and by operating capacity limits in its decisions regarding storage withdrawals for December 2000.

Q. IN YOUR OPINION, WAS ATMOS' USE OF STORAGE IN NOVEMBER AND DECEMBER 2000 CONSISTENT WITH OTHER MISSOURI LDCs?

A. Yes. Based upon information I have reviewed from Aquila in Case Nos. GR-2000-520 and GR-2001-461, it appears that Atmos independently made similar decisions regarding the use of storage in those months to those made by Aquila gas purchasing personnel. In addition, I have discussed the Atmos decisions with MGE personnel, and it is my understanding that Atmos' approach was also consistent with MGE's gas purchasing strategies during those months.

Q. DOES THE STAFF'S RECOMMENDATION RECOGNIZE THE FACTS THAT WERE KNOWN TO ATMOS AT THE TIME THE PURCHASING DECISIONS WERE BEING MADE?

A. No. Staff seems to be suggesting that Atmos should have planned for more storage withdrawals during January through March, 2001. However, based upon the information available at the time the purchasing decisions were being made, Atmos was concerned that colder than normal weather would continue into the rest of the winter, and Atmos would need to withdraw from storage for operational balancing and reliability purposes in January through March. It was therefore not prudent to refrain from purchasing flowing gas in January merely because the prices were higher. To the contrary, Company's decision was prudent because it believed it would be in a difficult situation from a reliability standpoint if it did not have sufficient gas in storage if a cold snap occurred later in the winter.

Q. PLEASE SUMMARIZE THE REASONS WHY THE COMMISSION SHOULD NOT ADOPT THE STAFF'S ADJUSTMENTS RELATED TO THE COMPANY'S USE OF STORAGE SERVICE DURING THE WINTER OF 2000-2001.

A. The Company strongly believes that its use of storage during the winter of 2000-2001 was prudent and reasonable. Atmos' purchasing practices in this ACA period were consistent with the custom and practices used throughout the LDC industry at that time. In addition, Atmos' decisions were based upon the best information the Company had available regarding the weather, levels of storage, and expected prices for natural gas for the relevant time period. In the end, the Company made decisions which it believed were in the best interests of its customers, to ensure that the Company had adequate supplies throughout the winter of 2000-2001. The Commission should not adopt the Staff adjustments since they are based exclusively upon a retrospective analysis and not upon the information that was available to the Company at the time the purchasing decisions were being made.

Q. DO YOU AGREE WITH THE STAFF RECOMMENDATION TO REDUCE THE SEMO DISTRICT GAS COSTS BY $5,462 FOR AGENCY FEES?

A. No. The Agency fees paid to Mississippi River Transmission (MRT) is a per unit fee. The Company views these per unit fees in the same manner as a premium to index pricing for gas commodity costs. The Company has requested that the Staff reconsider this adjustment.

Q. DO YOU AGREE WITH THE STAFF'S DISALLOWANCE OF $12,296 FOR DEMAND CHARGES PAID FOR THE BUTLER DISTRICT?

A. No. The supply contract for the Butler service area was with Aquila. It included reservation charges and had been entered into by Associated Natural Gas (ANG) on April 30, 2000, prior to the Company's acquisition of the Butler system. ANG extended the contract through April 30, 2001.

Atmos acquired the Butler service area on June 1, 2000. When the contract expired effective May 1, 2001, the supply contract was awarded to the successful bidder, Anadarko. This contract did not include a reservation charge.

Q. **DO YOU AGREE WITH THE STAFF'S DISALLOWANCE OF $20,824 FOR DEMAND CHARGES PAID FOR THE PIEDMONT SYSTEM IN THE SEMO DISTRICT?**

A. No. Atmos maintained all the previous year's capacity and supply arrangements that Associated Natural Gas had in place for the newly acquired gas property until such time as the Company had compiled a historical load profile from which the Company could make prudent capacity and supply decisions.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes. However, since the Staff has not, as yet, filed its testimony explaining its proposed adjustments, Atmos reserves the right to respond and elaborate upon this testimony after it has reviewed the Direct Testimony of Staff in this proceeding.

Final Report of the

Missouri Public Service Commission's

Natural Gas Commodity Price Task Force

Issued: August 29, 2001

In the Matter of a Commission Inquiry	**)**	**Case No. GW-2001-398**
into Purchased Gas Cost Recovery.	**)**	

SCHEDULE NO. JH-1

5. What Happened This Winter

5.a) Historical Natural Gas Prices and Heating Costs vs. the 2000-01 Winter

Most U.S. residential and general service natural gas customers are not aware of the per unit price they pay for natural gas or how much gas they are using day-to-day or month-to-month. These same customers are often economically sophisticated in other ways. They are more likely to know how much they paid for a gallon of gasoline this week compared to last week, and how many miles they drove their vehicle this week compared to last week. Thus, the typical driver can probably look at how much they spent for gasoline this week compared to last week and determine if it was due to different driving or different prices or both.

Based on numerous phone calls, letters, e-mails, and public meetings it is possible that these same people do not routinely do the same analysis of natural gas bills, or at least, not to the same degree. One reason that higher natural gas bills may surprise customers is that natural gas is consumed passively rather than actively. It is also paid for after usage has already occurred rather than before. Some natural gas customers may have made a decision to buy a higher efficiency furnace, install insulation, or use a setback thermostat for the heating system, but afterwards the furnace and water heater run automatically, controlled by thermostats. The customer does not normally make decisions daily on the purchase or use of natural gas.

Heating Degree Days (HDDs[5] base 65F) measure cold weather for the purpose of estimating space-heating demand. HDDs for the natural gas customer's heating system are like miles for a driver's automobile. The more miles traveled the more gasoline is burned and, the more HDDs the more natural gas a heating system uses to maintain the temperature set on the thermostat. Thus, the number of HDDs in a period of time determines the volumes of natural gas consumed by a space-heating customer during that time. The relationship between HDDs and space heating demand is virtually linear, once the temperature drops below an average of about 65 F.

In the heating season of 2000-01 (November 2000 through March 2001) typical residential natural gas customers had a limited awareness of the price of natural gas and their usage until receiving their bills in December 2000 and January 2001 with substantial increases over the same months in the previous heating season. Missouri was typical of most states in the U. S. during this heating season. Prior to the 2000-01 heating season, Missouri experienced the three consecutive heating seasons 1997-2000 with the fewest total HDDs in the last forty-one years

5 For natural gas usage for space heating, the most commonly used measure for weather is HDD. In theory, the heating requirements for one day having 10 HDD or two days each having 5 HDD will be the same. HDD are computed from a daily mean temperature (DMT). DMT is calculated from the daily maximum (T_{max}) and daily minimum (T_{min}) temperature, HDD are only positive or zero. For DMT at or above the base, 65 °F, HDD are zero. For DMT below 65 °F , HDD are the difference between DMT and 65 °F.

In equation form,

$$DMT = (T_{max} + T_{min})/2,$$

$$HDD = 65^{\circ} - DMT, \qquad \text{if } DMT \leq 65$$

$$HDD = 0, \qquad \text{if } DMT > 65.$$

(1960 – 2001), i.e. 1997-98, 34th; 1998-99, 40th; and 1999-00, 41st; (see Chart 5.1). The most recent Missouri heating season with a weighted HDD[6] total as high as 2000-01 was 1995-96. Each of the four heating seasons after 1995-96 was successively warmer than the previous. This HDD decline made natural gas bills during the heating season decline, as less natural gas was needed for heating. This decline in HDD was also the general pattern nationally. As the demand for natural gas decreased, the commodity price of natural gas in the unregulated wholesale natural gas market remained between $1.75 and $3.00 per Mcf (1,000 cubic feet of gas, approximately equivalent to 1,000,000 Btu). An Mcf is not the unit of usage that appears on most customer bills, but it is a common unit for markets. Most customers are familiar with Ccfs or Therms which represent about one tenth of an Mcf. A Ccf is equivalent to 100 cubic feet of gas and a Therm is equivalent to 100,000 Btu. A Ccf is often very close to the same as a Therm (assuming a heat output of about 1000 Btu/cubic foot). Over the last five years retail natural gas customers enjoyed the benefits of an unregulated wholesale market when the decline in HDD resulted in a decline in the need for space heating.

This decline in the demand for natural gas for space heating tended to compensate the market for increases in the demand for natural gas for other uses such as the generation of electricity. There was also a decline in demand as a result of the decline in the amount of gas put in storage during the non-heating season (April – October). This decrease in storage injections carried into the summer of 2000, as the wholesale price of gas increased.

During the summer of 2000 the cost of natural gas was high and many market participants held off making significant injections anticipating a drop in natural gas prices. This anticipated drop in prices did not materialize. Some of the reduction in storage injections may have also been due to a perception that the need for storage gas was not as great given the recent mild winters. The events of this winter have emphasized the importance of storage in any well designed gas supply portfolio.

For most of the US, including Missouri, the winter of 2000-01 contained the coldest combined November and December on record (see Chart 5.2). This early record cold placed an unexpected strain on gas supplies and the wholesale market responded. The remainder of the heating season (January – March) was not so severe, but the HDD total for the heating season was the ninth highest in forty-one years. The increase in HDD from 1999-00 (3,443 HDD) to 2000-01 (4,608 HDD) was the largest consecutive season-to-season difference in HDD in the last forty-one years. Statistically speaking, the return interval for a difference of this magnitude (1,165 HDD) is over 140 years. Once again, the pattern of HDD for November and December, and the total heating season in Missouri, was similar to the national pattern.

6 The weather stations used to compute Missouri weighted HDD are Cape Girardeau – 0.039661, Columbia – 0.101227, Conception – 0.005233, Kansas City – 0.295548, Kirksville – 0.014681, Springfield – 0.056022, St. Louis – 0.487627.

The volumes of natural gas consumed by the typical Missouri residential customer during the 2000-01 winter heating season greatly exceeded those of the previous season. The typical Missouri residential natural gas customer consumed a greater volume of natural gas in every month of the 2000-01 winter vs. the previous winter (see Chart 5.3). This winter's estimated total for a typical residential customer was 107.6 Mcf compared to the 1999-00 winter's total of 86.5 Mcf.

Chart 5.1 - Historical MO State Weighted HDDs

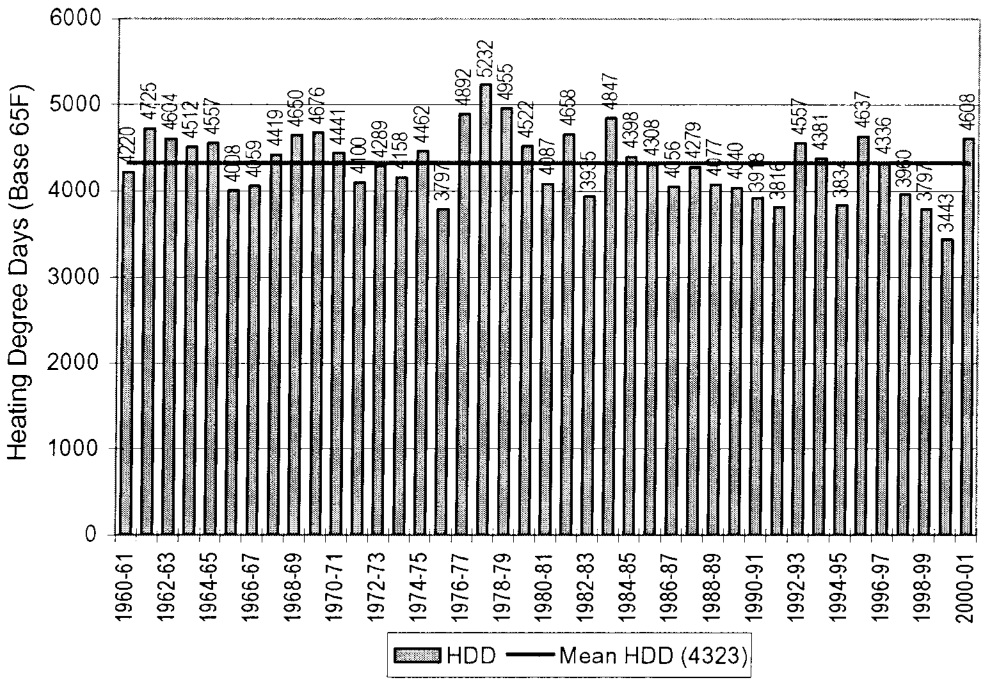


Chart 5.2 -Monthly MO Weighted Heating Degree Days

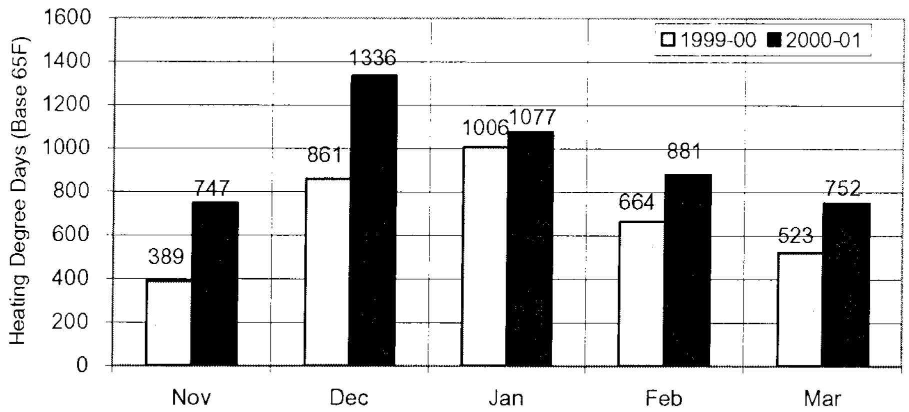
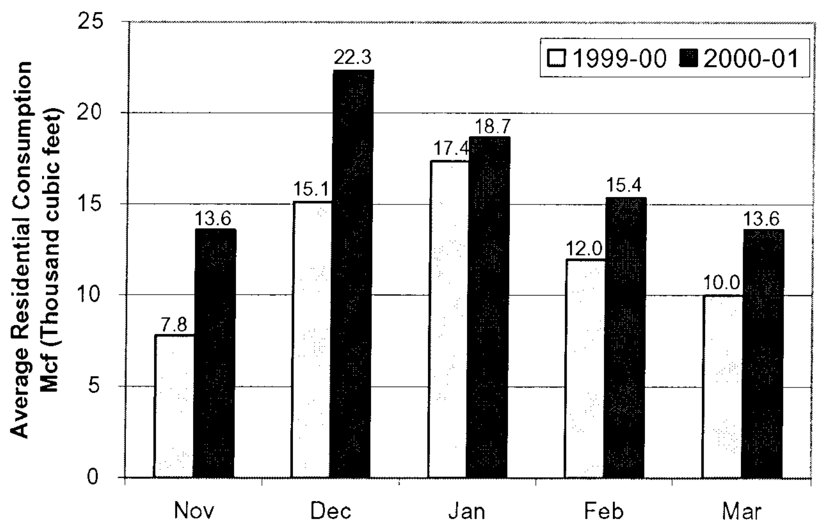


Chart 5.3 - MO Residential Natural Gas Customer Heating Season Monthly Usage



Additionally, retail natural gas customers encountered the negative consequences of a volatile unregulated wholesale market for natural gas during the 2000-01 winter heating season. The wellhead price of natural gas has been relatively low with an average of around \$2/Mcf since this price was deregulated over a decade ago. The commodity price of natural gas began to go above historic highs in the summer of 2000 when it went above \$4/Mcf in June, \$5/Mcf in September, and then in November it went over \$6/Mcf (see Chart 5.4).

This increase in volumes used and costs per unit are critical to natural gas consumers since 65 to 80 percent of the typical natural gas customer's bill is a result of the recovery of the commodity and transportation costs of natural gas.

The mechanism that links the retail customer of a regulated Missouri LDC to the commodity price of natural gas in the unregulated national wholesale market is the LDC's Purchase Gas Adjustment (PGA) rate and the type of pricing mechanisms that are in the contracts each LDC negotiates with its suppliers. The PGA mechanism allows LDCs to incorporate the commodity price they pay into the rates they charge their customers.

In October 2000, Missouri's three largest LDCs filed record high winter PGA rates in the range of \$6.44 to \$6.77/Mcf. The state weighted average PGA rates of regulated LDCs was \$6.68/Mcf with a range from \$3.77 to \$8.50/Mcf. The differences between PGA rates is due to several factors, some of which are a) overall system size and mix of the LDCs customer base, b) availability and use of storage capacity, c) how LDCs rely on index priced gas, fixed priced gas, and the LDC's transportation contracts, d) the LDCs hedging strategies as well as the different percentages of supplies from these sources and e) the LDCs willingness to incur large under recoveries rather than raising PGA rates in mid-winter. The 1999-00 winter MO weighted average PGA rate was \$3.89/Mcf. The state weighted average PGA rate in November 1999 was not much different than the PGA rate going back to November 1997 (see Chart 5.5). The details of the PGA mechanism established by the PSC will be discussed in the next section of this report.

From the inception of unregulated wholesale interstate natural gas in the 1980s until 2000 the commodity price generally varied from \$1 to \$3/Mcf. In the last five winters the commodity price might be above \$3/Mcf for a only few days in two or three months of the winter. Under these circumstances a change of \$.50/Mcf was significant. In addition to the commodity cost, LDC PGA rates include about \$1/Mcf in transportation cost, so the PGA rates before 2000 were in the \$2 to \$4 range (see Chart 5.5).

In addition to the PGA rate, LDC retail customers pay a monthly customer charge and a per unit distribution rate (a.k.a. Margin Rate) to the LDC. These rates are set in general rate cases by the MoPSC. In the winter months these rates add about \$3.50 to \$4.00/Mcf to the typical residential customer's cost of gas. So, in the winter months of 1999-00 the state weighted retail residential price of natural gas was between \$5.75 and \$6.48/Mcf (see Chart 5.4).

At the end of 2000, after two months of extraordinarily cold weather and continued reports of extreme storage withdrawals, the commodity price of natural gas spiked to nearly \$10/Mcf in late December. Speculation that the market would moderate and criteria for filing for unscheduled winter PGA rate changes resulted in LDCs not filing until January 2001 for PGA rate increases to reflect this extraordinary spike in prices.

Chart 5.4 - State Weighted Residential Retail Composite Price of Natural Gas and NYMEX Commodity Price of Natural Gas

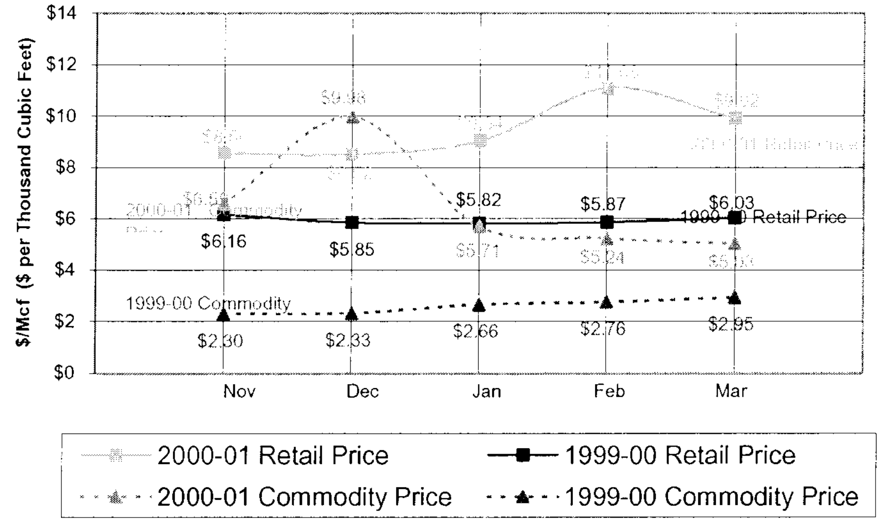
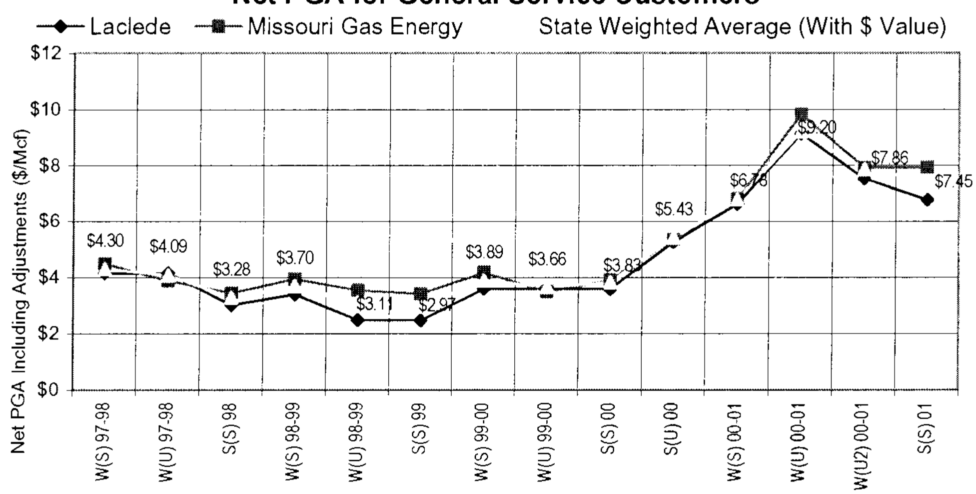


Chart 5.5 - MO Regulated Gas Utilities Net PGA for General Service Customers



Seasonal Filing -- W-winter (November - March), S-summer (April - October), (S) scheduled, (U) unscheduled

The Scheduled Winter PGAs become effective about November 1.
The Scheduled Summer PGAs become effective about April 1.
Unscheduled PGAs may become effective anytime during the season.

An unusual phenomenon occurred in December 2000 when the commodity price of natural gas was higher than the retail price of natural gas (see Chart 5.4). This resulted in many LDCs incurring a deficit because they were paying more for natural gas on the unregulated wholesale market than they were receiving from their customers through regulated rates. As will be explained in later sections, LDCs are allowed to recover this deficit in addition to bringing their PGA rates in line with the current commodity price when they file for unscheduled winter PGA rate changes (see Chart 5.5, *W(U) 00-01*). The further increase in PGA rates in January resulted in monthly gas bills remaining high in January, February, and March even though these months did not experience the record breaking cold of November and December (see Chart 5.6).

Chart 5.6 - MO Residential Natural Gas Customer Heating Season Monthly Bills

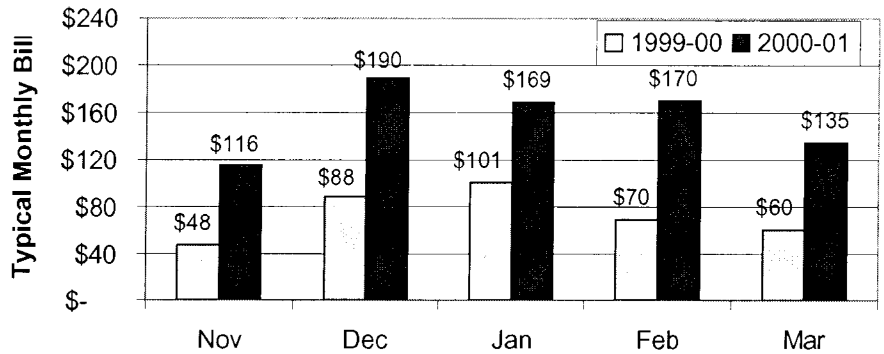
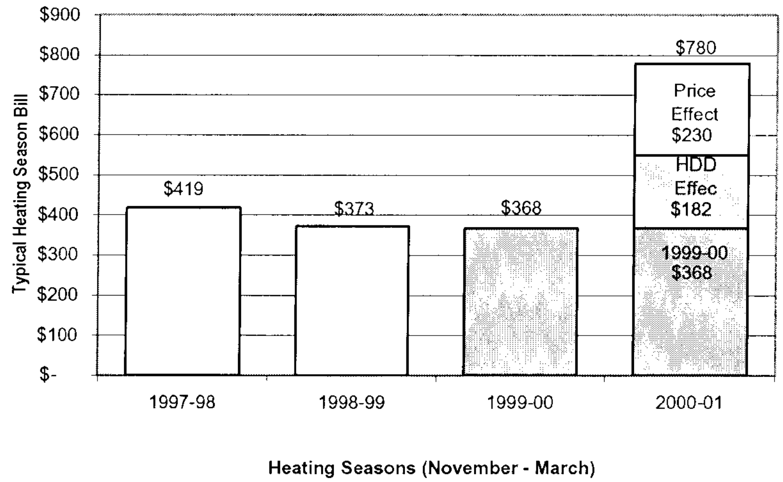


Chart 5.7 - MO Residential Natural Gas Customer Typical Heating Season Bill



By the end of the 2000-01 heating season, the typical residential customer's bill was more than twice their bill for the previous heating season (see Chart 5.7).

A similar pattern is seen when PGA rates and typical residential natural gas bills are compared to the two earlier heating seasons. In November 1997, the MoPSC changed its rules so that LDCs filed for scheduled PGA rate changes in November and March. At that time the state weighted PGA rate was \$4.30/Mcf. The heating season was mild and the estimated bill for the heating season of 1997-98 was \$419 for the typical residential customer. The state weighted PGA rate was below \$4.00 for the next two years as the wholesale market reflected the low demand due to mild heating seasons in most of the nation. This combination of mild heating seasons and a relatively steady PGA rate resulted in declines in the bills for Missouri's typical residential customer for the next two heating seasons (see Chart 5.7). Consequently, Missouri's LDCs and their customers had not experienced either the prolonged extreme cold or the high PGA rates in the previous three winters that occurred before the 2000-01 winter.

The increase in the heating season natural gas bill for the typical Missouri residential customer was from \$368 in 1999-00 to \$780 in 2000-01. This increase of \$412 has two primary components. The HDD effect, \$182, is the increase in the bill as a result of more volumes used due to colder weather; and the price effect, \$230, is the increase in the bill due to the higher retail price per Mcf of natural gas in 2000-01 compared to 1999-00 (Chart 5.7). The higher retail price was the result of Missouri LDC's higher PGA rates, and the higher PGA rates were due to the higher commodity cost of natural gas in the unregulated wholesale natural gas market. The increase in commodity cost was due to a number of factors but the primary factor was the record cold in November and December 2000 that affected most of the states east of the Rockies. This record cold occurred when the commodity price had already eclipsed \$5/Mcf and led to the first sustained increase in space heating demand for natural gas nationally in five years. This increased demand caused nine weeks of sustained or increasing commodity prices from \$4.50/Mcf the last week in October 2000 to \$9.98/Mcf the last week of December 2000.

5.b) Components of the Purchased Gas Adjustment (PGA)

The PGA Clause was instituted for Laclede Gas Company in 1962. Other LDCs received approval for their PGA Clauses in subsequent years. Most states have PGA Clauses (46 of 50 states), although the mechanism is unique as a ratemaking mechanism in that the costs that are applicable to it are not considered in the general rate case process. Costs that are subject to recovery through the PGA Clause typically include gas supply, pipeline transportation, and pipeline storage costs.

August 22, 2001

Summary of State Responses to Last Winter's High Natural Gas Prices & Consideration of Hedging and Other Risk Management Activities

I. Introduction

In May 2001, the National Association of Regulatory Utilities Commissioners' (NARUC) Staff Subcommittees on Gas and Accounting and Finance and the National Regulatory Research Institute (NNRI) developed a survey to find out how states responded to last winter's (2000-2001) high gas prices and whether hedging and other LDC risk management activities had been or would be considered.[1]

In June 2001 the survey was distributed to state regulatory staff and the majority of responses were received later that month. In July 2001, a preliminary summary of the state responses to the survey was distributed at the NARUC Summer Committee meetings in Seattle. Additional responses to the survey were received after the July 2001 NARUC Committee meetings and are included in this summary.

As of August 10, 2001, twenty-eight states or jurisdictions had responded to this survey.

This survey is intended to provide a sense of how commissions and utilities are responding to the increasingly volatile natural gas marketplace. Specifically, the survey asked questions regarding Commission rules, regulations and policies governing cold-weather service disconnections and payment provisions. Furthermore, the survey asked questions regarding the increased use of risk management tools by LDCs as a part of their overall natural gas procurement strategy. In addition, the responses provide a road map to where more detailed information might be found in the proceedings of state specific cases and dockets that have resulted in commission rules, orders, or policy guidelines.

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[1] In May 2001, NRRI issued its report on the Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues.

II. Summary of Survey Results & Comments

<u>Question No. 1</u>
Did your commission take any of the following actions last winter in response to high gas prices?

a. Increased consumer education and public awareness (e.g. public hearings, press releases, etc.)

yes: 21 no: 7

b. Increased protection from cold weather shut-offs, encouragement of LDC payment plans and/or "budget" billing alternatives.

yes: 21 no: 7

A "no" response may indicate no action was necessary because sufficient protection against unnecessary cold weather service disconnections already exists.

c. LDC gas procurement investigation or relaxation of gas cost recovery rules and/or PGA mechanisms.

yes: 12 no: 16

d. other?

yes: 6 no: 22

Six states (AK, DC, IL, NC, OK and UT) reported special investigations into various topics.

<u>Question No. 2</u>
Prior to, during, or after the 2000-2001 winter heating season, did your commission conduct an investigation, or address in some other way, alternative approaches for gas utilities to cope with cold weather and higher, more volatile natural gas prices? If so, what action, if any, did the commission take?

yes: 19 no: 9

Some of the "yes" answers indicate GCR investigations. Some of the "no" responses indicate no special investigations were conducted besides routine GCR investigations. Approximately ten states are looking specifically at the use of risk management tools and related gas purchasing issues.

Question No. 3

Has your commission addressed the use of hedging mechanisms and/or other risk management techniques (for example, use of fixed-price forward contracts rather than index-priced contracts, financial derivatives, such as futures contracts, options and swaps, weather options, etc.) by gas utilities?

yes: 26 no: 2

"Yes" responses include a few dockets in which decisions are pending. The responses indicate that many states permit but have not required the use of specific physical and/or financial hedging tools. Several responses indicate that hedging and risk management are an integral part of Commission-authorized gas purchasing incentive mechanisms. There are several pilot programs underway in various states.

Question No. 4

Has your commission addressed how hedging mechanisms should work in relation to any existing purchased gas adjustment (PGA)/gas cost recovery(GCR) mechanism?

yes: 24 no: 4

"Yes" responses include several pending dockets in various states. Responses indicate that treatment of hedging mechanisms for cost recovery purposes depends largely on each state's GCR/PGA rules and gas purchasing prudence review process.

Question No. 5

Has your commission addressed the recovery of costs associated with hedging mechanisms (for example, brokerage fees, deposits, etc?)

yes: 23 no: 5

Many of the "yes" responses indicate that prudently incurred costs associated with financial hedging and risk management can be recovered through the PGA/GCR process. However, only a few states provide advance prudence determinations on the execution or implementation of specific commission-authorized hedging strategies. Several states indicated that proceedings were underway that address the issue of cost recovery.

Question No. 6

Has your commission addressed how regulated LDCs might offer consumers a choice of pricing alternatives (for example, guaranteed fixed bills regardless of weather, guaranteed fixed commodity price regardless of the amount of gas consumed, etc.)

yes: 13 no: 15

Approximately half of the "yes" responses indicate that a docket is pending rather than resolved. Many states rely on non-regulated suppliers to offer consumers a choice of pricing alternatives rather than looking to their LDCs to develop regulated pricing alternatives. Michigan (and West Virginia) have rate freeze plans in effect.

III. State-by-state Summary of How Hedging Is Treated for Regulatory Purposes

Alabama

The PSC already allows LDCs to use hedging and fixed price contracts. Costs are fully recovered in the PGA.

Arizona

On October 31, 1998, price stability was formally recognized as a goal of the procurement process in the implementation of a new, rolling average PGA mechanism. On June 1, 2001, Commission staff proposed a new natural gas procurement review process. In August 2001, a workshop was held on the use of financial hedging in the purchase of natural gas.

Arkansas

On January 31, 2001, the Commission issued a Notice of Inquiry on gas utility hedging programs, fixed gas price options, and other related issues. In June 2001, the Commission issued its *Policy Principles for Gas Procurement Plans of Utilities*. (Ark. PSC Docket No. 01-023-NOI) The principles include guidelines for developing a diversified gas supply portfolio, the annual review of LDC hedging objectives, recovery of associated fee-based hedging costs, and hedging program documentation. LDCs are encouraged to explore, and if appropriate, develop and implement fixed-price commodity gas supply options for their customers.

Colorado

Hedging and risk management techniques are permitted. However, all gas pricing issues are currently under investigation. On May 9, 2001, the PUC issued its *Order Providing for Reply Comments and Setting Procedural Schedule*, (Decision No. C01-510, in Docket No. 01I-046G), In the Matter of the Investigation into Gas Pricing by Regulated Natural Gas Utilities. A rulemaking docket may be opened to address these issues further.

District of Columbia
A pilot hedging program may be considered for 2001-2002.

Florida
The use of hedging and risk management has not been addressed.

Idaho
Utilities are required to justify their purchasing decisions regardless of whether hedging transaction are used. Hedging costs in addition to changes in gas prices may be recovered in the PGA subject to usual prudence review.

Illinois
Investigation conducted into the increase in the price of natural gas and a staff report was issued in April 17, 2001. (ICC Notice of Inquiry, Docket No. 01 NOI-1) LDCs are encouraged to investigate hedging strategies. Prudent hedging mechanisms are recoverable through the PGA.

Indiana
LDCs are allowed to make acquisitions at fixed or collared prices. The IURC believes some level of hedging may be prudent and that "supply diversification" or a balanced portfolio approach is a sound gas procurement policy. The cost of hedging transactions may be flowed through the PGA.

Iowa
The use of hedging was addressed in the Board's Notice of Inquiry Docket No. NOI-94-1. Existing PGA rules were found to be sufficient to allow the use of hedging.

Kentucky
The Commission conducted staff workshops on the use of various types of financial hedging tools. In addition, the Commission initiated an investigation (Administrative Case No. 384) into last winter's increasing wholesale natural gas prices and the impact of such increases on retail customers. In the final order in that proceeding, the Commission ordered jurisdictional utilities to maintain the objective of procuring wholesale natural gas supplies at market clearing prices, within the context of maintaining a balanced natural gas supply portfolio that balances the objectives of obtaining low cost gas supplies, minimizing price volatility and maintaining reliability of supply. The Commission further indicated in the final order that it would retain the services of an outside consultant to conduct focused audits of the LDCs' gas procurement activities.

Pilot hedging programs have been approved for two utilities under Commission jurisdiction. Under the terms of one pilot, the utility will hedge a part of its gas supply using fixed price contracts, price caps, cost-averaging instruments based on the NYMEX strip price and no-cost collars. Under the second pilot, the utility will hedge a portion of its gas supply needs by using futures contracts.

Kentucky also has two utilities operating with gas costs incentive mechanisms designed to encourage the utilities to more actively manage their gas supply portfolios.

Maryland
Two gas utilities with index-based gas cost incentive mechanisms are authorized to hedge as part of those incentive mechanisms. However, hedging has not yet been approved for any utility with a "traditional" PGA mechanism. One utility has filed such a proposal and it will have initial consideration by the Commission on August 8, 2001.

Massachusetts
The use of hedging has not been addressed. The Department is considering whether to allow under- and over-collections of gas costs to be recovered more often than twice per year.

Michigan
The Commission has previously approved plans for frozen rates for 95% of the residential customers in the State. The cost per Mcf varied from $2.84 to $3.25. Other utilities had costs in excess of those numbers. Prior to the 2001-2002 winter heating season, this issue will be discussed as part of the Gas Cost Recovery proceeding for each utility as they file their plans. Almost 50% of the state's residential customers will have frozen rates through December 2001.

The Commission has approved recovery of costs associated with the use of NYMEX futures contracts and other financial instruments when presented as part of a comprehensive Gas Cost Recovery Plan, which must be filed prior to the start of the gas year pursuant to Act 304 of the Public Acts of 1982. (See Michigan Consolidated Gas Company, April 14, 1998 Order, Case No. U-11455)

Information about Michigan's gas customer choice programs is available on the Commission's website at: http://cis.state.mi.us/mpsc/gas/choice.htm

Minnesota
In June 2001, Reliant Energy Minnegasco (REM) was granted authority to include the cost of call options and the proceeds on the sale of call options in its purchased gas adjustment. REM's request was limited to the use of call options for the purchase of "swing" gas supplies. The PGA rules which only allow the "direct cost of natural gas delivered" to flow through the PGA were varied to allow REM to use call options. (Docket # G-008/M-01-540)

Previously, in November 1999, a pilot program for Northern States Power Company-Electric (Xcel) was authorized (and a variance to the fuel clause adjustment rules was granted) to allow the Company to flow various financial effects of various futures market activities, including gains, losses, and transaction costs related to futures contracts, puts, calls, and linked transactions through its fuel clause adjustment mechanism. Various safeguards were adopted as a condition of approval for the pilot program. (Docket # E-002/M-99-577)

In addition, in 1997-98, Northern States Power Company-Gas Utility, was authorized to start its Predictable Commodity Price Service Rider. This program began as a two-year pilot for firm Commercial & Industrial sales customers. In the first year, there were 26 customers; in the second, there were 399 customers. In September 1999 this became a permanent program. The commodity price is fixed for an estimated volume of gas for all of the participants in the program. If participants take more gas than originally estimated, they buy the excess at NSP's weighted average-cost-of-gas (WACOG). If they use less, the excess gas is used for NSP's system supply at NSP's WACOG and participants absorb the difference in a program specific true-up. (Docket # G-002/M-99-562.)

New York
The PSC has found that reliance on any one gas pricing mechanism or strategy does not appear to be a best practice. Utilities operating without a diversified portfolio approach bare a heavy burden to show prudence. The PSC has allowed recovery of costs associated with financial instruments that utilities have relied upon to reduce gas price volatility to end-users.

North Carolina
A comprehensive investigation into the use of hedging is under investigation in pending Docket No. G-100, SUB 84.

Ohio
PUCO Staff undertook an investigation into natural gas pricing and related items during the late winter, and issued its report in the spring of 2001. The results were published in hard copy as well as posted to the PUCO's website. The PUCO continues to encourage LDCs to utilize, as appropriate, risk management techniques, although such encouragement continues to focus on optimal utilization of natural gas storage, as well as "passive" hedging (fixed-price or triggered pricing from natural gas suppliers to the LDC) rather than "active" hedging techniques, especially financial derivatives.

Customer programs are well established at the three largest LDCs (reaching more than 90% of Ohio's natural gas consumers) and provide consumers with pricing alternatives from participating suppliers. Some suppliers offer variable rates pegged to, but often just under, the LDC's posted GCR or EGC. Other suppliers offered fixed price contracts for up to 3 years.

Oklahoma
Extensive discussions have been held and testimony heard on including the cost of various hedging mechanisms in the PGAs. In July 2001, two pilot programs were authorized.

Pennsylvania
LDC typically lock into a "contract strip" of natural gas supplies based on NYMEX futures prices during the summer or fall. Benefits and risks of hedging are recognized. Normally, a level that approximates 25% of total purchases is considered safe for hedging.

South Carolina

One hedging program was approved in 1995. The costs, gains and losses are recovered in the monthly cost-of-gas pass-through calculations.

South Dakota

PSC has approved the inclusion of hedging activities in the PGA on a company-by-company basis, pursuant to tariff. Hedging costs may be included in the PGA subject to review.

Tennessee

The major LDCs under the Tennessee Regulatory Authority's jurisdiction have PGAs and performance-based gas purchasing incentive mechanisms, which allow the LDCs to utilize a wide range of gas purchasing options, including hedging mechanisms and other risk management techniques.

Texas

In September 2000, the Railroad Commission solicited the LDCs' 2000-2001 gas supply plans. The Railroad Commission intends to solicit supply plans for 2001-2002 that will also address last year's performance compared to last year's plan and indicate any measures in place or that are being contemplated for 2001-2002 that address or mitigate against high prices and volatility, including hedging mechanisms and alternative pricing options. The Railroad Commission may issue a state-wide report on these plans prior to the 2001-2002 heating season.

Utah

The Commission's policy was changed, by order on May 31, 2001, so that price stability was added to the factors of price and reliability in procuring purchased gas supplies. Hedging can be used to achieve price stability. The net costs involved in acquiring more stably-priced gas supplies should be considered gas costs and may be recoverable in the 191 Account. If the LDC is required to make mark-to-market entries as described in FASB Statement 133 (something the LDC believes will not be required), they will be entered as separate, non-interest bearing line items in the 191 Account in a way that will not impact customers rates, nor the LDC's net income.

Vermont

Vermont Gas System (VGS) was allowed to defer high gas costs for later recovery. Costs are tracked internally. VGS does not have a PGA. VGA uses hedging strategies as a matter of course and purchases collars (options and swaps) for over a third of its supplies. Board has not taken a formal position on the use of hedging or on cost recovery. This may be addressed in November 2001 as part of a pending docket.

Washington

In May 1997, LDCs were asked to develop internal hedging policies for supply procurement to make sure they were within acceptable risk parameters. (Draft Commission policies required LDCs to submit hedging plans, strategies, policies and procedures to the Commission for review.) No prescriptive hedging criteria have been mandated but is an understanding that each utility has the discretion to hedge in an appropriate manner.

LDCs were also encouraged to ask for deferred accounting treatment associated with derivatives used to hedge risks. Approval of deferred accounting not considered pre-approval or authorization for any specific hedging activity, but is required to request cost recovery at a later time. Hedging costs have been allowed (amortized) through deferred cost filings. NW Natural hedged approximately 80% of its supply last winter.

Wisconsin

Use of financial derivatives approved on a case-by-case basis. Up to one-half of winter gas comes from storage priced at prior summer's cost. Some of the major utilities have PGAs that recover all costs on a one-for-one basis while other utilities have some incentive components in their PGA mechanisms. The Commission has always considered how a hedged position should flow through the PGA. As a general rule, if the utility has no control over the hedge (cannot affect its outcome, merely invokes the hedging tool mechanism) it goes through the PGA on a one-for-one basis. There are a limited number of cases in which the utility has the opportunity to arbitrage the system with little risk. Such hedges are in the incentive component of the PGA. If the Commission has approved the use of a hedging tool, then the costs associated with it are passed through to customers in the PGA mechanism.

Other states:

New Hampshire

On July 12, 2001, the Commission, in its Order No. 23,740, in Docket DG 01-125, approved a Fixed Price Option (FPO) pilot program and an associated hedging policy for Northern Utilities, Inc. The FPO program will be available for up to fifty-percent of the weather normalized winter period sales. The Company is required to use a variety of physical and financial tools to hedge a minimum of fifty percent of its 2001/2002 winter gas supply portfolio in support of its FBO program.

Two other LDCs (KeySpan Energy Delivery New England and New Hampshire Gas Corporation) offer FPO programs. Participation in these two programs was capped at 20% and they were significantly over-subscribed for 2000/2001.

West Virginia

The following report is available on the PSC's website: A Report on Natural Gas Pricing and an Evaluation of Opportunities for Price Risk Management Through Various Hedging Options, by David J. Ellis, Director of Utilities Division, Public Service Commission of West Virginia, July 10, 2001. www.psc.state.wv.us/hedging.pdf

IV. Concluding Comment

Approximately three-quarters of the states that responded to this survey reported they had taken extra steps (e.g. increased consumer education, modification of cold weather service disconnection policies, special attention to LDC gas procurement reviews, relaxation of the intervals between gas cost recovery filings) to review last winter's high gas prices. (Five states reported that special, extra-ordinary investigations had been or were being conducted.)

Over ninety percent of the states that responded to the survey indicated that they had addressed or that a decision was pending on the use of hedging mechanisms and/or the use of other kinds of risk management techniques. Approximately ten states reported that they had opened dockets to look specifically at the use of hedging and other risk management tools by their LDCs.

It appears that many states permit but have not required their LDCs to use financial instruments to hedge their gas costs. This has often been done as part of a commission-authorized gas supply plan or as an experimental gas hedging pilot program. A number of states have actively encouraged their LDCs to use passive, physical hedging techniques (e.g. pipeline & market area storage and fixed-price supply contracts) in their gas procurement strategies. Regulatory treatment of hedging costs varies tremendously from state-to-state and depends on each state's statutes and rules governing LDC gas cost recovery, state policy on prudence reviews for LDC gas purchasing practices, and whether LDCs are using gas purchasing incentives mechanisms.

Endnotes

Survey Responses
NRRI's compilation of the responses to this survey is available electronically on the NARUC website.

Disclaimer
This report is intended for information purposes only. The authors believe all of the information is correct, but can accept no responsibility for errors, damage, or disappointment caused through its use.

The views and opinions expressed in this report are not necessarily the positions of the National Association of Regulatory Utilities Commissioners, the NARUC Staff Subcommittees on Gas and Accounting and Finance, the National Regulatory Research Institute, or any particular state commission.

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REGULATORY QUESTIONS ON HEDGING: THE CASE OF NATURAL GAS

by

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SCHEDULE NO. JH-3

High gas prices during the winter of 2000-2001 stimulated unprecedented interest in the possible use of financial derivatives by local gas distribution companies (LDCs). Traditionally, LDCs have hedged price uncertainty by storing gas on a seasonal basis and by signing forward contracts. Although these mechanisms have historically been effective in stabilizing prices, their use may be more costly and less effective than using financial derivatives. For example, trading futures contracts can result in lower transaction costs and less risk exposure compared to using a forward contract.

Over the past year in particular, both LDCs and state public utility commissions (PUCs) have come to recognize the potential benefits of using financial derivatives to manage price risk. Trading on centralized exchanges and over the counter, these instruments reflect the natural outgrowth of the evolution of gas spot markets. Since the mid-1980s, wellhead gas has been considered by most industry experts as a commodity transacted in a highly competitive market. Driven by demand and supply forces, prices have exhibited high volatility and correlation with fluctuations in consumption and production. For example, the spot price of gas depends on factors such as production cost, storage levels, economic conditions, weather, pipeline capacity, and random shocks (e.g., events in the Middle East affecting oil prices). Depending on the publics' aversion and financial exposure to gas-price spikes, the question confronting PUCs becomes, how might the risk of spikes be managed?

Gas spot prices have been inherently volatile and unpredictable – just between January-October 2001, we witnessed the Henry Hub spot price falling from around $10 per MMBtu to less than $2 per MMBtu. Consequently, total reliance on the spot market may inflict unacceptable risks on both sellers and buyers. In response, market participants have demanded alternative transaction and risk-management mechanisms, including storage, bilateral contracting, vertical integration, and financial derivatives. Commodity markets characterized by volatile and unpredictable prices typically develop products that efficiently transfer risk between parties. While volatile prices are not necessarily bad, after all from the consumers' perspective price drops are desirable, commodity markets of high price volatility function more efficiently when market participants can shift risk to those entities more willing and able to bear it.

Gas futures contracts were first offered by NYMEX in April 1990. Options on gas futures contracts began trading in 1992, thus providing an additional tool and opportunity for local gas utilities to manage price risk. Later, private traders began to offer swaps, collars and other over-the-counter financial instruments. The development of a well-functioning spot market for any commodity must precede the start-up of a futures and options market, as well as the trading of other financial instruments.

It is only recently that local gas utilities and their regulators have become interested in financial instruments. Since FERC Order 637, local gas utilities have had to assume new responsibilities and risks regarding gas procurement and price-risk management – prior to that time, gas utilities purchased much of their gas as part of regulated "bundled sales" service from pipelines. Over the last several years, gas utilities have had (1) more choice of services and providers, (2) access to transparent price information (e.g., spot prices, futures prices), and (3) available to them a wide assortment of financial instruments. Since the winter of 2000-2001, the focus of gas utilities has shifted to achieving a balance between minimum prices, reliable supply, and moderate price volatility. More stable prices have most recently become an explicit objective of a gas utility's gas-management activities. Thus, partially induced by pressure from state regulators, this new objective has stimulated gas utilities' interest in using financial derivatives for hedging purposes.

This paper will highlight the major issues that state public utility commissions face with regard to the possible use of financial instruments by gas utilities. The questions and issues raised in this paper are very much applicable to the electric power industry as well. Hedging with these transactions pose different questions and problems for regulators, who more than anything want the assurance that utilities are doing the "right thing" in terms of advancing the economic interests of retail gas customers. One tough but important issue that has permeated several state regulatory proceedings deals with the prudence question relating to hedging. Some state commissions criticized gas utilities for not hedging more for the winter of 2000-2001 and, thus, mitigating the high spot price of gas. Utilities could have obviously hedged more and, with hindsight, they should have; but given the information available to them before that winter, it becomes less clear they should have (the pertinent prudence question).

BASIC QUESTIONS FOR REGULATORS

Hedging with financial instruments, as any economic activity, carries a cost that must be weighed against the expected benefits. Since the costs of hedging will be primarily borne by consumers, they should be the main beneficiaries. As discussed later, the prudence of a utility hedging with financial instruments raises difficult questions unlike those related to gas procurement. For example, in determining whether a utility undertook reasonable action by hedging with options or any financial instrument, a regulator cannot avoid the fundamental question of how much are consumers willing to pay to have more stable gas prices. Regulators should up-front ask themselves several questions:

1. In terms of advancing the public interest, should gas utilities hedge at all, in particular with financial instruments?

2. Should hedging strategies be designed to protect all so-called core customers" ? What should be its scale?

3. How much should a gas utility spend on hedging?

4. What should be the mix of hedging instruments, including financial derivatives, used by a gas utility?

5. What should be the essential components of a hedging strategy?

6. What role should price expectations play?

7. Can other mechanisms, such as budget billing and a fixed-price tariff, be used as substitutes for hedging?

At the most basic level, it is not absolutely clear that a utility should be hedging on behalf of its customers. After all, the protection afforded by hedging closely resembles insurance markets, in which whether and how much insurance should be purchased depends on the expectations and risk tolerance of purchasers. Just like insurance, hedging to avoid price uncertainty involves a cost. Thus, the pertinent question becomes, how much would consumers be willing to pay to have more stable gas prices and, thus, more stable gas bills? For them to be willing to pay anything, they must be risk averse toward unstable prices and they must perceive future gas prices to be uncertain. Risk aversion means that customers would be willing to lower their future expected wealth to be ensured of more stable prices – this is akin to the rationale behind the purchasing of insurance, where those who are insured pay a premium to be protected against certain large losses. In other words, if consumers are risk averse, they would be willing to pay some amount extra to have less volatile gas prices.

Risk aversion translates into customers willing to pay higher prices over time, or moderately higher prices during some periods of time, in order to avoid paying large price increases during any one period of time. Unambiguously, customers prefer lower prices to higher prices (assuming no effect on the reliability or quality of gas service). But, it is not so clear whether customers prefer more stable prices if, in fact, they result in higher expected prices over time or require payment in the form of a "risk premium" to those parties willing to shoulder the risk. It is safe to say that customers have unequal risk tolerances – some customers would be willing to float with the market while others would be willing to pay something to have more stable prices. The implication for establishing a prudence standard for hedging is that regulators must define an acceptable level of price volatility (i.e., the consumer-risk tolerance toward price volatility), as well as an acceptable average cost for gas, after accounting for the costs associated with hedging. Regulators cannot be expected to know with a high degree of precision the risk tolerances of customers. Consequently, they really have little idea how much hedging a gas utility should undertake and how much it should spend. On the other hand, it is much easier for a regulator to set a prudence standard for gas procurement where a reasonable price is generally interpreted as equivalent to the market price, namely, the spot price or the contract price indexed to a designated market price.

If evidence supports the purchase of hedging services by a gas utility, on what scale should these services be provided? Should the gas utility hedge for all of its core customers? For example, the utility could cap its pass-through price so that all of its purchased gas adjustment (PGA) customers would be eligible to benefit from the cap. Alternatively, the utility could offer a menu of individual tariffs, each differing by the degree of price fixity. That way customers could, by choosing their preferred tariff, select the kind of hedging that is best for them. The rationale for this option is that consumers know better than a utility how to manage their own price risk – as argued earlier, consumers have varying risk preferences and, thus, different demands for hedging and other forms of risk management.

If the utility proposes to provide protection to all of its pass-through customers, then how much monies should be expended to provide that protection? Clearly, the size of the hedging budget warrants close review by the regulator. The budget can be reduced as the utility's hedging strategy converges toward the least-cost solution. For example, substituting a futures contract for a forward contract could provide the same price stability at a lower cost. Because the cost of providing hedging is highly dependent upon the availability of financial and physical mechanisms, it is virtually impossible to separate the program cost from program design and administration.

The up-front costs of a hedging strategy will be highly sensitive to whether the utility, say, proposes to fix a price using a futures contract or cap a price using a call option. Rather than locking in a price with a futures contract, the utility may rely on options to leave open the possibility that prices may decrease in the future. That is, the utility hedges so that customers are able to retain the downside price risk and avoid the upside price risk. If this is the hedging strategy, the question then becomes, should the utility establish a price cap? If yes, at what level should the cap be set? Lower price caps, other things held constant, translate into higher hedging costs. Another question is, should all winter volumes be capped? Obviously, the more volume that is covered the greater the hedging cost.

If the utility proposes to use futures to establish a fixed price, what volume of gas should it hedge? Should all winter volumes be hedged, or instead some proportion? When should the futures hedge be put on? What volume of gas should be capped?

Rather than establishing a price cap, should the utility implement a price collar so that a range of prices is effectively locked in? If so, what should that range be? The size of the range will affect the cost of locking in the range. Besides caps and collars, a number of other hedging strategies can be employed. Only the hedger's imagination serves as a limit.

As another matter, the utility's expectation of future prices may influence its hedging decisions. If the utility expects prices to increase, it may prefer to hedge with futures contracts. Alternatively, if it expects prices to fall, then it may prefer to hedge with options. To the extent the utility's expectations influence its hedging strategy, establishing the reasonableness of that strategy will require some evaluation of the utility's expectations.

GUIDELINES FOR ASSESSING HEDGING ACTIVITIES

The previous section posed several questions regarding the regulatory evaluation of hedging strategies. It is unlikely that hedging strategies will take on a cookie cutter approach. In terms of specifics, different utility hedging strategies may vary in fundamental ways. It seems reasonable, however, that all hedging strategies should satisfy the same general principles and guidelines. The following guidelines are offered here for consideration:

1. *Establish the need*

   Because hedging is a costly activity, having evidence that customers are willing and able to pay for that service may provide both the utility and regulators with a picture of the appropriate scale of hedging activities in terms of budget, and the kind of protection consumers may prefer. For example, consumers may prefer "catastrophic protection," meaning protection from the possibility of extreme spikes. If so, that may reveal a preference for a price cap approach (and, thus, the use of options).

Furthermore, while retail residential customers may be risk averse, regulators should not simply conclude that all price volatility should be eliminated. After all, the financial integrity of the average (middle class) household is not greatly influenced by its monthly gas bill.

2. *Initially, keep a hedging strategy as simple as possible*

Gas-procurement decisions can be separated from hedging decisions. Utilities can purchase their required gas at index and then use financial derivatives to hedge the risks inherent in such a purchasing practice. It is probably easier and just as effective to pursue hedging-strategy objectives separate and distinct from the gas-procurement objectives. When hedging decisions become commingle with gas purchase decisions, as in the case of fixed-price gas contracts, it is more difficult to assess the prudence of that "bundled" decision.

Expanding on the last point, it may be useful to view the purchase of physical gas to meet demand (referred to here as "gas procurement") separately from price-risk management. From a gas utility's perspective, price-risk management, which includes hedging, attempts to control price risk by mitigating the consequences of high or increasing gas prices; this activity is carried out shifting unwanted risk to an entity that is more willing or capable of managing that risk. From the perspective of consumers, price risk can be defined as the product of the probability of high prices and the magnitude of losses from such prices – for example, the harm done to residential customers when they pay extremely high gas prices during the winter heating season.

Traditionally, gas procurement and price-risk management were bundled as one activity – for example, the case of forward contracts and storage. The advent of financial instruments such as futures contracts, options and swaps allows a utility to procure gas and manage price risk as separate unbundled activities. As a feasible if not economical strategy, a utility could purchase all of its physical gas on the spot market and, separately, purchase futures contracts to stabilize prices. Overall, gas procurement has more of a least-cost (or a so-called "best cost") objective, whereas price-risk management has the effect of truncating the range of prices to better match consumers' tolerance for risk.[1]

3. *Articulate and specify the objectives of a hedging strategy*

The utility should identify the general objectives of its hedging strategy. This would require identifying the specific risks being managed, as well as the specific hedging tools that will be used. It would also require the utility to explain the role, if any, that its price expectations play in its proposed hedging strategy. A utility that expects prices to fall may propose limited hedging activities. That could be defensible depending on the reasonableness of its expectations. By assessing the utility's expectations, regulators can also contain the possible utility's urge to speculate.[2]

Arguably, the major objective of hedging should be to limit extreme gas-price spikes during the winter heating season. By doing so, unacceptably high gas bills could be avoided, which probably would eliminate much of the economic harm from volatile gas prices. It would be incorrect to

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[1] Different mechanisms other than hedging by the utility exist for managing price risk to consumers. They include the offering of a fixed-price tariff by either the local gas utility or marketers when customer choice is available, budget billing, and structuring of the PGA to levelize recovery of purchased gas costs across the different periods of the year.

[2] Having noted that the average residential gas customer most likely does not face a significant amount of financial exposure from his monthly gas bill, it may be reasonable for LDCs to propose hedging programs with rather limited scopes. For instance, hedging some fraction of winter volumes in the neighborhood of 50 percent may be reasonable. Thus, it may be reasonable for LDCs to under-hedge, even though under-hedging can be viewed as speculative.

expect hedging to reduce the average cost of purchased gas over time. Since a premium would be paid to shift risk, it would be expected that the average cost would be higher. One could also question whether the objective of hedging should be to reduce the variability of gas bills; while consumers would undoubtedly benefit from not having to pay extremely high gas prices, they would be harmed from not enjoying the benefits of low market prices because of hedging.

4. *Identify all hedging-strategy costs*

   Needless to say, all costs, whether potential or actual, should be identified. Recovery provisions should be clearly articulated. Customers must understand that hedging activities are costly. Customers should also understand that expenditures on hedging do not always produce a benefit. They may pay for risk protection that may not be needed, after the fact. For example, money can be spent on options that are never exercised. Or by using futures, the utility may effectively lock in a price that turns out to be in excess of the average market price.

5. *Identify the LDC's hedging expertise*

   Hedging strategies should be designed and operated by sufficiently qualified personnel. Managers should have sufficient flexibility to make specific decisions. Regulators should resist the temptation to micro-manage the utility's hedging strategy. Instead, regulators should focus their attention on the general provisions and parameters of the overall hedging strategy.

6. *Establish reporting requirements*

   Every hedging strategy should require a reporting of all relevant activities so that regulators are fully informed of program development.

7. *Consider up-front approval of hedging-strategy proposals*

The prudence of purchasing a call option, for example, should not hinge upon whether the option was exercised. The reasonableness of a hedging strategy should be evaluated before a program is actually implemented. If regulators decide to perform *ex post* reviews, they run the risk of creating unrealistic or inefficient performance standards, or both. The success of a hedging strategy should not be evaluated strictly on how things turn out.

The important question of whether utilities need to be "pushed" in hedging depends upon different factors. Utilities that have pass-through (i.e., PGA) provisions may have little if any direct incentive to undertake hedging activities. On the other hand, hedging may reduce the LDC's risk exposure from customer non-payment of bills. There also may be other indirect pecuniary incentives. The consumer outcry heard during the winter of 2000-2001 was directed mostly at the gas utilities. There was a sense, rightly or wrongly, that utilities could have done more to hold down gas prices. If nothing else, the winter of 2000-2001 revealed that hedging represents a value-added service that gas customers may demand, and the gas utility can provide. If in fact customers want their utility to hedge, it may be hard to conclude that not satisfying that demand is in the public interest.

COMMISSION POLICIES

State PUCs can take a number of general policy positions with regard to utility hedging with financial instruments:

- <u>*Utilities should not hedge.*</u> For whatever reason, hedging with futures contracts, call options, or other financial derivatives may not be regarded as an appropriate activity for gas utilities. This position probably characterized the thinking of most state PUCs prior to the unexpected surge in gas prices during the 1996-1997 winter heating season. In opposing utility hedging, a state commission may fear that (1) utilities would speculate if allowed to participate in the futures market, (2) the futures price will turn out higher than the market price, (3) utilities are not adequately skilled to hedge,[3] or (4) the up-front hedging costs would exceed the expected benefits to consumers.

- *There is no prohibition of hedging but also no guidance given by a commission.* This has been the situation in some states where gas utilities have been reluctant to hedge with financial instruments because of the lack of clear signals from commissions on the treatment of gains and losses. This position would likely discourage hedging, since a utility would not know whether the costs associated with hedging would be recovered from consumers, and how the commission would retroactively view its hedging activities. At the minimum, commissions should establish general policy parameters for use by a gas utility in determining whether and how to carry out a hedging strategy.
- *A gas utility can hedge but only after obtaining approval from the commission of its hedging strategy or plan.* In this case, hedging is voluntary on the part of the utility, but it must receive permission from the commission on its overall hedging strategy. Approval of hedging strategies by the commission can signal to the utility that the associated costs would be recovered from consumers. Approval of a utility's hedging strategy may depend on the strategy's basic elements, which can include trading limits, an internal oversight process, other safeguards, clearly articulated objectives, and reporting and monitoring guidelines.

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[3] A gas utility could always hire an outside firm to conduct its hedging program. Several utilities have hired energy trading companies to manage their hedging programs. There may, however, be an agent-principal problem where the contractor would have interests divorced from those of the utility.

- *A commission requires utility hedging.* A commission might find hedging in the public interest and, therefore, order a utility to provide that service.[4] A commission would impose a penalty if the utility failed to step forward with a hedging proposal. Unless a utility directly benefits from a successful hedging strategy, however, it may lack the enthusiasm to successfully execute the plan, especially if it is able to pass through all gas costs, even high spot gas prices, to consumers. One potential problem stems from utilities subject to standard PGAs having little incentive to hedge. The reason is that a utility's shareholders are marginally affected by unstable gas prices. Aggravating this situation, a utility may fear that it will not be able to fully recover its costs associated with hedging and will receive no gains from hedging activities. As an example, to the extent a utility is able to pass through to consumers the entire cost of spot gas, regardless of the price, it may have little incentive to enter into fixed-price contracts or to hedge with financial instruments. Such contracts or hedging may expose the utility to the risk of cost disallowance should spot prices fall (the utility may be criticized, say, for locking into futures prices that turned out higher than the spot price), whereas any savings would directly go to consumers. Under these conditions, it is understandable why a utility would be hesitant to hedge with financial instruments.

The public-interest problem here is that a utility's decision not to hedge may be in its best interest but counter to consumer interests. The key for regulators is to provide utilities with incentives to mange their price risk in a way that advances consumer interests. A performance-based

[4] As an example, during the winter of 2000-2001 the Colorado Public Utilities Commission approved an emergency rule requiring gas utilities to mitigate natural-gas price volatility. The Commission also investigated a plan that would require gas utilities to hedge.

regulatory (PBR) mechanism can be designed to induce more hedging– for example, it could eliminate the need for hindsight reviews and allow the utility an opportunity to profit from hedging gains. An argument could be made for establishing separately (1) an incentive mechanism specifically for gas procurement, and (2) guidelines for hedging involving financial instruments. For example, gas-procurement costs can be benchmarked relative to a spot price, and a utility may not be permitted to spend more than a designated dollar amount on hedging activities.

During the summer of 2001, a survey conducted for the National Association of Regulatory Utility Commissioners (NARUC), among other things, asked state PUCs how they responded to the high gas prices during the winter of 2000-2001 and whether hedging and other gas utility risk-management activities had been or will be considered. The responses (which came from twenty-eight states) indicated that most states allow, but not require, the use of hedging with financial instruments by gas utilities. Permission by a commission for the use of financial instruments was often done in conjunction with a commission-authorized gas supply plan or an experimental hedging pilot program. Another typical response was that commissions would allow recovery of the costs associated with hedging, in most cases through the PGA, so long as it is consistent with prudence statutes and rules. Overall, 90 percent of the commissions responding have addressed, or a decision was pending, on the use of hedging mechanisms or other risk-management tools. As of late last summer (2001), ten states had open dockets addressing hedging and other risk-management activities. Undoubtedly, since the winter of 2000-2001 state commissions have assumed a much more pro-active role in promoting hedging activities by gas utilities. Still, the evidence points to the fact that many, if not most, commissions are less comfortable with financial instruments than with other hedging mechanisms such as storage and fixed-price contracts.

CONCLUSION

In the natural gas industry, risk management has become an integral activity of market participants. With unpredictable and volatile gas prices, the industry has developed products transferring risks between parties. Since the winter of 2000-2001, many state PUCs have shown greater interest in the use of financial instruments by local gas utilities. Commissions generally view hedging by utilities as an activity that can protect retail consumers, especially residential consumers, against unexpectedly high gas prices. Financial instruments may represent the least-cost option for utility hedging; for example, they are generally more liquid than physical hedges and often have lower transaction costs. Local gas utilities have taken a greater interest in the use financial instruments if only because they are being pressured by state PUCs.

State PUCs can choose among various policy options regarding utility hedging with financial instruments; they span the spectrum from prohibition to a mandate. The more defensible, middle-of-the-road course of action, and one that most commissions have taken so far, is to allow utilities to hedge with financial instruments so long as it is done "prudently."

Commissions should establish guidelines up-front. These guidelines can act as general policy statements on different aspects of hedging, including cost recovery, what constitutes a prudent decision on the part of the utility, and the elements of an acceptable hedging strategy. In hedging with financial derivatives, utilities need to know from their regulators what they should be doing and the "rules of the game." Otherwise, they will be reluctant to hedge even when it would be in the interest of consumers. Especially in an environment where rules are vague and all direct gains from hedging go to consumers, utilities understandably would have little incentive to hedge.

State commissions need to strike a proper balance between "signing off" on a hedging strategy but not micro-managing the execution of the plan. Commissions lack the necessary information to direct a utility's hedging activities on a daily basis or to advise a utility on every decision. This does not preclude a commission from evaluating the execution of a hedging strategy. But as an overall policy, it would be preferable for commissions to convey, prospectively, clarity to utilities than to partake in costly and contentious hindsight reviews that frequently turn into "Monday morning quarterbacking." Hedging is one of those activities, similar to the purchasing of insurance, where by design it is expected to result in a net loss to consumers. Consequently, hedging is vulnerable to *ex post* regulatory interpretation. But, in view of the intent to avoid large losses or harm – a "peace of mind-type" benefit – hedging with the result of higher prices to consumers or lower profits to a utility can still be regarded as successful and prudent.

In sum, commissions should not tell utilities how to hedge and second-guessing lies counter to the traditional prudence standard and, more important, discourages utility hedging. Yet, a commission has a legitimate and useful role to play in evaluating the reasonableness of (1) a utility's hedging strategy, prospectively, and (2) the execution of the strategy itself.

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To Larry Tarrant	From Elvia Lopez
Co.	Co.
Dept.	Phone # (713) 627-4925
Fax # (615) 790-9337	Fax #

Duke Energy.

January 8, 2001

Post-it® Fax Note 7671

To Gordon Roy &	Date 1-11-01 # of pages ▸ 4
Co./Dept. John Hack	From Phil Davis
Phone #	Co.
Fax # 972-855-3070	Phone #
	Fax #

United Cities Gas Co,, A Division of ATM
Attn: Larry Tarrant
377 Riverside Drive
Suite 201
Franklin, TN 37064-5393

RE: OFO TO BE EFFECTIVE 9:00 A.M. CT, JANUARY 12, 2001

On November 6, 2000, Texas Eastern Transmission Corporation ("Texas Eastern") notified firm storage customers that, as required by the Federal Energy Regulatory Commission's November 30, 1994 order, in Docket No. RP95-15, Texas Eastern would monitor customer storage activity and would issue customer-specific Operational Flow Orders ("OFOs") prior to the issuance of a system-wide storage OFO pursuant to Section 4.3 (L) of the General Terms and Conditions of Texas Eastern's FERC Gas Tariff, Sixth Revised Volume No. 1 ("Tariff").

As indicated in Texas Eastern's November 6, 2000 letter, the need for a customer specific OFO would be determined based on such customer's variance from the suggested storage withdrawal plan specified in November 6, 2000 mailing. The Withdrawal Plan indicates the maximum recommended storage withdrawals for each of four (4) withdrawal periods and is designed to reflect in the aggregate Texas Eastern's historical utilization of its storage facilities prior the implementation of the Commission's Order No. 636.

As of December 31, 2000, the United Cities Gas Co. ("Unit Cit MO") has exceeded, on its (SS-1) Rate Schedule Service Agreement(s), [400227], its recommended storage withdrawals during the November 16, 2000 to December 31, 2000, period by [(66,026)dth.] Accordingly, pursuant to Section 4.3 (M) of the General Terms and Conditions of Texas Eastern's Tariff, **Texas Eastern hereby issues this OFO and directs [Unit Cit MO] to schedule to the maximum extent contractually feasible firm transportation service under its Rate Schedule(s) CDS and FT-1 Service agreements for the delivery of its Maximum Daily Quantity ("MDQ") under such Service Agreements in the Market area before scheduling firm storage service pursuant to Service Agreements(s) [400227]. In the event [Unit Cit MO] does not comply with this OFO, [Unit Cit MO] will be subject to non-compliance penalties.** Specifically, if [Unit Cit MO's] actual deliveries on any day in the Market Area under its Rate Schedule(s) CDS and FT-1 Service Agreements are less than its maximum daily contractual entitlements under such Service Agreements, then the lesser of: (i) the difference between [Unit Cit MO's] actual deliveries and ninety-seven percent (97%) of it's maximum daily contractual entitlements Service Agreements(s) or (ii) the quantities of gas withdrawn pursuant to [Unit Cit MO's] Service Agreement(s) [400227] shall be deemed unauthorized quantities for which a charge of $25 per dth shall be assessed.

This OFO will be effective as of 9:00 a. m. CT, on January 12, 2001, and shall remain in effect until cancelled by Texas Eastern. In addition, [Unit Cit MO] may undertake certain remedial actions, as described in the November 6, 2000 letter, to expedite cancellation of this OFO. If [Unit Cit MO] has questions or needs assistance with such remedial efforts, please contact your Account Manager.

Sincerely,

Binford R. Halverson
General Manager
Gas Management / Producer Services

TEXAS EASTERN TRANSMISSION CORPORATION
CUSTOMER STORAGE WITHDRAWAL PLAN PERFORMANCE REPORT

As of : December 31, 2000

SHIPPER	Contract Number	Rate Sched	Withdrawal Plan	Actual Withdrawal	Difference	%
United Cities Gas Co. (MO, A Div of ATM)	400227	SS-1	150,794	216,820	(66,026)	-44% ****
Total			150,794	216,820	(66,026)	-44%

NOTE :
(1) (+) Under and (-) Over Withdrawal
(2) **** Exceeded Plan WD QTY.

Duke Energy.

Duke Energy Corporation
5400 Westheimer Court
P.O. Box 1642
Houston, TX 77251-1642

February 5, 2001

United Cities Gas Co., A Division of ATMO
Attn: Larry Tarrant
377 Riverside Drive
Suite 201
Franklin, TN 37064-5393

RE: **CANCELLATION OF CUSTOMER-SPECIFIC OFO**

On January 8, 2001, Texas Eastern Transmission Corporation ("Texas Eastern") issued an Operational Flow Order ("OFO") directing [United Cities Gas Co.] ("Customer") to schedule, to the maximum extent contractually feasible, firm transportation service under its Rate Schedule(s) CDS and FT-1 service agreements for the delivery of Customer's Maximum Daily Quantity under such service agreements in the Market Area before scheduling firm storage service. Due to [Unit Cit MO's] remedial action which corrected the prior period deviation from the withdrawal plan [400227], Texas Eastern hereby cancels such Customer Specific OFO effective as of 9:00 a.m. CT on Tuesday, February 6, 2001.

Texas Eastern will continue to monitor customer storage activity and may need to issue customer-specific OFOs if required by future circumstances. Similar to the current OFOs, any future customer-specific OFOs will be based upon each customer's variance from the suggested storage withdrawal plan provided to you and the other firm storage customers by letter dated November 6, 2000.

If you have any questions regarding the foregoing matters, please contact your Account Manager.

Sincerely,

Binford R. Halverson
General Manager
Gas Management / Producer Services

MO PSC Case No. GR-2001-397
Atmos Missouri Division
Hannibal/Bowling Green Storage
November 2000-March 2001

Bowling Green

Contract No.	Type	Month	MSQ	MDWQ	Beg Bal	Beg %	Net Inj/(WD)	End Bal	End %	% MSQ W/D	Invoice No.[1]
11794	IOS	Nov-00	52,000	520	43,037	83%	(3,928)	39,109	75%	8%	1100201
11794	IOS	Dec-00	52,000	520	39,109	75%	(3,438)	35,671	69%	7%	1200202
11794	IOS	Jan-01	52,000	520	35,671	69%	(2,848)	32,823	63%	5%	10100200
11794	IOS	Feb-01	52,000	520	32,823	63%	(4,722)	28,101	54%	9%	10200200
11794	IOS	Mar-01	52,000	520	28,101	54%	(2,874)	25,227	49%	6%	10300206

Hannibal

Contract No.	Type	Month	MSQ	MDWQ	Beg Bal	Beg %	Net Inj/(WD)	End Bal	End %		
11661	IOS	Nov-00	161,000	1,610	138,173	86%	(8,322)	129,851	81%	5%	1100201
11597	WS	Nov-00	108,000	540	102,738	95%	(11,166)	91,572	85%	10%	1100201
14088	FS	Nov-00	399,462	9,511	383,205	96%	(79,917)	303,288	76%	20%	1100201
Total Mo.			668,462	11,661	624,116	93%	(99,405)	524,711	78%	15%	1100201
11661	IOS	Dec-00	161,000	1,610	129,851	81%	17,622	147,473	92%	-11%	1200202
11597	WS	Dec-00	108,000	540	91,572	85%	(23,120)	68,452	63%	21%	1200202
14088	FS	Dec-00	399,462	9,511	303,288	76%	(160,648)	142,640	36%	40%	1200202
Total Mo.			668,462	11,661	524,711	78%	(166,146)	358,565	54%	25%	1200202
11661	IOS	Jan-01	161,000	1,610	147,473	92%	(35,510)	111,963	70%	22%	10100200
11597	WS	Jan-01	108,000	540	68,452	63%	(12,062)	56,390	52%	11%	10100200
14088	FS	Jan-01	399,462	9,511	142,640	36%	36,285	178,925	45%	-9%	10100200
Total Mo.			668,462	11,661	358,565	54%	(11,287)	347,278	52%	2%	10100200
		50,000 transferred from IOS to FS on 1/13/2001									
11661	IOS	Feb-01	161,000	1,610	111,963	70%	9,451	121,414	75%	-6%	10200200
11597	WS	Feb-01	108,000	540	56,390	52%	(26,410)	29,980	28%	24%	10200200
14088	FS	Feb-01	399,462	9,511	178,925	45%	(96,699)	82,226	21%	24%	10200200
Total Mo.			668,462	11,661	347,278	52%	(113,658)	233,620	35%	17%	
11661	IOS	Mar-01	161,000	1,610	121,414	75%	(35,836)	85,578	53%	22%	10300206
11597	WS	Mar-01	108,000	540	29,980	28%	(24,300)	5,680	5%	23%	10300206
14088	FS	Mar-01	399,462	9,511	82,226	21%	(58,302)	23,924	6%	15%	10300206
Total Mo.			668,462	11,661	233,620	35%	(118,438)	115,182	17%	18%	10300206
		25,000 transferred from IOS to FS on 3/26/2001									

SCHEDULE NO. JH-6

MO PSC Case No. GR-2001-397
Atmos Missouri Division
Hannibal/Bowling Green Storage
November 2000-March 2001

Total Hannibal/Bowling Green

	Type	Month	MSQ	MDWQ	Beg Bal	Beg %	Net Inj/(WD)	End Bal	End %				
	IOS	Nov-00	213,000	2,130	181,210	85%	(12,250)	168,960	79%	6%	1100201	Beg Bal	667,153
	WS	Nov-00	108,000	540	102,738	95%	(11,166)	91,572	85%	10%	1100201	End Bal	154,291
	FS	Nov-00	399,462	9,511	383,205	96%	(79,917)	303,288	76%	20%	1100201	Total W/D	(512,862)
Total Mo.			720,462	12,181	667,153	93%	(103,333)	563,820	78%	14%	1100201		
	Type	Month	MSQ	MDWQ	Beg Bal	Beg %	Net Inj/(WD)	End Bal	End %				
	IOS	Dec-00	213,000	2,130	168,960	79%	14,184	183,144	86%	-7%	1200202		
	WS	Dec-00	108,000	540	91,572	85%	(23,120)	68,452	63%	21%	1200202		
	FS	Dec-00	399,462	9,511	303,288	76%	(160,648)	142,640	36%	40%	1200202		
Total Mo.			720,462	12,181	563,820	78%	(169,584)	394,236	55%	24%	1200202		
	Type	Month	MSQ	MDWQ	Beg Bal	Beg %	Net Inj/(WD)	End Bal	End %				
	IOS	Jan-01	213,000	2,130	183,144	86%	(38,358)	144,786	68%	18%	10100200		
	WS	Jan-01	108,000	540	68,452	63%	(12,062)	56,390	52%	11%	10100200		
	FS	Jan-01	399,462	9,511	142,640	36%	36,285	178,925	45%	-9%	10100200		
Total Mo.			720,462	12,181	394,236	55%	(14,135)	380,101	53%	2%	10100200		
	Type	Month	MSQ	MDWQ	Beg Bal	Beg %	Net Inj/(WD)	End Bal	End %				
	IOS	Feb-01	213,000	2,130	144,786	68%	4,729	149,515	70%	-2%	10200200		
	WS	Feb-01	108,000	540	56,390	52%	(26,410)	29,980	28%	24%	10200200		
	FS	Feb-01	399,462	9,511	178,925	45%	(96,699)	82,226	21%	24%	10200200		
Total Mo.			720,462	12,181	380,101	53%	(118,380)	261,721	36%	16%	10200200		
	Type	Month	MSQ	MDWQ	Beg Bal	Beg %	Net Inj/(WD)	End Bal	End %				
	IOS	Mar-01	213,000	2,130	149,515	70%	(38,710)	110,805	52%	18%	10300206		
	WS	Mar-01	108,000	540	29,980	28%	(24,300)	5,680	5%	23%	10300206		
	FS	Mar-01	399,462	9,511	82,226	21%	(58,302)	23,924	6%	15%	10300206		
Total Mo.			720,462	12,181	261,721	36%	(121,312)	140,409	19%	17%	10300206		

Note 1: Hannibal and Bowling Green systems are served by Panhandle Eastern Pipeline Company

Hannibal
December 2000

	Contract MDQ	Capacity Required for IOS	Net Contract MDQ	Baseload Receipts	Swing Receipts	Total Purchase Receipts	Purch % of Net MDQ
1 FRI	8,045	1,610	6,435	5,474	0	5,474	85%
2 SAT	8,045	1,610	6,435	5,474	0	5,474	85%
3 SUN	8,045	1,610	6,435	5,474	0	5,474	85%
4 MON	8,045	1,610	6,435	5,474	0	5,474	85%
5 TUE	8,045	1,610	6,435	5,474	415	5,889	92%
6 WED	8,045	1,610	6,435	5,474	415	5,889	92%
7 THU	8,045	1,610	6,435	5,474	415	5,889	92%
8 FRI	8,045	1,610	6,435	5,474	415	5,889	92%
9 SAT	8,045	1,610	6,435	5,474	415	5,889	92%
10 SUN	8,045	1,610	6,435	5,474	415	5,889	92%
11 MON	8,045	1,610	6,435	5,474	415	5,889	92%
12 TUE	8,045	1,610	6,435	5,474	415	5,889	92%
13 WED	8,045	1,610	6,435	5,474	415	5,889	92%
14 THU	8,045	1,610	6,435	5,474	1,115	6,589	102%
15 FRI	8,045	1,610	6,435	5,474	1,115	6,589	102%
16 SAT	8,045	1,610	6,435	5,474	915	6,389	99%
17 SUN	8,045	1,610	6,435	5,474	915	6,389	99%
18 MON	8,045	1,610	6,435	5,474	415	5,889	92%
19 TUE	8,045	1,610	6,435	5,474	415	5,889	92%
20 WED	8,045	1,610	6,435	5,474	415	5,889	92%
21 THU	8,045	1,610	6,435	5,474	415	5,889	92%
22 FRI	8,045	1,610	6,435	5,474	415	5,889	92%
23 SAT	8,045	1,610	6,435	5,474	415	5,889	92%
24 SUN	8,045	1,610	6,435	5,474	415	5,889	92%
25 MON	8,045	1,610	6,435	5,474	415	5,889	92%
26 TUE	8,045	1,610	6,435	5,474	415	5,889	92%
27 WED	8,045	1,610	6,435	5,474	415	5,889	92%
28 THU	8,045	1,610	6,435	5,474	415	5,889	92%
29 FRI	8,045	1,610	6,435	5,474	415	5,889	92%
30 SAT	8,045	1,610	6,435	5,474	415	5,889	92%
31 SUN	8,045	1,610	6,435	5,474	415	5,889	92%
	249,395	49,910	199,485	169,694	13,605	183,299	92%