	Exhibit No.: ____________
Issues:	KPC Capacity Release Purchasing Practices – Hedging Purchasing Practices – Storage
Witness:	Michael T. Langston
Sponsoring Party:	Missouri Gas Energy
Case No.:	GR-2001-382

MISSOURI PUBLIC SERVICE COMMISSION

MISSOURI GAS ENERGY

CASE NO. GR-2001-382

DIRECT TESTIMONY OF

MICHAEL T. LANGSTON

Jefferson City, Missouri
January 15, 2003

Exhibit No. 3
Case No(s). GR-2001-382
Date 5-12-03 Rptr KF

DIRECT TESTIMONY OF

MICHAEL T. LANGSTON

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DIRECT TESTIMONY OF

MICHAEL T. LANGSTON

CASE NO. GR-2001-382

JANUARY 15, 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael T. Langston. My business address is Energy Worx, 1301 S. MoPac Expressway, Suite 400, Austin, Texas 78746.

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

A. I am employed by Energy Worx, a wholly-owned subsidiary of Southern Union Company ("Southern Union"), and hold the position of Vice President of Customer Service and Regulatory. However, during the period of this ACA case, I was employed by Southern Union as Vice President, Gas Supply, with responsibilities for MGE's gas supply activities.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science Degree in Electrical Engineering with honors from the University of Texas in Austin in 1975. I received a Master of Business Administration from Southern Methodist University in Dallas, Texas in 1978. I was employed by Mobil Pipe Line Company from 1975 to 1979 in various positions in their engineering department. From 1979 through most of 1986, I was employed by Texas Oil and Gas

Corp. and its affiliate, Delhi Gas Pipe Line Corporation, holding various positions in corporate planning, special projects, and project development. I joined Southern Union in September 1986 and have been employed by Southern Union since that time. I am also a Registered Professional Engineer in the states of Texas, Louisiana, and Oklahoma.

Q. PLEASE DESCRIBE THE NATURE OF YOUR DUTIES AS VICE PRESIDENT, GAS SUPPLY.

A. Prior to and during this ACA period (July 1, 2000 through June 30, 2001), I had responsibility for natural gas contracting and purchasing, contract administration, gas supply planning and the daily gas control function. This involved management of all negotiations with suppliers for natural gas purchases and utility pipeline companies for transportation service to deliver gas supplies to our various distribution systems. In many cases, I have been involved in extensive regulatory proceedings at the Federal Energy Regulatory Commission ("FERC"), or at applicable state commissions in order to ensure that the terms and conditions of service we have received from regulated pipeline companies are fair and reasonable. I have also been involved in negotiations and regulatory proceedings on operational matters involving our upstream supply and transportation services and suppliers. I am participating in this proceeding pursuant to a contract between MGE and Energy Worx as a fact witness only covering past periods due to my prior role and responsibility as Vice President, Gas Supply.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide factual information that responds to the allegations raised by the Staff of the Missouri Public Service Commission ("Staff") in its recommendation filed in Case No. GR-2001-382 on May 31, 2002. In its recommendation, Staff attached a memorandum (the "May 31, 2002 Memo") outlining three areas for which it was proposing a disallowance: 1) the Mid-Kansas Partnership/Riverside Pipeline Company ("MKP-RPC") gas supply and transportation contract; 2) capacity release on KPC, and 3) MGE's purchasing practices during the winter of 2000/2001. Specifically, with regard to the purchasing practices, Staff identified two sub-areas for which it was proposing a disallowance: (i) the volumes "hedged" by MGE; and 2) MGE's use of its storage inventory relative to flowing supplies.

Q. WILL YOUR TESTIMONY ADDRESS ALL OF THESE ISSUES?

A. No. My testimony will only address Staff's allegations regarding the release of capacity on KPC and MGE's purchasing practices during the winter of 2000/2001. The Commission has ruled that the MKP-RPC gas supply and transportation contract issue will not be taken up during this portion of this proceeding and will be deferred pending the outcome of judicial review of the Commission's order in Case No. GR-96-450.

Q. ARE YOU SPONSORING ANY SCHEDULES TO YOUR TESTIMONY?

A. Yes. I am sponsoring the following schedules:

Schedule MTL-1	Comparison of Pipeline Tariff Rates
Schedule MTL-2	KPC Discounted Interruptible Transportation Rates to Affiliates

Schedule MTL-3	Letter from KPC Indicating No Capacity Release Transactions
Schedule MTL-4	Copy of KPC Riverside I Contract
Schedule MTL-5	Copy of TransOk Lease
Schedule MTL-6	Letter from Duke Regarding Value of MGE's Capacity on KPC
Schedule MTL-7	KPC Capacity Release Postings, March-October 2002
Schedule MTL-8	Average Williams Capacity Release Rates, July – October 2000 and April – June 2001
Schedule MTL-9	Staff Workpaper Calculating Value of KPC/Williams Capacity Release
Schedule MTL-10	Williams Open Capacity Release Postings, July - December 2000
Schedule MTL-11	Non-Recallable Williams Capacity Release Postings, 2002
Schedule MTL-12	Letter from MGE to Staff, September 26, 2000
Schedule MTL-13	Staff Workpaper Calculating its Proposed Hedging Disallowance
Schedule MTL-14	MGE Storage Plans vs. Actual, November 1997 through March 2001
Schedule MTL-15	Comparison of Flowing Supplies, Staff vs. MGE
Schedule MTL-16	MGE Decision Summary, November 2000-March 2001

<u>**CAPACITY RELEASE ON KPC**</u>

Q. PLEASE DISCUSS STAFF'S ALLEGATION REGARDING THE RELEASE OF CAPACITY ON KPC.

A. Staff has alleged in its May 31, 2002 Memo that MGE should have posted for release to other shippers its Riverside I contract capacity on KPC for the months of July through October 2000 and April through June of 2001, or in other words, the summer months of the ACA period at issue in this proceeding. Staff has stated that, since MGE did not post its KPC capacity for release, the Commission should disallow $1,141,784 of gas costs. The calculation of Staff's proposed disallowance is based on the premise that MGE would have been able to release its capacity on KPC over the months in question, on a non-recallable basis, and receive 75% of the equivalent maximum rate on Williams.

Q. DOES MGE AGREE WITH STAFF'S POSITION THAT IT WAS IMPRUDENT FOR MGE NOT TO POST ITS KPC CAPACITY FOR RELEASE AND THAT A DISALLOWANCE IS APPROPRIATE?

A. No. First, and most importantly, I believe that MGE's conduct with regard to the capacity on KPC was reasonable and appropriate under the circumstances and that Staff has failed to adequately and sufficiently review the issue. As I will demonstrate below, MGE did not post for release its KPC capacity since the likelihood of that capacity being released was effectively zero due to numerous operational and economic limitations inherent with the capacity. In addition, MGE's experience in the market has shown that it is significantly more effective to negotiate releases with third-parties rather than post capacity for non-recallable release. Therefore, I believe that MGE's conduct with regard to its KPC capacity during the ACA period in question was prudent. In addition, even though MGE's conduct with regard to its KPC capacity was prudent, I will also demonstrate that the calculation of Staff's proposed disallowance is entirely incorrect and without basis.

Q. WHAT EXACTLY IS A CAPACITY RELEASE TRANSACTION?

A. A capacity release transaction is where a shipper on a natural gas pipeline, such as MGE, offers to sell to a third-party a portion of its contracted firm capacity on the pipeline that is not needed for a specific period of time. This is analogous to subleasing an apartment or office space that is not needed for a specific period of time. Local distribution companies ("LDCs"), such as MGE, need sufficient pipeline capacity to meet winter peak demands; however, pipeline shippers are typically required to purchase pipeline capacity for the entire year rather than to only meet their peak winter demands. Therefore, there are times of the year, specifically during the summer period when LDC demand is at its lowest level, that there is capacity that is not needed by the LDC. As a result, the FERC has mandated that all interstate pipelines provide a capacity release mechanism within their tariffs whereby customers may "release" to a third-party any available capacity.

Q. HOW ARE THESE CAPACITY RELEASE TRANSACTIONS IMPLEMENTED?

A. There are essentially two methods by which capacity is released to a third-party: private negotiation and open bidding. The first method, i.e., private negotiation, is when the company contractually holding the capacity on the pipeline, such as MGE, negotiates directly with a third-party to release a portion of its pipeline capacity. The negotiations include the quantity of capacity to be released, the price at which the capacity will be released, the term of the release, and other specific terms and conditions associated with the release, such as a specified load factor, and whether or not the capacity may be recalled by the original capacity holder.

Q. WHAT DO YOU MEAN BY "RECALLED?"

A. Generally, a capacity holder can release its capacity to a third-party in one of two ways, i.e., on a recallable basis or on a non-recallable basis, depending on the specific needs of the releasing shipper. If done on a recallable basis, the releasing shipper still has the right to utilize its capacity, if necessary, even though the capacity has been released to another party for a period of time. A recallable release would contain a provision allowing the original capacity holder (in this case, MGE) to "recall" or reclaim the capacity upon notice. In contrast, if the transaction is done on a non-recallable basis, the releasing shipper gives up its rights to its capacity for the duration of the release. Thus, a non-recallable capacity release would contain a contractual provision that states that the party to whom the capacity is released has the right to use the capacity for the entire period of the release, without the risk of it being recalled by the releasing shipper.

Q. PLEASE EXPLAIN THE SECOND METHOD FOR RELEASING CAPACITY, i.e., OPEN BIDDING?

A. Open bidding is when a shipper that wants to release capacity posts on the interstate pipeline's electronic bulletin board that such capacity is available for release and then third-parties can bid on the capacity. In this case, a company such as MGE, will post or offer a specified amount of capacity on the pipeline bulletin board for release, as well as outline the general terms and conditions of such release, including the quantity of capacity, the price and term of the release. However, unlike the private negotiation, these terms and conditions of the release are pre-determined by MGE and the third-parties then bid on the capacity based on the specific terms and conditions that MGE has provided. The highest bid will then be awarded the capacity.

Q. ONCE A CAPACITY RELEASE TRANSACTION IS NEGOTIATED OR A BID IS AWARDED, WHAT HAPPENS?

A. Once a capacity release transaction is completed, i.e., the terms and conditions have been agreed upon through a negotiated transaction or a winning bidder has been selected through an open bidding process, then the interstate pipeline company will send a transportation contract, generally electronically, to the third-party that has acquired the released capacity. The third-party and the pipeline will then enter into a contract for such capacity.

Q. HOW ARE THE RATES OR PRICES UNDER SUCH AGREEMENTS DETERMINED?

A. In general, the only component of the overall transportation rate that is negotiated (or bid on in the case of an open posting) is the demand (or reservation) charge on the interstate pipeline. Demand charges are the fixed monthly charges that are required to be paid to the pipeline whether any gas is transported. The demand charge portion of the overall rate is the only component that is negotiated or bid on during a capacity release transaction since interstate pipeline commodity rates cannot be discounted by a releasing shipper. Therefore, once the capacity has been released to a third-party, the interstate pipeline will charge that third-party the following: (i) the designated demand rate agreed to pursuant to the capacity release transaction; (ii) the applicable maximum commodity charge in the pipeline tariff; (iii) the applicable tariff fuel charges for moving the gas across the interstate pipeline system; and (iv) any applicable pipeline surcharges. Once the pipeline has received payment for the capacity release transaction from the third-party, then the demand charge portion of the rate, which was negotiated between the parties (or was bid on during the open posting), is credited against the original capacity holder's transportation invoice.

Q. DOES MGE RELEASE CAPACITY ON THE PIPELINES ON WHICH IT HOLDS CAPACITY?

A. Generally, yes. MGE is served by several interstate pipelines, including Williams, Kinder Morgan, Panhandle Eastern Pipe Line ("PEPL") and KPC. MGE generates capacity release revenues on both the Williams and the Kinder Morgan systems. MGE generally does not have capacity available for release on the PEPL system, since unlike the other interstate pipelines that serve MGE's distribution service territory, PEPL allows its shippers to contract for capacity on a seasonal, rather than annual, basis. In contrast, MGE has never released capacity on KPC since there are two factors that make it nearly impossible for MGE to release such capacity.

Q. WHAT FACTORS MAKE IT NEARLY IMPOSSIBLE FOR MGE TO RELEASE ITS KPC CAPACITY?

A. There are two primary factors that make it nearly impossible for MGE to release its KPC capacity. First, KPC's high commodity rates make it uneconomic for third-parties to obtain released capacity from KPC's shippers such as MGE. Second, there are severe operational limitations inherent with MGE's capacity on KPC that make it administratively and operationally difficult, and thus costly, for other parties to utilize.

Q. IN TERMS OF THE FIRST FACTOR, WHY DO KPC'S HIGH COMMODITY RATES MAKE IT UNECONOMIC FOR THIRD-PARTIES TO OBTAIN RELEASED CAPACITY FROM KPC'S FIRM SHIPPERS?

A. Basically, MGE faces three forms of competition for the release of its KPC capacity. First, MGE competes directly with other firm capacity holders on KPC that have capacity to release. Second, MGE competes directly with KPC itself as the pipeline is able to sell interruptible transportation capacity as an alternative to firm released capacity. Third, MGE competes directly with firm capacity holders on other pipelines that serve the same market as KPC and have capacity to release. Considering these competitive alternatives, KPC's relatively high commodity rates make it uneconomic for third-parties to obtain released capacity from KPC's firm shippers since it is financially more economic for third-parties to either purchase interruptible capacity directly from KPC or, if the capacity is needed on a firm basis, purchase capacity on other pipelines with lower variable costs (i.e., commodity rates and fuel charges) that serve the same market.

Q. WHY DOES KPC'S HIGH COMMODITY RATE MAKE ITS INTERRUPTIBLE TRANSPORTATION SERVICE A DIRECT COMPETITIVE ALTERNATIVE TO MGE'S FIRM CAPACITY ON KPC?

A. As noted above, MGE and other firm shippers, may only negotiate the demand rate component of the total rate charged by the pipeline, or in other words, MGE and other firm shippers cannot negotiate the commodity rate. Thus, for all capacity release transactions between firm shippers, the pipeline's maximum commodity rate and fuel charges apply and effectively form the basis of a price floor for which capacity can be released. However, the pipeline itself under interruptible transportation service may discount both the demand *and* the commodity portions of its rate. Therefore, when the pipeline's commodity rate is high compared to its total overall rate (i.e., the demand rate plus the commodity rate plus fuel charges), a discount of the commodity rate can be a substantial economic incentive for a third-party to purchase interruptible transportation capacity from the pipeline rather than purchase released firm capacity from one of the pipeline's firm shippers. This is exactly the case with KPC.

Q. HOW DO KPC'S COMMODITY RATES COMPARE TO THE COMMODITY RATES OF OTHER PIPELINES SERVING MGE?

A. KPC's commodity rates are very high compared to the commodity rates of the other interstate pipelines serving MGE's service territory. Attached as Schedule MTL-1 is a summary of the demand, commodity and fuel charges on each of the pipeline systems serving the MGE Kansas City area, i.e., Williams, PEPL, Kinder Morgan and KPC. As illustrated on Schedule MTL-1, KPC's commodity rate is $0.0625 per dth and is substantially higher than the commodity charges on the other pipeline systems capable of delivering natural gas into the Kansas City area. In fact, KPC's commodity rate is 1.82 times higher than PEPL's commodity rate, 2.41 times higher than Williams' commodity rate, and 3.06 times higher, or over triple the Kinder Morgan commodity rate.

Q. DOES THE FACT THAT KPC'S COMMODITY RATE IS SO HIGH MAKE THE CAPACITY OF KPC'S FIRM SHIPPERS, INCLUDING MGE, EFFECTIVELY UNMARKETABLE?

A. Yes, the firm capacity that shippers hold on KPC, including MGE, is effectively the least attractive alternative in the market as a result of KPC's high commodity rate. As discussed above, KPC can discount its commodity rate and sell interruptible transportation service at an overall rate that is substantially less than the rate for which MGE can release its firm capacity. Interruptible transportation service does not contractually have the same level of reliability as firm transportation service that is being offered for release by MGE. However, during the summer, interruptible service is nearly as effective as firm service since demand on the pipeline is at its lowest level and the likelihood of being interrupted is very low. Therefore, the distinction between firm and interruptible service is negligible during the summer months and the only meaningful difference between the two services being offered is the price. The lowest price at which MGE could release capacity on the KPC system would be $0.0625 per dth plus fuel charges, while KPC can, and does, offer substantial discounts below this level.

Moreover, the capacity MGE could release on KPC is also less desirable vis-à-vis capacity offered for release by shippers on the other pipelines capable of serving the same general market as KPC. Since the other pipelines serving MGE's service territory have substantially lower commodity rates already, firm shippers on those pipelines are able to offer released capacity in the same market as an alternative to the capacity on KPC at a much lower cost. Therefore, MGE's capacity on KPC that could be offered for release is effectively the least attractive alternative due to KPC's rate structure.

Q. DID KPC DISCOUNT ITS INTERRUPTIBLE RATE BELOW ITS MAXIMUM TARIFF COMMODITY RATE DURING THE ACA PERIOD IN QUESTION?

A. Yes. Attached as Schedule MTL-2 is a listing of the interruptible transportation transactions that occurred on KPC from July through October 2000 and April through June 2001. As illustrated in Schedule MTL-2, all of the interruptible transactions that occurred during the ACA period in question were transactions with affiliates of KPC and were all transacted for a total rate, including demand charges and commodity charges, at a rate substantially below the maximum commodity rate alone. For example, in July 2000, KPC sold 200,200 dth/day of interruptible transportation capacity to be delivered into KPC's Zone 3, which includes the Kansas City area, to its affiliate for the entire month at a rate of $0.0207 per dth. As noted above, the lowest rate that any firm shipper on KPC, including MGE, is able to release its capacity to another shipper is limited by KPC's maximum commodity rate of $0.0625 per dth. Therefore, KPC sold its interruptible transportation capacity for just one-third of the absolute lowest level that MGE could have released its capacity. As illustrated in Schedule MTL-2, similar transactions occurred throughout the ACA period in question in this proceeding.

Therefore, such discounts by KPC to its own affiliates for interruptible transportation service provide substantial competition to firm capacity holders such as MGE seeking to release its own capacity. Even though the release of capacity by MGE would be on a firm basis, the substantial difference between a discounted interruptible rate and the pipeline's commodity rate provides a very strong incentive for customers to acquire interruptible capacity directly from the pipeline rather than through released capacity from MGE.

Q. HAVE OTHER FIRM SHIPPERS ON KPC EVER RELEASED CAPACITY?

A. No. In addition to MGE, there are two other firm capacity holders on KPC, i.e., Kansas Gas Service and United Cities Gas. Attached as Schedule MTL-3 is a letter from the owner of KPC, Enbridge Midcoast Energy, Inc., stating that there had been absolutely no capacity release transactions on the pipeline from June 1, 1997 through the date of the letter, or April 2, 2002. In other words, there have been no capacity release transactions on KPC for nearly five years. Therefore, although Staff alleges that MGE should have posted for release its KPC capacity starting in July 2000, MGE knew that there had never been a successful capacity release transaction on the system in the three years prior and nothing had changed that would indicate capacity could be successfully released going forward.

Q. HAS STAFF RECOGNIZED THAT THERE HAVE NEVER BEEN ANY SUCCESSFUL CAPACITY RELEASE TRANSACTIONS ON KPC PRIOR TO, DURING OR AFTER THE ACA PERIOD FOR WHICH THEY ARE PROPOSING A DISALLOWANCE?

A. No. Staff made no mention of this fact in its May 31, 2002 Memo assessing the prudence of MGE's conduct regarding the release of its KPC capacity. In addition, as noted in the testimony of MGE Witness Reed, Staff has admitted in deposition that it effectively performed no due diligence other than simply looking at KPC's website and reviewing the Riverside I contract to determine whether there was even a capacity release market on KPC.

Q. PLEASE DISCUSS THE SECOND FACTOR, i.e., THE OPERATIONAL LIMITATIONS INHERENT WITH MGE'S CAPACITY ON KPC, THAT MAKES THAT CAPACITY UNATTRACTIVE FOR CAPACITY RELEASE?

A. Attached as Schedule MTL-4 is a copy of MGE's Riverside I contract for firm transportation on KPC. As noted in the contract, the KPC capacity includes leased capacity on the TransOk Intrastate Pipeline system ("TransOk") within Oklahoma. A copy of the TransOk lease is attached as Schedule MTL-5. As noted in the lease, there are very specific operational limitations on how gas volumes must be delivered into the TransOk system in order to be in compliance with the capacity lease agreement entered into between KPC and TransOk. As such, anyone acquiring MGE's released capacity on the KPC system would have to comply with these very specific volumetric delivery obligations associated with the TransOk lease.

Q. HAVE OTHER COMPANIES REVIEWED MGE'S CAPACITY ON KPC AND DETERMINED THAT THESE OPERATIONAL LIMITATIONS IMPACT THE VALUE OF THE CAPACITY IF IT WERE RELEASED?

A. Yes. Prior to the ACA period in question, Duke reviewed MGE's KPC's capacity and, at the time, Duke declined to accept release of the KPC capacity indicating that it had no value for numerous reasons, including the lack of flexibility and inherent operational limitations of the contract.

Attached as Schedule MTL-6 is a letter from a Duke representative outlining their company's review of MGE's capacity on KPC.[1] Based on their review of MGE's Riverside I contract, the Duke letter concludes that:

> Although the Transok/KPL capacity may have value for Missouri Gas Energy in its role as a local distribution company, the true value of released capacity from the perspective of a marketing company lies in the flexibility, spread value, and the matching of capacity to our marketing portfolio objectives. In this particular case, none of these criteria were met, *resulting in zero value placed on the capacity for valuation purposes*." (emphasis added)

Therefore, a nationally recognized marketing company reviewing the capacity prior to the 2000/2001 ACA period at issue in this proceeding, saw no value in the KPC capacity largely because of the operational limitations on the pipeline system discussed above.

Q. DO YOU BELIEVE THE STAFF HAS CONSIDERED THESE OPERATIONAL LIMITATIONS AS PART OF ITS PRUDENCE EVALUATION?

A. No. Similar to the failure of recognizing that capacity release cannot compete economically against discounted interruptible transportation or capacity release on other pipelines, and the fact that there has never even been a successful capacity release transaction on KPC by any party, Staff has also failed to consider the operational limitations of the KPC capacity that further inhibit MGE's ability to release its capacity. As noted in the testimony of MGE Witness Reed, Staff admitted in its deposition that it had reviewed MGE's contract with KPC; however, that appears to be the extent of Staff's

[1] Please note that there are two letters attached as Schedule MTL-4 since initially Duke misstated the effective date of the proposed transaction for the release of MGE's capacity on KPC. Subsequently, Duke noted the error and sent a letter to MGE correcting the date.

evaluation, as Staff has made no mention of the operational issues associated with that contract in its May 31, 2000 Memo or elsewhere in this proceeding.

Q. WAS THERE ANOTHER REASON THAT MGE DID NOT POST ITS AVAILABLE CAPACITY FOR RELEASE ON THE KPC BULLETIN BOARD?

A. Yes. In addition to the fact that no firm capacity holder has ever been able to release capacity on the KPC system and that there are significant operational limitations inherent in utilizing the capacity, it has been MGE's experience that negotiating capacity release transactions with third-parties has been more successful than posting capacity for bid on a pipeline bulletin board. For example, despite making open postings to release its capacity on the Williams system – capacity that is much more desirable to third-parties considering that it is a much more extensive pipeline system, serving many more markets with lower commodity and fuel charges, and without the severe operating limitations associated with the KPC system – MGE has never received any bids for such open postings.

For all of the reasons identified herein, it was MGE's belief during the 2000/2001 ACA period that neither open postings or negotiated release transactions would not have generated capacity release revenue on the KPC system. This continues to be MGE's belief since the circumstances have not changed that would make MGE's KPC capacity relatively more attractive to third-parties. It is simply a matter of competition and economics. Simply put, no parties have ever been interested in acquiring released capacity on KPC due to the operational limitations on the KPC system and the high commodity charge that places KPC's firm shippers at a cost disadvantage as compared to both the pipeline's interruptible transportation and firm shippers offering release capacity on other pipelines serving Kansas City. The Staff has assumed a market for capacity release where none has ever existed and does not now exist.

Q. SINCE MGE HAS BECOME AWARE OF STAFF'S RECOMMENDATION, HAS MGE MADE POSTINGS ON THE KPC SYSTEM JUST TO SEE WHAT WOULD HAPPEN?

A. Yes, in spite of the clear logic and compelling evidence described above indicating that such action is unlikely to produce successful results, MGE has in good faith, subsequently undertaken such postings. Attached as Schedule MTL-7 are copies of open postings that MGE has made on KPC since MGE became aware of the Staff's potential recommendation in this case. MGE made open postings for its KPC capacity beginning in late March 2002, and has made similar postings on the system since that time.

Q. HAS MGE RECEIVED ANY BIDS FOR ITS KPC CAPACITY?

A. No. MGE has posted its KPC capacity on both a recallable and non-recallable basis, and, as expected, no offers have been received, representing further proof of MGE's on-going belief that the capacity cannot be successfully released on KPC. In addition, MGE does not expect that it will ever receive any bids for its posted KPC capacity until circumstances change significantly.

Q. WHAT IS THE LOWEST DEMAND OR RESERVATION RATE FOR WHICH MGE HAS POSTED ITS KPC CAPACITY FOR RELEASE?

A. MGE has posted its KPC capacity for release, on a non-recallable basis, for a demand rate of $0.05 per dth, which represents less than 8% of the maximum 100% load factor demand rate of $0.6541 per dth. In other words, even with over a 92% discount off of the maximum demand rate, MGE has been unable to release its KPC capacity through open posting.

Q. WHY DO YOU BELIEVE MGE HAS RECEIVED NO RESPONSES FOR ITS KPC CAPACITY POSTINGS?

A. Once again, the operational limitations for parties delivering gas on the KPC system are significant, and therefore, require significant effort in order to utilize this capacity. Further, the cost differential between interruptible and firm capacity is so significant that interruptible service represents an economic opportunity that most parties cannot pass up, even assuming they can effectively deal with the operational limitations. In general, as noted above, it is our experience that only KPC's own affiliates have been utilizing the pipeline system under interruptible service. Therefore, there are no third-parties purchasing released capacity on KPC and no third-parties utilizing interruptible service on KPC either.

Q. HAS STAFF MADE ANY OTHER STATEMENTS REGARDING THE PRUDENCE OF MGE'S CAPACITY RELEASE ON KPC?

A. Yes. Staff has stated that, as an alternative to releasing capacity on KPC, MGE should have utilized its KPC capacity and then released its Williams capacity on a non-recallable basis.[2] In addition, Staff has also utilized this alternative, i.e., flowing the KPC capacity and releasing the Williams capacity, in order to calculate its proposed disallowance for MGE not releasing its KPC capacity. Staff has stated that MGE could have obtained 75% of the maximum tariff rate for released Williams capacity.

Q. IS STAFF'S ARGUMENT REASONABLE?

A. No. Staff's position is unsupported by the actual facts of the market and is entirely without merit. Even though it would have been extremely unlikely that MGE could have released its capacity on KPC due to the numerous reasons discussed earlier, it would also have been uneconomic for MGE to utilize its KPC capacity and release its Williams capacity on a non-recallable basis. The premise of Staff's position is undercut by the fact that there is simply no way that MGE could have obtained 75% of the Williams maximum tariff rate by releasing its Williams capacity.

Q. WHY COULD MGE NOT OBTAIN 75% OF MAXIMUM WILLIAMS TARIFF RATE?

A. Put simply, capacity on Williams during the time Staff has identified in its May 31, 2002 Memo (i.e., July through October 2000 and April through June 2001) was successfully awarded to replacement shippers at a small fraction of the maximum rate. Schedule MTL-8 illustrates the weighted average reservation rates for all capacity release

2 Deposition of David Sommerer, Missouri Public Service Commission, Case No. GR-2001-382, December 10, 2002, p. 13, ll. 3-18.

transactions for both the Production and Market Areas on Williams for the time period identified by Staff. As shown in Schedule MTL-8, the weighted average capacity release rates for the Production Area and Market Area during this time period were $0.02429/dth and $0.01669/dth, respectively. In contrast, the maximum tariff reservation rates, as stated on a volumetric basis, for the Production and Market Area were $0.18980/dth and $0.09740/dth, respectively. Therefore, Williams' shippers were only able to obtain 13% of the maximum reservation rate for their Production Area capacity and 17% for their Market Area capacity during this time period. For the Production Area and Market Area capacity on a combined basis, shippers were only able to obtain 14% of the total maximum reservation rate. Clearly, there is no way that MGE would have been able to obtain the 75% of the maximum tariff reservation rate on Williams for its capacity that Staff has assumed.

Q. PLEASE EXPLAIN WHY IT WOULD HAVE BEEN UNECONOMIC FOR MGE TO UTILIZE ITS KPC CAPACITY AND RELEASE ITS WILLIAMS CAPACITY ON A NON-RECALLABLE BASIS?

A. Attached as Schedule MTL-9 is a reproduction of Staff's own workpaper in this proceeding that it used to determine the economics of MGE utilizing KPC capacity and releasing Williams capacity. As shown on page 1 of Schedule MTL-9, Staff has assumed that MGE would have been able to obtain 75% of the maximum rate for the release of its KPC capacity, and thus, it would be economic for MGE to utilize its KPC capacity and release its Williams capacity. However, as discussed above, the weighted average release rate on Williams over the seven summer months during the ACA period in question in this proceeding was only 14% of maximum tariff rate. Therefore, as shown on page 2 of Schedule MTL-9, when Staff's own calculation is revised to reflect the capacity release credit on Williams that MGE would likely have obtained based on the then current market conditions, i.e., an average release rate of 14% of the maximum Williams tariff rate rather than the arbitrary 75% has suggested, the schedule shows that it would have been significantly uneconomic for MGE to utilize its KPC capacity and release its Williams capacity. In fact, if MGE had done what Staff has suggested in this proceeding, MGE would have cost its customers over $600,000 in additional costs.[3]

Q. ARE THERE OTHER PROBLEMS WITH STAFF'S ALTERNATIVE POSITION THAT MGE SHOULD HAVE POSTED ITS WILLIAMS CAPACITY FOR NON-RECALLABLE RELEASE?

A. Yes. Although it would have been more costly for MGE to utilize its KPC capacity and release its Williams capacity based on the average capacity release rates that were occurring at the time, MGE actually made open postings to release its Williams capacity during the ACA period in question in an attempt to obtain release revenues greater than what was occurring in the market at the time. Not only was MGE unsuccessful in obtaining 14% of the maximum Williams tariff rate, but MGE was unsuccessful in obtaining any release transactions whatsoever. Specifically, MGE posted its capacity on the Williams system, on a recallable basis, for the period July 2000 through December 2000. As a result of a resignation of personnel in the MGE's gas control department

[3] In fact, as shown on Schedule MTL-9, Staff's workpaper has assumed that the fuel rate for KPC was 3.61% during the ACA period in question in this proceeding. However, as shown on Schedule MTL-1, KPC's fuel rate was actually 3.86% during the ACA period in question. Therefore, if this additional error were corrected

during the December 2000 time frame, Williams capacity was not posted on an open basis for the period January 2001 through June 2001. The posting process was subsequently re-implemented later in 2001.

In addition, MGE has posted its Williams capacity on a non-recallable basis after the ACA period in question. In fact, once MGE became aware of Staff's position that it felt non-recallable capacity was substantially more valuable than recallable capacity, MGE started posting non-recallable capacity on the Williams bulletin board in order to show that this was not in fact the case. Attached as Schedule MTL-10 is a listing of the Williams postings that were made during the July through December 2000 time frame on a recallable basis. Schedule MTL-11 presents the non-recallable capacity postings MGE made during 2002.

Q. HAS MGE EVER RECEIVED A BID FOR ITS OPEN POSTED CAPACITY ON THE WILLIAMS SYSTEM?

A. No. Regardless of whether the capacity was posted for recallable or non-recallable release, MGE has never received a bid on an open posting on the Williams system for its capacity, either during the ACA period at issue in this proceeding or subsequently.

Q. WHY DO YOU BELIEVE THIS IS THE CASE?

A. A third-party who is seeking capacity only does so if they have a need to serve a specific market. The third-party knows what their supply costs are and must have a specified rate

on Staff's workpaper, the total additional cost to MGE (and its customers) of utilizing KPC capacity and releasing Williams capacity as Staff has suggested would have been over $700,000.

for their downstream transportation in order to move their supplies directly to the market with which they are contracting and to lock-in the total delivered cost. Potential buyers of capacity generally place more of a premium on the ability to negotiate and specify a rate in advance rather than bid on capacity that they may never actually obtain. In this way, the third-party knows that they are able to lock-in a profit on the overall transaction. In MGE's experience, all parties prefer to negotiate a specified rate that will allow them to have a known profit margin rather than openly bid on capacity.

Q. IS THIS THE CASE EVEN WHEN THEY COULD OBTAIN OPEN POSTED CAPACITY AT CHEAPER RATES?

A. Yes. In general, when a third-party bids on open posted capacity, they can be subject to bids from other third-parties. Because of the inherent uncertainty of a bidding process, the party seeking capacity will have no assurance that it can actually obtain the capacity at its bid price. In other words, when you participate in the auction, you run the risk of being outbid by another party.

Q. HAS MGE EVER NEGOTIATED RATES FOR RECALLABLE CAPACITY THAT WERE HIGHER THAN THE RATES IT HAD POSTED AS AVAILABLE FOR NON-RECALLABLE CAPACITY?

A. Yes. MGE has recently negotiated many recallable capacity release transactions with third-parties that were at rates significantly higher than the rates otherwise available to be obtained via the pipeline's bulletin board for open posted non-recallable capacity. Again, this is undoubtedly due to the fact that most third-parties need to finalize their transactions in advance so that they have capacity available at specified rates that will make their overall transaction profitable. If a third-party bids on capacity posted for release, even though such capacity will be non-recallable, it may have very little economic value to them if another company outbids them and they are left without the capacity they need.

Q. WHAT RATE DIFFERENTIAL HAS MGE ACHIEVED FOR NEGOTIATED VERSUS OPEN POSTED CAPACITY ON THE WILLIAMS SYSTEM?

A. For the months of September, October and November 2002, MGE posted Williams capacity for release on a non-recallable basis at a rate of 20% of the maximum tariff rate. For the production and market area capacity, this translates into a combined rate of $0.0576 per dth. MGE did not receive any bids for this capacity. However, in contrast, recallable capacity releases were negotiated with third-parties during these months at rates of $0.0807 per dth, $0.0807 per dth and $0.1007 per dth, respectively.

Q. THEREFORE, DO YOU DISAGREE WITH STAFF THAT NON-RECALLABLE RELEASES ARE GENERALLY MORE VALUABLE THAN RECALLABLE RELEASES?

A. Yes. First, based on my knowledge and experience observing markets in the recent past, I would say that MGE's position is that negotiated capacity release transactions have much greater value than open posted capacity release transactions. Second, I would say that non-recallable capacity does not have a premium over recallable capacity, specifically during the summer months in which MGE would generally be releasing capacity. It is possible that parties seeking capacity, particularly during the peak winter period, may pay more to obtain capacity on a non-recallable basis to insure that the capacity remains available for them for the entire term of the release. However, the winter period is exactly when MGE would need to have its capacity available for its own use in the event that it experiences a peak day or spike in demand. In contrast, during the summer months, when significant capacity is not being used by LDC customers, the value between recallable and non-recallable capacity is negligible, and therefore, no premium is associated with non-recallable capacity in the release market.

Q. PLEASE SUMMARIZE MGE'S POSITION WITH REGARD TO STAFF'S PROPOSED FINDING OF IMPRUDENCE FOR MGE NOT RELEASING ITS KPC CAPACITY?

A. First, as I have demonstrated, MGE did not post its KPC capacity for release since there was no value for KPC release capacity during the 2000/2001 ACA period, and there continues to be no value for KPC release capacity. The KPC capacity had no value due to its cost relative to other alternatives and the significant operational issues required to utilize such capacity as compared to other pipeline systems such as the Williams system. Second, Staff's alternative proposal, i.e., release Williams capacity and utilize KPC capacity, is also incorrect, as it would have been more costly for MGE to utilize its KPC capacity and release its Williams capacity. Lastly, open postings of capacity are actually less successful than negotiated transactions and non-recallable capacity release transactions do not have a significantly different value than recallable releases during the summer period.

Q. ARE THERE ANY OTHER POINTS YOU WOULD LIKE TO MAKE REGARDING STAFF'S FINDING OF IMPRUDENCE RELATIVE TO MGE'S RELEASE OF ITS KPC CAPACITY?

A. Yes. I would like to highlight the fact that MGE had an economic incentive to release capacity during the ACA period in question and Staff was clearly aware of this fact. A settlement agreement between MGE, Staff and the Office of Public Counsel ("OPC") approved by the Commission on August 1, 2000 for a Fixed Commodity Price PGA (which will be discussed in detail in the following section of my testimony) specifically included a capacity release incentive mechanism for MGE. The settlement provided for a sliding scale whereby MGE would retain a greater percentage of the capacity release revenues as a greater level of capacity release revenues were generated. Therefore, MGE not only had an economic incentive to successfully release capacity, but also to release its capacity for the highest possible rate. This is simply another reason why Staff's argument that it was imprudent for MGE not to release either its KPC or its Williams capacity is not supportable by the facts in this case.

PURCHASING PRACTICES – HEDGING

Q. PLEASE DISCUSS STAFF'S ALLEGATION REGARDING THE IMPRUDENCE OF MGE'S PURCHASING PRACTICES DURING THE WINTER OF 2000/2001?

A. As discussed earlier, Staff has alleged in its May 31, 2002 Memo that MGE's purchasing practices during the winter of 2000/2001 were imprudent with regard to (i) the level of physical and financial hedging (defined herein as storage inventory and the purchasing of financial instruments, respectively, to hedge the price of natural gas); and (ii) the use of its storage inventory relative to flowing supplies. This section of my testimony will address the first issue, while the following section of my testimony will address the second issue.

For the first issue, i.e., the overall level of "hedging" obtained, Staff asserts that MGE was imprudent since it did not have a "documented, formal plan to hedge the price it paid for natural gas during the winter of 2000/2001."[4] As a result, Staff proposes a disallowance of $614,365 based on its claim that it would have been reasonable for MGE to hedge a minimum of 30% of its normal natural gas requirements for each month during the winter of 2000/2001 to manage the risk of volatile prices. Staff has claimed that MGE did not meet Staff's minimum hedging level of 30% for the months of January and March 2001.

Q. DOES MGE AGREE WITH STAFF'S POSITION?

A. No, it does not. Staff has alleged that MGE was imprudent for not having a documented and formalized hedging plan for the winter of 2000/2001. However, MGE did negotiate and obtain agreement with Staff and OPC, and approval from the Commission, on a Fixed Commodity Price PGA tariff in Case No. GO-2000-705, which would have fixed the price for, or in effect, "hedged", 100% of MGE's gas supplies. MGE feels this was clearly a "documented" plan, as tariffs were in place.

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4 Staff Recommendation – Official Case File Memorandum, Missouri Public Service Commission, Case No. GR-2001-382, May 31, 2002, p. 3 of 6.

Q. WHY WAS THIS PLAN NOT IMPLEMENTED?

A. Unfortunately, the efforts to implement this approved financial hedging program were unsuccessful due to factors outside of MGE's control, namely unprecedented natural gas prices and Staff's reluctance to move forward with a hedging program for MGE in such a price environment, even though Staff had just signed a settlement a month prior with Laclede Gas Company ("Laclede") for a similar hedging plan. Thus, as a result, while MGE had established a formalized hedging program prior to the winter of 2000/2001, the program could not be implemented to provide a substantial level of price protection to its customers.

Q. WHAT STEPS DID MGE TAKE TO ATTEMPT TO PROVIDE A FORMALIZED HEDGING PROGRAM FOR ITS CUSTOMERS PRIOR TO THE WINTER OF 2000/2001?

A. Beginning in December 1998, or nearly two years prior to the winter of 2000/2001, MGE, Staff, and OPC entered into negotiations in an effort to implement a new natural gas purchasing incentive plan to replace the incentive plan that had originally been authorized for MGE by the Commission in Case No. GO-94-318. In general, the Staff expressed concerns about MGE's natural gas purchasing incentive plan established in Case No. GO-94-318 relative to (i) the impact of price volatility and uncertainty on overall customer bills; (ii) the fact that MGE could profit under that incentive plan during high-priced events as long as market-based price purchases were below the applicable benchmark levels; and (iii) an overall desire for a more "locked" or fixed pricing structure. It was essentially on the basis of these Staff concerns that negotiations were entered into by the parties in late 1998.

Q. WERE THESE NEGOTIATIONS SUCCESSFUL IN ESTABLISHING A FORMALIZED HEDGING PROGRAM FOR THE WINTER OF 2000/2001?

A. Yes. After months of negotiations, a stipulation and agreement among the parties was reached providing for, among other things, a Fixed Commodity Price PGA that would "fix" the commodity price for 100% of MGE's natural gas supplies and effectively fix the delivered cost to MGE's sales customers. The stipulation ("FCP Stipulation") was filed with the Commission on April 28, 2000 (amended on May 15, 2000 to include OPC) and was approved by the Commission on August 1, 2000.[5]

Q. WAS THE FIXED COMMODITY PRICE PGA ULTIMATELY IMPLEMENTED?

A. No. Pursuant to the FCP Stipulation, there was a level or a "trigger price" that natural gas prices in the market had to reach in order for the plan to be automatically implemented. Specifically, MGE would establish the fixed commodity price component for natural gas within the PGA when, and if, the New York Mercantile Exchange ("NYMEX") forward natural gas strip price for the nearest 12 month period, weighted by the average MGE volumes to be purchased by month, settled at or below $2.25 per MMBtu for five consecutive business days. However, due to an unprecedented rise in natural gas prices from the time the FCP Stipulation was first filed and the time the

[5] Missouri Public Service Commission, Order Approving Stipulation and Agreement, Case No. GO-2000-705, August 1, 2000.

Commission approved the settlement, the Fixed Commodity Price PGA was unable to be implemented. Specifically, the price for the NYMEX futures contract for November 2000 closed at $3.25 per MMBtu on April 28, 2000, or the date the FCP was originally filed, and closed at $4.30 per MMBtu on August 2, 2002, or the date following the Commission's approval of the FCP Stipulation. Prices in the natural gas market continued to rise after the Commission's approval, continually breaking all-time record highs, ultimately with the NYMEX forward price reaching $10.00 per MMBtu.

Q. DID THE FCP STIPULATION CONTAIN OTHER PROVISIONS THAT WOULD HAVE ALLOWED MGE TO ESTABLISH A FORMALIZED HEDGING PLAN PRIOR TO THE WINTER OF 2000/2001?

A. Yes. The FCP Stipulation contained a provision that, in the event the trigger price for the Fixed Commodity Price PGA was not reached within sixty days after Commission approval of the settlement, the signatory parties would discuss an adjustment of the trigger price that would be reflective of market prices so that the Fixed Commodity Price PGA could be implemented. Pursuant to the FCP Stipulation, this adjusted trigger price had to be agreed upon by Staff and OPC.

Q. DID MGE PROPOSE TO ADJUST THE TRIGGER PRICE DURING THIS TIME FRAME?

A. Yes. In late September of 2000, MGE sent a letter to Staff memorializing its proposal to increase the trigger price for the Fixed Commodity Price PGA so that MGE could have a fully hedged portfolio in place prior to the winter of 2000/2001 for its sales customers.

However, Staff did not agree to any change in the originally established trigger price. Therefore, the Fixed Commodity Price PGA could not be implemented based on its own terms.

Q. WHY DID STAFF NOT AGREE TO ADJUST THE TRIGGER PRICE?

A. As noted above, it was clear by mid-2000 that natural gas prices were at historically high levels. However, it was very difficult to determine whether natural gas prices would continue to trend upward or would turn downward and return to price levels that were more consistent with historical levels. Clearly, the history of the natural gas industry and pricing activities argued strongly for lower prices. Staff has admitted in a deposition in this proceeding that it was their hesitancy to agree to fix commodity prices that, at the time, were historically high price levels, that led Staff not to agree to increases in the trigger price, and thus, not allow the Fixed Commodity Price PGA to be implemented. Specifically, Staff Witness Sommerer stated in his deposition that:

> ...Staff and MGE obviously agreed upon the $2.25. That was contained within the stipulation and agreement, and believed that was a market-based – historically based and market-based trigger price. It just so happened that prices were in excess of that level by the time that it was approved and effectively submitted to the Commission. Subsequent to that, MGE did come forward and suggested that the trigger price should be in excess of $2.25. I believe they suggested, perhaps, $3.75. The Staff was reluctant to amend the agreement to go with $3.75. **Based upon the concern that to the extent that market prices did go back down to that level, it may be locking in a price that was historically high and, indeed, higher than what current market conditions would dictate. In other words, somehow the $3.75 would catch the market on a downturn as it continued to go down and then be locked in for the customers for two years at $3.75.** (emphasis added) (Deposition of Staff Witness David Sommerer, Missouri Public Service Commission, Case No. GR-2001-382, December 10, 2002, p. 122, ll. 5-24.)

Thus, while Staff obviously believed that price protection was an important element to be provided to MGE's sales customers since Staff signed the FCP Stipulation, Staff has admitted that the unprecedented market prices for natural gas at the time resulted in Staff's reluctance to modify the Fixed Commodity Price PGA.

Q. CONSIDERING THE HIGH NATURAL GAS PRICES AT THE TIME, DID MGE OFFER TO FIX THE COMMODITY PRICE PURSUANT TO THE FIXED COMMODITY PRICE PGA FOR ONLY THE WINTER OF 2000/2001 IN CASE PRICES DID RETURN TO MORE NORMAL LEVELS?

A. Yes. MGE had proposed to Staff that the trigger price for the Fixed Commodity Price PGA be modified only for the winter of 2000/2001 to address both Staff's and MGE's concern that market prices would return to more historical levels at some future point. Specifically, on September 26, 2000, MGE sent Staff a letter summarizing a conference call held by the parties on September 20, 2000 during which MGE proposed to Staff various alternatives to modify the Fixed Commodity Price PGA. A copy of the letter is attached as Schedule MTL-12. As MGE stated in the letter:

> We understand that nobody expected the current high prices and nobody can predict for certain whether they will last for three months, six months, twelve months or longer. Thus, the Staff's willingness to lock in a trigger price based on today's market for a period of two years is not entirely without justification. To address this concern, MGE offered the possibility of fixing the commodity cost within the PGA, on the basis of current market conditions, only for this winter season [i.e., the winter of 2000/2001]. (Letter from Robert J. Hack, Vice President Pricing and Regulatory Affairs, MGE to Thomas R. Schwarz, Jr., Deputy General Counsel, Missouri Public Service Commission, September 26, 2000)

Q. IN ADDITION TO THE FIXED COMMODITY PRICE PGA, WERE THERE OTHER STEPS THAT WERE AGREED TO BY THE PARTIES THAT WOULD HAVE FINANCIALLY HEDGED A PORTION OF CUSTOMERS' NATURAL GAS SUPPLIES IN THE EVENT THAT THE FIXED COMMODITY PRICE PGA WAS NOT IMPLEMENTED?

A. Yes. As part of the FCP Stipulation, the parties also agreed that MGE would seek to re-implement the Price Stabilization Fund that had been supported by the Staff, approved by the Commission and utilized by MGE for the three prior winters (i.e., the winters of 1997/1998, 1998/1999 and 1999/2000).[6] Beginning after the natural gas price spike during the winter of 1996-1997, Staff and MGE implemented several changes to its PGA, including seasonalizing the PGA filings, as well as implementing a Price Stabilization Fund that would allow MGE to financially hedge according to specific parameters in order to provide its sales customers a specified level of price protection. Specifically, the Price Stabilization Fund that commenced in the winter of 1997/1998 and utilized for the next two winters specified (i) the type of hedging instrument that could be purchased; (ii) the amount of volume that could be hedged; (iii) the total amount of money that could be spent to purchase financial instruments; and (iv) the cap on the strike price at which the instruments were to be purchased.

Q. PURSUANT TO THE FCP STIPULATION, WAS THE PRICE STABILIZATION FUND FOR THE WINTER OF 2000/2001 TO BE SIMILAR TO THE MECHANISMS USED IN THE PREVIOUS THREE WINTERS?

A. Yes. The Price Stabilization Fund that would have been re-implemented for the winter of 2000/2001 would have been consistent with the mechanism previously approved by the Commission in Case No. GO-2000-231, meaning that there were specific parameters on how the financial hedging would be done. Specifically, the FCP Stipulation stated with regard to the Price Stabilization Fund for the winter of 2000/2001 that:

> Until such time as the fixed commodity price component of the PGA takes effect, MGE shall be authorized to make use of financial instruments to obtain price protection on natural gas supplies in accordance with the Commission's order in Case No. GO-2000-231. Subject to all of the terms and conditions of the Commission's order in Case No. GO-2000-231, except for the dates which shall be extended for another year, financial instruments shall be purchased for the upcoming heating season no later than September 30 of the immediately preceding summer. (FCP Stipulation, May 15, 2000, p. 13)

Therefore, the FCP Stipulation clearly stated that MGE only was authorized to purchase financial instruments in accordance with the Price Stabilization Fund parameters approved by the Commission for the three previous winters, which as noted above, included very specific parameters, including a specific amount of money ($3.05 million) to hedge a specific amount of volumes (winter volumes of 26,000,000 MMBtu) that were to be purchased by a specific date (by September 30, 2000) and not to exceed a specific price cap ($4.40/MMBtu).

Q. WAS THE PRICE STABILIZATION FUND ULTIMATELY IMPLEMENTED FOR THE WINTER OF 2000/2001?

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[6] The Price Stabilization Fund was initially implemented in Case No. GO-97-409 for the 1997-1998 winter, and was subsequently reauthorized for the 1998-1999 winter in Case No. GO-98-364, and for the winter of 1999-2000 in Case No. GO-2000-231.

A. No. Again, the unprecedented natural gas market conditions prevailing from August 1, 2000 (when the Commission approved the FCP Stipulation) through September 30, 2000 (the deadline for purchasing financial instruments pursuant to the FCP Stipulation) precluded MGE from purchasing financial instruments within the parameters authorized by the Commission. Therefore, MGE could not implement the agreed-upon price stabilization plan that was approved by the Commission.

Q. DID MGE ATTEMPT TO NEGOTIATE WITH STAFF TO MODIFY THE PARAMETERS OF THE PRICE STABILIZATION FUND TO REFLECT THE THEN CURRENT MARKET CONDITIONS SO THAT A PRICE STABILIZATION MECHANISM COULD BE IMPLEMENTED FOR THE WINTER OF 2000/2001?

A. Yes. When it became clear that market conditions would not permit implementation of the Price Stabilization Fund that had been previously utilized, MGE sought permission to modify that plan to reflect the then current market conditions. On September 26, 2000 in Case No. GO-2001-215, MGE filed to re-implement the Price Stabilization Fund with the modifications necessary to reflect the then current market conditions, namely modifying the maximum price cap price at which MGE was permitted to purchase financial instruments and the date by which MGE was required to purchase those financial instruments.

Q. DID THE STAFF SUPPORT THIS FILING?

A. No. While Staff agreed in the FCP Stipulation that it was reasonable and appropriate for MGE to provide financial hedging pursuant to the parameters of the Price Stabilization Funds used in the three previous winters, Staff opposed implementation of the modifications to the Price Stabilization Fund to reflect prevailing market conditions.

Q. WERE YOU SURPRISED BY STAFF'S OPPOSITION?

A. Yes. After the parties had agreed, substantially at the Staff's insistence, that such mechanism be re-implemented as part of the FCP Stipulation, opposition to the tariffs that would have allowed MGE to implement the Price Stabilization Fund was indeed surprising. It was especially surprising when MGE later learned that Staff had signed a Unanimous Stipulation and Agreement between Laclede, Staff and OPC ("Laclede Settlement") on September 1, 2000, or less than a month prior to MGE's filing, that provided Laclede with a similar hedging mechanism.[7] In fact, Staff filed a letter supporting Laclede's hedging settlement on September 21, 2000, or just five days before MGE's filing to modify the Price Stabilization Fund.

Q. HOW DID THE COMMISSION ULTIMATELY RULE ON MGE'S PROPOSAL TO RE-IMPLEMENT THE PRICE STABILIZATION FUND?

A The Commission issued an order on October 26, 2000 (the "October 26th Order") denying the re-implementation of the Price Stabilization Fund.

[7] Laclede Gas Company, Unanimous Stipulation and Agreement, Missouri Public Service Commission, Case No. GO-2000-394, p. 2.; Missouri Public Service Commission, Order Granting Motion to Stay Setting of Procedural Schedule and Approving Unanimous Stipulation and Agreement, Case No. GO-2000-394, September 28, 2000.

Q. WHAT FINANCIAL HEDGING AUTHORITY WAS MGE PROVIDED BY THE COMMISSION PRIOR TO THE WINTER OF 2000/2001?

A. As discussed above, the Commission provided MGE with very specific authority regarding its ability to utilize financial instruments to hedge its natural gas supply portfolio prior to the winter of 2000/2001. In fact, prior to the winter of 1997/1998, MGE did not utilize financial instruments to hedge the price of natural gas since it did not have authority from the Commission to purchase such instruments or the ability to recover the costs of providing price stability to its sales customers through financial hedging. Then, as discussed above, starting with the winter of 1997/1998 and for the following two winters, the Commission approved the Price Stabilization Fund that permitted MGE to purchase financial instruments to hedge the price of natural gas, but only under very specific parameters approved by the Commission.

Then, after the Price Stabilization Fund for the winter of 1999/2000 had expired on its own terms, the Commission approved the FCP Stipulation that, if the trigger price for the Fixed Commodity Price PGA had been met, would have hedged 100% of MGE's natural gas requirements for the winter of 2000/2001. Again, the FCP Stipulation granted MGE the authority to hedge, but only pursuant to the parameters set forth in the FCP Stipulation. In addition, as part of the FCP Stipulation, the parties agreed that MGE could utilize the Price Stabilization Fund to provide price protection to, and recover the associated costs from, its customers, but only within the approved parameters of the Price Stabilization Fund.

Q. WHAT AUTHORITY OR GUIDANCE REGARDING HEDGING DID THE COMMISSION PROVIDE TO MGE IN ITS OCTOBER 26TH ORDER?

A. In its order, the Commission stated simply:

> Staff is correct when it states that MGE should apply reasonable purchasing practices based upon its own evaluation of risks in its gas supply portfolio. MGE's business decisions will be subject to prudence review as are MGE's other gas supply choices. (Order Denying Application to Renew Price Stabilization Fund and Rejecting Tariff, Missouri Public Service Commission, Case No. GO-2001-215, October 26, 2000, mimeo p. 3)

While Staff did not support re-authorization of the Price Stabilization Fund, it did file proposed tariff language in its comments on MGE's proposal suggesting to the Commission that MGE's tariff should be modified to include language authorizing the use of financial instruments to hedge natural gas prices and recognize hedging costs as gas costs to be recoverable in the PGA pursuant to a prudence review as all other gas costs. However, as noted in the quote from the October 26th Order above, the Commission did not address Staff's proposed tariff language, did not specifically grant MGE authority to purchase financial instruments to hedge the price of natural gas outside the parameters already established pursuant to the FCP Stipulation, nor did it grant MGE the ability to recover the cost of any financial instruments used to hedge natural gas if purchased outside the parameters of the Fixed Commodity Price PGA.

Q. WAS MGE OBLIGATED TO FINANCIALLY HEDGE 100% OF ITS NATURAL GAS SUPPLY PORTFOLIO AFTER THE COMMISSION ISSUED ITS OCTOBER 26TH ORDER?

A. Yes, within certain parameters. As explained above, the Commission had approved the Fixed Commodity Price PGA that in effect, subject to the trigger price being met, provided for 100% of MGE's natural gas supply portfolio to be financially hedged according to the specific parameters set forth in the FCP Stipulation. The FCP Stipulation clearly stated that MGE would remain obligated to the hedging parameters of the Fixed Commodity Price PGA absent an alternative, Commission-approved PGA mechanism:

> In the event that MGE submits an alternative proposal regarding commodity cost recovery and the Commission approves an alternative proposal regarding commodity cost recovery prior to the fixed commodity price component of the PGA taking effect under this Stipulation and Agreement, the provisions of this Stipulation and Agreement regarding the fixed commodity price component of the PGA shall be of no further force and effect. In the event that MGE submits an alternative proposal regarding commodity cost recovery and the fixed commodity price component of the PGA under this Stipulation and Agreement takes effect prior to the Commission's approval of an alternative proposal regarding commodity cost recovery, MGE shall withdraw its alternative proposal regarding commodity cost recovery from Commission consideration. (FCP Stipulation, May 15, 2000, p. 4)

Thus, when the Commission issued its October 26th Order, the tariff language approving the Fixed Commodity Price PGA remained in force and effect, leaving MGE with an obligation to fix the price on, or in effect to hedge, 100% of its natural gas requirements for its sales customers if natural gas prices reached the appropriate trigger price.

Q. WAS THE COMMISSION'S OCTOBER 26TH ORDER SIGNIFICANTLY DIFFERENT FROM ITS PRIOR ORDERS IN TERMS OF THE GUIDANCE OR AUTHORITY THAT MGE WAS TO HAVE REGARDING THE PURCHASE AND COST RECOVERY OF FINANCIAL HEDGES?

A. Yes. In my opinion, the Commission's October 26th Order was dramatically different than the orders previously issued by the Commission governing the authority of and parameters for MGE to purchase financial instruments to provide natural gas supply price stability. The Commission's October 26th Order was quite vague and, as stated above, did not specifically grant MGE authority to utilize financial hedging instruments outside of the parameters in the FCP Stipulation that the Commission had previously approved. In addition, if MGE purchased additional financial instruments to hedge its portfolio outside the parameters of the Fixed Commodity Price PGA (and for which it did not clearly have Commission authority to do so pursuant to the October 26th Order), it was quite unclear whether the cost of those hedging instruments could even be recovered by MGE.

Therefore, five days before the official start of the winter heating season when natural gas prices were already at an all-time high, MGE had a pair of specific hedging programs approved by the Commission as part of the FCP Stipulation, i.e., the Fixed Commodity Price PGA and the Price Stabilization Fund, yet neither program could be implemented due to unprecedented market conditions and MGE did not have authorization to conduct any other hedging activity outside of the parameters of those two programs. Furthermore, MGE was obligated pursuant to the FCP Stipulation to fix the price on, or in effect, to hedge 100% of its natural gas supplies even after the Commission's October 26th Order, if natural gas prices were at or below the trigger price level.

Q. **DOES MGE FEEL THAT ITS PURCHASES IN ANY EVENT WERE PRUDENT?**

A. Yes. As a general policy, MGE believes that, absent a clear statement of policy by the Commission, a decision to purchase natural gas at prevailing market prices is, by definition, prudent. These prices for natural gas commodities are determined in a fair and open market through arms-length transactions. Therefore, in and of itself, purchases of natural gas at market prices are prudent. For example, the most recent order issued by the Commission involving MGE that was indicative of the Commission's views regarding the prudence of market-based pricing was issued in Case No. GO-94-318. The Commission's order in that proceeding effectively approved market-based pricing and set a benchmark at 104% of a market index which was calculated by taking 70% of a Williams market index and 30% of a PEPL market index. In that plan, no prudence review and no cost disallowance would be generated if the overall total cost of the commodity required by the company was below 104% of the benchmark level, or 1.04 times the market index (70% Williams/30% PEPL).

Q. DOES MGE BELIEVE THAT FAILURE TO REACH AGREEMENT WITH THE STAFF ON AN APPROPRIATE MARKET PRICE LEVEL LIMITED MGE'S ABILITY TO EFFECTIVELY HEDGE GAS COSTS IN THE WINTER OF 2000/2001?

A. Yes. The parties had negotiated for sixteen months to agree to the various terms and conditions that were ultimately set forth in the FCP Stipulation. The inability to agree to a trigger price that was representative of market prices effectively precluded MGE from implementing both the Fixed Commodity Price PGA and the Price Stabilization Fund. Also, as a result of the timing associated with the final resolution and denial of the reauthorization of the Price Stabilization Fund (i.e., five days prior to the winter heating season), MGE's ability to conduct any effective financial hedging for that winter was severely hindered. Specifically, the timing of the resolution of the Price Stabilization Fund based on the Commission's October 26th Order forced MGE to make financial hedging decisions that would be considered very late in the process compared to a more planned approach that could have been implemented earlier in 2000.

Q. DOES MGE TAKE ISSUE WITH ANY OTHER PORTIONS OF STAFF'S RECOMMENDATION REGARDING MGE'S HEDGING PRACTICES FOR THE WINTER OF 2000/2001?

A. Yes. In addition to the fact that Staff's overall recommendation regarding MGE's hedging practices is incorrect and unsupportable, I would like to point out that the calculation of Staff's proposed disallowance is also incorrect and without basis. As noted earlier in my testimony, Staff has taken the position that it believes 30% of MGE's normal requirements for each month of the winter of 2000/2001 should have been hedged either through storage injections or fixed price purchases.

Q. PRIOR TO THE WINTER OF 2000/2001, DID STAFF EVER COMMUNICATE TO MGE THAT IT WAS PLANNING ON ASSESSING LDC HEDGING PERFORMANCE BASED ON A MINIMUM OF 30% OF NORMAL REQUIREMENTS?

A. No. Staff never communicated the hedging "standard" that it has used in this proceeding to calculate its proposed disallowance. In fact, as explained by MGE Witness Reed, Staff has admitted that it did not communicate its "standard" to MGE until after the winter of 2000/2001 and that the derivation of the 30% level was completely arbitrary. In addition, highlighting the arbitrary nature of its disallowance, Staff has acknowledged in its May 31, 2000 Memo that the 30% level is not an optimal level to be used by the Commission as future precedent.

Q. EVEN IF STAFF HAD COMMUNICATED TO MGE THAT IT WAS INTENDING TO UTILIZE A MINIMUM 30% HEDGING "STANDARD" FOR THE WINTER OF 2000/2001, WOULD IT BE APPROPRIATE FOR STAFF TO APPLY ITS HEDGING "STANDARD" ON A MONTH-BY-MONTH BASIS RATHER THAN TO THE ENTIRE HEATING SEASON?

A. No. Physical and financial hedging is not conducted on a month-by-month basis during the winter heating season, but rather done prior to the winter heating season for the entire heating season overall. Due to changes in weather, changes in customer demand, pipeline operational issues, prices in the natural gas market and other events outside the control of the LDC, these variations undoubtedly cause and result in the actual amount of volumes hedged to vary significantly from month-to-month. In fact, the validity of the seasonal approach to hedging is confirmed by the Laclede Settlement discussed earlier that was approved by the Commission on September 28, 2000.[8] The Laclede Settlement specifically stated that "financial protection may, at the Company's election, be procured in the same or varying quantities for each month, including zero for certain months." In other words, Staff agreed in Laclede's case that the guiding principal for hedging was the total volumes that were to be hedged over the entire winter season, and not a specific volume amount each month.

Q. DID MGE HEDGE OVER 30% OF ITS VOLUMES FOR THE WINTER OF 2000/2001?

A. Yes. Through the use of its storage inventory and fixed price arrangements, MGE hedged well over 30% of its normal requirements. In fact, this can be demonstrated by simply looking at Staff's own workpaper that it used to calculate its proposed disallowance on this issue. Attached as Schedule MTL-13 is a copy of Staff's workpaper that shows how Staff calculated the $614,365 disallowance proposed for MGE's hedging practices. As can be seen in Column B on page 1 of the worksheet, 30% of MGE's normal requirements is shown to total 15,984,365 MMBtu. As shown in Column D, MGE financially hedged a total of 3,477,309 MMBtu. In Column E, the workpaper shows MGE's actual volumes withdrawn from storage of 16,856,032 MMBtu. Therefore, the total of the financially and physically hedged volumes for the winter of 2000/2001 equaled 20,333,341 MMBtu, or over 38% of MGE's normal requirements, clearly exceeding 30% of normal requirements. It is only after Staff applies the 30% on a month-by-month basis and ignores the months when MGE hedged more than 30% of the volumes that it calculates a shortfall in the volumes hedged for certain months.

PURCHASING PRACTICES - STORAGE

[8] Laclede Gas Company, Unanimous Stipulation and Agreement, Missouri Public Service Commission, Case No. GO-2000-394, p. 2.; Missouri Public Service Commission, Order Granting Motion to Stay Setting of Procedural Schedule and Approving Unanimous Stipulation and Agreement, Case No. GO-2000-394, September 28, 2000.

Q. HAS STAFF MADE ADDITIONAL ALLEGATIONS WITH REGARD TO MGE'S PURCHASING PRACTICES?

A. Yes. Staff has alleged that MGE should have operationally utilized its storage inventory in a different manner.

Q. WHAT IS NATURAL GAS STORAGE?

A. Natural gas storage facilities are caverns under the earth that have geological features that allow gas to be re-injected into them and subsequently withdrawn from the cavern during specific times of the year. These caverns used for natural gas storage facilities are generally depleted oil or natural gas reservoirs from which all of the oil or natural gas has been consumed, or underground caverns carved out of salt dome deposits located relatively close to the surface of the earth. MGE does not own the storage facilities that serve its customers, but rather has contracted for storage service from storage facilities owned and operated by Williams and PEPL. Pursuant to these pipelines' tariffs, MGE's storage contracts provide MGE the right to a specific amount of capacity in the storage facilities so that natural gas can be stored, as well as provide MGE with the right to inject or withdraw gas into or out of these facilities during specific times of the year. Generally, natural gas is injected into the storage facilities during the summer months, i.e., defined in the tariffs as April through October, and gas is withdrawn during the winter months, i.e., November through March.

Q. SPECIFICALLY, WHAT HAS STAFF ALLEGED WITH REGARD TO MGE'S STORAGE UTILIZATION FOR THE WINTER OF 2000/2001?

A. In its May 31, 2002 Memo and in its depositions in this proceeding, Staff has alleged that MGE's utilization of storage for the winter of 2000/2001 was imprudent for two reasons. First, Staff has alleged that MGE's storage plan for the winter of 2000/2001 was imprudent since MGE's storage withdrawal plan anticipated withdrawing a greater percentage of its storage inventory in November 2000 than Staff would have expected based on normal weather patterns. Second, Staff has alleged that it was imprudent for MGE to order less first-of-month flowing supplies for December 2000 than was planned to meet normal December requirements because MGE believed natural gas prices would decline in December. Staff claims that MGE has provided no support for its belief that prices would drop in December. As a result of these two factors, Staff claims that MGE's actions resulted in the company having to use greater levels of flowing volumes (i.e., volumes not taken from storage) in January through March 2001 when natural gas prices were higher, and thus has proposed a disallowance of $8,051,149.

Q. WHAT IS YOUR POSITION REGARDING STAFF'S FIRST ISSUE, i.e., MGE'S STORAGE PLAN FOR THE WINTER OF 2000/2001 WAS IMPRUDENT?

A. First, I believe that MGE's storage withdrawal plan for the winter of 2000/2001 was in fact prudent and that Staff's recommendation suffers from fatal flaws that, if MGE were to attempt to implement in the real world, would be entirely unworkable and would result in a detriment, rather than a benefit, to MGE's customers. Second, as discussed below and in greater detail by MGE Witness Reed, Staff has failed to meet the Commission's prudence standard required in order to support a disallowance related to MGE's storage plan. Thus, I believe Staff's finding that MGE's storage plan is imprudent is simply without merit.

Q. WHY IS STAFF'S RECOMMENDATION FATALLY FLAWED AND UNWORKABLE IN THE REAL WORLD?

A. Staff's proposal is fatally flawed since it is based on the premise that MGE should have, for the winter of 2000/2001, calculated the level of first-of-the-month flowing supplies by using an average monthly demand. LDCs, including MGE, do not base their planned level of monthly flowing supplies on an average monthly demand as Staff has suggested, even if that monthly average demand is based on a warmer-than-normal demand scenario. In contrast, MGE has developed its storage plan and the level of first-of-month flowing supplies based on its experience with customer baseload monthly demand rather than average monthly demand as Staff has suggested. MGE and other LDCs plan their level of first-of-month flowing supplies on a minimum level of daily demand that is projected to occur on any day during the month, or in other words, a baseload level of flowing supplies that customers will consume each and every day for the month. In layman's terms, Staff's proposal is analogous to using a 30-day average temperature to predict the temperature for a single day. The "normalized" or average monthly heating degree day distributions relied upon by Staff do not take into account the daily volatility in weather that can be actually experienced during the specific winter months.

Q. WHAT ARE FIRST-OF-MONTH FLOWING SUPPLIES?

A. First-of-month flowing supplies are supplies of natural gas purchased by MGE to be used to serve the current month's expected consumption and represent volumes that will not be withdrawn from storage. These flowing supplies are nominated prior to the start of the month for delivery on a consistent basis over the entire month. For example, MGE could purchase and nominate 10,000 dth/day of natural gas to be delivered for each day of the month of June, but the nomination would have to be made to the supplier for those deliveries at the end of May.

Q. HOW HAS STAFF CALCULATED THE LEVEL OF FIRST-OF-MONTH FLOWING SUPPLIES THAT MGE SHOULD HAVE NOMINATED?

A. Specifically, in its proposal, Staff has calculated the level of first-of-month flowing supplies that MGE should have scheduled based on the average monthly demand from MGE's warmer-than-normal demand scenario that MGE filed with the Commission in July 2000 as part of its Reliability Report. (It should be noted that MGE's warmer-than-normal demand scenario is based on an overall monthly weather pattern, and is not based on specific daily weather variations.) After determining the level of first-of-month flowing supplies, Staff then simply calculates the storage withdrawal amount for each month as the difference between the forecasted monthly demand in MGE's normal weather or "base case" demand scenario and the level of flowing supplies calculated above.

Specifically, MGE's actual storage utilization plan for November 2000 and Staff's proposal of what MGE's storage plan should have been are as follows:

	MGE Storage Plan	Staff Proposal
Storage Withdrawals	138,339 dth/day	65,414 dth/day
Flowing Volumes	108,340 dth/day	181,265 dth/day
Total	246,679 dth/day	246,679 dth/day

Q. WHAT WOULD HAPPEN IF MGE WERE TO PLAN ITS MONTHLY FLOWING SUPPLIES FOR THE WINTER PERIOD ON AVERAGE MONTHLY DEMAND RATHER THAN ON BASELOAD MONTHLY DEMAND?

A. If MGE planned its level of flowing supplies based on average monthly demand as Staff has suggested rather than on baseload monthly demand, MGE would be placing itself in the position of having significantly more gas than was going to be consumed by its customers for a considerable number of days in the month. This is due to the fact that an average monthly demand is inherently based on days of the month when demand is greater than the average, as well as days of the month when demand is less than the average. While the daily demand variability around the average monthly demand may not be substantial in certain months of the year, the daily variability from the monthly average is greatest in those months in which the weather, and thus demand, can change significantly from day-to-day. This is exactly the case with the month of November in MGE's service territory.

Q. PLEASE EXPLAIN THE WEATHER AND DEMAND VARIABILITY THAT MGE EXPERIENCES IN NOVEMBER ON ITS SYSTEM.

A. November is more of a shoulder month and can experience a week or two of very warm weather, particularly during the first part of the month, and then experience very cold periods. The significant weather variability in this month causes demand to fluctuate considerably day-to-day and week-to-week during the month. For example, in consecutive years, the demand on MGE's system for November has ranged from a low of 4,414,515 MMBtu (November 1999) to a high of 8,899,925 MMBtu (November 2000), or a 100% variation in total demand. In fact, subsequent to the ACA period in question in this proceeding, the demand for November 2001 was 4,317,691 MMBtu.

Attached as Schedule MTL-14 is a summary of MGE's flowing supplies and storage withdrawals for each winter month from November 1997 through March 2002. Specifically, Schedule MTL-14 provides: (i) the normal expected volumes for both purchases of flowing supplies and withdrawals of storage; (ii) the actual heating degree days; (iii) the normal heating degree days; (iv) the actual volumes for both flowing supplies and storage withdrawals; and (v) the variance between normal and actual storage withdrawals. As can be seen in Schedule MTL-14, MGE's service territory experiences a substantial variation in the actual weather relative to the normal weather during the winter months, and this variability must be taken into account in MGE storage utilization plans.

MGE's storage utilization plan for the winter of 2000/2001 (and the same plan that it continues to utilize) relies on a higher storage withdrawal amount in November due to the extremely volatile weather experienced in this month and the impact on demand that this variability produces. For example, as illustrated on Schedule MTL-14, the number of heating degree days in November of 1999 was 59.5% of the normal number of heating degree days. As shown in that schedule, there was no other winter month that was even close to experiencing weather that was 59% of normal. In addition, the number of heating degree days in November 2000 was 127% of the normal number of heating degree days. Simply put, there is no other winter month in which the weather, as measured by heating degree days, varies so significantly from the normal level. Therefore, November represents the most volatile month in terms of weather-sensitive demand.

Q. CONSIDERING THE SIGNIFICANT WEATHER AND DEMAND VARIABILITY MGE EXPERIENCES ON ITS SYSTEM IN NOVEMBER, WHAT COULD HAVE OCCURRED IN THE WINTER OF 2000/2001 IF STAFF'S STORAGE UTILIZATION PROPOSAL WAS IMPLEMENTED?

A. Schedule MTL-15 illustrates the illogic inherent in Staff's proposal by using the actual daily demand experienced on MGE's system for November 1999, 2000 and 2001. These years were utilized in the Schedule since they represent very recent history, including the ACA period in question in this proceeding, and represented a cross section of the overall weather experienced on MGE's system. Specifically, November 2000 was the coldest November on record, while November 1999 and November 2001 were two of the warmest Novembers on record.

As shown on Schedule MTL-15, actual demand in November 1999 and November 2001 was not only below, but significantly below, the level of flowing supplies that Staff has claimed that MGE's storage utilization plan should have reflected, or 181,265 dth/day. Specifically, in November 1999, actual demand would have been below Staff's proposed level of first-of-month flowing supplies on 21 of the 30 days in the month, and in November 2001, on 24 of the 30 days. Only in November of 2000, or the coldest November ever experienced, would Staff's proposed level of first-of-month flowing supplies not resulted in MGE having excess gas on the majority of the days of the month. In other words, by proposing that MGE's storage utilization plan should have been based on an average monthly demand calculation, Staff's proposal would have resulted in MGE having excess flowing supplies for 70% and 80% of the days in November 1999 and November 2001, respectively. In fact, as illustrated on Schedule MTL-15, Staff's proposal would have resulted in MGE having an excess of over 100,000 dth/day for 7 days in November 1999 and 11 days in November 2001.

Q. WHAT IS THE POTENTIAL IMPACT OF STAFF'S PROPOSAL?

A. Staff's proposed methodology would be both costly as well as potentially harmful to MGE's customers in terms of negatively impacting reliability. As illustrated in Schedule MTL-15, under Staff's proposal, in both relatively normal years and significantly warmer-than-normal years, MGE would be forced to sell a significant amount of its excess first-of-month flowing supplies in the market at precisely the time when demand would be at its lowest, and thus, the price in the market would be at its lowest. This is particularly true in November since storage is full. MGE would effectively be dumping gas into the market and, if it was able to sell the excess gas, would be doing so at prices likely well below the price for which it had purchased the gas at the first-of-month index. In addition, if MGE was unable to sell all or a portion of the excess first-of-month flowing supplies and operationally could not temporarily "store" the gas on the pipeline (subject to imbalance penalties), MGE would potentially be forced to abrogate its supply contract and thus risk the reliability of its existing and future supplies.

Staff's proposed storage utilization and flowing supplies plan for the winter of 2000/2001 would have been reasonably adequate. However, the only reason that it would have been adequate was that the winter of 2000/2001 included the coldest November and December ever recorded. Therefore, it is clear that Staff's proposal was prepared after-the-fact specifically for this ACA proceeding and only for this ACA proceeding, and would be totally unworkable in almost every other year that does not experience the same level of record cold weather.

Q. IS THE PLAN THAT MGE UTILIZED FOR THE WINTER OF 2000/2001 MORE REASONABLE?

A. Yes. As highlighted in Schedule MTL-15, for November 2000, MGE planned for first-of-month flowing supplies at levels more closely aligned with normal baseload requirements as opposed to average requirements in order to meet normal year conditions. As discussed above, it is reasonable for MGE to plan on utilizing storage at a relatively higher level for November than any other month due to the extreme weather, and thus demand, variability that MGE experiences in its service territory in November. Storage inventories are normally very close to full capacity by the end of October and cannot accommodate significant additional injections. As such, in order to schedule adequate flowing gas volumes for the entire month, a baseload monthly demand level must be utilized as there can be tremendous pipeline balancing issues associated with relatively high flowing volumes if demand is less than expected. MGE has generally planned to withdraw approximately 4,000,000 MMBtu of gas from storage during a typical November. In very warm winters, storage withdrawals will be significantly less, as they were in November 1999 when MGE withdrew 1,092,365 MMBtu. Similarly during periods such as November of 2000, when demand is extraordinarily high, storage withdrawals increased to 5,673,557 MMBtu to meet the significant increase in demand. Therefore, storage is clearly the most effective way to deal with this actual physical variation in customer demand during a specific winter month.

Q. ARE THERE OTHER PROBLEMS WITH STAFF'S FINDING THAT MGE'S STORAGE WITHDRAWAL PLAN WAS IMPRUDENT?

A. Yes. In addition to the errors with Staff's imprudence finding identified above, Staff's recommendation also suffers from additional problems. While MGE's operational storage plan has evolved since the winter of 1994/1995, or post-acquisition of MGE by Southern Union, MGE has utilized the same storage withdrawal plan that it used for the winter of 2000/2001 since the winter of 1998/1999. In addition, MGE continues to utilize this same storage withdrawal plan. Therefore, MGE utilized the same storage plan that it used for the winter of 2000/2001 as it had for the two previous winters.

Q. HAD STAFF EVER INFORMED MGE OR THE COMMISSION PRIOR TO THE ACA PERIOD IN QUESTION IN THIS PROCEEDING THAT MGE'S STORAGE PLAN WAS INAPPROPRIATE, UNREASONABLE OR IMPRUDENT?

A. No. Despite the fact that MGE had effectively utilized the same storage plan for the two winter periods prior to the ACA period in question in this proceeding, Staff at no time indicated that MGE's storage plan was unreasonable or deficient in any manner. In fact, as explained in the testimony of MGE Witness Reed, Staff has admitted that (i) it reviewed MGE's storage withdrawal plan prior to the winter of 2000/2001, but; (ii) it never told MGE that it believed MGE's storage plan was deficient; and (iii) it only asserted that MGE's storage plan was deficient after the winter of 2000/2001. Based on these representations, Staff's allegations that MGE's storage plan was imprudent is, in and of itself, unreasonable.

Q. HAS MGE PROVIDED STAFF A MORE DETAILED EXPLANATION OF ITS DECISION-MAKING PROCESS RELATING TO HOW MGE ESTABLISHED ITS STORAGE PLAN AND UTILIZED ITS STORAGE INVENTORY?

A. Yes. MGE has provided a substantial amount of information to Staff regarding this issue, including month-by-month planning documents, MGE's perception of market prices throughout the 2000-2001 winter period, and how such perceptions impacted its overall decisions relative to the use of flowing supplies and storage withdrawals on a month-by-month basis. Attached as Schedule MTL-16 is a detailed listing and analysis of the decisions made by MGE throughout the winter period. It is MGE's opinion that, while all decisions did not ultimately result in the absolute lowest price for the consumers based on the benefit of perfect hindsight, the decisions were well reasoned, prudent, and within normal operating parameters based on the knowledge that MGE had at the time. Expectations as to market prices in certain cases were not realized, but based on the information received from outside sources and the historically high levels of prices that had occurred during the winter period, the actions taken by MGE were reasonable.

Q. STAFF HAS ALSO ALLEGED THAT MGE SPECULATED ON PRICE DECREASES IN DECEMBER 2000 WITHOUT ADEQUATE SUPPORT FOR THAT POSITION, AND WAS THUS IMPRUDENT. WHAT IS YOUR RESPONSE TO THAT ALLEGATION?

A. I disagree both with Staff's characterization of MGE as speculating on natural gas prices in December, as well as Staff's allegation that MGE did not have adequate support for its belief that market prices would decline in December 2000. First, MGE did not speculate on price decreases in December 2000. As Staff is fully aware, MGE was not under any type of natural gas purchasing incentive mechanism whereby there may have been an incentive, albeit a risky one, for MGE to speculate on natural gas prices. For the winter of 2000/2001, the primary natural gas purchasing goals of MGE were the ability to continue to provide reliable natural gas supply at the lowest reasonable cost. At no time did MGE have an incentive to speculate on natural gas prices in order to increase shareholder profits. MGE always has an incentive to keep gas costs as low as possible and that was its goal in the winter of 2000/2001. MGE has very a strong incentive to keep gas prices as low as possible since MGE is concerned about the impacts on its customers, natural gas competes with other fuels for load, and high gas bills lead to greater uncollectible expenses.

Second, while MGE based its decision to order less first-of-month flowing supplies for December on relatively short-term analysis due to the circumstances that existed at the time, its decisions were in fact based on solid, reputable data sources. In addition, Staff has stated in its May 31, 2000 Memo that MGE had to order first-of-month supplies for December 2000 by November 22, 2000. Staff based its assumption on its review of MGE's supply contracts. Typically, this would in fact be the case; however, in November 2000, MGE's supplier (i.e., Duke) allowed MGE to nominate its first-of-month supplies by the close of business on November 27, 2000 as a result of the Thanksgiving holiday and the unusual market conditions at the time.

Q. WHAT WAS THE BASIS OF MGE'S BELIEF NEAR THE END OF NOVEMBER 2000 THAT PRICES FOR DECEMBER 2000 WOULD DECLINE?

A. Starting on November 1, 2000, the price for the NYMEX December futures contract was \$4.69/MMBtu and that price rose until reaching a record peak natural gas price of \$6.58/MMBtu on November 22, 2000, or the Wednesday before the Thanksgiving holiday. Similarly, the Williams Gas Daily Index price rose from \$4.07/MMBtu on November 1, 2000 and closed at a record high of \$6.21/Mcf on November 22, 2000. As discussed in the testimony of MGE Witness Reed, most experts in the market had not forecasted and were clearly not expecting the incredibly high prices that were being experienced. Then, on November 27, 2000, the Monday immediately after the Thanksgiving holiday, and the date MGE needed to nominate its first-of-month supplies for December pursuant to MGE's agreement with Duke, the NYMEX futures contract for December 2000 fell to \$6.37/MMBtu and the Williams Gas Daily Index price fell to

$6.06/Mcf. In addition, the National Weather Service ("NWS") was predicting warmer than normal weather for the next 6-10 days in the central United States and normal weather for the entirety of the United States for the following two weeks. Specifically, GSC Energy's Natural Gas Morning Bulletin stated:

> The latest NWS 6-10 day forecast calls for above normal temperatures in the central US. The big change is the absence of the expected below normal temperatures after the milder weather. The NWS 8-14 day forecast calls for the entire country to be normal. (GSC Energy, Natural Gas Morning Bulletin, November 27, 2000)

Therefore, at the time, considering prices were moderating and that the NWS was predicting warmer-than-normal weather for the central United States, MGE did not believe that it would be prudent to nominate (and thus pay for) its entire flowing supply at first-of-month prices when it clearly appeared that prices could in fact moderate in December from the record high levels. Moreover, as discussed in the testimony of MGE Witness Reed, numerous sophisticated entities in the natural gas market did exactly what MGE did, i.e., nominate less first-of-month supplies for December due to the belief that prices would decline in December. And in fact, natural gas prices did decline through the end of November 2000 after MGE made its first-of-month nominations for December 2000.

Q. WHAT IS YOUR OVERALL VIEW OF STAFF'S PROPOSAL?

A. As discussed above, I believe that Staff's recommendations that MGE's storage plan and MGE's utilization of its storage inventory vis-à-vis its flowing supplies were imprudent have absolutely no basis and are completely unsupported by actual market conditions. Staff's proposed methodology for determining the imprudence of MGE's storage plan for the winter of 2000/2001 is simply incorrect, as it does not consider weather impacts on year-to-year, month-to-month and, most importantly, daily demand variations. In addition, if MGE had utilized such a storage plan over the past few years, it likely would have been extremely costly to MGE's customers and potentially harmful in terms of reliability. Furthermore, Staff's proposal is clearly based on hindsight review. Lastly, the decisions that MGE made at the time regarding the level of first-of-month flowing supplies that it was going to order for December 2000 was based on sound market analysis and not on speculation as Staff has suggested.

OTHER ISSUES

Q. DID STAFF RAISE OTHER ISSUES IN THEIR MAY 31, 2002 MEMO?

A. Yes. The Staff memorandum questioned various issues within the reliability report filed by MGE. The Staff raises five specific issues which it feels MGE needs to change.

Q. HAS MGE SOUGHT TO MAKE THESE ADJUSTMENTS?

A. Following its receipt of a draft of a Staff recommendation in this case, and the subsequent filing of the recommendation on May 31, 2002, MGE filed a Reliability Report, effective July 1, 2002. MGE believes all of the Staff's issues should have been adequately dealt with in this report. In addition, Staff has implemented an informal meeting with all utilities within the state to propose a gas supply reporting requirement. This is currently ongoing at the Staff level, and Staff has sought comments from the industry on the information that should be included in such filings. It is MGE's position that it is inappropriate in this ACA case to address such reliability report issues. They are more appropriately addressed through an industry-wide rulemaking in which a record can be adopted as to the most appropriate information that needs to be provided on a statewide basis. MGE would recommend that the Commission take no action in this ACA proceeding as a result of Staff's recommendation regarding reliability report information issues.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Purchased Gas Cost Adjustment tariff Revisions to be reviewed in its 2000-2001 Actual Cost Adjustment.	))))	Case No. GR-2001-382

AFFIDAVIT OF MICHAEL T. LANGSTON

STATE OF Kentucky)
) ss.
COUNTY OF Daviess)

Michael T. Langston, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Direct Testimony in question and answer form, to be presented in the above case; that the answers in the foregoing Direct Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

MICHAEL T. LANGSTON

Subscribed and sworn to before me this 14th day of January 2003.

Susan Vanbruggen
Notary Public

My Commission Expires: 4-10-04

MLT I

Pipeline Tariff Rates

Reservation Rates

Williams Gas Pipelines Central	$ 8.7549
Average per unit rate	$ 0.2878
Panhandle Eastern Pipeline	$ 9.3800
Average per unit rate	$ 0.3084
Kinder Morgan Interstate (Cheyenne)	$ 17.3397
Average per unit rate	$ 0.5701
Kansas Pipeline Tariff Rates	$ 19.8965
Average per unit rate	$ 0.6541

Commodity Rates

Williams Gas Pipelines Central	$ 0.0259
Panhandle Eastern Pipeline	$ 0.0343
Kinder Morgan Interstate	$ 0.0204
Kansas Pipeline Tariff Rates	$ 0.0625

Total Equivalent Rates

Williams Gas Pipelines Central	$ 0.3137
Panhandle Eastern Pipeline	$ 0.3427
Kinder Morgan Interstate	$ 0.5905
Kansas Pipeline Tariff Rates	$ 0.7166

Missouri Gas Energy
Pipeline Fuel Rates

	WNG	PEPL 200-300	PEPL 100-200	TOK/KPC	KN
Pro	1.64%	1.18%	1.18%	N/A	N/A
Mar	0.69%	1.35%	0.90%	N/A	N/A
Total	2.33%	2.53%	2.08%	3.86%	3.30%
Inj	0.81%	1.34%		N/A	N/A
Wth	N/A	0.31%		N/A	N/A
	Eff. 1/02	Eff. 4/02	Eff. 4/02	Eff. 10/01	Eff. 1/00

MLT 2

Affiliated Discount Offers
July 2000

Offer Date	Discount No.	Discount Rate	Quantity	Delivery Point
6/30/2000	000701	$0.0207	200,200 Dt/d	Zone 3
6/30/2000	000702	$0.0207	60,400 Dt/d	Zone 2
6/30/2000	000703	$0.0078	700 Dt/d	Zone 3
6/30/2000	000704	$0.0078	200 Dt/d	Zone 3
6/30/2000	000705	$0.0078	200 Dt/d	Zone 1
6/30/2000	000706	$0.0170	400 Dt/d	Zone 1
6/30/2000	000708	$0.0041	200 Dt/d	Zone 2
6/30/2000	000710	$0.0207	200 Dt/d	Zone 3

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Conditions for Affiliated Discount Offers

Discount Offer 000701 dated 06/30/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 07/01/2000 through 07/31/2000.

3. This rate receives gas from MS# 11120, 10379, 10634, 11185, and 1G500 on Transok (KPPZ1) for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0207 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Conditions for Affiliated Discount Offers

Discount Offer 000702 dated 06/30/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 07/01/2000 through 07/31/2000.

3. This rate receives gas from MS# 11120, 10379, 10634, 11185 and 1G500 on Transok (KPPZ1) for delivery into Zone 2.

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0207 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000703 dated 06/30/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 07/01/2000 through 07/31/2000.

3. This rate receives gas from MS# 2B162 in KPC's Zone 2 for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.5106 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0078 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Conditions for Affiliated Discount Offers

Discount Offer 000704 dated 06/30/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 07/01/2000 through 07/31/2000.

3. This rate receives gas from MS# 1G500 in KPC's Zone 1 for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0078 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000705 dated 06/30/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 07/01/2000 through 07/31/2000.

3. This rate receives gas from MS# 2B162 in KPC's Zone 2 for delivery into Zone 1 (backhaul).

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0078 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000706 dated 06/30/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 07/01/2000 through 07/31/2000.

3. This rate receives gas from MS# 1G500 in KPC's Zone 1, through Zone 2 for redelivery into Zone 1 (west leg).

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

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Conditions for Affiliated Discount Offers

Discount Offer 000708 dated 06/30/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 07/01/2000 through 07/31/2000.

3. This rate receives gas from MS# 2B162 in KPC's Zone 2 for delivery into Zone 2.

4. The maximum Tariff rate for this point to point is $0.2270 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0041 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000710 dated 06/30/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 07/01/2000 through 07/31/2000.

3. This rate receives gas from MS# 11120 on Transok (KPPZ1) for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0207 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Affiliated Discount Offers
August 2000

Offer Date	Discount No.	Discount Rate	Quantity	Delivery Point
7/28/2000	000801	$0.0207	220,000 Dt/d	Zone 3
7/28/2000	000802	$0.0170	60,400 Dt/d	Zone 2
7/28/2000	000803	$0.0078	1,310 Dt/d	Zone 3
7/28/2000	000804	$0.0170	30,600 Dt/d	Zone 3
7/28/2000	000805	$0.0041	310 Dt/d	Zone 1
7/28/2000	000806	$0.0170	400 Dt/d	Zone 1
7/28/2000	000808	$0.0041	310 Dt/d	Zone 2

Conditions for Affiliated Discount Offers

Discount Offer 000801 dated 07/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 08/01/2000 through 08/31/2000.

3. This rate receives gas from MS# 11120, 10379, 10634, 11185, and 1G500 on Transok (KPPZ1) for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0207 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000802 dated 07/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 08/01/2000 through 08/31/2000.

3. This rate receives gas from MS# 11120, 10379, 10634, 11185 and 1G500 on Transok (KPPZ1) for delivery into Zone 2.

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Conditions for Affiliated Discount Offers

Discount Offer 000803 dated 07/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 08/01/2000 through 08/31/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.5106 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0078 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000804 dated 07/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 08/01/2000 through 08/31/2000.

3. This rate receives gas from MS# 1G500 and 11120 in KPC's Zone 1 for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000805 dated 07/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 08/01/2000 through 08/31/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 1 (backhaul).

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0041 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Conditions for Affiliated Discount Offers

Discount Offer 000806 dated 07/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 08/01/2000 through 08/31/2000.

3. This rate receives gas from MS# 1G500 and 11120 in KPC's Zone 1, through Zone 2 for redelivery into Zone 1 (west leg).

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000808 dated 07/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 08/01/2000 through 08/31/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 2.

4. The maximum Tariff rate for this point to point is $0.2270 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0041 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Affiliated Discount Offers
September 2000

Offer Date	Discount No.	Discount Rate	Quantity	Delivery Point
8/31/2000	000901	$0.0207	140,000 Dt/d	Zone 3
8/31/2000	000902	$0.0170	10,200 Dt/d	Zone 2
8/31/2000	000903	$0.0078	1,310 Dt/d	Zone 3
8/31/2000	000904	$0.0170	30,580 Dt/d	Zone 3
8/31/2000	000905	$0.0170	310 Dt/d	Zone 1
8/31/2000	000906	$0.0170	200 Dt/d	Zone 1
8/31/2000	000908	$0.0041	310 Dt/d	Zone 2

Conditions for Affiliated Discount Offers

Discount Offer 000901 dated 08/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 09/01/2000 through 09/30/2000.

3. This rate receives gas from MS# 11120, 10379, and 10634 on Transok (KPPZ1) for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0207 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (713) 650-8900 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000902 dated 08/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 09/01/2000 through 09/30/2000.

3. This rate receives gas from MS# 11120 on Transok (KPPZ1) for delivery into Zone 2.

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000903 dated 08/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 09/01/2000 through 09/30/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.5106 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0078 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Conditions for Affiliated Discount Offers

Discount Offer 000904 dated 08/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 09/01/2000 through 09/30/2000.

3. This rate receives gas from MS# 11120 on Transok (KPCZ1) for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (713) 650-8900 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000905 dated 08/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 09/01/2000 through 09/30/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 1 (backhaul).

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0041 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (713) 650-8900 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 000906 dated 08/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 09/01/2000 through 09/30/2000.

3. This rate receives gas from MS# 11120 on Transok (KPCZ1) through Zone 2 for redelivery into Zone 1 (west leg).

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (713) 650-8900 to discuss or request any potential discount.

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Conditions for Affiliated Discount Offers

Discount Offer 000908 dated 08/31/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 09/01/2000 through 09/30/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 2.

4. The maximum Tariff rate for this point to point is $0.2270 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0041 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (713) 650-8900 to discuss or request any potential discount.

Affiliated Discount Offers
October 2000

Offer Date	Discount No.	Discount Rate	Quantity	Delivery Point
9/28/2000	001001	$0.0207	170,380 Dt/d	Zone 3
9/28/2000	001002	$0.0170	10,200 Dt/d	Zone 2
9/28/2000	001003	$0.0078	1,310 Dt/d	Zone 3
9/28/2000	001004	$0.0207	200 Dt/d	Zone 3
9/28/2000	001005	$0.0170	310 Dt/d	Zone 1
9/28/2000	001006	$0.0170	200 Dt/d	Zone 1
9/28/2000	001008	$0.0041	310 Dt/d	Zone 2

Conditions for Affiliated Discount Offers

Discount Offer 001001 dated 09/28/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 10/01/2000 through 10/31/2000.

3. This rate receives gas from MS# 11120, 10379, and 10634 on Transok (KPPZ1) for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0207 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Conditions for Affiliated Discount Offers

Discount Offer 001002 dated 09/28/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 10/01/2000 through 10/31/2000.

3. This rate receives gas from MS# 11120 on Transok (KPPZ1) for delivery into Zone 2.

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 001003 dated 09/28/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 10/01/2000 through 10/31/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.5106 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0078 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 001004 dated 09/28/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 10/01/2000 through 10/31/2000.

3. This rate receives gas from MS# 11120 on Transok (KPCZ1) for delivery into Zone 3.

4. The maximum Tariff rate for this point to point is $0.7192 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0207 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 001005 dated 09/28/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 10/01/2000 through 10/31/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 1 (backhaul).

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

Conditions for Affiliated Discount Offers

Discount Offer 001006 dated 09/28/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 10/01/2000 through 10/31/2000.

3. This rate receives gas from MS# 11120 on Transok (KPCZ1) through Zone 2 for redelivery into Zone 1 (west leg).

4. The maximum Tariff rate for this point to point is $0.4356 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0170 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

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Conditions for Affiliated Discount Offers

Discount Offer 001008 dated 09/28/2000 has the following limiting conditions:

1. The offer is for an IT contract.

2. The rate offered is effective from 10/01/2000 through 10/31/2000.

3. This rate receives gas from MS# 2B162 and 2B163 in KPC's Zone 2 for delivery into Zone 2.

4. The maximum Tariff rate for this point to point is $0.2270 per Dt.

Additional Comments:

The affiliate involved in this transaction is MarGasCo Partnership, $0.0041 rate exclusive of fuel and add ons.

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Please contact KPC at (913) 888-7139 to discuss or request any potential discount.

KPC - Affiliate Discount Offers

Period	Marketing Affiliate	Discount Rate	Maximum Tariff Rate	Rate Component	Daily Quantity	Discount Begin Date	Discount End Date	Zone
4/2001	MarGasCo	$0.0207	$0.7192	IT	49,500	4/1/2001	4/30/2001	Meter # 30914, 10385, and 10235 on Transok (KPCZ1) delivered into Zone 3.
4/2001	MarGasCo	$0.0170	$0.4356	IT	16,500	4/1/2001	4/30/2001	Meter # 30914, 10385 and 10235 on Transok (KPCZ1) delivered into Zone 2
4/2001	MarGasCo	$0.0078	$0.5106	IT	200	4/1/2001	4/30/2001	Meter# 2B162 in KPC's Zone 2 for delivery into Zone 3
4/2001	MarGasCo	$0.0050	$0.2270	IT	200	4/1/2001	4/30/2001	Meter# 2B162 in KPC's Zone 2 for delivery into Zone 2
4/2001	MarGasCo	$0.0170	$0.4356	IT	8,250	4/1/2001	4/30/2001	Meter# 30914, 10385, 10235 on Transok (KPCZ1) through Zone 2 for redelivery into Zone 1
4/2001	Midcoast Marketing	$0.0207	$0.7192	IT	5,000	4/7/2001	4/30/2001	Meter #10235 on Transok (KPCZ1) delivered into Zone 3
4/2001	Midcoast Marketing	$0.0207	$0.7192	IT	10,000	4/7/2001	4/30/2001	Meter #10235 on Transok (KPCZ1) delivered into Zone 3

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Contact David Croucher at (713) 821-2200 to discuss or request any potential discount.

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KPC - Affiliate Discount Offers

Period	Marketing Affiliate	Discount Rate	Maximum Tariff Rate	Rate Component	Daily Quantity	Discount Begin Date	Discount End Date	Zone
5/2001	MarGasCo	$0.0207	$0.7192	IT	45,000	5/1/2001	5/31/2001	Meter # 30914, 30846, and 10379 on Transok (KPCZ1) delivered into Zone 3.
5/2001	MarGasCo	$0.0170	$0.4356	IT	15,000	5/1/2001	5/31/2001	Meter # 30914, 30846 and 10379 on Transok (KPCZ1) delivered into Zone 2
5/2001	MarGasCo	$0.0078	$0.5106	IT	200	5/1/2001	5/31/2001	Meter# 2B162 in KPC's Zone 2 for delivery into Zone 3
5/2001	MarGasCo	$0.0050	$0.2270	IT	200	5/1/2001	5/31/2001	Meter# 2B162 in KPC's Zone 2 for delivery into Zone 2
5/2001	MarGasCo	$0.0170	$0.4356	IT	7,500	5/1/2001	5/31/2001	Meter# 30914, 30846, 10379 on Transok (KPCZ1) through Zone 2 for redelivery into Zone 1

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Contact David Croucher at (713) 821-2200 to discuss or request any potential discount.

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KPC - Affiliate Discount Offers

Period	Marketing Affiliate	Discount Rate	Maximum Tariff Rate	Rate Component	Daily Quantity	Discount Begin Date	Discount End Date	Zone
6/2001	MarGasCo	$0.0207	$0.7192	IT	60,000	6/1/2001	6/30/2001	Meter #30914, 30846, 11120, and 10235 on Transok (KPCZ1) delivered into Zone 3.
6/2001	MarGasCo	$0.0170	$0.4356	IT	15,000	6/1/2001	6/30/2001	Meter # 30914, 30846 and 10235 on Transok (KPCZ1) delivered into Zone 2
6/2001	MarGasCo	$0.0078	$0.5106	IT	200	6/1/2001	6/30/2001	Meter# 2B162 in KPC's Zone 2 for delivery into Zone 3
6/2001	MarGasCo	$0.0050	$0.2270	IT	200	6/1/2001	6/30/2001	Meter# 2B162 in KPC's Zone 2 for delivery into Zone 2
6/2001	MarGasCo	$0.0170	$0.4356	IT	7,500	6/1/2001	6/30/2001	Meter# 30914, 30846, 10235 on Transok (KPCZ1) through Zone 2 for redelivery into Zone 1
6/2001	MarGasCo	$0.0207	$0.7192	IT	60,000	6/26/2001	6/30/2001	Meter #30914 Transok (KPCZ1) delivered into Zone 3

Procedures for similarly situated non-affiliated Shippers requesting a comparable discount offer:

Contact David Croucher at (713) 821-2200 to discuss or request any potential discount.

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