Exhibit No.:	________
Issues:	KPC Capacity Release Purchasing Practices – Hedging Purchasing Practices – Storage
Witness:	John J. Reed
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 JOHN J. REED

Jefferson City, Missouri
January 15, 2003

Exhibit No. 1
Case No(s). GR-2001-382
Date 5-12-03 Rptr KF

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 JOHN J. REED

COMMONWEALTH OF MASSACHUSETTS	)	
	)	ss.
COUNTY OF MIDDLESEX	)	

John J. Reed, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Rebuttal Testimony in question and answer form, to be presented in the above case; that the answers in the foregoing Rebuttal 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.

John J. Reed

Subscribed and sworn to before me this 9 day of January, 2003.

Jo Ann L. Erven

My Commission Expires: March 31, 2006

DIRECT TESTIMONY OF

JOHN J. REED

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DIRECT TESTIMONY OF

JOHN J. REED

CASE NO. GR-2001-382

JANUARY 15, 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Reed. My business address is 313 Boston Post Road West, Suite 210, Marlborough, Massachusetts 01752.

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

A. I am Chairman and Chief Executive Officer of Commonwealth Energy Advisors, Inc. ("CEA"). CEA is a management consulting firm specializing in financial and economic services to the energy industry.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I have more than twenty-five years of experience in the North American energy industry. Prior to my current position with CEA, I have served in executive positions with various consulting firms and as Chief Economist with Southern California Gas Company. I have provided expert testimony on financial and economic matters on more than 125 occasions, including numerous proceedings regarding natural gas local distribution company ("LDC") and pipeline prudence-related matters, before the Federal Energy Regulatory Commission ("FERC"), various Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. A copy of my résumé and listing of the testimony I have sponsored previously is included as Attachment A.

Q. ON WHOSE BEHALF ARE YOU SPONSORING TESTIMONY IN THIS PROCEEDING?

A. I am sponsoring testimony on behalf of Missouri Gas Energy ("MGE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the recommendations issued by the Staff ("Staff") of the Missouri Public Service Commission ("Commission") on May 31, 2002 in Case No. GO-2001-382 regarding the purchasing practices of MGE for the 2000-2001 Annual Cost Adjustment ("ACA") period. Specifically, my testimony will: (i) provide an overview of the generally-accepted industry standards applicable to prudence reviews; (ii) discuss the prudence standards specific to Missouri and previously relied on by the Commission; and (iii) evaluate MGE's actions during the winter of 2000-2001 considering these prudence standards.

GENERALLY-ACCEPTED STANDARDS OF PRUDENCE

Q. WHAT IS THE PRUDENCE STANDARD IN UTILITY RATEMAKING?

A. In 1923, a United States Supreme Court decision articulated a standard commonly known as the "prudence standard" or "prudent investment rule". In a separate, concurring opinion, Justice Brandeis wrote ("Brandeis Opinion"):

> There should not be excluded from the finding of the [rate] base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown... (Separate concurring opinion of Justice Brandeis, Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission, 262 US 276 (1923)).

That decision, and its application since, has established two fundamental principles of ratemaking. The first principle is that only reasonable or prudent expenditures are to be included in a utility's rates. The second principle is that a utility's expenditures are presumed to be prudent until it can be demonstrated that the expenditures were imprudent through clear evidence of utility misconduct.

Q. HAVE THERE BEEN ADDITIONAL PRUDENCE PRINCIPLES ESTABLISHED SPECIFICALLY FOR THE ENERGY INDUSTRY?

A. Yes. The National Regulatory Research Institute ("NRRI"), the regulatory research affiliate of the National Association of Regulatory Utility Commissioners ("NARUC"), has identified four principles to be followed by state utility commissions when evaluating the prudence of a utility's actions. In The Prudent Investment Test in the 1980s, NRRI identified the following four principles:

1) a presumption of prudence;
2) a rule of reasonableness under the circumstances;
3) a proscription against hindsight; and
4) a retrospective, factual inquiry. [1]

NRRI found that the above guidelines would likely be useful, and perhaps necessary, for a court to sustain a commission's findings regarding prudence.

[1] The Prudent Investment Test in the 1980s, Burns, Poling, Whinihan and Kelly, 1984, p. 55.

Q. PLEASE EXPLAIN WHAT IS MEANT BY THE FIRST PRINCIPLE, i.e., A PRESUMPTION OF PRUDENCE.

A. The first principle when reviewing utility prudence matters is that there is to be a presumption of prudence for utility actions and that this presumption must be rebutted sufficiently in order to proceed further. This presumption of prudence rests on case law stemming from the Brandeis Opinion, i.e., "every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown." Thus, this presumption of prudence creates a threshold requirement for a party to first overcome in order to challenge further the prudence of a utility's actions.

Q. PLEASE EXPLAIN THE SECOND PRINCIPLE, i.e., A RULE OF REASONABLENESS UNDER THE CIRCUMSTANCES.

A. Once the prudence threshold has been crossed, the next step requires that the action of the utility's management be evaluated in light of what was known, or reasonably knowable, at the time the decisions in question were made. In particular, given the potential effect on customers, the commission needs to evaluate whether the decisions and conclusions were appropriate given the information available at the time. It is important to note the distinction here – that while the results of management conduct can be used to rebut a presumption of prudence, results of management conduct cannot be relied upon to determine whether that conduct was prudent.

Q. THE SECOND PRINCIPLE TIES DIRECTLY INTO THE THIRD PRINCIPLE, i.e., A PROSCRIPTION AGAINST HINDSIGHT, DOES IT NOT?

A. Yes. Since the utility's actions must be judged based on the reasonableness of the circumstances that existed at the time, using hindsight to evaluate a utility's actions will not result in a supportable finding. Thus, any evaluation of a utility's actions must be based on the information available, and the circumstances that existed, at the time the decision was made. This requires that factual information from that period be collected and evaluated without consideration of the eventual outcome or result of that decision. In fact, NRRI has specifically stated that "if a state commission engages in hindsight, any finding of imprudence is subject to reversal."[2] In addition, in a presentation prepared by NRRI regarding the evaluation of utility actions and the prudence of those actions, NRRI stated that the "prudence standard establishes the basis for evaluation in terms of 'bad decisions' rather than 'bad outcomes' (no 20/20 hindsight)" and that information available after a decision was made is irrelevant to the prudence evaluation.[3]

Q. PLEASE EXPLAIN THE LAST PRINCIPLE, i.e., A RETROSPECTIVE, FACTUAL INQUIRY.

A. The last principle requires that a commission develop a record of the facts, not opinions, as they existed at the time the utility's decision was made. It is this record that should be used to measure and evaluate the utility's decisions against the prudence standard in effect.

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2 The Prudent Investment Test in the 1980s, NRRI 84-16, p. 60.

3 http://www.nrri.ohio-state.edu/programs/gas.html ; See: "A Prudence Standard for Risk Management", Ken Costello, NRRI.

Q. PLEASE DESCRIBE THE THEMES THESE PRINCIPLES SUPPORT.

A. The principles support two related themes:

1. The prudence standard applies to decisions, not to results; and
2. Costs cannot be imprudent, only actions.

The first theme is that the prudence standard is applied to the decisions and actions taken by management. This is distinct from the results of the action. If management uses available information to make reasonable decisions within the then-current framework, the decision is prudent, *regardless of the outcome*. The second theme follows the first, i.e., costs, in and of themselves, cannot be prudent or imprudent. Rather, costs are only imprudent if they arise out of imprudent management action.

Q. WHEN JUDGING MANAGEMENT CONDUCT FOR PRUDENCE, IS THERE TYPICALLY A SINGLE CORRECT ACTION OR DECISION THAT IS APPROPRIATE OR REASONABLE?

A. No. Reasonable and appropriate management actions and decisions vary over a wide range. In addition, in times of chaos, emergency, or unprecedented occurrence, the range of reasonable behavior is typically more broad as compared to times of relative stability due to the lack of experience with such situations and the limited time in which to make informed decisions. Therefore, an important consideration when applying the four principles discussed above is to define a reasonable range of behavior, and a minimally acceptable level of conduct.

Q. IS IT IMPORTANT FOR THE STANDARDS BY WHICH PRUDENCE IS TO BE EVALUATED BE KNOWN IN ADVANCE?

A. Yes. There are two reasons why it is essential that the range of prudent behavior or the minimally acceptable level of behavior be communicated to the utility in advance of the utility being subject to those standards. First, unless a minimally acceptable level of behavior can be defined, then imprudence cannot be defined. This is consistent with the principle discussed above prohibiting hindsight review or second-guessing, meaning that without a defined standard communicated in advance, it is not reasonable to expect a utility to be able to necessarily meet that standard. In addition, not only does a minimally acceptable level of behavior need to be defined in advance of making a utility subject to that standard, but the minimally acceptable level needs to be communicated with sufficient time in order for the utility to reasonably meet the standards.

Second, setting a minimally acceptable level of behavior is also important for the calculation of costs associated with imprudent action. Assuming that there is a range of reasonable conduct, then only the costs associated with the conduct that is below the minimally acceptable level of behavior should be considered for disallowance.

PRUDENCE STANDARDS IN MISSOURI

Q. DOES THE MISSOURI PUBLIC SERVICE COMMISSION HAVE AN ESTABLISHED POLICY REGARDING UTILITY PRUDENCE ISSUES?

A. Yes. The Commission has articulated its policy regarding utility prudence issues in various cases in the past, in connection with both nuclear power plant construction costs (*Union Electric*) and LDC gas costs (*Western Resources*).[4] In the Commission's *Union Electric* decision regarding the construction of the Callaway Nuclear Plant ("Callaway Decision"), the Commission addressed both the presumption of prudence, as well as the manner in which utility prudence should be evaluated.

First, in terms of the presumption of prudence, the Commission stated that it agreed with the conclusions of the Washington D.C. Circuit Court of Appeals and the Brandeis Opinion, in finding that:

> Utilities seeking a rate increase are not required to demonstrate in their cases-in-chief that all expenditures were prudent...However, where some other participant in the proceeding <u>creates serious doubt</u> as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent. (emphasis added) (Missouri Public Service Commission, Case Nos. EO-85-17 and ER-85-160, March 29, 1985, mimeo p. 193)

Therefore, the Commission has found that there is a presumption of prudence for utility expenditures until a third-party creates "serious doubt" as to the prudence of a utility expenditure. Only after serious doubt has been created does the utility bear the burden of proving the expenditure was incurred as a result of prudent conduct.

Q. IN THE CALLAWAY DECISION, WHAT DID THE COMMISSION CONCLUDE REGARDING THE MANNER IN WHICH UTILITY PRUDENCE SHOULD BE EVALUATED?

[4] See, e.g., *Union Electric Company,* Missouri Public Service Commission, Case Nos. EO-85-17 and ER-85-160 (1985); *Western Resources*, Missouri Public Service Commission, Case No. GR-93-140 (1995).

A. The Commission has adopted a "reasonable care standard" regarding how utility prudence should be evaluated. In its Callaway Decision, the Commission found that the appropriate prudence standard was enunciated in an order issued by the New York Public Service Commission ("NYPSC") in a case involving Consolidated Edison of New York (the "ConEd Case"). The Commission quoted from the ConEd Case, in which the NYPSC found in favor of a reasonable care standard stating that:

> ...the company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company. (Ibid., mimeo p. 194)

The Commission went on to state in its Callaway Decision that it would not rely on hindsight and that it would assess management decisions at the time they were made by asking the question, "Given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it addressed the situation?"[5] The Commission specifically stated that, by accepting the reasonable care standard, it did not adopt a standard of perfection, but rather the relevant factors to consider were the "manner and timeliness in which problems were recognized and addressed."[6]

Q. WHAT HAS THE COMMISSION CONCLUDED REGARDING UTILITY PRUDENCE IN PRIOR GAS COST PROCEEDINGS?

[5] Ibid.

[6] *Ibid.*

A. In its 1995 decision in a Western Resources ACA proceeding ("Western Resources Decision"), the Commission reiterated its position that a party must first create serious doubt as to the prudence of a utility's expenditure(s), then the utility has the burden of proof to demonstrate and prove that those expenditures were in fact prudently incurred.[7] In addition, in the same order, the Commission took the opportunity to further elaborate and clarify its prudence standard:

> The incurrence of expenditures or accrued liabilities on the part of local distribution companies in exchange for the physical delivery of natural gas results from action or inaction on the part of individuals in the employ of the local distribution company at some point in time. It appears to the Commission that it needs to clarify the parameters of gas cost prudence reviews. The Commission is of the opinion that a prudence review of this type must focus primarily on the cause(s) of the allegedly excessive gas costs. Put another way, the proponent of a gas cost adjustment must raise a serious doubt with the Commission as to the prudence of the decision (or failure to make a decision) that caused what the proponent views as excessive gas costs. The Commission is of the opinion that evidence relating to the decision-making process is relevant to the extent that the existence of a prudent decision-making process may preclude the adjustment. Specifically, the Commission needs evidence of the actual expenditure(s) incurred during the ACA period resulting from the alleged imprudent decision. In addition, it is helpful to the Commission to have evidence as to the amount that the expenditures would have been if the local distribution company had acted in a prudent manner. The critical matter of proof is the prudence or imprudence of the decision from which the expenses result. (emphasis added) (Ibid, pp. 14-15)

As can be seen from the order in *Western Resources*, the Commission has found that utility prudence or imprudence must focus on the utility's conduct or decision-making process, not the results or outcome of the utility's actions or decisions.

7 *Western Resources*, Missouri Public Service Commission, Case No. GR-93-140, July 14, 1995, mimeo p. 14.

Q. IS THE COMMISSION'S PRUDENCE STANDARD CONSISTENT WITH THE BRANDEIS OPINION AND THE PRINCIPLES OUTLINED BY NRRI YOU DISCUSSED EARLIER?

A. Yes. The Commission's reasonable care standard is consistent with the utility prudence conclusions in the Brandeis Opinion and the prudence theory outlined by NRRI discussed earlier. Specifically, in its previous cases, the Commission has found that:

(i) serious doubt must be demonstrated by another party before the Commission should evaluate the prudence of utility conduct;

(ii) only the utility's actions or inaction will be reviewed for prudence, not the results of the action or inaction;

(iii) it will not rely on hindsight when reviewing a utility's actions; and

(iv) all circumstances at the time of the utility's action or inaction will be considered, including the manner and timeliness for recognizing and addressing the problems.

Q. DO YOU BELIEVE THAT THE COMMISSION SHOULD USE THOSE SAME STANDARDS IN REVIEWING THE PRUDENCE OF MGE'S CONDUCT DURING THE 2000/2001 ACA PERIOD?

A. Yes. I believe that the Commission's prudence standards represent sound regulatory policy, are consistent with the prudence standards of other regulatory agencies, and are an appropriate way in which to assess the prudence of MGE's conduct.

STAFF RECOMMENDATIONS VIS-À-VIS THE PRUDENCE STANDARD

Q. PLEASE PROVIDE A SUMMARY OF THE STAFF'S POSITION REGARDING MGE'S 2000/2001 ACA FILING.

A. On May 31, 2002, Staff filed a memorandum (the "May 31, 2002 Memo") in Case No. GR-2001-382 stating its recommendations regarding MGE's natural gas costs during the 2000-2001 ACA period, i.e., July 1, 2000 through June 30, 2002. In that memorandum, Staff recommended three primary areas of cost disallowance that I will address in this testimony. First, regarding MGE's purchasing practices during the ACA period, Staff asserts that MGE's storage utilization plan for the winter of 2000/2001 was inappropriate, and that MGE ordered less flowing supplies for December 2000 based on presumed price declines for which it did not have adequate support. Second, regarding MGE's hedging practices, Staff asserts that MGE should have had a documented, formalized hedging plan for the winter of 2000/2001 and that it is reasonable to expect that MGE should have hedged a minimum level of 30% of its natural gas purchases for the winter months of the ACA period. Lastly, Staff asserts that MGE should have posted for release to other shippers its idle capacity on Kansas Pipeline Company ("KPC"). As a result of its positions on these matters, Staff recommends that the Commission require MGE to credit $8.05 million, $0.61 million and $1.14 million, respectively, back to the ACA balance.

PURCHASING PRACTICES - STORAGE

Q. PLEASE EXPLAIN THE BASIS OF STAFF'S ASSERTION THAT MGE'S UTILIZATION OF STORAGE WAS IMPRUDENT DURING 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 planned on withdrawing a greater percentage of its storage inventory in November 2000 than Staff would have expected based on relative heating demand in November as compared to the other winter months. 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 supplies in January through March 2001 when natural gas prices were higher. Staff concluded in its May 31, 2002 Memo "that MGE could have reasonably avoided its exposure to the higher prices" in January, February and March 2002 "by (1) following a reasonable approach for planned flowing gas and storage withdrawals; and (2) not speculating on price decreases in December 2000 without adequate analysis and documentation to support such a course of action."

Q. FIRST, WHAT IS TRADITIONALLY THE PRIMARY PURPOSE OF NATURAL GAS STORAGE?

A. There are four primary reasons that LDCs contract for natural gas storage service: reliability, operational flexibility, price stability and economics. First, storage is purchased to provide reliable natural gas supplies during times when supplies are difficult or impossible to obtain in the production regions as a result of factors such as weather, excess demand, or force majeure events. When natural gas supplies cannot be purchased or purchased in the quantities sufficient to meet demand, storage volumes can be withdrawn to supplement purchased volumes to maintain the reliable provision of natural gas service by the LDC.

Second, storage also provides an LDC with flexibility in dealing with the swings in customer demand, both up and down, that can be experienced from day to day. Depending on the weather, these swings can be quite substantial and relatively unexpected. For example, an LDC can either inject excess natural gas into storage during the summer months, i.e., April through October, if the weather is warmer than anticipated and not needed by its customers, or withdraw additional gas from storage during the winter (i.e., November through March) if the weather turns out to be colder than expected causing increased demand. Therefore, storage provides the flexibility to deal with these daily demand swings throughout the year that pose operating challenges in terms of pipeline balancing, and which can also directly impact reliability.

Third, storage also provides price stability for LDC customers as an alternative seasonal baseload supply. Typically, natural gas prices are lower in the summer when natural gas can be injected into storage as compared to the winter period when demand is at its highest. Therefore, storage provides a physical hedge against high winter prices of natural gas, as LDCs can supplement generally higher priced flowing supplies in the winter with lower priced storage supplies that were injected during the summer in order to reduce the overall average cost of natural gas.

Lastly, storage, especially market area storage, can often be the most economical supply option for peak season demands because of the more efficient use of pipeline capacity. With market area storage, an LDC only needs to hold pipeline capacity downstream of the storage field (i.e., from the storage facility to the LDC city gate) in order to meet its peak demand, and does not need to hold the same amount of pipeline capacity upstream of the storage facility (i.e., from the production area to the storage facility). Since demand is lowest in the summer months, LDCs are able to utilize their pipeline capacity upstream of the storage field to inject natural gas in the summer, and if necessary, supplement that firm pipeline capacity upstream of the storage facility with interruptible pipeline capacity in order to meet its necessary storage injections. Therefore, with market area storage, the LDC is able to forego the purchase of upstream capacity that it would otherwise need, and the fixed demand charges that are associated with purchasing that capacity and which are assessed by the pipeline regardless of whether the capacity is utilized. Overall, this improves the economics of pipeline capacity utilization, and is an attractive means of meeting peak season demands.

Q. THE FIRST ALLEGATION STAFF MAKES REGARDING IMPRUDENCE IS THAT MGE DID NOT FOLLOW A REASONABLE PLAN FOR STORAGE WITHDRAWALS FOR THE WINTER OF 2000/2001. DID MGE UTILIZE A STORAGE PLAN THAT WAS DIFFERENT FROM PRIOR YEARS?

A. No. As explained in the testimony of MGE Witness Langston, MGE's storage utilization plan for the winter of 2000/2001 was the same as the plan that had been used since the winter of 1998/1999. As clearly stated in MGE Witness Langston's testimony, it had been MGE's policy since the winter of 1998/1999 to utilize storage as a flexible resource in November to meet the wide variations in weather that can be experienced in that month. Therefore, MGE plans to utilize storage as a "shock absorber" to adjust supplies to meet either warmer than expected weather or meet excess demand as a result of colder than expected weather.

Q. PRIOR TO THE WINTER OF 2000/2001, DID STAFF REVIEW MGE'S STORAGE WITHDRAWAL PLAN FOR THAT WINTER?

A. Yes. Staff has stated in this proceeding that they did in fact review MGE's storage plan prior to the winter of 2000/2001. Furthermore, Staff has stated that it never indicated or communicated to MGE that the storage withdrawal plan was in any way deficient. Specifically, the Staff employee responsible for evaluating the prudence of MGE's conduct regarding storage utilization has stated that:

> Q. Did you or any other member of the Staff review MGE's storage utilization plan during prior ACA reviews?
>
> A. Yes.
>
> Q. And does that – does your answer mean that you reflect – you reviewed it or that other people reviewed it?
>
> A. Both.
>
> Q. Okay. In those reviews on plans prior to the winter of 2000 and 2001, did the Staff ever provide any indication or notice to MGE that the Staff believed that MGE's storage utilization plan was deficient.
>
> A. I did not. I can't speak for whether anyone else did. (Deposition of Staff Witness Lesa Jenkins, Missouri Public Service

Commission, Case No. GR-2001-382, December 10, 2002, p. 33, ll. 1-13)

Therefore, MGE generally had the same storage utilization plan for three winters including for the winter of 2000/2001, and at no time prior to the winter of 2000/2001 did Staff ever indicate to MGE or the Commission that such storage plan was deficient or unreasonable.

Q. HAS STAFF ADMITTED THAT ITS REVIEW OF THE STORAGE WITHDRAWAL PLAN WAS DONE AFTER THE FACT, OR IN OTHER WORDS, CONDUCTED AFTER THE WINTER OF 2000/2001?

A. Yes. Staff has also admitted that its review of MGE's storage withdrawal plans were done after the winter of 2000/2001. Again, the Staff employee responsible for evaluating the prudence of MGE's conduct regarding storage utilization has stated that:

> Q. In your previous answer where you had – you only looked at actuals, I take it from that answer that you only looked at the storage utilization questions after the fact, after the storage had already been utilized, as opposed to some kind of review as to whether the plan itself was reasonable or not on a going-forward basis?
>
> A. When I did those previous reviews, yes. You need to understand, I've only been at the Commission three years. So when I first started out, it started out with reviews of capacity and trying to fully explain to understand that and get explanations from the companies, and then kind of develop that knowledge through time.
>
> Q. But your reviews have always been after the fact as opposed to trying to warn a company that their plan is deficient. Is that right?
>
> A. The reviews are after the fact. (Deposition of Staff Witness Lesa Jenkins, Missouri Public Service Commission, Case No. GR-2001-382, December 10, 2002, p. 34, ll. 3-19)

Therefore, Staff's criticism of MGE's storage withdrawal plan for the winter of 2000/2001 is not based on MGE's conduct and decisions at the time the storage plan was prepared, but rather is clearly based on the results of the winter of 2000/2001, i.e., the high gas costs experienced.

Q. EVEN THOUGH STAFF AT NO TIME PRIOR TO THIS ACA PROCEEDING IDENTIFIED MGE'S STORAGE UTILIZATION PLAN AS INADEQUATE, ARE THERE OTHER PROBLEMS WITH STAFF'S FINDING THAT MGE'S STORAGE WITHDRAWAL PLAN WAS IMPRUDENT?

A. Yes. Staff has criticized MGE's storage withdrawal plan on the basis that MGE has a greater level of storage withdrawals planned in November 2000 than would be expected based on overall heating demand for November. However, as explained in detail by MGE Witness Langston, Staff's analysis of MGE's storage withdrawal plan has relied on an average monthly demand rather than a baseload monthly demand, which would be highly likely to impose additional costs on MGE's customers. As presented in MGE Witness Langston's testimony, MGE can experience very dramatic changes in daily demand in the early part of the winter as a result of changes in the weather. As I explained above, one of the primary functions and benefits of natural gas storage is that it acts as a "shock absorber" by providing operational flexibility to an LDC and its customers. Storage is typically the best operational and financial alternative that a LDC has available to deal with those significant swings in daily demand, especially in months such as November on MGE's distribution system. Therefore, the premise of Staff's argument and finding of imprudence is fatally flawed, and the result of Staff's error is that, if MGE were to utilize such a storage withdrawal plan based on Staff's methodology, MGE would be in the position of having significant levels of excess gas on many days of the month. This would likely be costly both financially as well as operationally for MGE and its customers. Therefore, as a result of Staff's misunderstanding of how storage is utilized by MGE, especially during November, I believe that Staff's position regarding MGE's storage withdrawal plan is unfounded.

Q. DID MGE FOLLOW ITS STORAGE WITHDRAWAL PLAN FOR THE WINTER OF 2000/2001?

A. Yes, to the extent possible, MGE followed its established plan for storage utilization. However, no storage plan can be followed exactly due to the numerous factors LDCs face throughout a winter heating season, including daily weather fluctuations, natural gas pricing dynamics, gas supply production limitations, producer failure, and pipeline operational issues. In MGE's case, extreme and record-setting weather experienced during November and December 2000, as well as record-high natural gas prices leading up to and during the winter of 2000/2001, led to higher than planned storage withdrawals for the months of November and December.

Q. WAS MGE ALONE IN WITHDRAWING GREATER LEVELS OF STORAGE IN NOVEMBER AND DECEMBER?

A. Absolutely not. MGE, as well as many other LDCs across the United States, withdrew greater levels of storage in November and December as a result of the extreme cold weather that the country experienced, as well as the record high and volatile gas prices at the time. In fact, MGE's utilization of its storage inventory in November and December 2000 is consistent with, or below, the storage withdrawal trend experienced for the entire United States. The AGA, which has maintained storage inventory level data for the United States since 1993, has indicated that storage withdrawals for November and December 2000 were significantly greater than the historical average. Schedule JJR-1 provides a summary of the AGA storage data and an analysis of the United States storage withdrawal levels in the winter of 2000/2001 compared to the historical averages.

As illustrated in Schedule JJR-1, total United States storage withdrawals in November 2000 were 210 Bcf, representing a 71% increase in storage withdrawals as compared to the historical average, and a dramatic change from the prior year when the United States experienced a net injection of 6 Bcf for November 1999.[8] Similarly, for December 2000, storage withdrawals were 773 Bcf or 70% greater than the historical average. In fact, the storage withdrawals in December 2000 were greater than at any time since AGA has maintained data and 25% greater than the highest previous withdrawal amount for the month of December.

Q. HOW DO THE NATIONAL STORAGE WITHDRAWAL TRENDS COMPARE TO MGE'S ACTUAL STORAGE WITHDRAWALS FOR THE WINTER OF 2000/2001?

[8] The historical average is based on an average of the earliest available storage data from AGA through the winter of 1999/2000. For example, no storage data was available for November 1993, therefore, the average for November is based on the six years 1994 through 1999. In contrast, storage data was available for January 1994, thus the average for January is based on the seven years 1994 through 2000.

A. MGE's actual storage utilization for the winter of 2000/20001 was consistent with the national trend for storage withdrawals. For example, MGE withdrew more storage during the early part of the winter, i.e., November and December 2000, and withdrew less storage in the latter part of the winter, i.e., January through March 2001. This same trend occurred on a national scale as well, as identified above in Schedule JJR-1. More specifically, MGE's storage withdrawals for November and December 2000 were also consistent with the national trend. In the storage plan that MGE provided to Staff and Staff stated that it reviewed, MGE estimated that it would withdraw 7.6 Bcf of natural gas from storage for November and December 2000. Due to the unprecedented winter weather and pricing conditions experienced in November and December 2000, MGE actually withdrew 12.4 Bcf of natural gas from storage. In other words, for these two months, MGE's actual storage withdrawals were 63% greater than planned. In comparison, the national trend was that storage was being withdrawn for these months at levels approximately 70% greater than the historical average. Therefore, MGE's storage withdrawals, while greater than anticipated due to unprecedented weather and market conditions, was actually slightly lower than storage utilization at the national level during the winter of 2000/2001.

Q. WHAT WERE THE MAJOR CAUSES OF THE PRICE INCREASES EXPERIENCED IN THE NATURAL GAS MARKET DURING THE SUMMER OF 2000 THROUGH THE WINTER OF 2000/2001?

A. There were numerous factors that caused natural gas prices to rise during the summer of 2000 and through the winter of 2000/2001, including an anticipated demand/supply imbalance, lower inventories and rising prices of alternative fuels, and colder than normal expected weather relative to the previous few years. Specifically, the Energy Information Administration ("EIA") noted that the natural gas price increases were a result of:

- a rapidly growing economy enhancing the demand for natural gas and electricity;
- increased natural gas-fired generation to produce electricity;
- lower than normal storage inventory levels due to difficulties in refilling storage as a result of summer electric generation demand;
- lagging domestic natural gas production;
- rising crude oil prices; and
- inventories of other winter fuels, i.e., heating oil in the Northeast and propane in the Midwest also being below average.[9]

Then, as the winter commenced, the weather ended up being far colder than normal. In fact, the November and December of 2000 were the coldest November and December on record since the National Weather Service has been collecting temperature data.

Q. WHAT WAS THE PROJECTION FOR NATURAL GAS PRICES PRIOR TO THE WINTER OF 2000/2001?

A. EIA provides publicly-available long-term and short-term natural gas price outlooks for the energy industry. EIA's forecasts are based on its complex internal forecasting models, populated with the most recent energy data collected and provided by the United States Department of Energy. In October 2000, or immediately prior to the winter of 2000/2001, EIA projected in its Base Case forecast that natural gas prices would remain

[9] Energy Information Administration, "Natural Gas Winter Outlook 2000-2001", Natural Gas Monthly, October 2000.

in the range between \$4.00/Mcf to \$5.00/Mcf for the entire winter of 2000/2001.[10] Under its Colder-Than-Normal scenario, EIA projected that natural gas prices would start the winter heating season at approximately \$4.50/Mcf and peak at approximately \$5.75/Mcf, then return to approximately \$5.00/Mcf by the end of the winter. EIA also stated that "natural gas wellhead prices are projected to rise sharply to an average of \$4.48 per Mcf this winter, almost double the \$2.26 per Mcf average price recorded during the 1999-2000 heating season." EIA added that "during the entire last half of September, spot prices for gas have hovered over the [sic] \$5.00 per Mcf. Although the spot price for natural gas has exceeded these levels in the past for short periods of time, they have not remained at these levels over such a sustained period of time."

Q. WAS EIA's PROJECTION OF NATURAL GAS PRICES FOR THE WINTER OF 2000/2001 ULTIMATELY CORRECT OR WITHIN THE RANGE ANTICIPATED?

A. No, although EIA projected that average natural gas price of \$4.48 per Mcf would represent a "sharp rise" in prices, in fact, actual prices experienced in the winter of 2000/2001 were significantly greater than those projected by EIA in its forecast issued just prior to the winter of 2000/2001. While EIA projected prices, depending on the weather scenario, to remain under \$6.00/Mcf for the entire winter heating season, actual prices experienced by shippers in the market were significantly higher. The New York Mercantile Exchange ("NYMEX") futures price for natural gas in January 2001 at Henry Hub reached a high of \$9.98/Mcf at the end of December 2000. In addition, the NYMEX

[10] Ibid.

futures price for natural gas in February 2001 at Henry Hub was above $9.00/Mcf for four days in mid-January 2000, reaching a high of $9.82/Mcf on January 9, 2000.

Q. WAS THERE ANY PRECEDENT FOR THE PRICE LEVELS OR VOLATILITY THAT THE GAS MARKET EXPERIENCED IN THE WINTER OF 2000-2001?

A. No. Considering that natural gas prices were already at record levels entering the winter of 2000/2001, and at double the prices of the prior year, no one could reasonably have been expected to anticipate the significant rise in natural gas prices during the winter of 2000/2001. Schedule JJR-2 illustrates the United States natural gas wellhead prices, by month, since 1980. As shown in Schedule JJR-2, natural gas wellhead prices ranged from a low of $1.26/Mcf to a high of $3.40/Mcf in the twenty years 1980 through 1999. The average natural gas price during this time period was $1.99/Mcf. Therefore, the natural gas prices that were experienced in the latter half of 2000 and the beginning of 2001, which reached more than $10.00/Mcf on a monthly basis and even more on a daily basis, were so extreme, and so far removed from historical experience, that it would not be reasonable to expect that any party could have adequately forecasted the dramatic price increases during this time period.

Q. DID YOU DISCOVER ANY FORECASTS THAT ANTICIPATED THE PRICES ACTUALLY EXPERIENCED IN THE MARKET?

A. No. Based on a review of then-current publications and publicly-available information, it appears that there was a general expectation that winter prices would be substantially higher than the previous year. However, the level to which prices rose and the overall price volatility was unforeseen and took virtually all market participants by surprise. While analysts took full advantage of revising forecasts based on theretofore unexpected price increases, it is apparent from the materials provided in Schedule JJR-3 that even the revised forecasts going into November and December of 2000 did not envision the unprecedented level of price escalation and volatility that materialized.

For example, in June 2000, Lehman Brothers' natural gas price forecast was described as "bullish" with an estimated third quarter NYMEX price of $3.17/Mcf and an estimated fourth quarter NYMEX price of $2.90/Mcf.[11] At the same time, EIA was warning that while winter prices were projected to be as much as 60% above the prior year, "[t]hese projections could unravel if weather turns out to be mild."[12] Later in the summer of 2000, there were still predictions that Alliance Pipeline coming on-line would provide "certainly enough gas to put some downward pressure on [Midwest] prices."[13] In a presentation to the Northeast-Midwest Congressional Coalition on September 13, 2000, EIA was predicting prices near $3.00/Mcf at the wellhead for 2000.

Even after the September and early October price spikes, analysts still did not predict the additional increases. Salomon Smith Barney estimated "an unprecedented $5.00/MMBtu" for the fourth-quarter, WEFA forecast an "even more bullish" average Henry Hub price of $5.30/MMBtu, and DRI predicted estimated average monthly Gulf Coast spot prices of $5.11/MMBtu in November and $5.15/MMBtu for December,

[11] Oil and Gas Interests, June 1, 2000.

[12] Gas Daily June 7, 2000.

[13] Inside FERC Gas Market Report, August 18, 2000.

attributing the November fall-off to new supply from the Alliance pipeline.[14] In reality, November spot prices on Williams exceeded $6.00 per MMBtu, which were followed by December 2000 and January 2001 prices that peaked at $11.53/MMBtu and $10.62/MMBtu respectively, or far beyond the predicted levels.

Q. HOW HAVE OTHER REGULATORY AGENCIES ACROSS THE UNITED STATES VIEWED THE WINTER OF 2000/2001 WITH REGARD TO THE NATURAL GAS INDUSTRY?

A. Similar to the reaction of the market, utility regulatory commissions across the country have commented on the unprecedented gas prices of the winter of 2000/2001 in various orders, opinions, and statements:

> The Kentucky Public Service Commission stated that "[t]he increase in natural gas wholesale prices over the past several months are a reflection of many different ... nationwide factors ... LDCs and state regulatory commissions are positioned to monitor and analyze these factors but are not positioned to exert significant influence on them..."[15]

> Faced with approving increases in the cost of gas for its utilities, the Idaho Public Utilities Commission ("Idaho PUC") stated that "natural gas prices have reached new all-time highs nationwide."[16]

> The Idaho PUC also stated in another proceeding that "[n]ot only is gas expensive, but also the market continues to be extremely volatile. Prices

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[14] Ibid., October 27, 2000.

[15] Kentucky Public Service Commission, In the Matter of: An Investigation of Increasing Wholesale Natural Gas Prices and the Impacts of Such Increases on the Retail Customers Served by Kentucky's Jurisdictional Natural Gas Distribution Companies, Administrative Case No. 384, January 30, 2001.

[16] Idaho Public Utilities Commission, In the Matter of the Application of Intermountain Gas Company for Authority to Increase its Rates for Service (12/00), Order No. 28578, December 2000.

> continue to change ten to twenty percent or more in a single day.... These are extraordinary times in the energy industry..."[17]

> In Massachusetts, the Department of Telecommunications and Energy stated, "[t]he situation in today's gas markets, whether national or local, has no precedent... The winters of 1998-99 and 1999-2000 were two of the warmest in the history of the US Weather Bureau; the winter of 2000-01 has been the coldest across the entire US in the 105 years of Bureau record-keeping. Latent demand accumulated in the previous warm winters became actual demand this winter. Price has risen steeply as a result."[18]

> The Arkansas Public Service Commission stated that "[a]s a result of 'colder than normal' winter temperatures and the sharp escalation in wholesale natural gas prices, Arkansas natural gas customers are now paying two to three times more for natural gas service than last winter."[19]

> Chairwoman Ruth Kretschmer of the Illinois Commerce Commission's gas policy committee stated that "I keep telling people there is no conspiracy. But with gas prices rising, people like to point a finger."[20]

Q. ALTHOUGH NATURAL GAS PRICES WERE AT THEIR HIGHEST LEVELS EVER DURING THE WINTER OF 2000/2001, HAVE OTHER REGULATORY COMMISSIONS ALLOWED GAS COST RECOVERY FOR THIS WINTER?

A. Yes. Numerous utility regulatory commissions have found that the natural gas costs incurred by the LDCs that they regulate were prudently incurred for the winter of 2000/2001, even though the prices were dramatically higher than prices that had occurred in the past. For example, the utility commissions in Idaho, Kentucky, Illinois and

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[17] Idaho Public Utilities Commission, Order No. 28641 In the Matter of Application of Avista Corporate DBA Avista Utilities – Washington Water Power Division (Idaho) for an Order Approving a Change in Natural Gas Rates and Charges, February 8, 2001.

[18] Massachusetts Department of Telecommunications and Energy, DTE 01-01 though DTE 01-18, LDCs Request for Authorization to Adjust its Gas Adjustment Factor, January 31, 2001.

[19] Arkansas Public Service Commission, In the Matter of a Notice of Inquiry into Whether Arkansas Gas Utilities Should Integrate Gas Price Hedging, Fixed Price Options, and Other Alternative Mechanisms Into Gas Procurement Plans, Docket No. 01-023-NOI, Order No. 1, January 31, 2001.

[20] Gas Utility Report, January 12, 2001, pp. 1-2.

Massachusetts have all found that the natural gas costs charged by the LDCs they regulate to be prudently incurred for the winter of 2000/2001. Specifically:

> The Idaho PUC approved increases to both Intermountain Gas Co.'s and Avista's respective weighted average costs of gas, acknowledging that the rate increase "may be a hardship to many Idahoans" but concluding that "it would not be prudent to put off a rate increase now in lieu of a larger increase next year." In addition, the Idaho PUC recognized that "... the costs included in the Company's PGA are external costs over which the Company has little or no control." [21]
>
> The Illinois Commerce Commission found that most of the LDCs within its jurisdiction acted "reasonably and prudently" in their purchase and management of natural gas.[22]
>
> The Kentucky Public Service Commission stated that "Kentucky's LDCs appear to be performing their gas procurement obligations in a reasonable and cost-effective manner."[23]

Q. DO YOU BELIEVE THAT MGE'S CONDUCT REGARDING THE OPERATION OF ITS STORAGE INVENTORY FOR THE WINTER OF 2000/2001 WAS PRUDENT?

A. Yes. Based on my review of the materials in this proceeding and understanding of the circumstances in the natural gas market up to and during the winter of 2000/2001, I believe that MGE's utilization of its storage was prudent. Based on the circumstances that existed at the time, including the unprecedented weather and natural gas prices experienced at the time, MGE's increased utilization of storage in November and

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21 Idaho Public Utilities Commission, In the Matter of the Application of Intermountain Gas Company for Authority to Increase its Rates for Service, Order No. 28578, December 2000; and Idaho Public Utilities Commission, In the Matter of Application of Avista Corporate DBA Avista Utilities – Washington Water Power Division (Idaho) for an Order Approving a Change in Natural Gas Rates and Charges, Order No. 28641, February 8, 2001.

22 Illinois Commerce Commission, Reconciliation of Revenues Collected Under Gas Adjustment Charges With Actual Costs Prudently Incurred, 00-0717, 00-0722. et. al.

December 2000 in order to mitigate the high prices and ensure reliability of supply was reasonable. Furthermore, (i) MGE utilized the same storage plan that it had used in the two winters prior which Staff had never questioned; (ii) MGE's service territory experiences significant swings in weather in the early part of the winter, that create day-to-day and week-to-week swings in demand that must be accounted for in a storage withdrawal plan; (iii) no one could have projected the level and duration of the extreme weather and price volatility that was experienced; (iv) other regulatory jurisdictions have noted the unprecedented nature of the winter of 2000/2001; and (v) MGE's utilization of storage in November and December 2000 was consistent with other LDCs in the United States at the time as illustrated by the AGA data. In addition, I believe that MGE has shown that its storage withdrawal plan is based on sound gas supply principles, is appropriate for the weather and demand volatility that can be experienced, and is clearly within the realm of reasonable conduct. All of these factors demonstrate that MGE's storage utilization conduct for the winter of 2000/2001 should be considered prudent.

Q. STAFF HAS ALSO ALLEGED THAT MGE SPECULATED ON PRICE DECREASES IN DECEMBER 2000 WITHOUT ADEQUATE ANALYSIS AND DOCUMENTATION TO SUPPORT SUCH A COURSE OF ACTION. WAS IT REASONABLE FOR MGE TO EXPECT THAT, PRIOR TO ITS SCHEDULING OF FIRST-OF-MONTH SUPPLIES FOR DECEMBER 2000, THE PRICE SPIKES THAT THE MARKET WAS EXPERIENCING WOULD DECLINE?

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[23] Kentucky Public Service Commission, An Investigation of Increasing Wholesale Natural Gas Prices and the Impacts of Such Increases on the Retail Customers Served by Kentucky's Jurisdictional Natural Gas Distribution Companies, Administrative Case No. 384, January 30, 2001, mimeo p. 9.

A. Yes, it was reasonable for MGE to believe at the time that prices in the market would decline. While there were conflicting projections of the sustainability of the price increases, this must be considered in light of the projections at the time that were forecasting prices that were substantially lower than the prices that were in fact being experienced. While storage projections generally drove forecasts up and weather forecasts caused substantial short term volatility, there were contemporaneous projections of market corrections based on increased drilling and rig count statistics, as well as some expectation that the commencement of service of Alliance Pipeline would drive Midwest natural gas prices down. In addition, the most current projections available at the time from EIA and analysts, predicting prices in the $4.00 to $5.00 per MMBtu range, would have contributed to a buyer expecting a decline from the prices available during bidweek for first-of-month volumes for December 2000.

As shown on Schedule JJR-3, there were several indications that the market in general expected the November and December prices to fall, for example:

> The forecasts are expected to add downward pressure to cash and futures prices...the value chain is eroding and we have no solid fundamentals to support prices let alone drive them up...The November contract rolls off the board today 'and anyone who's still long winter is scared of' the December contract. (Inside FERC Gas Market Report, October 27, 2000)

> Gas Daily stated that Midcontinent prices should continue down as updated weather forecasts predict more mild weather for November. A trader in the Midwest stated that "[t]here were no bids out there for November gas. I had utilities telling me they were long November gas and were looking for a place to put it. November [bidweek] is over, a disaster." (Gas Daily, November 1, 2000)

> Adam Sieminski of Deutsche Bank Alex Brown stated, "[o]ur main point is that we think a lot of forecasts are too high. Our feeling is that gas

> prices are not going to be $4 on average next year. We're officially saying \$3.40. If you twisted my arm, and depending on the weather, I might concede another 25 cents, but not more. Too many people are basing their outlooks on the current situation, which is very tight. But it won't necessarily stay that way. If we're right that we get a bit of an economic slowdown and a bit less demand, along with more production and imports, then supply and demand for natural gas might rebalance much more quickly than many analysts believe possible." (Petroleum Finance Week, November 6, 2000)

> Despite the confusion brought by major price volatility and winter temperature, we are convinced that fundamental market forces are at work to put downward pressure on these record natural gas prices. (Energy Daily, November 20, 2000).

Q. DID OTHER MARKET PARTICIPANTS ALSO CHOOSE TO RELY ON DAILY PURCHASES OR STORAGE WITHDRAWALS FOR DECEMBER 2000 RATHER THAN CONTRACTING FOR MONTHLY BASELOAD SUPPLIES DURING BIDWEEK OF NOVEMBER 2000?

A. Yes. Industry publications reflect that both buyers and sellers were engaged in trying to anticipate whether the daily cash markets would be higher or lower than the bidweek first-of-month pricing. The material I have reviewed has indicated that a number of buyers at the time engaged in a strategy of making daily spot purchases in December 2000 in lieu of making month-long commitments for first-of-month supplies. Still others relied heavily on storage withdrawals rather than supplemental market purchases to meet the higher-than-expected demands and to minimize the purchase of high priced supplies during December 2000. It is apparent that many LDCs tried to avoid paying the seemingly too high price available during bidweek, which was both volatile, and in many cases, substantially above then available projections.

For example, as illustrated in Schedule JJR-3, other LDCs were making the same choices that MGE did for December 2000:

> Burned last month by a surging day market, many local distribution companies took a different approach to January bidweek by locking in a large part of their January baseload supply at spot index rather than negotiating fixed-price deals or taking their chances in the spot market. (Inside FERC Gas Market Report, January 5, 2001)

In addition, as discussed in the testimony of MGE Witness Langston, at the time MGE was making its decision to schedule first-of-month supplies for December 2000, the National Weather Service's six to ten day forecast was predicting warmer than normal weather for the central United States and its eight to fourteen day forecast was calling for normal weather for the entire United States. Simply put, MGE's actions throughout the winter season were consistent with other market participants even though the strategy, in retrospect, did not prove advantageous.

Q. THEREFORE, DO YOU BELIEVE THAT MGE'S DECISION TO SCHEDULE LESS FIRST-OF-MONTH FLOWING SUPPLIES FOR DECEMBER WAS PRUDENT?

A. Yes. Based on the information that was available to MGE at the time its decisions were made to either purchase first-of-month flowing gas or purchase daily gas and/or utilize storage withdrawals, I believe that MGE's conduct was prudent. Based on the circumstances that existed at the time, including record high natural gas prices, predictions that prices would return to more normal historical levels, and, as discussed by MGE Witness Langston, projected warmer than normal weather for the central United States and normal weather for the entirety of the United States for the first part of

December, it was clearly within the realm of reasonable behavior for MGE to assume that prices would likely fall during December and schedule less first-of-month supplies.

PURCHASING PRACTICES - HEDGING

Q. WHAT HAS STAFF STATED IN ITS MAY 31, 2002 MEMO REGARDING MGE'S HEDGING PRACTICES FOR THE WINTER OF 2000/2001?

A. Staff has stated that since MGE did not have a formalized, documented hedging plan in place prior to the winter of 2000/2001, MGE's conduct was imprudent. For example, in his deposition, Staff Witness Sommerer stated:

> Q. ...as I understood your testimony, there first has to be a threshold finding of imprudence for a company. Then you would try to apply the 30 percent standard – or you would apply the 30 percent standard if there was an imprudence finding. Correct?
>
> A. Correct.
>
> Q. What was the imprudence finding for MGE that caused you to apply the 30 percent in this case?
>
> A. The concern that MGE did not have a documented hedging plan in place for that winter. (Deposition of Staff Witness David Sommerer, Missouri Public Service Commission, Case No. GR-2001-382, December 10, 2002, p. 94, line 18 through p. 95, line 2)

As a result, Staff has proposed a cost disallowance of $614,365 based on the assumption that is was reasonable to expect MGE to hedge a minimum level of 30% of its natural gas purchases for each month during the winter of 2000/2001. Staff has also stated that the 30% minimum hedge level should be viewed only as a reasonable and attainable level for the winter of 2000/2001, and not be viewed as an optimal level nor as precedent for future hedging levels.

Q. IS STAFF'S ALLEGATION OF THE IMPRUDENCE OF MGE'S HEDGING CONDUCT, AND IN TURN, ITS PROPOSED DISALLOWANCE, THE BASIS OF WHICH IS ITS RECOMMENDATION OF A MINIMUM 30% HEDGING LEVEL, CONSISTENT WITH THE COMMISSION'S PRUDENCE STANDARD?

A. Absolutely not. Pursuant to the Commission's prudence standard, the prudence or imprudence of a utility's conduct is to be based on information available to the utility, and the circumstances in existence, at the time the decisions were made or actions were taken. Therefore, in order for MGE's conduct to be imprudent, the Staff would have to demonstrate in this proceeding that:

(1) there was a statutory or Commission requirement, or that minimally prudent conduct required, that MGE have a formalized, documented hedging plan in place prior to the winter of 2000/2001;

(2) the hedging standard equates to a minimum 30% of natural gas volumes be hedged each winter month;

(3) there was sufficient time for MGE to implement such a hedging strategy; and

(4) MGE's conduct for the winter of 2000/2001 did not result in the appropriate level of hedging pursuant to the statutory or Commission-approved standard.

Staff has not provided any evidence in this proceeding that a single one of these things occurred prior to the winter of 2000/2001.

Q. REGARDING YOUR FIRST TWO POINTS, WAS THERE A HEDGING REQUIREMENT IN PLACE PRIOR TO THE WINTER OF 2000/2001, AND IF SO, DID THAT STANDARD REQUIRE THAT, AT A MINIMUM, MGE HEDGE 30% OF ITS NATURAL GAS SUPPLY EACH WINTER MONTH?

A. No. At no time prior to the winter of 2000/2001 was there a statutory or Commission requirement that MGE have a documented, formalized hedging plan or that MGE hedge a minimum of 30% of its natural gas requirements for the winter of 2000/2001. In fact, the Commission's Natural Gas Commodity Price Task Force stated in its Final Report on the commodity price spikes in the winter of 2000/2001 that:

> The task force was made aware that although the Commission had approved the use of financial instruments for hedging purposes under certain conditions for certain LDCs prior to the winter of 2000-01, and certain LDCs had undertaken financial hedging activities prior to and during the winter of 2000-01, <u>**neither the State of Missouri nor the Commission had any formal policy of broad applicability in place regarding the use of financial instruments for gas supply cost hedging purposes prior to the winter of 2000-01 beyond the application of the prudence standard**</u>. This standard was further clarified in the Commission's October 26, 2000 Order Denying Application to Renew Price Stabilization Fund and Rejecting Tariff in Case No. GO-2001-215, which states "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." (emphasis added) (Final Report of the Missouri Public Service Commission's Natural Gas Commodity Price Task Force, August 29, 2001, p. 81)

In addition to the Commission's own task force recognizing that there was no formal policy or hedging standard, Staff Witness Sommerer admitted in his deposition that there was no such hedging requirement:

> Q. And is there some requirement by rule or statute that MGE have a documented hedging plan in place prior to the winter?
>
> A. No.
>
> Q. It's just the -- is it then just the Staff's belief that there ought to be a, quote, documented, unquote, hedging plan in place for every utility?
>
> A. It's the Staff's belief that there should be a documented plan that addresses hedging for every LDC. (Deposition of Staff Witness David Sommerer, Missouri Public Service Commission, Case No. GR-2001-382, December 10, 2002, p. 95, lines 3-11)

Furthermore, it is not standard industry conduct that in order for an LDC to be considered "minimally prudent" it would be obliged to have a hedging plan established covering at least 30% of its volumes. The decisions of whether to hedge the price of natural gas, how much to hedge, and when to hedge are highly judgmental ones in which an LDC is attempting to ascertain the risk acceptance or aversion levels of its customers. Many LDCs perform little or no financial hedging, and rely on only a small portion of physical hedges through storage management. The obligations that the Staff seeks to impose on MGE in this proceeding are not generally accepted in the industry and are highly arbitrary.

Q. HAS STAFF ADMITTED THAT ITS RECOMMENDATION THAT MGE SHOULD HAVE HAD A FORMAL HEDGING PLAN IN PLACE PRIOR TO THE WINTER OF 2000/2001 IS BASED ON ITS OWN AFTER-THE-FACT PROPOSAL?

A. Yes. In fact, Staff has admitted that: (1) it never communicated to MGE or any other LDCs in Missouri, prior to the winter of 2000/2001 that there should be a hedging standard; and (2) it never communicated prior to the winter of 2000/2001 that the "standard" was to be 30% of normal requirements for each month of the winter heating season. Specifically, Staff stated:

> Q. Is there a piece of paper somewhere that shows someone what the Staff means by a documented hedging plan, what the components and the requirements of a documented hedging plan is supposed to look like?
>
> A. The Staff has circulated as part of the generic proceeding examples of what we believe should be contained in a well-conceived hedging plan.

Q. But that circulation, I assume from your answer, did not take place prior to the winter of 2000 and 2001 in time for MGE to react to it for the ACA we're looking at here, did it?

A. Not to my recollection. (Ibid., p. 96, line 20 through p. 97, line 9)

Staff Witness Sommerer went on to state in his deposition that:

Q. You still can't recall the specific month, I guess, when you had this meeting that produced the 30 percent. Is that right?

A. That's correct.

Q. But it was after the winter of 2000 and 2001. Correct?

A. Yes.

Q. So is it fair to say that the Staff did not communicate to any local distribution company in Missouri prior to the winter of 2000 and 2001 that they were going to expect each of those companies to have some form of hedge for 30 percent of that company's normal requirements for that winter or that they could possibly face imprudent disallowances? In other words, the Staff didn't make anybody aware that that standard existed prior to the time that it was going to take effect. Right?

A. That's correct. (Ibid., p. 103, line 3-20)

Thus, while Staff has alleged that MGE's conduct was imprudent because it did not have a hedging plan in place prior to the winter of 2000/2001, Staff has admitted that there was no requirement for MGE to have such a plan in place. In addition, Staff has admitted that its own proposal is simply based on its own belief and conjecture regarding LDC hedging programs and not based on Commission precedent or other established principles or common industry practice. Therefore, the foundation of Staff's imprudence recommendation regarding hedging is without merit. Moreover, not only has Staff failed to demonstrate that MGE's conduct, i.e., the so-called lack of a formal hedging plan, was imprudent, but it has also admitted that its proposal is based on its own after-the-fact review and second-guessing and not based on the circumstances that existed at the time and faced by MGE. This clearly violates the Commission's prudence standard that an LDC's conduct is to be judged based on the facts and circumstances that existed at the time and not based on a hindsight review.

Q. IN TERMS OF ITS PROPOSED DISALLOWANCE CALCULATION, HOW HAS STAFF JUSTIFIED ITS PROPOSED 30% HEDGING LEVEL?

A. Staff has provided virtually no justification for this "standard". Again, similar to its allegation of imprudence for not having a formal hedging plan, Staff admitted in their depositions that their proposed 30% "standard" used to calculate the disallowance was not based on a statutory or Commission-approved hedging plan or methodology, but rather was simply an arbitrary hedging level selected by the Staff in an internal meeting without any meaningful basis. Specifically:

> Q. Were you involved in the development and the origin of the 30 percent?
>
> A. Yes.
>
> Q. Would you tell me what you recall about how this 30 percent number came to be?
>
> A. The Staff was coordinating its view of how it would review the various programs and procurement activities that were in place for the winter of 2000/2001. And prior to any Staff recommendation, a discussion took place about the appropriate hedging percentage, what one would have expected to have been in place for that winter, the range that might be expected, the impact that a particular hedging percentage would have on storage versus flowing supply, the ability of the company to hedge the volumes without having exposure to overhedging. And based upon that discussion, with input from various Staff members, it was decided that 30 percent represented the absolute minimum level that was reasonable for that particular winter. (Ibid., p. 69, line 10 through p. 70, line 5)

Q. DO YOU BELIEVE THAT THE COMMISSION SHOULD DISREGARD STAFF'S PROPOSED DISALLOWANCE?

A. Yes, the Commission should disregard Staff's recommendation and proposed disallowance regarding this issue. First, Staff has admitted that there was never any requirement that MGE have a formalized, documented hedging plan prior to the winter of 2000/2001. In addition, Staff has admitted that it has not evaluated MGE's conduct based on the circumstances that existed at the time as required by the Commission's prudence standard, but rather has evaluated MGE's conduct based on an arbitrary, after-the-fact proposal. Moreover, Staff even implied in its May 31, 2002 Memo that, for the calculation of its proposed disallowance, its recommended hedging level was arbitrary by stating that "the 30% of normal requirements minimum should not be viewed as an optimal level nor as precedent for future hedging levels, but only as a minimum level that was reasonable and attainable for the winter of 2000/2001." Therefore, even Staff appeared to be uneasy with its own after-the-fact recommendation, recognizing that is was not optimal nor should it be used in the future.

Q. IN THE FUTURE, IS IT APPROPRIATE THAT THE HEDGING STANDARD BE KNOWN BY THE UTILITY PRIOR TO WHEN THE STANDARD IS GOING TO BE VIEWED IN LIGHT OF THE UTILITY'S CONDUCT AND EVALUATED FOR PRUDENCE?

A. Yes. As a general policy matter, it is essential that the standards by which utility conduct is going to be based, or in other words, the rules of the game, be established prior to the time in which the standard is going to be used to evaluate the prudence of utility conduct.

This ties directly into the principles discussed earlier in my testimony regarding both the rule of reasonableness under the circumstances and the prohibition of hindsight review. Without first establishing the rules of the game, it is unreasonable to condemn a utility's conduct, and it is egregious to attempt to apply a standard after-the-fact based on hindsight review.

Q. HAS THE POSITION THAT UTILITIES SHOULD BE PROVIDED HEDGING GUIDANCE BY THE REGULATORY COMMISSION PRIOR TO APPLYING PRUDENCE STANDARDS FOR HEDGING PRACTICES BEEN DISCUSSED IN RELATION TO THE WINTER OF 2000/2001?

A. Yes. In a recent paper concerning the high natural gas prices experienced in the winter of 2000/2001, NRRI addressed various issues relating to hedging and offered guidelines to state utility commissions for assessing hedging activities. In that paper, NRRI stated that:

> State PUCs can take a number of general policy positions with regard to utility hedging with financial instruments:
>
> ...(2) *There is no prohibition of hedging but also no guidance given by a commission.* This has been the situation in some states where gas utilities have been reluctant to hedge with financial instruments because of the lack of clear signals from commissions on the treatment of gains and losses. This position would likely discourage hedging, since a utility would not know whether the costs associated with hedging would be recovered from consumers, and how the commission would retroactively view its hedging activities. **At a minimum, commissions should establish general policy parameters for use by a gas utility in determining whether and how to carry out a hedging strategy.**
>
> State PUCs can choose among various policy options regarding utility hedging with financial instruments; they span the spectrum from prohibition to a mandate. The more defensible, middle-of-the-road course of action, and one that most commissions have taken so far, is to allow utilities to hedge with financial instruments so long as it is done "prudently". **Commissions should establish guidelines up-front. These guidelines can act as general policy statements on different aspects of**

> **hedging, including cost recovery, what constitutes a prudent decision on the part of the utility, and the elements of an acceptable hedging strategy. In hedging with financial derivatives, utilities need to know from their regulators what they should be doing and the "rules of the game."** Otherwise, they will be reluctant to hedge even when it would be in the interest of consumers. Especially in an environment where rules are vague and all direct gains from hedging go to consumers, utilities understandably would have little incentive to hedge.
>
> ...as an overall policy, **it would be preferable for commission to convey, prospectively, clarity to utilities** than to partake in costly and contentious hindsight reviews that frequently turn into "Monday morning quarterbacking."
>
> **The reasonableness of a hedging strategy should be evaluated before a program is actually implemented. If regulators decide to perform ex post reviews, they run the risk of creating unrealistic or inefficient performance standards, or both.** The success of a hedging strategy should not be evaluated strictly on how things turn out. (emphasis added) (NRRI, Regulatory Questions on Hedging: The Case of Natural Gas, Ken Costello, February 2002, pp. 11-12, 15-16.)

As discussed earlier in my testimony, in the absence of a specific prudence standard and in the absence of industry standards for this issue, MGE's conduct does not even approach a level that could be fairly described as imprudent.

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

A. As described in the testimony of Witness Langston, prior to the winter of 2000/2001, the Commission had provided MGE with very specific authority regarding MGE's ability to utilize financial instruments to hedge its natural gas supply portfolio. Specifically, MGE was authorized to hedge a portion of its natural gas portfolio for the winters of 1997/1998, 1998/1999 and 1999/2000 pursuant to a Commission-approved Price Stabilization Fund that expressly provided for (i) a specific amount of money that could be spent to purchase financial instruments; (ii) a specific amount of volumes that were to be hedged; and (iii) a specific price cap for which the strike price of the financial instruments could not exceed. Therefore, for the three winters prior to the winter of 2000/2001, the Commission, with input from both Staff and the Office of Public Counsel ("OPC"), provided very specific guidance and parameters regarding the authority and ability of MGE to financially hedge its MGE's natural gas supply portfolio.

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

A. Again, as described in the testimony of MGE Witness Langston, after the Price Stabilization Fund for the winter of 1999/2000 expired on its own terms, MGE, Staff and OPC signed a Stipulation and Agreement of Settlement for the establishment of a Fixed Commodity Price PGA ("FCP Stipulation") that would have fixed the price to sales customers for, or in effect, hedged, 100% of the MGE's natural gas requirements for the winter of 2000/2001. The Commission approved the FCP Stipulation on August 1, 2000, thus again granting 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 continue to utilize the Price Stabilization Fund previously authorized, but only within approved parameters. Unfortunately, neither of these hedging mechanisms could be implemented based on the specified terms due to unprecedented market conditions, i.e., record high natural gas prices. While MGE attempted to implement the Price Stabilization Fund on a modified basis to reflect then current market conditions, Staff did not support such effort.

Q. WERE OTHER LDCS IN MISSOURI PROVIDED THE AUTHORITY TO HEDGE NATURAL GAS PRICES FOR THE WINTER OF 2000/2001?

A. Yes. As discussed in the testimony of MGE Witness Langston, Laclede Gas Company ("Laclede"), Staff and OPC signed a Unanimous Stipulation and Agreement ("Laclede Settlement") on September 1, 2000, that provided Laclede with a hedging mechanism similar to MGE's Price Stabilization Fund.[24] The Commission approved the Laclede Settlement on September 28, 2000.[25] Therefore, Laclede had received specific guidance and Commission authorization to conduct hedging activities for the winter of 2000/2001 not less than a month prior to MGE's filing to modify its Price Stabilization Fund to reflect current market conditions so that it could be implemented for the winter of 2000/2001. It is my understanding that Laclede did engage in hedging activities for the winter of 2000/2001, and that Staff has not recommended the disallowance of costs associated with Laclede's hedging activities.

Q. WAS THE FACT THAT MGE'S HEDGING PROGRAMS WERE NEVER IMPLEMENTED DUE TO IMPRUDENT CONDUCT, ACTION OR INACTION BY MGE?

A. No. MGE attempted on three separate occasions to implement a hedging program for the winter of 2000/2001 and seek Commission approval of such plan. First, described in detail in the testimony of MGE Witness Langston, after months of negotiations, MGE,

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[24] Laclede Gas Company, Unanimous Stipulation and Agreement, Missouri Public Service Commission, Case No. GO-2000-394, p. 2.

[25] Order Granting Motion to Stay Setting of Procedural Schedule and Approving Unanimous Stipulation and Agreement, Missouri Public Service Commission, Case No. GO-2000-394, September 28, 2000.

Staff and OPC agreed and signed the FCP Stipulation that would have fixed the price for 100% of the MGE's natural gas requirements for the winter of 2000/2001. The Commission approved the Stipulation on August 1, 2000, however, market prices did not permit the plan to be implemented.

Second, the FCP Stipulation also contained a provision that permitted the parties to reexamine the trigger price in light of changing natural gas markets two months after the Commission's approval, or in late September 2000. After the filing of the Fixed Commodity Price PGA, MGE initiated discussions with Staff, and the parties exchanged correspondence regarding the fact that market conditions were such that the trigger price in the Fixed Commodity Price PGA could not be, and was likely not to be, attained for the winter of 2000/2001. Therefore, MGE attempted to negotiate alternative parameters for the Fixed Commodity Price PGA in line with current market conditions that would allow the plan to be implemented. However, the parties were unable to agree on an appropriate market price in order for the Fixed Commodity Price PGA to be implemented.

Lastly, also as discussed in the testimony of MGE Witness Langston, MGE attempted to re-implement the Price Stabilization Fund that had been used for the three previous winters to provide price protection for customers. MGE filed for authorization to re-implement the Price Stabilization Fund approved in the FCP Stipulation with modifications to reflect current market conditions. However, although similar to the Laclede Settlement, again, re-authorization of MGE's Price Stabilization Fund was not supported by Staff and was rejected by the Commission on October 26, 2000 ("October 26th Order"), or five days prior to the start of the winter heating season. Furthermore, as described by MGE Witness Langston, the October 26th Order did not specifically grant MGE the authority to financially hedge outside of the parameters approved in the FCP Stipulation.

Therefore, MGE attempted to gain Commission approval to provide price stability for its customers for the winter of 2000/2001 by working collaboratively with the Staff and the OPC over a period of nearly two years prior to the winter of 2000/2001. Ultimately, factors outside of MGE's control, i.e., natural gas prices, timing of approvals, and Staff's reluctance at the time to support a hedging mechanism or strategy, resulted in a formal hedging program not being implemented.

Q. DO YOU BELIEVE THAT MGE'S ACTIONS SEEKING COMMISSION APPROVAL FOR ITS HEDGING PROGRAM WERE CONSISTENT WITH THE COMMISSION'S PRUDENCE STANDARDS?

A. Yes, I believe that MGE's actions and decisions attempting to implement a formal hedging program to provide customer price stability prior to the winter of 2000/2001 were prudent. As discussed in detail in the testimony of MGE Witness Langston and as I have briefly discussed above, MGE attempted on three separate occasions to implement a hedging program for the winter of 2000/2001 and seek Commission approval of such plan. It was reasonable for MGE to believe that Commission authorization was required for a hedging program for the winter of 2000/2001 considering that the Commission had approved very specific hedging programs for the three winters prior, the details of which included (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 hedging instruments; and (iv) the cap on the strike price at which the instruments to be purchased.

Q. DID MGE TAKE ACTION UPON RECEIPT OF THE COMMISSION'S OCTOBER 26TH ORDER?

A. Yes. Despite the timing of the Commission's order (i.e., five days prior to the winter heating season), the fact that the natural gas market was in turmoil and prices were at record levels, and that MGE had minimal guidance regarding the authorization or appropriateness to hedge going forward, MGE nevertheless took constructive action very quickly upon receiving the Commission's October 26th Order. MGE arranged a number of fixed price transactions for December, January and February natural gas supplies.

Q. WHAT WOULD BE CONSIDERED REASONABLE PURCHASING BEHAVIOR FOR MGE ABSENT OTHER COMMISSION-DEFINED PROVISIONS OR SPECIFIC GUIDANCE?

A. In the absence of any other Commission-defined or approved strategy and/or parameters regarding the purchase of financial instruments to hedge natural gas prices, purchasing natural gas at the prevailing market price is considered within the range of reasonable utility behavior and considered prudent. This position also has been supported by NRRI.

After the price increases experienced in the winter of 2000/2001, NRRI provided guidance to state utility regulatory commissions supporting the position that, absent any other Commission guidelines regarding hedging activities, market-based purchasing practices are inherently prudent:

> The implication for establishing a prudence standard for hedging is that regulators must define an acceptable level of price volatility (i.e., the consumer-risk tolerance toward price volatility), as well as an acceptable average cost of gas, after accounting for the costs associated with hedging. Regulators cannot be expected to know with a high degree of precision the risk tolerances of customers. Consequently, they really have little idea how much hedging a gas utility should undertake and how much it should spend. **<u>On the other hand, it is much easier for a regulator to set a prudence standard for gas procurement where a reasonable price is generally interpreted as equivalent to the market price, namely, the spot price or the contract price indexed to a designated market price.</u>** (emphasis added) (NRRI, Regulatory Questions on Hedging: The Case of Natural Gas, Ken Costello, February 2002, p. 5.)

Therefore, absent a general hedging strategy or other parameters provided by the Commission, as well as authorization from the Commission to engage in hedging activities, purchasing natural gas at the prevailing market price is considered prudent.

Q. IN ADDITION TO DEMONSTRATING THAT THERE WAS A STANDARD IN PLACE PRIOR TO THE WINTER OF 2000/2001, YOU INDICATED THAT THERE WERE TWO ADDITIONAL POINTS THAT STAFF WOULD NEED TO MAKE TO DEMONSTRATE IMPRUDENCE., i.e., THERE WAS SUFFICIENT TIME TO IMPLEMENT THE REQUIRED HEDGING PLAN AND THAT MGE'S CONDUCT DID NOT MEET THE APPROPRIATE HEDGING REQUIREMENT. HAS STAFF DEMONSTRATED EITHER OF THESE POINTS?

A. No. The final two points are essentially irrelevant since it is clear that neither Commission rules nor industry conduct can be cited to support Staff's 30% minimum hedging "standard" for the winter of 2000/2001.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING HEDGING PURCHASING PRACTICES?

A. Yes. I would like to stress the importance of developing, collaboratively and prospectively, an appropriate hedging plan for utilities. As noted by NRRI in its paper to state utility commissions, it is critical to establish upfront whether a utility is authorized to hedge, and if so, the parameters of that hedging authority by which prudence will be reviewed at a future date. In a traditional pass-through PGA mechanism, there is no direct financial incentive for utilities regarding the purchase of natural gas, but rather only a financial disincentive as a result of a disallowance for being found to be imprudent after-the-fact and/or escalating uncollectible account balances which exceed the amount allowed for recovery in the cost of service. Utilities under a traditional PGA, such as MGE in this case, do not have an incentive to speculate on natural gas prices in the market for shareholder gain, or a financial incentive in the dispatch of its storage inventory, but rather have the duty to provide customers with a reliable natural gas supply at the lowest reasonable cost within the parameters authorized by the respective utility Commission.

Customers have varying levels of tolerance for natural price risk based on their specific set of circumstances, thus certain customers will prefer market-based pricing, while others will prefer more price stability. Since obtaining price stability or price insurance requires a financial premium in order to shift the risk of volatility to another party, inherently hedging will generally not result in the lowest possible price for natural gas and may not be appropriate for certain customers. Therefore, in order to meet the needs of these various customers, the regulatory goals and policies of the Commission and its staff, and the goals of the utility and its shareholders, the parties need to work collaboratively to prospectively define an appropriate hedging strategy that the utility can reasonably implement that addresses the needs of all of these interests. The parties in this case were attempting to do exactly that prior to the winter of 2000/2001; however, despite the best efforts of the parties, there was clearly a complete breakdown in that process as market conditions became volatile and natural gas prices rose to unprecedented levels. Going forward, it is critical that the ambiguity and lack of a collaboratively defined hedging strategy relevant to this proceeding be addressed to mitigate the potential of it happening again at the expense of all parties.

Q. DOES THE UNCERTAINTY AND AMBIGUITY OF NOT HAVING A PRE-DEFINED HEDGING PLAN IN PLACE CAUSE HARM EVEN WHEN THERE HAS BEEN NO IMPRUDENT CONDUCT?

A. Yes. The uncertainty and ambiguity of not having a prospectively established, Commission-approved policy for hedging or gas supply management harms all parties involved, even when there is no imprudent LDC conduct. Without a pre-defined hedging plan, customers are potentially not provided with the appropriate level of price flexibility, price stability, or service reliability that could otherwise be provided if a plan was established ahead of time. In addition, the Commission, its Staff, the LDC and other interested parties expend a significant amount of time and resources, and thus, money, to litigate the issues after-the-fact. Moreover, the uncertainty can harm the LDC (and indirectly its customers) in numerous ways, even when the LDC has acted prudently. For example, the uncertainty can cause higher borrowing costs, greater uncollectible expenses (e.g., MGE's uncollectibles for the 2000/2001 ACA period were nearly triple the amount allowed in the cost of service), significant bad press, and higher customer call volume and complaints that require additional resources. Effectively, most of these issues could be mitigated or eliminated if an appropriate, collaboratively determined plan is established in advance.

CAPACITY RELEASE ON KPC

Q. WHAT HAS STAFF ALLEGED REGARDING MGE'S CAPACITY ON KPC?

A. Staff has claimed that MGE should have posted for release its idle capacity on KPC for the periods July through October 2000 and April through June 2001, which correspond to the summer months of the ACA period in this proceeding. Specifically, Staff stated in its May 31, 2002 Memo that MGE could have released its Riverside I contract on KPC on a non-recallable basis, thereby maximizing the capacity's value in the market. Staff claims that non-recallable releases typically have higher market values since there are no provisions for the releasing shipper to call-back the capacity.

Q. IN TERMS OF THE PRUDENCE STANDARD, HAS STAFF FIRST DEMONSTRATED THAT THERE IS SERIOUS DOUBT AS TO MGE'S ACTIONS REGARDING ITS KPC CAPACITY?

A. No. The first threshold issue regarding utility prudence in Missouri is the requirement that a proponent of a gas cost adjustment, i.e., Staff in this proceeding, demonstrate serious doubt. The Commission has stated that "the proponent of a gas cost adjustment must raise a serious doubt with the Commission as to the prudence of the decision (or failure to make a decision) that caused what the proponent views as excessive gas costs."[26] Other than simply stating that MGE did not post for release its KPC capacity during the periods July through October 2000 and April through June 2001, Staff has provided no evidence to support its statement that MGE's action (or inaction in this instance) has raised serious doubt. As explained below, Staff has not assessed whether there is even a market for released capacity on KPC, whether MGE's capacity on KPC was economic relative to the alternatives (assuming there was in fact a market for released capacity), or whether there were any operational or administrative factors associated with the KPC capacity that would impact the ability of the capacity to be released. While the Commission has not defined the criteria indicative of "serious doubt", the fact that MGE's capacity on KPC was simply not posted for release during the ACA period in question does not, in and of itself without further evidence, raise doubt, let alone serious doubt, as to the prudence of MGE's actions.

[26] *Western Resources*, Missouri Public Service Commission, Case No. GR-93-140, July 14, 1995, mimeo p. 14.

Q. PRIOR TO MAKING ITS CLAIM THAT MGE SHOULD HAVE POSTED ITS KPC CAPACITY FOR RELEASE, DID STAFF REVIEW, EVALUATE OR PERFORM ANY ANALYSIS REGARDING MGE'S RIVERSIDE I CONTRACT OR THE MARKET FOR CAPACITY RELEASE ON KPC AT THE TIME?

A. No. Staff admitted in its deposition that, even though it did not have access to the KPC bulletin board to determine the level of capacity release activity on KPC, it made absolutely no other attempt to evaluate the viability of MGE releasing capacity on KPC. Specifically, when asked during the deposition in this proceeding, Staff stated:

> Q. Did you attempt to determine whether there was an electronic bulletin board during – for KPC during this ACA?
>
> A. I attempted to determine the capacity release procedures of KPC by reviewing their tariffs and reviewing the contracts, and it was my understanding that they generally followed the FERC rules.
>
> Q. So I'm going to assume from your answer that you've never tried to access and physically look at KPC's electronic bulletin board?
>
> A. I have seen KPC's website, where their tariffs are posted. Sometimes the bulletin board requires special access, a special dial-up access. Certainly when the pipelines started developing their bulletin board systems, they were generally available to – to all end users. You had to have a special agreement to access those bulletin boards. So I did make the attempt, but I don't …I did not access the bulletin board.
>
> Q. In doing your work on this audit leading up to making your recommendations, did you find any situation where anyone has posted capacity for release on the KPC bulletin board during the specific months that you say MGE should have posted a release of capacity?
>
> A. No.
>
> Q. Did you make any kind of a direct inquiry to Kansas Pipeline about trying to access or get this information, as opposed to going through and looking at their website? In other words, did you write them a letter or send them a data request and say, tell me how many capacity release transactions you've had and what they are since FERC jurisdiction occurred?
>
> A. No.

Q. Do you have any documents or information which shows someone else with capacity – someone else other than MGE with capacity on Kansas Pipeline has done what you say MGE should have done and has obtained the results that MGE should have obtained according to your proposal?

A. No.

Q. Do you have any documents or information which shows that anyone has ever bid on a capacity release posting on the KPC system?

A. No.

Q. Is there any specific company that you're aware of that has stated to you that they were willing during this relevant time frame to obtain KPC capacity at the rate level you calculated?

A. No.

Q. So would it be fair to say that you have no evidence that anyone else has ever done what you say MGE should have done in this proposed adjustment?

A. Yes.

Q. And you have no evidence that anyone else has ever achieved the same result that you say MGE should have achieved in this adjustment?

A. That's correct. (Deposition of Staff Witness David Sommerer, Missouri Public Service Commission, Case No. GR-2001-382, December 10, 2002, p. 18, l. 17 through p. 19, l. 12; p. 21, ll. 8-16; p. 23, l. 13 through p. 24, l. 2; and p. 28, l. 21 through p. 29, l. 3.)

Q. ALTHOUGH STAFF HAS ADMITTED IT DID NOT MAKE ANY REASONABLE ATTEMPT TO EVALUATE THE MARKET FOR CAPACITY ON KPC, WAS STAFF AWARE THAT THERE WAS EFFECTIVELY NO CAPACITY RELEASE MARKET ON KPC, PRIOR TO, DURING AND AFTER THE ACA PERIOD IN QUESTION?

A. Even though Staff did not do any further due diligence in an attempt to support its position that MGE should have released its capacity on KPC, Staff has admitted that it was aware there was little, if any, capacity release activity on KPC. Specifically, when asked in the deposition in this proceeding, Staff stated:

> Q. How active is the market for release of capacity on the KPC system?
>
> A. There's very little, if any, activity for release of capacity on the KPC system. ...and in addition to that, through various discussions and discovery with MGE, I also understand that releases on that particular system are rare. (Deposition of Staff Witness David Sommerer, Missouri Public Service Commission, Case No. GR-2001-382, December 10, 2002, p. 19, ll. 15-18; and p. 21, ll. 5-7.)

Therefore, although familiar with the Riverside I contract and the KPC system in general, Staff did not review or make any reasonable attempt to determine whether or not there was even any capacity release market on KPC. In addition, although MGE has never had a capacity release transaction on KPC, this is the first instance in which Staff has raised this as an issue. Essentially the only "evidence" that Staff has put forward in an attempt to raise serious doubt was the fact that MGE did not post its capacity on KPC for release during the time period in question. Again, this basic claim, in and of itself, does not raise serious doubt as to MGE's conduct.

Q. IF THE COMMISSION WERE TO FIND THAT STAFF HAS RAISED SERIOUS DOUBT BY NOTING THAT MGE DID NOT POST ITS KPC CAPACITY FOR RELEASE, WOULDN'T THE BURDEN OF PROVING ITS ACTIONS WERE PRUDENT FALL TO MGE?

A. Yes. If the Commission were to find that serious doubt is effectively raised by MGE not posting its Riverside I contract for release during the ACA period in question, the burden of demonstrating that its actions were reasonable and prudent at the time falls on MGE based on the Commission's prudence standard.

Q. IF THIS WERE THE CASE, IN YOUR OPINION, DO YOU BELIEVE THAT MGE HAS DEMONSTRATED THAT ITS ACTIONS, AT THE TIME, WERE PRUDENT?

A. Yes. Based on my understanding of the utility prudence standard in Missouri and common industry practice regarding utility prudence issues discussed above, I believe that MGE has demonstrated that its actions at the time were prudent. As noted earlier in my testimony, the Commission has based its evaluation of utility prudence on the actions or inactions of the company at the time, based on the knowledge and facts known or knowable to the company at that time, and has not relied on hindsight review or second guessing.

MGE Witness Langston has stated in his testimony in this proceeding that the KPC capacity was not posted for release based on the following facts known by the Company at the time:

(1) MGE had an economic incentive to release capacity, as MGE had a Commission-approved incentive mechanism whereby MGE would retain a percentage of all capacity release revenue (with that percentage generally increasing as the level of capacity release revenue increased);

(2) MGE knew that there had never been a single capacity release transaction on KPC by any party since June 1, 1997;

(3) MGE's capacity on KPC has inherent operational limitations, both receipt and delivery point limitations, that significantly reduces the value of the capacity in the release market;

(4) The commodity cost on KPC was significantly higher than on other pipelines serving similar markets, making it difficult, if not impossible

based on historic capacity release activity, for KPC capacity to compete against released capacity on these other pipelines;

(5) Interruptible capacity was also a sufficient alternative for released firm capacity in the non-winter months on KPC, and a much more economical alternative based on KPC's high commodity rate, as evidenced by the numerous interruptible transactions KPC was able to transact; and

(6) In MGE's experience, the most effective way in which to release capacity (based on pipelines other than KPC since there had never been a successfully released transaction by MGE or any other party) was not by conducting open postings for capacity, but rather negotiating release transactions.

Based on the above evidence, including the absence of any successful capacity releases by any party on KPC, the operational and economic difficulties associated with the KPC capacity, and MGE's experience on other pipelines with negotiated capacity release transactions rather than open postings of capacity release, it is my opinion that it was reasonable for MGE not to post its KPC capacity for release and thus acted prudently.

Q. WHAT ABOUT STAFF'S ALTERNATIVE PROPOSAL THAT MGE SHOULD HAVE RELEASED ITS WILLIAMS CAPACITY AND FLOWED ITS KPC CAPACITY?

A. As clearly stated in MGE Witness Langston's testimony, Staff's position is simply not supportable. Staff has presumed a robust market for capacity release on Williams during the summer months that simply did not exist. The average release rate on Williams was only 14% of the maximum tariff rate during the summer months for the ACA period in question in this proceeding, thus, not even close to the 75% of the maximum rate that Staff has assumed. Therefore, as illustrated in the testimony of MGE Witness Langston, when Staff's own workpaper is revised to accurately reflect the market for released capacity on Williams, the analysis clearly shows that it would have been more costly for MGE to utilize its KPC capacity and release its Williams capacity rather than the actions that MGE actually took, i.e., flowing its Williams capacity and leaving its KPC capacity unutilized since it could not be released. Thus, both Staff's primary and alternative positions are not supported by the facts of the marketplace and Staff cannot disprove the fact that MGE's actions with regard to its KPC capacity were prudent.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Schedule JJR-1
Case No. GR-2001-382

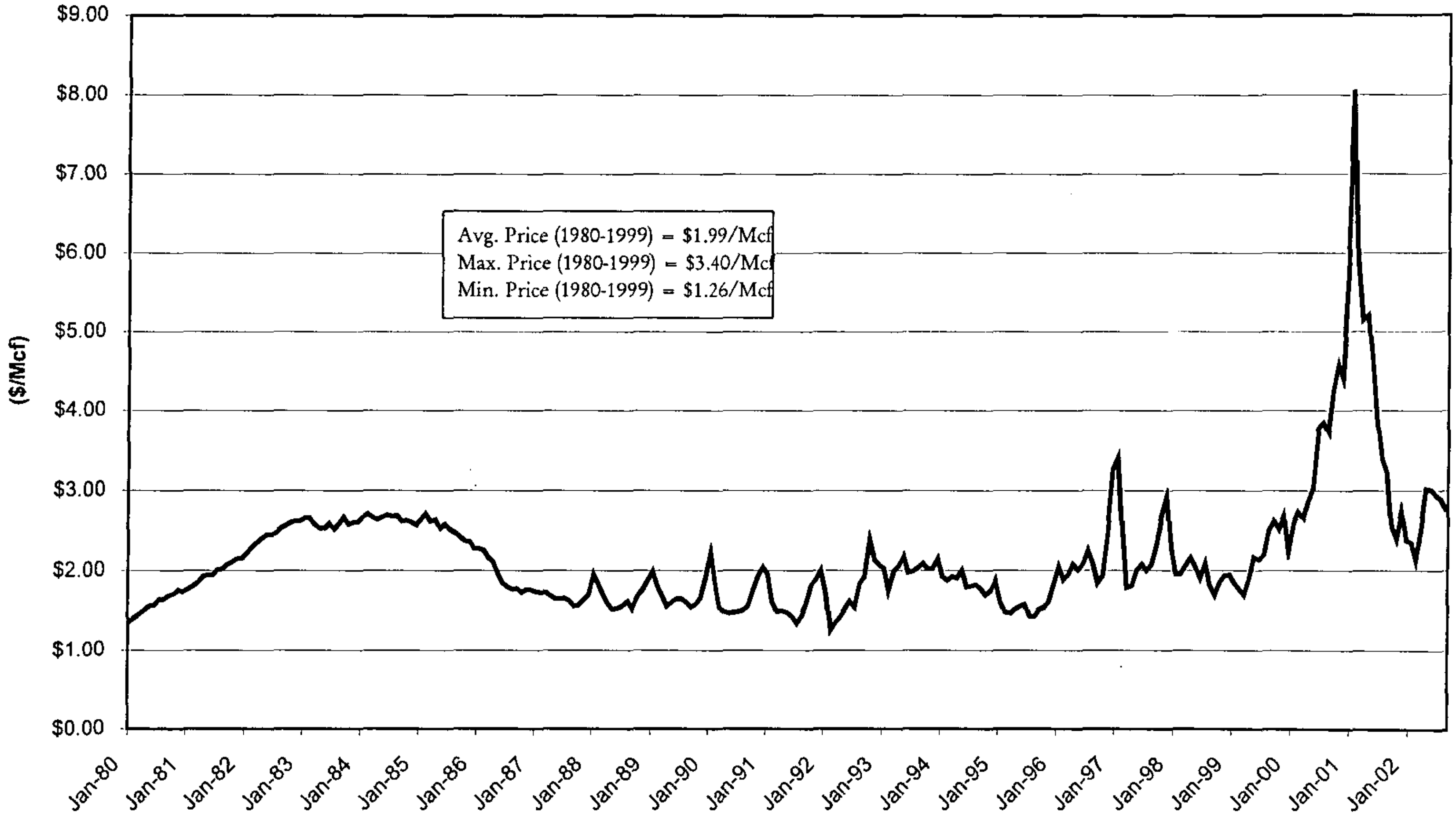
United States Storage Withdrawal Activity

Description	Withdrawn Volumes during Month (Bcf)				
	Nov	Dec	Jan	Feb	Mar
Winter 93/94			743	551	208
Winter 94/95	58	454	540	585	284
Winter 95/96	217	619	601	597	346
Winter 96/97	251	383	715	361	157
Winter 97/98	201	436	571	298	295
Winter 98/99	17	274	764	377	327
Winter 99/00	-6	564	662	581	163
Historic Average	123	455	657	479	254
Winter 00/01	210	773	488	382	232
% Above/(Below) Historic Average	71%	70%	-26%	-20%	-9%

Source: American Gas Association.

Schedule JJR-2
Case No. GR-2001-382

US Natural Gas Wellhead Price 1980-2002



Source: Energy Information Administration

Gas Market Chronology

2000-2001

After much fumbling for the key, natural gas producers have arrived in wonderland. So Lehman Brothers Inc.'s energy price forecasters are bullish on natural gas. "There's no question that we won't live north of $ 3 gas, permanently," said Richard G. Gross II, senior vice president for equity research at the investment banker's New York headquarters. ..... Lehman Brothers forecasts that natural gas prices on the New York Mercantile Exchange will average $ 3.06 per thousand cubic feet during the current quarter; $ 3.52 in the third quarter and $ 3.53 in the final three months of 2000. In 2001, it expects NYMEX gas prices to average $ 3.48 per Mcf in the first quarter, $ 3.22 in the second quarter, $ 3.17 in the third quarter and $ 2.90 in the fourth quarter. The firm predicts that gas prices will average $ 3.14 per Mcf for all of 2000, $ 3.19 for all of 2001, $ 2.70 for all of 2002, $ 2.50 for all of 2003 and $ 2.60 for all of 2004. A long-term Henry Hub average price of $ 2.60 to $ 2.70 per Mcf would attract drilling capital, support loading existing liquefied natural gas import capacity and make construction of more gas-fired power plants economically attractive, according to Gross.	Petroleum Finance Week May 29, 2000
"The bottom line on our U.S. natural gas forecast is that supply and demand is tightened to the point where average gas prices should generally stay above $ 3.50 [per thousand cubic feet] as suppliers struggle to meet U.S. gas demand," according to Raymond James. On May 22, Raymond James raised its U.S. natural gas price forecast for 2000 from $ 3 to $ 3.55 per Mcf, making the firm one of the biggest bulls on the Street. "We expect gas prices to remain well above the $ 3.50 level over the next 12 to 18 months." Over at Simmons and Co. International, David Pursell, the Houston oil and gas investment banker's vice president of upstream research, is in the midst of fine-tuning his gas price outlook. Currently, his 2001 forecast is $ 2.60, but it won't stay that low for long. "Clearly it's going to be in the $ 3 range for this year and next," Pursell told Petroleum Finance Week. "It is moving up." And Robert Morris, who follows exploration and production for Salomon Smith Barney in New York, has raised his 2000 composite forecast from $ 2.78 per million BTUs to $ 3.25, and his 2001 forecast from $ 2.65 to $ 3.25.	Petroleum Finance Week May 29, 2000
Gas prices will increase by 50% this summer compared to last summer, EIA said in its forecast. For this coming winter, prices are expected to increase by 60% over the last heating season. The wellhead price for 2000 is projected to average more than $ 3/mcf, with a slight easing of the price in 2001. "However, these projections could unravel if weather turns out to be mild for sustained periods of time in the gas consuming regions of the nation," EIA said.	Gas Daily June 7, 2000
Despite another warm winter, prices remain strong and demand has risen because of structural growth in the power sector. Moody's has revised conservative expectations of a $ 2.50/ mmBtu average gas price for 2000 to somewhere in the $ 2.90-$3 range.	Gas Daily

"A case can readily be made for higher prices in 2000," says the report, "but that outcome also risks hastening or intensifying a price softening." Although Moody's expects supportive prices in 2001, it does not rule out a moderation from 2000 levels. An aggressive second half 1999 and 2000 ramp-up in North American drilling could have a significant impact on prices.	June 12, 2000
Nationwide, storage facilities were about 62% full as of Aug. 11. And with the beginning of heating season only 11 weeks away, time to fill the remaining space is starting to run out, some market sources contend. One factor: The futures market has been in backwardation for months. Winter-month contract values have traded nearly flat to the summer-month contracts for an extended period, creating a distinct lack of storage arbitrage opportunities... Greg McMichael of A.G. Edwards & Sons Inc., who recently upped his 2000 gas price estimate to $ 3.01/MMBtu from $ 2.50/MMBtu, said price revisions were common among analysts because this year's market dynamics are so unpredictable -- and unprecedented. Indeed, McMichael isn't alone in his price revisions over the past few weeks. PaineWebber Inc.'s Ronald Barone has revised quarterly and year-end forecasts several times this year. His year-end estimate currently stands at $ 3.35/MMBtu, up from a low of $ 2.50/MMBtu early in the year. Stephen Thumb of Energy Ventures Analysis Inc. revised his 2000 forecast considerably, to $ 3.55/MMBtu from $ 2.43/MMBtu. And the Energy Information Administration upped its estimate by more than 50 cents to $ 3.12/MMBtu from $ 2.45/MMBtu.	IFGMR August 18, 2000
This autumn, the dynamics of the U.S. gas market will experience the biggest change in nearly two years when Alliance Pipeline L.P. begins moving as much as 1.3 Bcf/day of Canadian gas to the Midwest..... "I think the Canadian producers will take a bit of time to fill the pipeline; there is always a ramp-up period," Ellsworth said. Judging by past experience with new pipes and his projections for Canadian production levels, Ellsworth said he expects initial throughput on Alliance to be between 500,000 and 700,000 Mcf/day. Still, that is nothing to scoff at, Ellsworth pointed out. He said supply to the Midwest in October and November averages 17 Bcf/day and, assuming his projections, Alliance would boost that by 3% to 4% -- a "significant increase" given the continued lack of capacity to move Chicago-area gas to the East. "That is certainly enough gas to put some downward pressure on [Midwest] prices," Ellsworth said. "My guess is it's probably not enough to upset the whole U.S. market, but a lot depends on weather-related demand. If it's cold, Alliance will merely take the edge off and keep prices from shooting up. But if we have another warm start to winter, it could be enough to send prices crashing back to the $ 2.50/MMBtu level. No matter how you look at it, that is a large amount of gas to be hitting the market all at once."	IFGMR August 18, 2000
Many analysts point to a long-term shift toward higher prices as domestic industries increasingly take advantage of gas's fuel efficiency and environmental benefits. And most said they believe current prices of $4.10-4.50 (U.S.) per million	The Toronto Star August 21, 2000

British thermal units are an aberration, citing the steep fall in energy prices in 1997-1998, which dealt a severe blow to further exploration and production activity, a major cause behind today's falling supplies and rising prices. The industry's response to high prices, with a record 765 rigs now drilling for gas, will likely lift 2001 output to about 19 trillion cubic feet and ease pressure on prices, said EIA analyst Dave Costello.	
"Many investors believe this gas shortfall and subsequent runup in gas prices is only a short-term problem or anomaly that will quickly correct itself," the analyst continued.	IFGMR September 1, 2000
A strong September bid-week saw Louisiana gas prices in the $ 4.60/MMBtu range and New York city gate prices nearing $ 5, but lighter-than-normal bid-week volumes could be signaling the market's perception that light September loads could cool the sizzling market.	The Oil Daily September 5, 2000
Companies that have been injecting high-cost gas into storage may wish they hadn't done so when the heating season rolls around, an official with the Energy Information Administration says. The unusually narrow spread between current spot values and winter-month futures prices creates "a source of considerable risk for storage operators who acquired gas at recent elevated prices," said Mark Rodekohr, EIA director of energy market and contingency information.	IFGMR September 15, 2000
When the September monthly indexes set record highs, some market players were convinced that aftermarket prices would tank, especially given that September is a shoulder month. They didn't. With the exception of the Southern California border and one day's trading on Southern Natural Gas Co., daily spot lows between Sept. 5 and Wednesday were higher -- and in some cases much higher -- than the comparable September indexes.... "Looks like producers won round one," a Houston-based trader declared, referring to this month's baseload standoff between producers and would-be buyers. Some players on both sides opted to buy or sell their supplies on the daily spot market instead of making monthly deals because they believed prices would swing in their favor.	IFGMR September 15, 2000
In its latest "Short-Term Energy Outlook," EIA said it expects average U.S. wellhead prices to average $ 4.48/Mcf this winter, compared with approximately $ 2.20/Mcf in the winter of 1999-2000. The price forecasts are a product of basic supply and demand factors in North America, Mark Mazur, acting EIA administrator, told a Washington press conference last week.	IFGMR October 13, 2000
Prices dropped yesterday about 30[cent] overall, with Pacific Gas & Electric (PG&E) citygate experiencing a nearly 45[cent] drop. Other-western points saw a more modest fall of about 20[cent]. The trader reported November weather forecasts were calling for mild weather. "No one's in a big hurry to put gas in the ground," he said. His prediction for next week's storage number was somewhere around 50 billion cf because of the mild weather. A Canadian trader wasn't surprised the cash market "crashed and burned"	Gas Daily October 20, 2000

yesterday. "The AGA [American Gas Assn.] number was where I thought it would be," he said, "but a lot of traders expected a smaller number, so I guess it had to go down." ... Gas futures continued to free-fall in active trading yesterday on the NYMEX. Prices gapped down considerably with an opening price of $ 5.14, but quickly began to drop as aggressive selling activity commenced. "Traders and funds in long positions are still cutting losses," a gas futures trader said. As long as the market continues to fall, additional stop-loss mechanisms will continue to trigger, adding additional downward momentum to the market, he added. "We're seeing the typical domino effect here, but hopefully things will level out soon." Prices continued to swan dive in the late afternoon, sending the November contract to a day low of $ 4.91 before meeting support levels. As the market came to a close, prices managed to inch up slightly as short-term traders began to take advantage of contracts at lower pricing levels. At closing, November contracts settled at $ 4.951, down 27.7[cent]	
Over the last two weeks, the gas industry has watched the November gas-futures contract fall more than $ 1.00/MMBtu from its $ 5.76/MMBtu all-time high on Oct. 12 to a low of $ 4.62/MMBtu just nine trading days later. Consequently, many of the bulls have begun to retreat and some traders say they now believe that an early, sustained cold blast is the only thing that will bring futures and cash values back above the $ 5.00/MMBtu level. The National Weather Service's 6- to 10-day and 8- to 14-day forecasts issued Tuesday, which covers the period Oct. 30 through Nov. 7, show relatively mild weather in most regions and widespread temperatures in the 40s and 50s. The forecasts are expected to add downward pressure to cash and futures prices, a Houston-based trader said. "On one hand, the market is starting to act like it should in a shoulder month. But on the other hand, the value chain is eroding and we have no solid fundamentals to support prices, let alone drive them up." ... A New York-based marketer Wednesday pointed out that open interest in the November, December and January Henry Hub futures contracts has increased this week, a week during which the contracts have moved down. "That's a classic 'buy the rumor, sell the fact' move. It means that more sellers are coming out into the market and people are going short -- and that means that [the sellers] expect [futures prices] to go lower," he said. Some market players believe market conditions are ripe for a repeat performance of what the industry witnessed a year ago this week, when the futures contract began to drop sharply. On Oct. 27, 1999, the November Henry Hub contract rolled off the board at $ 3.092/MMBtu, while the December contract settled at $ 3.223/MMBtu. A month later, on Nov. 24, the December contract rolled off the board at $ 2.12/MMBtu, a loss of $ 1.103/MMBtu, or about 34%. The November contract rolls off the board today, "and anyone who's still long winter is scared of" the December contract, the trader asserted. The December contract Wednesday settled at $ 4.771/MMBtu. A 34% drop would equate to a loss of about $ 1.62/MMBtu -- or a contract value of $ 3.151/MMBtu. "I would really	IFGMR October 27,2000

hate to think that could happen, but obviously it's possible. I'm sure others are banking on" the possibility, the trader said.	
Ron Denhardt, a vice president at Wefa Inc., was even more bullish, pegging his average Henry Hub spot price for 2001 at \$ 4.60/MMBtu. Denhardt projects an average 2000 Henry Hub spot price of \$ 4.00/MMBtu and an average fourth-quarter 2000 Henry Hub price of \$ 5.35/MMBtu. DRI, meanwhile, predicted that fourth-quarter prices would fluctuate. In a monthly forecast released last week, DRI analysts said they expect an average November Gulf Coast spot price of \$ 5.11/MMBtu, down a bit from \$ 5.19/MMBtu in October, and a December Gulf Coast price of \$ 5.15/MMBtu. The projected November fall-off is due to the expectation of new supply from Alliance Pipeline L.P. that is now scheduled to come on line Nov. 13 (see related story, page 11). The U.S., however, "will likely get a smaller and slower increase from Alliance than the total additional [1.325 Bcf/day] capacity indicates," DRI acknowledged.	IFGMR October 27,2000
Spot prices for natural gas are estimated to have averaged between \$ 4.90 and \$ 5.00 per thousand cubic feet (mcf) in September, nearly double the price from 1 year ago. Average natural gas wellhead prices (which reflect some short- and longer-term contract prices) are projected to post an average of \$ 4.48 per mcf this winter, also almost double the average recorded during the 1999-2000 season, the EIA forecast says.	Energy User News November 1, 2000
Midcontinent, San Juan and Rockies spot prices dipped below \$4 yesterday, while prices overall dropped about 20 cents-25 cents from Monday. The bottom dropped out of the November market yesterday as well, as many traders reported going long on November gas. "There were no treats in the market today," one uninspired Midcontinent trader said. "It was nothing but one big trick. We were trading 30 cents behind the screen and couldn't find a market." Midcontinent prices should continue down as updated weather forecasts predict more mild weather for November. "There were no bids out there for November gas," she said. "I had utilities telling me they were long November gas and were looking for a place to put it. November is over, a disaster."	Gas Daily November 1, 2000
U.S. spot natural gas prices retreated from their mid-October peak of more than \$ 5.52 per million BTUs (MMBtu) at the Henry Hub to a range between \$ 4.64 and \$ 4.81 last week. Two consecutive weeks of injections added 141 billion cubic feet of gas to inventories, bringing storage above 2.7 trillion cubic feet. Warmer than normal temperatures in key heating regions also helped prices to decline, Wall Street natural gas analysts said.... The First Call consensus of natural gas analysts forecasts an average price of \$ 3.85 per MMBtu next year, while gas futures on the New York Mercantile Exchange traded above \$ 4 for all of 2001 the middle of last week, according to Adam Sieminski of Deutsche Bank Alex. Brown in Baltimore. "Those prices seem a little bold," he said . "A lot of the forecasts were made when prices were more than \$ 5 per million BTUs. If you look at the strip, it's very high." Sieminski cited two basic trends that support his view. First, he said that the most recent U.S. Commerce Department data show that economic growth has fallen to 2.7 percent annually - its slowest pace since 1999 and weaker than what most	Petroleum Finance Week November 6, 2000

economists expected. Federal Reserve figures, for the third quarter as a whole, show that the total industrial production index advanced by an annual rate of only 2.8 percent, the slowest quarterly rise since 1999's first quarter. "In our view, despite the drop in the 'intensity' of energy consumption since 1980, we are starting to experience some of the spillover effects of higher oil and gas prices," Sieminski maintained. "Natural gas is the largest industrial fuel in the United States, accounting for more than 40 percent of industrial energy use. A slower economy has to have some impact on natural gas demand." Second, he noted that the number of rigs drilling for natural gas domestically continues to increase. "With the natural gas rig count approaching 850, it is hard to believe that there will not be a fairly substantial supply response in 2001," Sieminski declared. Barone also pointed this out, saying that the average U.S. gas rig count in October rose to a record level of 842 units (32 rigs more than the previous record of 810 in September, and 232 rigs higher than October 1999's 601-rig average). "It's worth noting that October represented the fifth consecutive month of new all- time highs, suggesting that the long-awaited increase in deliverability is pending," he said... Sieminski remains skeptical. "Our main point is that we think a lot of forecasts are too high. Our feeling is that gas prices are not going to be $ 4 on average next year," he told Petroleum Finance Week. "We're officially saying $ 3.40. If you twisted my arm, and depending on the weather, I might concede another 25 cents, but not more. Too many people are basing their outlooks on the current situation, which is very tight. But it won't necessarily stay that way. If we're right that we get a bit of an economic slowdown and a bit less demand, along with more production and imports, then supply and demand for natural gas might rebalance much more quickly than many analysts believe possible."	
Cash prices in most regions were at odds with the December futures contract early this week, hanging back while the contract rallied on forecasts of an early winter and trading higher only when cold weather actually surfaced. After huge fluctuations in both spot and futures prices during November bidweek, aftermarket spot prices in most regions leveled off last week, trading relatively close to November indexes. But in the futures market, the tide began to turn late Monday afternoon when the National Weather Service released its six- to 10-day forecast showing below-normal temperatures in the western half of the country, above-normal temperatures in Florida and normal temperatures everywhere else. "This is the widest [spread] I've seen in a while," said one trader, commenting on the basis between Henry Hub cash and December futures. Henry Hub cash prices Tuesday ranged from $ 4.61 to $ 4.75/MMBtu, trading 23 cents to 37 cents/MMBtu behind the December contract's low that day of $ 4.98/MMBtu.	IFGMR November 10, 2000
Oil prices were a main factor in pushing gas prices higher, EIA observed, adding that another key driver was market concern about underground storage levels, which were relatively low for much of the summer. Yet, "there was some feeling among observers of the gas industry that the market may have overreacted. The downward tumble in spot prices over the last few weeks may be evidence of this," the report said.	IFGMR, November 13, 2000
After seemingly defying the law of gravity for the previous two days, the NYMEX futures contract fell back to earth yesterday as a market correction and	Gas Daily, November 17, 2000

milder weather forecasts offset some of the bullish sentiment in the market.	
A leading Wall Street analyst, Ronald Barone of UBS Warburg, raised his price projections for 2000 and 2001, citing low storage and other factors. At the same time, he warned the market would remain highly volatile, saying in a November 16 research note, "the industry is poised for one heck of a ride." Barone boosted his 2000 projection for the 12-region composite spot price to \$3.75 per million British thermal units (MMBtu), up from his previous \$3.60/MMBtu estimate... Barone's predictions clash somewhat with November 8 projections by the Energy Information Administration, which said natural gas prices would ease in 2001 due to rising production. EIA also said prices had been tamped down by a mild October. And other analysts also noted the EIA productions in arguing that prices would moderate in 2001. Jeffrey Brown, vice president of Beacon Energy, said that despite the high NYMEX prices, analysts at the McLean, Va.-based energy consulting firm expected wellhead cash prices to average \$3.25/MMBtu next year-down about 15 percent from the expected average price for 2000. "Despite the confusion brought by major price volatility and winter temperature, we are convinced that fundamental market forces are at work to put downward pressure on these record natural gas prices," Brown said Wednesday.	Energy Daily November 20,2000
Many market players are calling November the most volatile month in spot and futures price history. Record-high futures prices have been backed by physical demand in high-consumption regions like the Midwest and Northeast, while high demand for power generation and pipeline constraints pushed Southern California border prices to the \$ 15.00/MMBtu mark. The New York Mercantile Exchange's December contract on Nov. 15 hit a record-high of \$ 6.32/MMBtu, only to fall more than 50 cents the following day to a low of \$ 5.785/MMBtu. By Monday, however, the contract rose again to meet and then break that all-time record, posting a high of \$ 6.36/MMBtu.	IFGMR November 24, 2000
Cash prices lost some altitude yesterday as mild-to-moderate weather in most regions combined with a falling NYMEX contract to take some of the edge off the market. And as the sun set on the year's last NYMEX futures contract, December closed about 30 cents down from the previous day's settlement....	Gas Daily November 29, 2000
In general, futures markets can work well for both buyers and sellers when there are no unexpected movements in the overall level of price but there is much movement up and down around a relatively constant level of price, or around an expected upward or downward trend in price. Today, buyers may understandably be unwilling to hedge their price risk going forward. They may be expecting a decline in price by spring due to increased supplies and reduced demand, both brought on by high prices greater than the decline in forward prices on the futures contract market. They are willing to remain exposed to price movements and are hostage to their own or to others' forecasts. It appears that the value of the art of forecasting has increased in the last year along with the shift in the price level - an event that may have come as a pleasant	Gas Daily December 1, 2000

surprise to those who practice this art.	
Boston-based Energy Security Analysis Inc, meanwhile, said it expects December spot prices to average \$ 6.50/MMBtu. It also forecast a \$ 6/MMBtu average for January and \$ 5.50/MMBtu for February. "As cold waves move across the country, we expect price volatility to remain very high, meaning occasional bouts above \$ 8/MMBtu followed by gut-wrenching collapses to \$ 6/MMBtu," ESAI said in its December Natural Gas Stockwatch report released Dec 1.	Platts' Oilgram December 5, 2000
In the wake of record-high monthly indexes for December, aftermarket prices screamed into the double digits in some regions amid fears of sustained cold weather and inadequate gas supplies this winter. Swing prices shot up dramatically this week in every part of the country as predictions of more arctic temperatures rattled the market. Henry Hub cash values topped \$ 9.00/MMBtu Wednesday, compared with a December baseload index there of \$ 6.02/MMBtu. "Anyone that didn't do baseload because they thought it was too expensive is thinking about jumping out a window right now," one Houston-based trader remarked, pointing to the huge basis between first-of-the-month indexes and daily swing prices. While the 73-Bcf storage withdrawal estimate by the American Gas Assn. for the week ending Dec. 1 garnered little reaction, some sources Wednesday said they expect next week's withdrawal to exceed 200 Bcf -- which would be a very bullish signal for cash. "Think about why people would withdraw," a New York-based trader said. "One, because they need to use the supply and two, because [daily] cash prices are so high above first-of-the-month index right now." While some traders during bidweek said they believed monthly gas for December was overpriced, the aftermarket has failed to bear that out. At most pricing points, daily indexes early this week week were several dollars above monthly postings. In the Mid-Continent, when spot prices Wednesday shot as much as \$ 1.25/MMBtu above Tuesday's indexes, one trader lamented that cold weather in many parts of the country did not justify the magnitude of the price surges. "In February and March of 1996, it made sense for things to be wacky," one trader said. "There's nothing to drive this." He reported that many market players are removing gas from storage to sell, "but if this is a rough winter then they're going to be in trouble."	IFGMR December 8, 2000

Predictions just three weeks ago of gas holding in the $ 5-to-$ 6-range were blown apart last week as the NYMEX contract reached a high of $ 9.50 during Wednesday after-hours trading and closed up $ 1.911 for the week at $ 8.584. Twice last week trading was shut down for an hour when the contract gained the 75[cts.] limit, but the brief time-outs did little to cool prices. NYMEX continues to raise natural gas margins to keep track with the rocketing prices. The week's trading was highlighted by big jumps, gaining 76[cts.] Monday and a monster leap of $ 1.101 Thursday. Pushed by tight storage and the now ever-present weather factor, the contract price gained more than 25% in one week. And while there was much expectation prices would come back down after what is shaping up to be an unpredictable winter, the Energy Information Administration (EIA) said last week that "significant increases in natural gas demand ... will probably prolong the much-above-normal price movement through 2001."	Gas Daily December 11, 2000
A timid start to this winter, similar to the mild weather conditions of the first six weeks of 1998 and 1999, would likely have kept at least a $ 5 lid on prices, perhaps even pressing prices below $ 4. But this winter has proven that the gas industry still hasn't figured out a strategy for successfully reining in the risk of misbehaving gas prices during periods of cold weather. Since the end of October, when the November NYMEX Henry Hub gas futures contract settled at $ 4.541, the near-forward contract has more than doubled into the mid-$ 9 range. For several months heading into heating season, many in the industry thought gas prices would surge if the winter proved cold. But no one predicted the market would take prices to the heights seen so early in the winter. Once again, the industry underestimated the power of weather, which should be credited almost entirely -- with a little support from the costly follies in California -- for the $ 4 to $ 5 leap in prices since Nov. 1.	Gas Daily December 22, 2000
January 2001 indexes published by Inside F.E.R.C.'s Gas Market Report were derived from one of the most volatile and high-priced bidweeks ever -- Colorado Interstate Gas Co. in the Rockies had the lowest January index at $ 8.63/MMBtu, while Transcontinental Gas Pipe Line Corp. zone 6 in the Northeast had the highest at $ 19.33/MMBtu.... Burned last month by a surging day market, many local distribution companies took a different approach to January bidweek by locking in a large part of their January baseload supply at a spot index prices rather than negotiating fixed-price deals or taking their chances in the swing market. One LDC trader who buys mainly at Sumas, Wash., said his company tied most of its deals to Inside F.E.R.C.'s Gas Market Report's index even though he expected the Sumas posting to be a record $ 14.00/MMBtu or higher. "Last month we thought the baseload market was too strong, so we went into the month short at Sumas figuring we'd buy day to day," he said. "Then we saw prices shoot from [a December index of $ 13.69/MMBtu] into the $ 20.00s/MMBtu, and then the $ 30.00s/MMBtu, and then into the $ 40.00s/MMBtu, and the front office was asking us, 'What happened?' We didn't want to take that chance again."	IFGMR January 5, 2001

A greater share of peak-day gas was purchased on the daily spot market this winter than was evident during the preceding heating season. On average, 14 percent of the 2000-01 peak-day gas supplies were bought in the spot market [defined as daily spot] compared to nine percent of the 1999-00 peak-day volumes.	AGA LDC System Operations and Supply Portfolio Management During the 2000-2001 Winter Heating Season, July 2, 2001

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 25 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 125 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join CEA as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 20 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

Litigation Support and Expert Testimony

Provided expert testimony on more than 125 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Commonwealth Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

Navigant Consulting, Inc. (1997- 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988-1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983-1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981-1983)
Senior Consultant
Consultant

Southern California Gas Company (1976-1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

BS, Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses.

BOARDS OF DIRECTORS (PAST AND PRESENT)

Commonwealth Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

National Association of Business Economists
International Association of Energy Economists
American Gas Association
New England Gas Association
Society of Gas Lighters
Guild of Gas Managers

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Conn. Department of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
District Of Columbia PSC				
Potomac Electric Power Company	3/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Direct)
Potomac Electric Power Company	5/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Supplemental Direct)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Potomac Electric Power Company	7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Rebuttal)
Federal Energy Regulatory Commission				
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Natural Gas Company	9/92	Northern Distributor Group	RP92-1-000, et al	Cost of Service

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92	Lakehead Pipe Line Co. L.P.	IS92-27-000	Rate Case Analysis Cost of Service
Colonial Gas, Providence Gas	7/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	8/93	Algonquin Gas Transmission	RP93-14 – Rebuttal	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transcontinental Gas Pipeline Corporation	1/94	Transco Customer Group	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates
Tennessee Gas Pipeline Company	1/95	Tennessee GSR Group	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
Pacific Gas Transmission	2/95	Pacific Gas Transmission	RP94-149-000	Rate Design
Tennessee Gas Pipeline Company	3/95	Tennessee GSR Customer Group	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/2000	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Tennessee Gas Pipeline Company	1/96	ProGas and Texas Eastern	RP93-151	Declaration
El Paso Natural Gas Company	96	PG&E and SoCal Gas	RP92-18	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger

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Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/2000	Hawaiian Electric Light Company, Inc.	Docket No. 99-0207	Standby Charge
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/2001	Northern Indiana Public Service Company	Docket No. 99-0207	Direct Testimony, Valuation of Electric Generating Facilities
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR
Maryland Public Service Commission				
Eastalco Aluminum Potomac Electric Power Company	3/82 8/99	Potomac Edison Potomac Electric Power Company	Docket No. 7604 Docket No. 8796	Cost Allocation Stranded Cost & Price Protection (Direct)
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
The Berkshire Gas Company	5/92	The Berkshire Gas Company	DPU #92-154	Gas Purchase Contract Approval
Essex County Gas Company	5/92	Essex County Gas Company	DPU #92-155	Gas Purchase Contract Approval

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Fitchburg Gas and Elec. Light Co.	5/92	Fitchburg Gas and Elec. Light Co.	DPU #92-156	Gas Purchase Contract Approval
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation
The Berkshire Gas Company	11/93	The Berkshire Gas Company	DPU #93-187	Gas Purchase Contract Approval
Colonial Gas Company	11/93	Colonial Gas Company	DPU #93-188	Gas Purchase Contract Approval
Essex County Gas Company	11/93	Essex County Gas Company	DPU #93-189	Gas Purchase Contract Approval
Fitchburg Gas and Electric Company	11/93	Fitchburg Gas and Electric Company	DPU #93-190	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity
Hudson Light & Power Department	4/95	Hudson Light & Power Dept./ Town of Stow	DPU #94-176	Stranded Costs – Direct
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Regulatory Issues

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	98	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmoutain Pipe Line	RH-1-93	Cost of Capital
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study

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New Hampshire Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
Northern Utilities	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Hilton New Jersey Corp.	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	New Jersey Utilities Association	BPU AX96070530	PBOP Cost Recovery
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions

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Central Hudson, ConEdison and Niagara Mohawk	9/2000	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/2001	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Evaluate their use of storage
Pennsylvania Public Utility Commission				
Pennsylvania Public Utility Commission	4/95	ATOC	Docket No. R-00943272	Tariff Changes
Pennsylvania Public Utility Commission	3/96	ATOC	Docket No. P-00940886	Rate Service - Direct
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices

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Texas Railroad Commission				
Southern Union Gas	5/85	Southern Union Gas Company	G.U.D. 1891	Cost of Service
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Tariff Filing
Green Mountain Power	7/98	Green Mountain Power	Docket No. 6107	Direct Testimony
Green Mountain Power	9/2000	Green Mountain Power	Docket No. 6107	Rebuttal Testimony
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR

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American Arbitration Association, Chicago, IL				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/2000	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
American Arbitration Association				
ProGas Limited	7/92	ProGas Limited v. Texas Eastern	Arbitration Panel	Gas Contract Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
State of Rhode Island, Providence City Court				
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service

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U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation
U. S. District of California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U.S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Expert Report, Shortnose Sturgeon Case
Central Hudson Gas & Electric	8/2000	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Revised Expert Report, Shortnose Sturgeon Case
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation