Final Report of the

Missouri Public Service Commission's

Natural Gas Commodity Price Task Force

Issued: August 29, 2001

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

Exhibit (Schedule) 11

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1. Executive Summary, Observations, and Recommendations

Task Force Organization

The Missouri Public Service Commission's (Commission, MoPSC or PSC) January 23, 2001, Order Establishing Case and Creating Task Force stated:

> "Recent price increases in the commodity cost of natural gas have lead to significant increases in the prices paid by customers of natural gas local distribution companies (LDCs). The Commission establishes this case to investigate the process for the recovery of natural gas commodity cost increases by LDCs from their customers. A natural gas commodity price task force will be created to investigate and discuss options on this issue."

The MoPSC further stated in its Order:

> "The Commission wants to hear from the public on the issues raised herein, and to that end, will direct its Staff to propose general time frames and dates for local public meetings around the state."

The Order also directed notice to interested parties so that they would have an opportunity to apply for membership on the task force.

Numerous parties expressed interest in joining the task force. In its March 15, 2001, Order Naming Participants of the Natural Gas Commodity Price Task Force and April 9, 2001, Second Order Naming Participants of the Natural Gas Commodity Price Task Force, the Commission established the task force membership. Stakeholders from among the LDCs, consumers, and others were assigned to the task force. All stakeholders expressing an interest in task force participation were granted representation. A list of all task force members is provided in Appendix C.

Task Force Public Meetings

The first task force meeting took place April 20, 2001, in Kansas City, MO. The morning session was devoted to discussions regarding the organization, purpose and goals of the task force. Much time was spent helping participants understand what happened during the past winter and why. How the current natural gas cost recovery process works was also discussed. The morning discussions laid the groundwork for the afternoon. The primary focus of the afternoon session was discussion of options for changing the natural gas costs recovery process. The discussions involved significant debate on the pros and cons of the current system and the objectives for any changes that the task force would recommend. Most of the options for future consideration were developed in this meeting and introduced for comment in the public meetings to hear the public's concerns.

Subsequent to the first task force meeting six public meetings were held around the state:

Public Meeting Areas & Dates		Approximate Attendance Public	Task Force Members
Kansas City	April 26, 2001	22	8
St. Louis	May 4, 2001	6	5
Jefferson City	May 10, 2001	38	11
Kirksville	May 24, 2001	10	3
Sikeston	June 7, 2001	0	3
Joplin	June 12, 2001	0	4

The public meetings of the task force were held to inform the public about how the current process works, receive input from the public, and hear the public's concerns on current options under consideration by the task force for future modifications to the process. The transcripts from these meetings are available on the Internet at the link identified in Appendix A.

Comments from the public meetings focused on the high natural gas heating bills experienced last winter, disconnect notices, budget billing program adjustments, and insufficient funding for low and fixed income programs. The public input had bearing on different options that the task force developed, and later voted upon. A constant theme in the public meetings was the need to better address the needs of low and fixed income customers, and support for reducing the volatility of natural gas prices, even if a premium must be paid to do so.

Following the last of the public meetings the task force held its remaining task force meetings as follows:

Task Force Meeting Areas & Dates	
St. Louis	June 15, 2001
Jefferson City	June 29, 2001
Jefferson City	July 12, 2001

The task force divided itself into four subcommittees to discuss the issues identified at the first meeting, and to recommend options for future action. Each subcommittee was charged with further developing options and potential recommendations to be presented to the full task force. The final options identified and voted on by the full task force are provided in section 4. Section 3 provides an analysis of the votes of the task force members, which formed the basis for the recommendations contained in this report.

Policy Statement and Recommendations

In addition to the recommendations regarding specific options, the task force developed and voted on a general policy statement. All stakeholder groups broadly supported this statement:

Natural Gas Commodity Price Task Force Policy Statement

The Missouri Public Service Commission's Natural Gas Commodity Price Task Force (Task Force) examined several means or mechanisms that may be used to mitigate large-scale swings in natural gas prices. Each mechanism may be desirable in certain circumstances, but each has unique risks and costs that require evaluation in each circumstance.

The Task Force reached a consensus regarding the overall strategy of employing various mechanisms to mitigate and control upward gas price volatility. Our sense was that Local Distribution Companies (LDCs) in Missouri should be encouraged by the Commission and all other stakeholders to utilize various mitigation tools to balance market price risks, benefits, and price stability. LDCs should create a balanced portfolio of gas supply contracts with various price structures in an attempt to reduce, but not eliminate, market sensitive pricing. Part of a balanced portfolio may be over market at times and this is necessary to dampen price volatility. It is also recognized that gas price stability and especially limits to upward gas price spikes are desired and valued by many customers but may result in higher gas costs over the long-term due to the costs of hedging and fixed-price contracts.

A number of options were supported by a majority. The tables in section 3 show that the greatest level of consensus exists on options 2.h, 3.a, 3.c, 4.a, 4.b, and 4.d. Option 2.h deals specifically with actions to address the needs of low and fixed income customers through legislative actions and was consistently supported in the public meetings. Options 3.a and 3.c are different from the other options in that they deal with whether utilities should consider using fixed price contracts, call options, collars, and natural gas storage. The task force strongly supported the recommendation that gas utilities "consider" using these options as part of an analysis of prudent gas purchasing options. The policy statement adequately addresses the caveats of using these mechanisms. All stakeholder groups strongly supported the options identified and recommendations addressed in the following areas:

- **2.h)** Alternative Recovery Mechanisms for Low and Fixed Income Customers w/Legislative Actions for Collection of Funding vs. Ratepayer Allocations
- **3.a)** Fixed Price Contracts, Call Options, and Collars
- **3.c)** Natural Gas Storage
- **4.a)** Properly Structured Incentive Plans
- **4.b)** Performance Based Regulations (PBRs) in the Form of Rate or Bill Caps Should Not Be Implemented
- **4.d)** Expanded Information Exchange between LDCs, PSC, and OPC Regarding Procurement Plans & Strategies Should be Pursued to Reduce Disincentives in Gas Costs

The task force is also making a number of other recommendations that were not as broadly supported overall. This group of recommendations received a favorable response from the voting task force members. These options did not however receive as broad a range of support as those previously identified. This group of options includes:

1.a) Use of Dual Tariffs w/Fixed Price or Standard PGA Options
2.b) Changing PGA Rates More Frequently (4 times per year was discussed)
3.b) Use of Weather Derivatives
3.d) Use of Outsourcing/Agency Agreements
4.c) The Commission should Pursue Incentive Measures for Encouraging Energy Efficiency

The remaining options presented in this report did not receive widespread support from the various stakeholders. Therefore the task force has included the materials developed on these options, but does not provide recommendations regarding these options. Tables 3.1, 3.2, 3.3 and 3.4 provide lists of the options addressed by the task force and how the task force members voted on each of them.

The task force hopes that decision makers find this document useful in assessing the options that are available, the associated advantages and disadvantages of each, and which options this diverse group regarded favorably. Numerous members of the task force have indicated that they found development of these options and the associated discussions with other stakeholder groups both enlightening and productive.. The task force mechanism provided a forum for participation by stakeholder groups that do not often have a voice in the processes that affect them and an opportunity for all stakeholders to discuss and recommend options to their mutual benefit.

It is important to note that as of the date of this Final Report of the Missouri Public Service Commission's Natural Gas Commodity Price Task Force the Commission has not reviewed or approved any of the statements or recommendations of this report. The recommendations of this report were a direct result of the voting results of the voting task force members and do not necessarily represent the opinions of any particular group or individual.

2. Input from Public Meetings

In its January 23, 2001 Order that created this case the MoPSC stated that:

> "The Commission wants to hear from the public on the issues raised herein, and to that end, will direct its Staff to propose general time frames and dates for local public meetings around the state."

The first of the task force meetings took place April 20, 2001 in Kansas City, MO. The afternoon focus of this meeting was brainstorming on ideas for how to change the natural gas costs recovery process in the future. Most of the options for future consideration were developed in this meeting. These options were noted in the public meetings that followed to hear the public's concerns. The six task force public meetings held around the state were:

Public Meeting Areas & Dates	
Kansas City	April 26, 2001
St. Louis	May 4, 2001
Jefferson City	May 10, 2001
Kirksville	May 24, 2001
Sikeston	June 7, 2001
Joplin	June 12, 2001

The public meetings of the task force were held to discuss the current process, what options the task force is considering to change this process, and to hear the public's concerns. The transcripts from these meetings are available on the Internet at the link identified in Appendix A.

Not surprisingly, much of the input from the public meetings focused on how high 2000-01 winter natural gas heating bills were, disconnect notices, budget billing program adjustments, utility profit levels, deregulation of wellhead natural gas, and low and fixed income programs running out of funding. A number of concerned citizens indicated strong support for programs that reduce the volatility of natural gas prices, even if a small premium must be paid to do so.

The task force viewed the public meetings as critical because they provided an opportunity to gain the public's perspective of how well the current process worked this past winter and opinions regarding the options the task force was considering. The input from public meetings repeatedly showed that some of the public participants are interested in the process but generally most consumers are most interested in what changes to the process will do to their natural gas bills. Not surprisingly, the greatest interest regarding natural gas is what it costs. The unprecedented gas prices of this past winter were substantial and had a very clear affect on the pocket books of many Missouri consumers.

One consistent message throughout the task force meetings was concern for the hardships of last winter on low and fixed income customers. In depth information from the Energy Information Administration (EIA), a branch of the U.S. Department of Energy (DOE), is summarized below[1] describing this past winter's impact on low and fixed income customers.

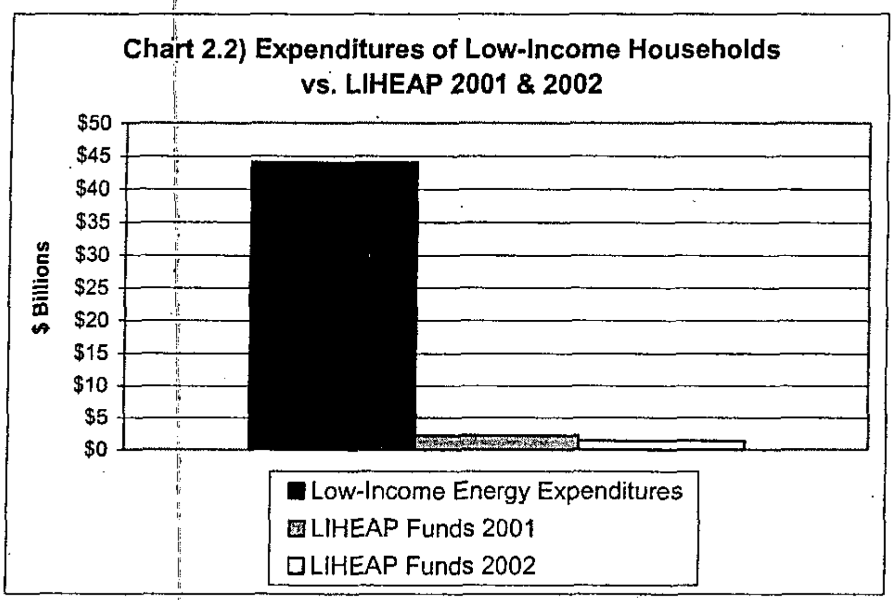
While all customers suffered the impact of increased natural gas prices, the DOE estimates that those households with incomes at or below 60% of their state's median income (roughly $21,000 for a family of three) spent approximately 20% more of their annual income on energy costs. The "Energy Burden" placed on low income families is estimated at 19.5% (bills/annual income) while the average for all other households is 3.7%. When examined by type of fuel used for heating, the energy burden for those customers utilizing natural gas escalated to 24% and 5% respectively as shown in Table 2.1. Overall, the DOE reports that 2000-01 winter bills for natural gas showed an increase of 42% compared to bills for the 1999-00 winter heating season.

Table 2.1) Yearly Impact of Energy Costs by Heating Fuel

Heating Fuel	Low-Income Total Energy Bills Oct '00 – Sep '01	Low-Income Twelve Month Average Energy Burden (% of income spent)	Other Consumers: Total Energy Bills Oct '00 - Sep '01	Other Consumers: Average Energy Burden (% of income spent)
Fuel Oil	$1,672	21%	$2,274	5%
Natural Gas	$1,806	24%	$2,133	5%
Electricity	$1,086	13%	$1,369	3%
Propane	$1,963	22%	$2,741	6%
Kerosene	$1,270	15%	–	–

1 *"The Winter Behind, The Summer Ahead: A Harsh Spring Faces Low-Income Energy Consumers"* by *Meg Power, PhD of Economic Opportunity Studies*

While more financial assistance may be needed to help low-income families pay for energy costs, preventative measures, such as weatherization of low-income housing, can prove to be a viable economic alternative. The DOE estimates that weatherization investments already in place in low-income housing may have resulted in avoided energy costs of nearly $1.2 billion, which is 55% of the projected LIHEAP expenditures of $2.2 billion in FY 2001. As of midyear 2001 the President's LIHEAP Budget for FY 2002 was $1.4 billion. This is illustrated in Chart 2.2.



Another winter of unusually high natural gas prices would undoubtedly pose additional hardship to the lower-income consumer already struggling with the high cost of energy from this past winter and possibly still carrying forward unpaid balances. Task force Options 2.g and 2.h deal specifically with alternative approaches for low and fixed income customers. Option 2.h, a legislative approach for low and fixed income customers, was broadly supported by all stakeholder groups of the task force.

3. Task Force Member Votes & Recommendations

In its last meeting on July 12, 2001, the task force voted on the options that the four subcommittees had developed for consideration. Each task force member that attended the last meeting, and had attended at least one other meeting, voted on the options presented. The results of this voting process formed the basis for the recommendations contained in this report. Each task force member identified the stakeholder group they were most closely associated with; utility, consumer, or other interest. Utility personnel typically represented utility interests. Both members of the general public and the Office of the Public Counsel (OPC or Public Counsel) represented consumer interests. Other interests were represented by personnel from the Missouri Public Service Commission Staff (Staff), energy consultants, general practice attorneys, and attorneys who have represented the interest of large commercial and industrial consumers.

Each voting task force member voted on each option using a 0 to 10 scale. A vote of 0 indicated that the task force member strongly believed that this option **should not be** implemented. A vote of 10 indicated that the task force member strongly believed that this option **should be** implemented. A vote of 5 indicated that the task force member was indifferent to this option being implemented. Some of the options are stated as things to stop doing or to eliminate in the current process. A vote of 0 on this type of option indicated that the task force member believed that the action or item being voted upon should remain in the current process.

The options developed by the task force and voted upon:

<u>Group 1: Choice Issues</u>
1.a) Use of Dual Tariffs w/Fixed Price or Standard PGA Options
1.b) Dual Tariff – Fixed Bill or Standard PGA
1.c) Dual Tariff – Weatherproof or Standard PGA
1.d) Supplier Choice – Partial Consumer Choice With Default Service Option
1.e) Supplier Choice –LDC Fully Exit the Merchant Function
1.f) State Takeover Gas Purchasing Function
1.g) State Oversees Third Party Purchasing of Gas for State

<u>Group 2: Process: Alternate PGA Methods</u>
2.a) How Missouri Does It Now
2.b) Changing PGA Rates More Frequently (4 times per year was discussed)
2.c) Changing Frequency of PGA Filing – Less Frequently
2.d) Eliminating the PGA and Collecting in General Rates
2.e) PGA Rate Caps with Summer Recoveries
2.f) PGA Rate Floors and Funding Price Stabilizing Funds
2.g) Alternate Recovery Mechanisms for Low and Fixed Income Customers, Developed Through the Regulatory Process
2.h) Alternative Recovery Mechanisms for Low and Fixed Income Customers w/Legislative Actions for Collection of Funding vs. Ratepayer Allocations

Group 3: Price Mitigation Tools
3.a) Fixed Price Contracts, Call Options, and Collars
3.b) Weather Derivatives
3.c) Natural Gas Storage
3.d) Outsourcing/Agency Agreements

Group 4: Incentive / Performance
4.a) Properly Structured Incentive Plans
4.b) Performance Based Regulations (PBRs) in the Form of Rate or Bill Caps Should Not Be Implemented
4.c) The Commission Should Pursue Incentive Measures for Encouraging Energy Efficiency
4.d) Expanded Information Exchange between LDCs, PSC, and OPC Regarding Procurement Plans & Strategies Should be Pursued to Reduce Disincentives in Gas Costs

The next four pages are Tables 3.1, 3.2, 3.3, and 3.4. These tables are the completed voting forms for all voting task force members. The identifiers (number.letter) in these tables coincide with the options developed by the four groups and those shown in the list above and the Table of Contents.

Table 3.1 - Group 1 Options, Task Force Votes

OPTIONS (number.letter identifiers match Table of Contents & Section 4 identifiers):

Group	NAMES:	Representing	1.a	1.b	1.c	1.d	1.e	1.f	1.g
Consumer	Bill Guinther	*Parkway School District*	8	0	0	8	3	6	6
	Martha Hogerty	*Office Public Counsel*	5	5	7	5	5	3	3
	Robert Kindle	*Concerned Citizen*	8	4	3	2	0	0	0
	Jan Marcason	*Mid Amer. Assist. Coal.*	6	6	2	7	0	0	3
	Mary Matalone	*Concerned Citizen*	4	9	2	0	0	0	0
	Rich Taylor	*Concerned Citizen*	7	7	7	0	0	0	0
	Vicki Walker	*Concerned Citizen*	0	2	0	0	0	6	7
	Jim Busch	*Office Public Counsel*	7	0	3	5	5	1	1
	Barb Meisenheimer	*Office Public Counsel*	7	7	9	4	2	5	5
	Doug Micheel	*Office Public Counsel*	5	5	7	5	5	3	3
	Brenda Wilbers	*DNR Energy Center*	6	3	3	5	0	5	5
	Average		5.7	4.4	3.9	3.7	1.8	2.6	3.0
Utility	Bob Amdor	*UtiliCorp United*	5	5	6	3	3	0	3
	David Beier	*Fidelity Natural Gas*	3	1	3	2	0	2	8
	Pat Childers	*Atmos Energy Corp.*	7	7	7	7	7	0	0
	Jim Fischer	*Fischer & Dority P.C.*	7	5	7	3	5	0	0
	Rob Hack	*Missouri Gas Energy*	6	6	5	2	7	2	2
	Rich Kovach	*Ameren Services*	1	0	6	0	7	5	7
	Cathleen Meyer	*City Utilities Springfield*	8	5	3	0	0	0	5
	Mike Pendergast	*Laclede Gas Company*	5	3	3	1	5	0	1
	Gary Wood	*Bethany Municipal Gas*	6	7	7	7	3	1	1
	Tom Byrne	*Ameren Corporation*	1	1	5	0	5	0	1
	Scott Glaeser	*Ameren Corporation*	2	0	5	0	8	0	0
	Average		4.6	3.6	5.1	2.3	4.5	0.9	2.5
Other	Stuart Conrad	*Finnegan & Conrad P.C.*	10	10	10	10	0	0	0
	Jeremiah Finnegan	*Finnegan & Conrad P.C.*	10	10	10	10	10	8	8
	Charles Laderoute	*Independent Consultant*	9	7	5	8	0	0	7
	Anne McGregor	*MC² Utility Consultants*	7	6	5	10	4	8	10
	Joseph Schulte	*Gas Workers Local 5-6*	4	6	7	0	0	0	0
	Tim Schwarz	*Public Serv. Comm. Staff*	8	8	8	1	1	0	2
	David Sommerer	*Public Serv. Comm. Staff*	8	7	5	5	2	1	2
	Warren Wood	*Public Serv. Comm. Staff*	9	10	6	3	2	4	5
	Lesa Jenkins	*Public Serv. Comm. Staff*	8	10	9	3	1	0	0
	Average		8.1	8.2	7.2	5.6	2.2	2.3	3.8
	Consensus Avg.		6.1	5.4	5.4	3.9	2.9	2.0	3.1

Option Titles

1.a) Use of Dual Tariffs w/Fixed Price or Standard PGA Options

1.b) Dual Tariff – Fixed Bill or Standard PGA

1.c) Dual Tariff – Weatherproof or Standard PGA

1.d) Supplier Choice, Partial Consumer Choice With Default Service Option

1.e) Supplier Choice, LDC Fully Exit the Merchant Function

1.f) State Takeover Gas Purchasing Function

1.g) State Oversees Third Party Purchasing of Gas for State

<u>All votes should be given as a number from 0 to 10.</u>

A vote of 0 means that you feel strongly that this option **should not** be implemented.

A vote of **10** means that you feel strongly that this option **should** be implemented.

A vote of **5** means that you are generally **indifferent** to the implementation of this option.

Table 3.2 - Group 2 Options, Task Force Votes

OPTIONS (number.letter identifiers match Table of Contents & Section 4 identifiers):

Group	NAMES:	Representing	2.a	2.b	2.c	2.d	2.e	2.f	2.g	2.h
Consumer	Bill Guinther	*Parkway School District*	3	7	0	4	0	3	10	10
Consumer	Martha Hogerty	*Office Public Counsel*	5	5	6	10	5	5	10	10
Consumer	Robert Kindle	*Concerned Citizen*	8	8	2	0	0	0	5	5
Consumer	Jan Marcason	*Mid Amer. Assist. Coal.*	5	2	7	2	7	0	10	10
Consumer	Mary Matalone	*Concerned Citizen*	9	0	7	2	8	5	2	8
Consumer	Rich Taylor	*Concerned Citizen*	0	8	0	10	3	0	0	5
Consumer	Vicki Walker	*Concerned Citizen*	3	3	6	6	0	0	9	9
Consumer	*Jim Busch*	*Office Public Counsel*	5	5	5	8	2	4	9	9
Consumer	*Barb Meisenheimer*	*Office Public Counsel*	5	0	7	10	6	6	7	7
Consumer	*Doug Micheel*	*Office Public Counsel*	5	5	5	10	5	5	10	10
Consumer	*Brenda Wilbers*	*DNR Energy Center*	4	7	5	6	4	5	10	10
	Average		4.7	4.5	4.5	6.2	3.6	3.0	7.5	8.5
Utility	Bob Amdor	*UtiliCorp United*	8	10	0	0	0	3	7	10
Utility	David Beier	*Fidelity Natural Gas*	8	10	0	0	3	3	2	8
Utility	Pat Childers	*Atmos Energy Corp.*	4	10	0	0	0	0	7	10
Utility	Jim Fischer	*Fischer & Dority P.C.*	8	10	0	0	0	0	5	10
Utility	Rob Hack	*Missouri Gas Energy*	5	7	1	0	2	5	6	6
Utility	Rich Kovach	*Ameren Services*	6	9	0	0	1	2	1	9
Utility	Cathleen Meyer	*City Utilities Springfield*	6	8	3	0	4	2	5	10
Utility	Mike Pendergast	*Laclede Gas Company*	5	10	1	0	2	5	2	10
Utility	Gary Wood	*Bethany Municipal Gas*	6	4	4	3	4	3	4	6
Utility	*Tom Byrne*	*Ameren Corporation*	6	9	1	0	1	1	0	9
Utility	*Scott Glaeser*	*Ameren Corporation*	6	9	0	0	1	2	1	10
	Average		6.2	8.7	0.9	0.3	1.6	2.4	3.6	8.9
Other	Stuart Conrad	*Finnegan & Conrad P.C.*	0	8	0	10	2	0	0	0
Other	Jeremiah Finnegan	*Finnegan & Conrad P.C.*	0	8	0	10	5	0	0	5
Other	Charles Laderoute	*Independent Consultant*	2	9	1	0	0	1	0	10
Other	Anne McGregor	*MC^2 Utility Consultants*	0	10	0	10	0	0	10	10
Other	Joseph Schulte	Gas Workers Local 5-6	7	8	0	0	3	2	3	5
Other	Tim Schwarz	*Public Serv. Comm. Staff*	8	2	2	1	1	2	10	2
Other	David Sommerer	*Public Serv. Comm. Staff*	3	4	1	5	7	3	1	7
Other	Warren Wood	*Public Serv. Comm. Staff*	8	9	4	2	6	4	8	8
Other	*Lesa Jenkins*	*Public Serv. Comm. Staff*	8	6	0	0	1	2	2	7
	Average		4.0	7.1	0.9	4.2	2.8	1.6	3.8	6.0
	Consensus Avg.		5.0	6.8	2.1	3.6	2.7	2.3	5.0	7.8

Option Titles

2.a) How Missouri Does It Now

2.b) Changing PGA Rates More Frequently (4 times per yr. was discussed)

2.c) Changing Frequency of PGA Filing - Less Frequently

2.d) Eliminating the PGA and Collecting in General Rates

2.e) PGA Rate Caps with Summer Recoveries

2.f) PGA Rate Floors and Funding Price Stabilizing Funds

2.g) Alternative Recovery Mechanisms for Low and Fixed Income Customers Developed Through the Regulatory Process

2.h) Alternative Recovery Mechanisms for Low and Fixed Income Customers w/Legislative Actions for Collection of Funding vs. Ratepayer Allocations

<u>All votes should be given as a number from 0 to 10.</u>

A vote of **0** means that you feel strongly that this option **should not** be implemented.

A vote of **10** means that you feel strongly that this option **should** be implemented.

A vote of **5** means that you are generally **indifferent** to the implementation of this option.

Table 3.3 - Group 3 Options, Task Force Votes

OPTIONS (number.letter identifiers match Table of Contents & Section 4 identifiers):

	NAMES:	Representing	3.a	3.b	3.c	3.d
Consumer	Bill Guinther	Parkway School District	10	10	10	8
	Martha Hogerty	Office Public Counsel	10	5	10	5
	Robert Kindle	Concerned Citizen	8	0	10	4
	Jan Marcason	Mid Amer. Assist. Coal.	8	7	10	8
	Mary Matalone	Concerned Citizen	9	4	10	4
	Rich Taylor	Concerned Citizen	9	8	10	8
	Vicki Walker	Concerned Citizen	10	0	10	2
	Jim Busch	Office Public Counsel	10	0	10	5
	Barb Meisenheimer	Office Public Counsel	9	7	10	7
	Doug Micheel	Office Public Counsel	10	5	10	5
	Brenda Wilbers	DNR Energy Center	9	5	10	7
	Average		9.3	4.6	10.	5.7
Utility	Bob Amdor	UtiliCorp United	10	10	10	10
	David Beier	Fidelity Natural Gas	10	5	10	8
	Pat Childers	Atmos Energy Corp.	10	5	10	5
	Jim Fischer	Fischer & Dority P.C.	10	5	10	5
	Rob Hack	Missouri Gas Energy	10	10	10	10
	Rich Kovach	Ameren Services	10	10	10	6
	Cathleen Meyer	City Utilities Springfield	10	6	10	9
	Mike Pendergast	Laclede Gas Company	10	8	10	8
	Gary Wood	Bethany Municipal Gas	7	7	7	7
	Tom Byrne	Ameren Corporation	10	9	10	5
	Scott Glaeser	Ameren Corporation	10	9	10	4
	Average		9.7	7.6	9.7	7.0
Other	Stuart Conrad	Finnegan & Conrad P.C.	10	8	10	4
	Jeremiah Finnegan	Finnegan & Conrad P.C.	10	9	10	8
	Charles Laderoute	Independent Consultant	10	8	10	10
	Anne McGregor	MC² Utility Consultants	10	10	10	10
	Joseph Schulte	Gas Workers Local 5-6	5	5	10	3
	Tim Schwarz	Public Serv. Comm. Staff	8	8	10	7
	David Sommerer	Public Serv. Comm. Staff	10	5	10	7
	Warren Wood	Public Serv. Comm. Staff	10	8	10	5
	Lesa Jenkins	Public Serv. Comm. Staff	10	8	10	7
	Average		9.2	7.7	10	6.8
	Consensus Avg.		9.4	6.6	9.9	6.5

Option Titles

3.a) Fixed Price Contracts, Call Options and Collars

3.b) Weather Derivatives

3.c) Natural Gas Storage

3.d) Outsourcing/Agency Agreements

All votes should be given as a number from 0 to 10.

A vote of 0 means that you feel strongly that this option **should not** be implemented.

A vote of 10 means that you feel strongly that this option **should** be implemented.

A vote of 5 means that you are generally **indifferent** to the implementation of this option.

Table 3.4 – Group 4 Options & Policy Statement, Task Force Votes

OPTIONS (number.letter identifiers match Table of Contents & Section 4 identifiers):

	NAMES:	Representing	4.a	4.b	4.c	4.d	Policy Stmnt
Consumer	Bill Guinther	*Parkway School District*	2	2	10	7	10
	Martha Hogerty	*Office Public Counsel*	3	10	7	9	7
	Robert Kindle	*Concerned Citizen*	10	10	10	8	9
	Jan Marcason	*Mid Amer. Assist. Coal.*	8	3	8	2	7
	Mary Matalone	*Concerned Citizen*	8	2	8	5	10
	Rich Taylor	*Concerned Citizen*	7	5	0	9	7
	Vicki Walker	*Concerned Citizen*	10	10	10	10	8
	Jim Busch	*Office Public Counsel*	2	9	10	9	10
	Barb Meisenheimer	*Office Public Counsel*	7	10	8	10	7
	Doug Micheel	*Office Public Counsel*	6	10	7	9	7
	Brenda Wilbers	*DNR Energy Center*	10	5	10	10	7
	Average		7.4	6.9	8.0	8.0	8.1
Utility	Bob Amdor	*UtiliCorp United*	10	10	10	10	10
	David Beier	*Fidelity Natural Gas*	5	8	8	10	10
	Pat Childers	*Atmos Energy Corp.*	10	10	0	7	10
	Jim Fischer	*Fischer & Dority P.C.*	10	10	10	7	10
	Rob Hack	*Missouri Gas Energy*	10	10	8	5	9
	Rich Kovach	*Ameren Services*	10	10	2	6	10
	Cathleen Meyer	*City Utilities Springfield*	8	9	5		10
	Mike Pendergast	*Laclede Gas Company*	10	10	6	6	10
	Gary Wood	*Bethany Municipal Gas*	6	6	6	6	6
	Tom Byrne	*Ameren Corporation*	10	9	5	7	10
	Scott Glaeser	*Ameren Corporation*	10	9	5	7	10
	Average		9.0	9.2	5.9	7.1	9.5
Other	Stuart Conrad	*Finnegan & Conrad P.C.*	8	10	0	3	8
	Jeremiah Finnegan	*Finnegan & Conrad P.C.*	6	10	0	8	8
	Charles Laderoute	*Independent Consultant*	9	3	8	9	10
	Anne McGregor	*MC² Utility Consultants*	0	10	10	0	10
	Joseph Schulte	*Gas Workers Local 5-6*	5	10	7	4	5
	Tim Schwarz	*Public Serv. Comm. Staff*	7	9	9	9	9
	David Sommerer	*Public Serv. Comm. Staff*	7	8	5	9	10
	Warren Wood	*Public Serv. Comm. Staff*	8	8	9	7	10
	Lesa Jenkins	*Public Serv. Comm. Staff*	10	8	10	9	10
	Average		6.7	8.4	6.4	6.4	8.9
	Consensus Avg.		7.7	8.2	6.8	7.2	8.8

Option Titles

4.a) Properly Structured Incentive Plans

4.b) Performance Based Regulations (PBRs) in the Form of Rate or Bills Caps Should Not Be Implemented

4.c) The Commission Should Pursue Incentive Measures for Encouraging Energy Efficiency

4.d) Expanded Information Exchange Between LDCs, PSC, and OPC Regarding Procurement Plans & Strategies Should Be Pursued to Reduce Disincentives in Gas Costs

(Policy Statement) **See Page 3 or 15**

All votes should be given as a number from 0 to 10.

A vote of **0** means that you feel strongly that this option **should not** be implemented.

A vote of **10** means that you feel strongly that this option **should** be implemented.

A vote of **5** means that you are generally **indifferent** to the implementation of this option.

The voting results shown in Tables 3.1, 3.2, 3.3 and 3.4 can be assessed in different ways. The first would gauge support within each stakeholder group (utility, consumer, and other). An option was considered generally favorable if it received a vote of 6.0 or higher on a scale of 10. If all stakeholder groups supported a recommendation with a vote of 6.0 or higher, it is being treated as a "strong" recommendation of the task force. The Office of the Public Counsel has objected to this criterion. The following provides information on which options were favored by the different stakeholder groups but does not constitute a recommendation of the task force group because a sufficient level of consensus did not result from the task force voting. The level of consensus on these different options is addressed in more detail below.

The utility stakeholders favored the following options:
2.a, 2.b, 2.h, 3.a, 3.b, 3.c, 3.d, 4.a, 4.b, 4.d, and the policy statement.

The consumer stakeholders favored the following options:
2.d, 2.g, 2.h, 3.a, 3.c, 4.a, 4.b, 4.c, 4.d, and the policy statement.

The other stakeholders favored the following options:
1.a, 1.b, 1.c, 2.b, 2.h, 3.a, 3.b, 3.c, 3.d, 4.a, 4.b, 4.c, 4.d, and the policy statement.

A second assessment of the voting results analyzes support from all stakeholder groups. The options that all stakeholder groups supported were as follows: 2.h, 3.a, 3.c, 4.a, 4.b, 4.d, and the policy statement. Option 2.h deals specifically with options for how to address the needs of low and fixed income customers and was consistently supported in the public meetings. Options 3.a and 3.c are different from the other options in that they deal with the question of whether utilities should consider using fixed price contracts, call options, collars, and natural gas storage. The task force strongly supported the idea of utilities "considering" using these options available to them. However, these task force recommendations should not be construed as implying that use of these mechanisms in gas portfolios be preapproved. Options 4.a and 4.b deal with properly structured incentive plans and aspects of performance based regulations that should be avoided. Option 4.d recommends more exchange of data on procurement plans and strategies "up front".

The titles of the strongly supported recommendations of the task force are as follows:

2.h) Alternative Recovery Mechanisms for Low and Fixed Income Customers w/Legislative Actions for Collection of Funding vs. Ratepayer Allocations
3.a) Fixed Price Contracts, Call Options, and Collars
3.c) Natural Gas Storage
4.a) Properly Structured Incentive Plans
4.b) Performance Based Regulations (PBRs) in the Form of Rate or Bill Caps Should Not Be Implemented
4.d) Expanded Information Exchange between LDCs, PSC, and OPC Regarding Procurement Plans & Strategies Should be Pursued to Reduce Disincentives in Gas Costs

In addition to the recommendations regarding specific options, the task force developed and voted on a general policy statement. All stakeholder groups broadly supported this statement:

> **Policy Statement)** The Missouri Public Service Commission's Natural Gas Commodity Price Task Force (Task Force) examined several means or mechanisms that may be used to mitigate large-scale swings in natural gas prices. Each mechanism may be desirable in certain circumstances, but each has unique risks and costs that require evaluation in each circumstance.
> The Task Force reached a consensus regarding the overall strategy of employing various mechanisms to mitigate and control upward gas price volatility. Our sense was that Local Distribution Companies (LDCs) in Missouri should be encouraged by the Commission and all other stakeholders to utilize various mitigation tools to balance market price risks, benefits, and price stability. LDCs should create a balanced portfolio of gas supply contracts with various price structures in an attempt to reduce, but not eliminate, market sensitive pricing. Part of a balanced portfolio may be over market at times and this is necessary to dampen price volatility. It is also recognized that gas price stability and especially limits to upward gas price spikes are desired and valued by many customers but may result in higher gas costs over the long-term due to the costs of hedging and fixed-price contracts.

A third assessment of the voting results shows overall weighted averages of all stakeholder groups. This method captures options that some groups favored, and others did not strongly oppose. This method identified options that were favored by the task force but not as strongly as the "strong" recommendations. This method identified the following options that were not already identified as "strong" recommendations: 1.a, 2.b, 3.b, 3.d, and 4.c. Option 1.a recommends that customers have the option of choosing a fixed price per unit from their LDC in addition to the current PGA method. Option 2.b deals with the possibility of permitting LDCs to change their PGA rates more frequently than the current process permits. Option 3.b is different from the other options in that it deals with the question of whether utilities should consider using weather derivatives in a prudently developed gas supply plan. Option 3.d deals with LDCs contracting with third party providers to perform the gas supply planning/procurement function. Options 4.c recommends that the Commission pursue measures to encourage energy efficiency.

The titles of these options are as follows:

- **1.a)** Use of Dual Tariffs w/Fixed Price or Standard PGA Options
- **2.b)** Changing PGA Rates More Frequently (4 times per year was discussed)
- **3.b)** Use of Weather Derivatives
- **3.d)** Use of Outsourcing/Agency Agreements
- **4.c)** The Commission should Pursue Incentive Measures for Encouraging Energy Efficiency

4. Gas Costs Recovery & Price Mitigation Options & the Pros and Cons of Each

During the first task force meeting the members developed a list of options for changing the mechanisms by which natural gas costs are incurred and passed on to consumers. These options were grouped based upon their general concepts. The groups were Choice Issues, Process Analysis/Review, Price Mitigation Tools, and Incentive/Performance Plans. Much of the work of the task force's 2nd and 3rd meetings was directed at debating the aspects of each option and developing them for voting upon by the entire task force group. The option papers from the four groups are provided in this section of the task force report. These were the options that were voted on by the task force members in the last task force meeting held on July 12, 2001. The identifiers (number.letter) coincide with the identifiers used on the voting forms provided in Section 3 as Tables 3.1, 3.2, 3.3, and 3.4 and those shown in the Table of Contents.

Group 1 Option Papers: Choice Issues

During the task force discussions, seven options were discussed as possible consumer choice options for the purchase of natural gas: (a) Dual Tariff - Fixed Price or Standard Purchased Gas Adjustment (PGA), (b) Dual Tariff - Fixed Bill or Standard PGA, (c) Dual Tariff - Weather Proof or Standard PGA, (d) Supplier Choice - Partial Consumer Choice With Default Service Option, (e) Supplier Choice - LDC Fully Exit Merchant Function, (f) State Takeover Gas Purchasing Function, and (g) State Oversees Third Party Purchasing of Gas for State.

The first three choice options outlined below pertain to stabilizing the commodity portion of the bill with respect to fluctuations in weather and/or cost of gas and these options could be offered pursuant to a dual tariff approach where the consumer would have various rate or tariff options or could continue to pay for service from the LDC under the current PGA process. The fourth and fifth choice options pertain to selection of the natural gas supplier. In these two options, the LDC would still provide the local distribution service. If either of these options are selected, it is recommended that a pilot project be implemented in the state to give an LDC an opportunity to change its business practices, identify additional consumer education needs, and identify and address any problems before rolling out statewide to all small commercial and residential customers. The last two choice options pertain to creation of a statewide gas purchasing function.

In the following outline, a description of the seven consumer choice options will be discussed along with the pros and cons of each option.

1.a) Dual Tariff – Fixed Price or Standard PGA

The fixed price option is a fixed price per Ccf (100 cubic feet of gas) consumed, but the customer's bill will still be affected by usage related to weather or other factors. The customer knows the rate that will be paid, but a colder winter will result in a higher bill for more Ccfs consumed, and a warmer winter will result in a lower bill for fewer Ccfs consumed. If the customer chooses this program, he/she will pay a pre-determined rate for the volumes consumed. Example: Customer consumes 100 Ccf times flat rate of $0.75 or customer consumes 80 Ccf times a flat rate of $0.75.

Pros:

- Reduces price volatility and provides relative price stability.
- Customer knows what rate they will pay for the natural gas.
- Easier to budget.
- Provides price protection for the customer. If prices go higher than pre-determined rate, customer is capped at pre-determined rate.
- Promotes Energy Conservation. Customer can choose to set back thermostat when aware colder weather is approaching, thus reducing consumption.
- No true up in gas cost, but the flat rate will likely change on an annual basis.

Cons:

- Not a guarantee of savings. If market prices fall below pre-determined rate, customer would end up paying more than other customers (on standard PGA).
- Consumer education. Consumer may confuse fixed price with fixed bill or level payment option.
- It is unclear whether small LDC's have enough volume to cover the cost or if there is enough consumer demand to cover the cost of the option.

1.b) Dual Tariff – Fixed Bill or Standard PGA

If the customer chooses the fixed bill option he/she will pay a pre-determined dollar amount for natural gas service, regardless of the price of natural gas or usage due to the weather. Software is used to compute a consumer's bill based on previous natural gas consumption, contracted natural gas prices, average temperatures, and administrative costs. A tolerance is established so that a bill can be adjusted for changes in habits (e.g. turning up the thermostat and opening the windows). Example: Customer will pay $100.00 per month for gas consumption. A customer's usage patterns (a home with less insulation or a large number of residents) will affect the pre-determined monthly bill.

Pros:

- Reduces volatility and provides relative price stability (predetermined rate may change from year to year).
- Customer can budget for gas consumption.
- Provides price protection.
- Provides bill protection during cold winters.
- Some programs issue an annual efficiency report and provide immediate discounts for installing efficient appliances.

Cons

- Doesn't promote energy conservation as long as consumption falls within tolerance level range. Usage could creep up and customer may not notice usage increase if next year's predetermined rate is comparable.
- Consumer education. Difficulty in distinguishing Fixed Bill from Fixed Price or Weatherproof and explaining tolerance level.
- Customer would possibly be removed from the option or have to true-up the costs of monthly bills if consumption is outside of the tolerance level.
- It is unclear whether small LDC's have enough volume to cover the cost or if there is enough consumer interest to cover the cost of the option.
- Not all customers may qualify for the option (e.g. recently moved and/or insufficient information about usage patterns).

1.c) Dual Tariff – Weatherproof or Standard PGA

The customer under this program will pay for a fixed number of volumes consumed regardless of actual usage due to weather. The bill will vary based on price of gas. Software is used to compute a consumer's bill based on previous natural gas consumption, average temperatures, and administrative costs. The customer bill may ultimately be adjusted for the price of gas (e.g. if price of gas is $5 versus $3/Mcf), but it will not be adjusted if the usage varies because the weather is colder or warmer than normal.

Pros:

- Reduces volatility and provides price stability for weather.
- Customer can budget for gas consumption.
- Some programs issue an annual efficiency report and provide immediate discounts for installing efficient appliances.

Cons:

- Need a large utility customer base for outside vendor(s) to offer program.
- Doesn't promote energy conservation since customer does not see bill change for increased usage during cold weather. Customer may not consume within tolerance level range.
- Customer would possibly be removed from the program or have to true-up the costs of gas if consumption is outside of the tolerance level.
- Bill still varies based on cost of gas.
- Consumer education.
- Not all customers may qualify for the option (e.g. recently moved and insufficient information about usage patterns).

1.d) Supplier Choice – Partial Consumer Choice with Default Service Option

The customer under this option will have the opportunity but not the requirement to choose a supplier other than the LDC. Example: Customer can choose to purchase the commodity (natural gas) from supplier ABC instead of taking natural gas from the LDC. It is recommended that a pilot project be implemented in the state to give an LDC an opportunity to change its business practices, identify additional consumer education needs, and identify and address any problems before rolling out statewide to all small commercial and residential customers. Some of the "con" statements below pertain to issues that must be addressed if this option is selected.

Pros:

- Increased competition may drive-prices down.
- Multiple options may exist for choice of suppliers, firmness of service, limitation of volumes risk and commodity price risk.
- Possible pooling/aggregation of low income customers may be used to facilitate providing assistance.

Cons / Issues:

- Supply reliability – assuring that supplier has firm capacity to make firm delivery.
- Peak day reliability – assuring that supplier has adequate gas on utility system to meet gas consumption needs on an extremely cold day.
- Stranded costs issues must be addressed. What does the utility do with the excess pipeline capacity or excess in gas supply contracts that were previously held?
- Utility is supplier of last resort. What happens if supplier walks? Who has legal jurisdiction?
- Security or performance bond level determination.
- Billing issues must be addressed - Who provides the billing to the customer? (LDC? Supplier?) If LDC bills on behalf of supplier, communication is vital to assure accurate bill.
- Communications and consumer education.

- There is little margin at the residential/small commercial level, so there could potentially be few marketers participating especially if consumers are not able to aggregate loads. Want to avoid having marketers going only after customers with best load factors – cherry picking and leaving the rest for the LDC.
- System balancing: Ensuring receipts match deliveries.
- Minimal savings. Big hassle/complex in choosing appropriate supplier.
- Not a guarantee of savings.
- Cash out set equitably to assure no unfair detriment.
- Marketer qualifications to enter into program must be addressed.
- Local governments may lose significant tax revenues. If new or additional taxes are instituted to make up for lost revenues under gross receipts taxes, there could be possible problems due to the requirements of the Hancock Amendment in Missouri.
- Consumers could be inundated with aggressive and misleading marketing tactics, fraudulent practices such as slamming and improper billing practices.
- Low-income consumers may be left without affordable service.
- If marketers pursue customers with better load factors or better payment records the cost of natural gas for the remaining LDC customers may increase.
- Who represents the consumers in disputes over gas supply?
- Issues arising due to affiliated transactions by LDC marketing affiliates.

1.e) Supplier Choice –LDC Fully Exit the Merchant Function

Under this option, LDCs would no longer sell natural gas, but would be limited to providing distribution service only. This option would be similar to what happened with the pipelines under Federal Energy Regulatory Commission (FERC) Orders 436 and 636 in which the pipelines exited the merchant function and no longer provided sales service, but transportation only. The customer would purchase gas directly from a gas marketer. It is recommended that this type service should be offered on an optional limited, pilot type basis initially to give an LDC an opportunity to change its business practices, identify additional consumer education needs, and identify and address any problems before rolling out statewide to all small commercial and residential customers. This time would also benefit marketers who wish to get established. Some of the "con" statements below pertain to issues that must be addressed if this option is selected.

Pros:

- Customers have a choice of gas supplier and may receive benefits of competition.
- Prices may come down due to competition.
- More options for customers as to types of service - i.e. less than full firm.
- Can be part of additional unbundling of services by the LDC.
- From the LDC's perspective removes the risk and insufficient reward that LDCs face in providing commodity gas where no gas procurement incentive plan is in effect.
- From the LDC's perspective, reduced regulatory burden associated with gas supply and PGA issues.
- Possible pooling/aggregation of low income customers may be used to facilitate providing assistance

Cons / Issues:

- Significant consumer education is necessary.
- Consumer confusion - e.g. communication issues between them, the marketer and the LDC. Understanding of firm versus interruptible or less firm options and the various costs and risks associated with these.
- Supplier of last resort issues must be addressed. Who is it? Who pays?
- What is the LDCs obligation to serve in case of problems?
- What happens when a gas marketer defaults?
- How is the system balanced? Easier for LDCs with their own storage.
- Gas supplies ~~or~~ pipeline services used by a marketer may not in fact be firm.
- Stranded cost issues must be addressed. Winding down of all the supply and capacity commitments that an LDC has entered into. Possible stranded costs.
- Increased administrative burdens for LDC in dealing with multiple markets, multiple pools, aggregation and balancing issues. May require costly computer software changes.
- Local governments may lose significant tax revenues. If new or additional taxes are instituted to make up for lost revenues under gross receipts taxes, there could be possible problems due to the requirements of the Hancock Amendment in Missouri.
- Consumers could be inundated with aggressive and misleading marketing tactics, fraudulent practices such as slamming and improper billing practices.
- Prices may go up (e.g., Low income consumers may be left without affordable service).
- If marketers pursue customers with better load factors or better payment records the cost of natural gas for the remaining LDC customers may increase.
- Reliability – who assures/checks for adequate capacity for peak days?
- Increased administrative burdens for customers – e.g. may now be 2 bills for gas service, or the time involved in selecting a supplier.
- Who represents the consumers in disputes over gas supply?
- Issues arising due to affiliated transactions by LDC marketing affiliates.

1.f) State Takeover Gas Purchasing Function

Responsibility for procuring natural gas for customers of the State's ten LDCs currently resides with each individual LDC. These LDCs are served by a number of different interstate and intrastate pipelines and range in size from very small (less than 500 customers) to very large (more than 600,000 customers). This option would place the procurement and nomination function for the commodity (natural gas) under the jurisdiction of the state.

Under the current approach, each LDC makes its gas commodity purchases and undergoes an annual audit by the PSC staff. These audits may result in recommended disallowances (e.g., that not all gas commodity costs will be recovered) based on the Staff's allegations of imprudence. Very infrequently, LDCs have been permitted to earn financial profits on gas commodity transactions (e.g., the MGE incentive plan from 1996-1999 and the Laclede incentive plan from 1997-2000). In some cases there is substantial litigation (and ensuing judicial review) surrounding recommended imprudence disallowances as well as gas commodity incentive plans.

Pros:

- Economies of scale and increased buying power in performing the gas procurement function could lead to decreased procurement cost per Ccf of gas delivered.
- The aggregation of purchasing power may make financial hedging a more viable option than is presently the case for the State's smaller LDC systems, which may help bring price stability to those customers in a more cost-effective fashion.
- Eliminates the costly, time-consuming and repetitive administrative litigation process currently know as the Actual Cost Adjustment (ACA) review. This elimination of administrative litigation may generate cost savings.
- Maintain current standards of reliability.
- Maintain current PGA rate structures based on serving interstate pipelines.

Cons:

- Knowledge of each individual system's idiosyncrasies may be lost and may compromise reliability to some extent in the short term.
- Governmental administration of procurement activities may be less than nimble, which could result in increased costs.
- Transition could be complicated and may cause more questions than answers in terms of who ultimately will be responsible for gas control, interstate pipeline storage and transportation contracts, etc. As a result, personnel savings from consolidation of purchasing activities may be minimal.
- Gas costs for some LDC service areas could go down, but costs to others could go up.
- Whether government would be properly motivated to achieve most favorable gas procurement arrangements versus just meeting basic needs. May lead to government review of government activities, which could dilute the cost savings that may be possible by eliminating ACA review and litigation.

1.g) State Oversees Third Party Purchasing of Gas for State

Missouri's investor owned gas LDCs currently each rely mostly on the gas procurement departments located within each LDC or an affiliate of the LDC. Some of these gas procurement departments procure gas supplies for a service territory that is largely contiguous (e.g. Laclede) while others procure gas for geographically separate districts that make up their entire Missouri service territory (e.g. AmerenUE, ANG, MO Public Service, and MGE).

As an alternative to the current gas procurement process, the State could oversee a competitive bidding process where gas marketers (e.g. Williams, Enron, Dynegy, Aquila, and Shell) compete for the business opportunity of being designated at the statewide or regional level to be the gas supply procurer for all of Missouri's LDCs. The statewide gas procurer would have responsibility for the full range of gas procurement responsibilities including gas commodity procurement and associated hedging of commodity price and volumes risk, storage, and pipeline capacity reservation, nominations, and balancing. Individual LDCs could be allowed to "opt out" of the new gas procurement procedures but this would decrease the potential benefits.

Pros

- Economies of scale and increased buying power in performing the gas procurement function could lead to decreased procurement cost per Ccf of gas delivered.
- Costs may decline as the utilization of gas supply assets and contracts is optimized on a statewide basis. For example, the projected peak day demand should be less than the sum of the projected peak day demands of all Missouri LDCs. Also, capacity release and off system sales revenues might be increased if the gas supply assets and contractual rights from several LDCs could be bundled and sold as a package.
- A concern is that current gas incentive plans use arbitrary incentive levels that may be considerably higher than the amount needed to incent beneficial gas procurement outcomes. If a competitive market exists for outsourcing the gas procurement function, then the costs of increased efficiency and cost effective procurement practices will be limited to the amount necessary to achieve desired outcomes. Missouri consumers may be able to enjoy significant savings if desired outcomes from the current incentive plans can be achieved at a fraction of the cost.
- Decreased costs of regulation, regulatory compliance, and litigation associated with gas procurement.

Cons

- A methodology would need to be devised for allocating gas procurement costs among LDCs. However, Missouri LDCs already have experience with allocating gas procurement costs (e.g. pipeline capacity and storage costs) among the geographically distinct districts that they serve.

- One Missouri utility has its own storage facility and some have propane peaking capabilities that would need to be incorporated into the statewide gas procurement. Missouri would be "breaking new ground" in initiating this process on a statewide basis so a certain amount of trial and error would likely be required as the new process is implemented.
-
- The State may not have personnel with the required skills to oversee this process.
- Knowledge of each individual system's idiosyncrasies may be lost and may compromise reliability to some extent in the short term.
- Transition could be complicated and may cause more questions than answers in terms of who ultimately will be responsible for gas control, interstate pipeline storage and transportation contracts, etc. As a result, personnel savings from consolidation of purchasing activities may be minimal.
- Gas costs for some LDC service areas could go down, but costs to others could go up.

Group 2 Option Papers: Alternate PGA Methods

2.a) How Missouri Does It Now

Description:
Regulated natural gas LDCs are currently permitted to change their PGA rates up to 3 times per year. Once in a winter filing that takes place in November, again in a summer filing that takes place in April, and last in an emergency or unscheduled filing when market conditions shift unexpectedly to the degree that they result in a relatively large under or over recovery balance. Generally, interest is paid by the utility for over recoveries and interest is paid by the consumers for under recoveries, outside of a bandwidth in recoveries. PGA rates in each of these filings are based on current market and near term future prices, fixed price contracts, storage withdrawal gas prices, and considers the percentages of supplies anticipated from each of these supply sources. Transportation contract costs, fuel losses, and any under or over recovery balances are also generally considered.

Pros:
This approach is a reasonable trade between having rates change more or less often than three times per year. Changing rates more often than three times per year complicates proration and customer rate expectation issues. Changing rates less often than three times per year further exaggerates PGA rate shifts when they do occur and further distorts customer rates vs. market conditions. The current approach was actually adopted as a result of the price spike in the 1996-97 winter. The price spikes of the 2000-01 winter combined with monthly PGA rate changes would have resulted in customers paying more for natural gas during the 2000-01 winter than they did under the current approach. Numerous people at the task force public meetings said they preferred rate stability. The total costs of natural gas to the utility would not have been any different but the recovery process would have resulted in more of these costs being collected during the winter if rates changed each month. Under the current approach, these balances will need to be collected over the summer and possibly, to some degree, the following winter. In defense of the PGA rate changes that occurred this winter, it must be noted that many factors resulted in a "perfect storm" scenario that drove rates dramatically higher throughout the country – not just in Missouri. Record cold weather, electrical generation demand for natural gas, an increased population, growing economy, flat supply growth, and lower than average storage levels all played a part in what happened. The current PGA process was not at the "heart" of what happened.

Cons:
This is the process that was in place during the 2000-01 winter. The average Missouri residential LDC customer saw their winter natural gas bill approximately double from what they paid one year ago while the market price of natural gas went up by more than a factor of four. The current process results in a significant lag between market price spikes and the associated adjustments to customer rates. This results in market signals to customers that are not consistent with actual market conditions. The under/over recovery balances required to trigger emergency PGA rate changes result in long payback periods that further distort rates to customers vs. what conditions exist in the market. Only permitting three changes in PGA rates per year can result in larger swings in rates than would otherwise occur with rates able to

change more than three times per year. The regulatory lag under the current approach, coupled with winters like the 2000-01 winter, result in significant under recoveries that result in *consumers paying interest on what they did not pay for in the winter and result in higher natural* gas costs throughout the summer. Consumers with high summer usage (i.e. laundry businesses and restaurants), end up paying more than their share of these high summer costs to collect winter under recoveries.

2.b) Changing Frequency of PGA Filing – More Frequently

Pros

- Filing more than 2-3 PGA changes each year would result in a smaller pool of gas costs, compared to the current formula, to be recovered over the succeeding months. In periods of moderate price changes, the rate charged to customers would generally be stable.
- Filing more frequent PGA filings would result in more immediate, but smaller rate changes. *Under the current formula, in periods of substantial price changes, an increase* or decrease in gas prices might not be passed on to customers for several months.
- Filing monthly PGA changes would bring Missouri into conformity with the PGA formulas used in most other Midwest states, including Iowa, Kansas, Minnesota and Michigan.

Cons

- Filing more frequent PGA changes would expose customers to price spikes. A substantial, short-term increase in gas prices would result in higher gas bills the succeeding months. The current system tends to average out such price spikes.

2.c) Changing Frequency of PGA Filing – Less Frequently

Pros

- In periods of changing natural gas prices, this system provides more stable rates for customers and is less work for all parties involved in the filing process.

Cons

- Filing fewer PGA changes each year would result in a larger pool of gas costs than under the current formula. In periods of changing gas prices, the financial impact on customers is delayed and it may take months to repay under recoveries.

2.d) Eliminating the PGA and Collecting in General Rates

Description:
LDCs currently recover the vast majority of their gas supply (gas and pipeline) costs through the provisions of standard statewide PGA clauses approved by the MoPSC. The administrative application of this cost recovery mechanism permits the LDC to make one scheduled summer and one scheduled winter PGA filing each year, and one unscheduled winter PGA filing when there are certain specified projections of over- or under-recoveries of gas supply costs. The reconciliation of LDCs' gas supply costs and the recovery of such costs from customers are reviewed in annual audits conducted by the MoPSC Staff for each LDC.

In most states (46 out of 50), commodity gas costs are recovered outside the forum of a general rate case through some form of PGA mechanism. PGA clauses, which grew rapidly in popularity after the 1973 oil price shock, were instituted to allow a gas utility to recover its commodity gas costs (plus, in many states, interstate pipeline costs) in a timely fashion that averts financial instability for LDCs. With gas supply and pipeline costs being approximately 65-80% of total LDC rates for natural gas, the use of PGA clauses avoids the deployment of additional LDC and regulatory commission resources that would be required to process a complete rate case.

The complete elimination of the PGA clause would, in effect, treat gas supply costs the same as all other LDC operating expenses, e.g. customer service labor, meter reading, billing, etc., which are allowed by the MoPSC to be included in the LDCs' base rates for natural gas service. This option would basically make the LDCs treat natural gas and pipeline costs, for ratemaking purposes, the same as electric utilities currently treat their variable fuel costs, which constitute approximately 30-35% of total electric operating revenues.

Pros:

The "pros" of adopting this option of eliminating the PGA clause from LDC tariffs are as follows:

- Using a rate case forum to establish rates for the recovery of gas supply costs would permit the MoPSC to review an LDC's entire operations and financial condition in establishing the LDC's total future rates for natural gas service. The MoPSC currently looks at all LDCs costs in establishing rates but does so through a process that considers gas costs separate from non-gas costs.
- Under an assumed rate case filing schedule of no more than once each year, the annual number of changes in the LDC gas cost recovery rate would be reduced from the current maximum of three per year. However, MoPSC rules still permit the LDCs to petition the MoPSC for emergency rate relief during current or projected periods of financial distress.
- Gas price volatility, and the risks associated therewith, will be transferred entirely to the LDC. While this will stabilize the rates for gas cost recovery for customers, it will not necessarily result in lower rates for customers as a result of the LDC's costs of managing this added risk.

- Customer bills may be simplified if the resulting LDC rates and billing format reflect a single combined rate for both gas supply and LDC gas distribution costs, instead of containing two separate rates or charges for these two components of cost.
- If a methodology could be developed for the determination of a "rolled-in" level of gas costs, to be included in an LDC's base rates for gas service, that is mutually acceptable to both LDCs and the MoPSC, LDCs could strive to earn profits on their gas supply procurement activities without the impending risk of a MoPSC prudence review.
- Gas supply incentive plans may no longer be necessary, if LDCs are allowed the opportunity to earn higher equity returns as compensation for the assumption of the higher risk of recovering all gas costs from a fixed price in its base rates, and the recovery of gas costs from LDC customers is no longer limited to an absolute dollar-for-dollar basis.

Cons:

The "cons" of adopting this option of eliminating the PGA clause from LDC tariffs are as follows:

- As gas supply costs constitute some 65-80% of total LDC rates for natural gas, a series of regulatory proceedings would be required for Missouri's LDCs, in order to initially establish an appropriate level of gas costs to be included in gas rates. It can be anticipated that, in such proceedings, there is a high chance of litigation.
- Due to the magnitude of LDC gas costs and the importance of their timely recovery to the financial condition of the LDCs, and the normal eleven month suspension period for processing rate cases, it can be anticipated the majority of the LDCs will likely make a "Holiday" rate case filing each year, in order to have their projected costs of gas supply, as well as all other increases in plant investment and operating expenses, incorporated into their base rates no later than the subsequent December 1st of each calendar year. More frequent rate cases will result in greater rate case expenses and these costs are generally borne by ratepayers.
- With the added financial risk of having a fixed level of gas costs embedded in LDC base rates, LDCs will likely attempt to limit such additional risks through the greater use of various financial instruments. While the use of such instruments may limit exposure to extreme gas prices during peak periods, their cost has the potential of increasing overall gas costs.
- The rate case approach to the recovery of the LDCs' significant level of gas costs will likely result in a roller coaster of much higher and more volatile profits or deficits for the LDCs, due to their assumption of the total risk of the variations in gas prices and weather occurrences. While this added risk to the LDCs generally provides justification for increased equity returns and increased overall gas rate levels, such risks could also result in LDC financial situations where their ability to maintain service to their customers becomes jeopardized or impaired.
- The rate case option also deprives, or shields, customers from the level of seasonal price signals associated with the recovery of gas costs under the PGA and will also likely result in shifting a larger portion of the recovery of gas supply costs between customer classes with different seasonal gas consumption patterns.

- While the rate case option of fixing a gas price as a part of the LDC's base rates would shield customers from significant price spikes in the wholesale gas markets, it also eliminates the customer's opportunity to participate in any steep decline in such prices by locking the customer into paying a set price for gas costs until the next LDC rate case.

2.e) PGA Rate Caps with Summer Recoveries

Description:
Regulated natural gas local distribution companies (LDCs) would have a "cap" set on their PGA rates. If the market for natural gas goes above this cap the PGA would not rise above the preset cap to reflect the market rise in natural gas prices for those volumes that the LDC bought at the higher market price. This would result in the LDC under-collecting for those volumes bought at the higher market price vs. what price was set in the PGA rate cap. This balance would be recovered in the summer when market prices would presumably be lower. No legislative action would be required to have this happen in the state of Missouri as described.

Pros:
Because of the potential volatility of the natural gas market, price spikes such as were common in the 2000-01 winter, can be mitigated to the consumer thus allowing for more accurate budgeting and cash flow needs. Also, there may not be as great a need for social service funds because this option allows for the natural spreading out of costs to the ultimate consumer. The mechanism could be used with the current PGA system or one that changes PGA rates more or less often.

Cons:
Studies will show that over the long run, this option actually costs consumers more due to the carrying costs of delayed recoveries of un-recovered gas costs. Rate caps have the impact of muffling price signals to consumers. The result of this muffling is that there is less conservation.
Consumers may not want price caps. In none of the presentations made, was consumer research presented on what the consumer is looking for in terms of price options. This option still does not give any incentive to the utility to minimize the overall price it pays for natural gas, as they would still have full recovery of gas costs. Deferring the recovery of un-recovered gas costs to the summer billing periods may inappropriately shift PGA gas costs from the customer classes for whom the winter gas costs were incurred to those customers with high or levelized year round gas usage in the summer periods.

2.f) PGA Rate Floors and Funding Price Stabilizing Funds

Description:
Regulated natural gas LDCs would have a "floor" set on their PGA rates. If the market for natural gas dropped below this floor, the PGA would not drop below the preset floor to reflect the market drop in natural gas prices for those volumes that the LDC bought at the lower market price. This would result in the LDC collecting an over recovery for those volumes bought at the lower market price vs. what price was set in the PGA rate floor. This balance could be used to perform a number of functions – depending on its magnitude. No legislative action would be required to have this happen in the state of Missouri as described. If these over recovery balances were targeted for low and/or fixed income customers – legislative action might be required to address inequities in treatment of customers in like situations. Consumer education would be necessary with this type of program to explain the PGA floor and avoid confusion.

Pros:
The winter of 2000-01 demonstrated that natural gas market prices can be extremely volatile and can reach levels that exceed what many of Missouri's LDC customers can pay. This mechanism would provide for a source of funding that would be of very minor impact to the typical LDC customer. This mechanism would also avoid unrealistic expectations of customers. Temporary price drops contribute to unrealistic customer expectations as to what natural gas rate is "average" and "reasonable". Not participating in these market drops to their full magnitude would help to fund price stabilizing funds and not contribute to unrealistic customer expectations. These price-stabilizing funds could be used directly to offset winter price spike cost or purchasing forms of "price insurance" like call options or weather derivatives. The mechanism could be used with the current PGA system or one that changes PGA rates more or less often.

Cons:
This would further contribute to an already administratively burdensome ACA process. No certainty would exist in the level of funding available from a program like this from year to year. Some years would result in large balances for price stabilization efforts and others would result in zero funding. This mechanism has some very real feast or famine funding issues that couldn't be predicted from year to year. Customers may become outraged that the utility is keeping a portion of market natural gas costs drops vs. PGA rates for any purpose, even the purpose of helping to stabilize future rates. How these funds would be addressed in the ACA process could be cumbersome and the LDC's prudence in how it spent these funds would be of concern. This is a type of pre-approved funding mechanism vs. reviewing costs and determining prudence after-the-fact through the current actual costs adjustment (ACA) audit process.

2.g) Alternate Recovery Mechanisms for Low and Fixed Income Customers, Developed Through the Regulatory Process

Description:
Low-income Americans (those earning less than the Federal poverty guidelines, see below) face severe challenges in meeting their housing requirements, including utility service. Low-income citizens spend about 20% of their income to purchase their basic home energy supplies for heat, hot water, lights, and appliances. This compares with 4% for middle and upper income customers. It was reported that during the cold winter months of this past winter, many low-income citizens spent more than 30% of their income on home heating costs. The consequences of this economic hardship include health and safety problems, children displaced from their homes because of the lack of utility service, senior citizens forced to sell their homes, and even homelessness. The National Fuel Funds Network reports that Missouri has $6.3 million in natural gas arrearages owed by 13,091 households. Current efforts to assist low-income citizens with utility bills include affordability programs, educational programs, and efficiency programs. Examples of these types of programs and some related statistics are attached.

One path toward implementation of this option could be the Missouri Legislature adopting legislation to establish a "low income" category of utility ratepayers, based on the federal poverty level guidelines. Establishing this rate class will enable further discussion of options to help low-income customers with their current energy cost burden, the economic advantages of this plan to the utility companies, and the appropriate designation of funds for weatherization of the homes of low-income customers. If such legislation is adopted, the "Cold Weather Rule" prohibiting disconnection of service during certain months may need to be modified to insure that a discounted service fee is paid by these customers in order to maintain service.

A number of options exist for how this new rate class could be treated:

Percentage of Income Plan to normalize the percentage of income paid for utilities across the utility customer base. Income would be verified by social service agencies on a quarterly or annual basis. LIHEAP funding available to these customers would be directly assigned to the utility company.

Percentage of Actual Bill Plan: Low-income customers would pay a pre-determined percentage of their actual bill for energy usage. Income would be verified by social service agencies on a quarterly basis. This option promotes conservation of energy use by the customer.

Customer Support for a Low-Income Fund: For a minor levee (up to a maximum amount of less than $2 per year), all residential customers in the non-low income rate category would support a fund to assist low-income customers.

Utility Company-Sponsored Assistance for Low-Income Customers: Companies would be required to support a low-income utility assistance fund from shareholders and/or corporate revenue (not supported by ratepayers).

Another task force on low-income customer programs could be developed to deal with just this issue while the legislature is considering the change in statute. This would give more time to examine all the aspects of these (and possibly) other low-income customer programs.

Pros of Low-Income Assistance Programs: Maintaining the utility service of the most vulnerable customers during the cold winter months and the hot summer months pays off in averting major health care costs, preventing unsafe home heating alternatives, such as kitchen stoves, candles, or space heaters, avoiding non-payment that forces families to move or illegally re-connect energy supplies, and encourages family and neighborhood stability. Low-income energy assistance programs reduce utility company uncollectables that would otherwise be borne by increased costs to all ratepayers. Maintaining utility service to low-income customers reduces the fixed costs of the company's disconnecting and reconnecting homes and customer service staff.

Cons of Low-Income Assistance Program: Paying utility company customers are involuntarily subsidizing those who do not pay their bills. Low-income customers are discouraged from meeting their financial obligation because they often cannot get assistance unless their service has been disconnected. Inflexible income guidelines prevent many working families from being eligible for utility assistance programs. Utility companies are providing a social service for which their employees are unqualified or otherwise unable to adequately administer. With limited funding, arbitrary decisions about who receives assistance are often unavoidable. Utility companies must rely on government or private social service payment of delinquent bills, which is sometimes not forthcoming in a timely manner.

2.h) Alternate Recovery Mechanisms for Low and Fixed Income Customers, Developed Through the Legislative Process

This is the same option as "2.g" above except low-income assistance programs would be developed through the Legislature and would likely involve increased LIHEAP funding and/or some sort of tax on the general public instead of just ratepayers.

Information Related to Options 2.g and 2.h:

150% of Poverty Guidelines: 2001 U.S. Department of Health and Human Services

Family Size	Monthly Income	Yearly Income
1	$ 1,073.75	$ 12,885.00
2	$ 1,451.25	$ 17,415.00
3	$ 1,828.75	$ 21,945.00
4	$ 2,206.25	$ 26,475.00
5	$ 2,583.75	$ 31,005.00
6	$ 2,961.25	$ 35,535.00
7	$ 3,338.75	$ 40,065.00
8	$ 3,716.25	$ 44,595.00

Categories of Low-Income Assistance Programs and Examples from Around the Country:

Affordability Programs:
LIHEAP (Low-Income Home Energy Assistance Program), a Federal program distributed through State governments to assist low-income customers.

ECIP (Emergency Crisis Intervention Program), a subsidiary of the LIHEAP program to assist those who face shut-off, senior citizens, and families with young children. These funds are available for home heating and cooling costs.

Customer Contribution Funds: Voluntary contributions from utility company customers usually added to the ratepayer's monthly bill and distributed through private social service agencies.

Involuntary Customer Contribution Funds: A standard addition to all customer bills to assist low-income customers.

Privately Donated Utility Funds: Donations to private assistance funds, usually administered by social service agencies or religious/charitable organizations.

Percentage of Income Plans: These plans insure that low-income customers do not pay a disproportionate percentage of their income on utility costs.

Education Programs:
Budgeting Classes: Usually conducted by Consumer Credit Counseling, universities, and utility companies.

Conservation Classes: Conducted by utility companies, weatherization programs, and universities to teach consumers to conserve energy. These efforts usually result in an approximate 10% reduction in utility costs.

Weatherization/Efficiency Programs:
Government Programs of the U.S. DOE, and U.S. Department of Housing and Urban Development encourage weatherization of existing homes (including insulation, window replacement – *not usually with federal funds*, furnace replacement, energy saving appliances, etc.) and energy-efficiency guidelines for new home construction. Energy saving of up to 40% can be realized through weatherization.

Private weatherization programs supported by utility companies. These programs' guidelines usually include credit worthiness and other customer requirements.

Examples of Effective Affordability Programs from other States
Ohio Percentage of Income Plan (PIP): A qualifying customer in Ohio pays the gas utility a fixed percentage of his/her income for utility service, regardless of usage. Some programs may require the consumer to make a monthly contribution on any arrearage. The Ohio PIP programs are individually administered by each gas utility and funded by mandatory contributions from the utilities' customers.

Kentucky Customer Assistance Program (CAP): This program, operated by a Kentucky gas utility, is funded by a mandatory contribution from residential customers. The customer funding is matched, dollar for dollar, by the company's shareholders. The funding is capped at 1.5 cents per Mcf or about $1.50 per customer per year. The program is administered by a local low-income advocacy organization.

Illinois "Hands-Up" Program: This program is a community/utility company partnership that allows customers to work off their utility bills at a rate of $10 per hour by providing labor for community needs or by attending certain classes.

Group 3 Option Papers: Price Mitigation Tools

Initial Comments Regarding the Scope of the Group 3 Options

This subgroup examined several means or mechanisms that may be used to mitigate large-scale swings in natural gas prices. Each mechanism may be desirable in certain circumstances, but each has unique risks and costs that require evaluation in each circumstance.

The subgroup reached a consensus regarding the overall strategy of employing various mechanisms to mitigate and control gas price volatility. Our sense was that LDCs in Missouri should be encouraged by all stakeholders to utilize various mitigation tools to balance market price risk with price stability. LDCs should be allowed to create a balanced portfolio of gas supply contacts with various price structures to reduce, but not eliminate, market sensitive pricing. Part of a balanced portfolio will be over market at times and this is necessary to dampen price volatility. It is also recognized that gas price stability, which is desired and valued by customers, may result in higher gas costs over the long-term due to the costs of hedging and fixed-price contracts.

This section of the task force report will address each of the mechanisms studied, provide a brief explanation of the mechanism, and provide pros and cons regarding the mechanism.

3.a) Price Mitigation Tools and Hedging Instruments[2]

There are various types of price mitigation/hedging tools that LDCs can utilize. Dependent upon the overall goal of the gas purchaser, certain tools may be more appropriate to use than other tools at a given time. It is the consensus of this subgroup that the following tools should be used together in an overall price mitigation strategy.

Fixed Price Contracts

Explanatory Discussion
Fixed Price Contracts are natural gas supply agreements in which the buyer locks in a specific price of gas from a seller for a fixed volume delivered in a future period. The contracted volume must be delivered by the seller and received by the buyer during the term of the contract so both sides of the transaction have volume certainty. As a result fixed price contracts are typically structured as baseload transactions.

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[2]By Scott Glaeser, Manager, Natural Gas Supply and Transportation, AmerenEnergy Fuels and Services Company, Affiliated Agent on behalf of AmerenUE. Mr. Glaeser is deeply involved in natural gas purchasing activities for AmerenUE and has experience in the use of various types of financial instruments employed in the natural gas industry.

A fixed price contract can also be performed in the financial markets with New York Mercantile Exchange (NYMEX) futures contracts or over-the-counter (OTC) swaps with a financial institution such as Bank of America or Morgan Stanley.

In a NYMEX futures contract, the buyer purchases a NYMEX futures contract (which is defined in multiples of 10,000 MMBtu) for a future period at a set price. When the buyer sells this contract back to the futures market to liquidate the position, the difference between the market price at liquidation and the contract price is settled as a cash flow from or to the buyer (depending upon the market price). This cash flow is used to offset a corresponding gain or loss (compared to market) on a physical gas supply transaction. The financial structure is similar for an OTC swap except it is performed with a specific seller and can be tailored to certain receipt points and pipelines to eliminate basis risk.

Pros:
Fixed price contracts eliminate future market volatility and provide complete certainty in the future price of gas under that transaction. NYMEX futures contracts allow greater flexibility than physical contracts (i.e., more liquid and transparent market) and also eliminate credit risk issues.

Cons:
Fixed price contracts force the buyer to establish a future price position that risks being above the actual cost of gas when that future period arrives. They also lock the buyer into a baseload volume commitment that is inflexible compared to the dynamic gas supply requirements of a LDC. The financial contracts also require margin call transactions that may become substantial during periods of market volatility.

Call Options

Explanatory Description
Call options are financial instruments that give the buyer the right *but not the obligation* to purchase a futures contract at a set price in a future period. A fixed payment or premium is paid to the seller of the call option (NYMEX or financial institution) based upon market volatility and the time period the option is active. For example, an option for August 2003 would be more expensive than an option for August 2001 due to the uncertainty of the longer time period, which is referred to as time decay. If the call option is "in the money" based upon the value of gas in the futures market, the buyer can "strike" on the option and take possession of the futures contract for liquidation. Call options can be structured into physical gas supply agreements to create a price ceiling or cap in a market-based contract. A premium is paid for the cap through a demand charge, which is the implied value of the call option plus other premiums for firm supply and operating flexibility.

Pros:
Call options create a fixed and known maximum ceiling price for gas in a future period for a specific contract volume. However, the buyer is not obligated to "strike" on the option, which enables volume flexibility. When call options are structured into physical gas supply agreements, they allow the buyer to participate in downward price movements while limiting the risk of price spikes. The premium for the option is the only financial obligation of the buyer, which eliminates the financial risks of market volatility encountered with futures contracts.

Cons:
The premium of call options can become a substantial cost that may overshadow the financial benefits of acquiring the option. The strike price and premium of call options is derived from the underlying futures market, which reduces their effectiveness during periods of high gas prices and market volatility. The time decay component of call option pricing makes it financially unattractive to purchase for extended future periods.

Collars

Explanatory Discussion
Collars are a combination of a call option purchase and a put option sale by a buyer to create a price ceiling in exchange for guaranteeing the seller a price floor. The premium paid by the buyer for the call option is offset by the payment received for selling the put option to the seller. When the put option sale revenue matches the call option premium, the collar has a net financial outlay of zero and is referred to as a "costless collar". Collars can be financial instruments from the NYMEX and OTC markets or can be structured into physical gas supply contracts.

Pros:
Collars create a fixed and known maximum ceiling price for gas in a future period for a specific contract volume with reduced or no cost to the buyer. They allow the buyer to participate in downward price movements, until the price floor is reached, while limiting the risk of price spikes within the range of the collar. The premium, if any, for the collar is the only financial obligation of the buyer, which eliminates the financial risks of market volatility encountered with futures contracts.

Cons:
Collars require a fixed volume commitment in future periods, which essentially limits their use to baseload gas supply contracts. The strike price and premium of call options and put options used to create a collar are derived from the underlying gas futures market. This reduces the effectiveness of collars during periods of high gas prices and market volatility. The time-decay component of call option and put option pricing make it financially unattractive to purchase for extended future periods.

3.b) Weather Derivatives

Explanatory Discussion
Weather derivatives represent a newly evolving market based upon trading weather-related financial risks between parties. A strike price or value per unit of weather is defined by two parties to initiate a transaction (i.e., $10,000 per Heating Degree Day deviation from normal for Chicago Illinois during the month of December 2001). Once the strike or value of the weather derivative is agreed by both parties, the weather derivative becomes a financial instrument and functions like a futures contract. Once the actual weather of the defined area is realized, the financial contract is settled between the parties with a payment obligation from one party to the other depending upon which side of the position they assumed.

Pros:
Weather derivatives enable any entity with weather-related financial risk to lay off this risk onto another party with opposite but equal weather-related risks. The weather derivatives can enable entities to control revenue or cost variations due to weather volatility. They are designed more for insulating corporate earnings from weather volatility than stabilizing PGA rates.

Cons:
Weather derivatives are an immature and illiquid market that can only be performed in the OTC markets (not traded on NYMEX). Weather derivatives are only useful when there is a strong and consistent correlation between weather and a defined financial risk to the company or customer. The market value of weather derivatives can be heavily influenced by recent weather events that may bias the value of the hedge.

3.c) Natural Gas Storage[3/]

Explanatory Discussion
Natural gas storage principally refers to depleted natural gas production fields or below-ground caverns possessing a geology that permits the injection and withdrawal of natural gas from those reservoirs. In some limited cases it may also refer to smaller above-ground facilities, but these are typically of limited capacity. Historically, subterranean storage fields were owned and operated by interstate pipelines and most major storage fields are still owned and operated by pipelines today. In some cases today, private parties and LDCs may also own and/or operate storage fields.

[3/]By James Busch and Stu Conrad. Mr. Busch is a member of the Missouri Public Counsel's technical staff and frequently investigates and prepares testimony for rate cases on the utilization of storage by local distribution companies. Mr. Conrad is an attorney in private practice in Kansas City and has extensive experience in representing natural gas transporters at the Missouri Public Service Commission and at the Federal Energy Regulatory Commission in issues including pipeline natural gas storage and storage-related transportation issues.

If owned by interstate pipelines, storage fields are considered part of plant in service for the pipeline and rates, terms and conditions of service for storage are regulated by the FERC. For third party storage fields, the FERC typically allows market-based rates that are set by the competitive market and not on cost-of-service rate making. LDC-owned storage fields may be regulated by state agencies that regulate the LDCs.

Pros:
The storing of natural gas by LDCs has two main objectives. The first objective is to have natural gas available during the winter heating months for their customers. The second main objective is that it provides a physical hedge against winter price spikes.

First, natural gas is used for a variety of reasons. Heating demand, industrial use, and electric power generation are some of the main uses for natural gas. Historically, natural gas usage would peak in the wintertime due to the increase in demand for residential heating. Since production facilities were not capable of producing excessive quantities of natural gas to meet the increased demand, storage fields were utilized to help meet this demand. This meant that LDCs could purchase natural gas in the summer, often referred to as the injection season, inject it into storage, and then withdraw it in the winter when it was needed most. Natural gas storage is limited in quantity. Currently, nationwide, there are just over 3.2 Tcf of natural gas storage facilities available for use by LDCs and other users of natural gas. This corresponds with an overall annual demand of natural gas of over 23 Tcf.

The second factor that storage is used for is as a physical hedge. A hedge can be defined as an attempted protection against adverse price movements. Usually, hedging is done using financial instruments such as futures or options that are addressed elsewhere in this section. Sometimes, a user may decide to physically hedge against price movements. This can be done in the natural gas industry by utilizing storage.

When used as a physical hedge, storage works like this: Historically, the price of natural gas has been lower in the summer than in the winter, due to the relative lack of demand. An LDC could purchase natural gas at lower prices in the summer, put the natural gas in storage, and then use it in the winter, thereby helping to mitigate the costs that customers could ultimately end up paying for natural gas and avoiding seasonal price spikes. The lower priced summer natural gas is physically purchased and injected into storage to help prevent price spikes on that portion of a LDC's demand.

There are other positive impacts of using storage. These include reliability of supply and flexibility of operations. Having stored natural gas helps insure natural gas will be available and gives LDCs flexibility in handling their supply portfolio. Storage also could be beneficial if other parties have too much natural gas and need to get rid of it. An LDC could purchase this excess natural gas at a reduced cost and inject it into storage until it is needed. Stored natural gas may also be cheaper to move to the city gate than natural gas that needs to be compressed and transported from well-head production areas.

Cons:
There are some negatives to using storage. One is the loss that occurs in the storage field. Natural gas can escape due to the condition of the reservoir. Losses can also occur during the injection or withdrawal of the natural gas into storage. This loss however is not in any sufficient amount to dissuade the use of storage. Also, there are costs to using storage. There are financial carrying costs of having to purchase the natural gas in the summer, store it, and then withdraw the gas in the following winter. Again, these costs pale in comparison to the positive aspects of using storage.

Consensus of Sub-Group Regarding Natural Gas Storage
The consensus of this subgroup was that the intelligent use of natural gas storage may be a significant tool used by the LDC to manage its natural gas costs. It may additionally enhance the reliability and security of the LDC's supply.

3.d) Outsourcing/Agency Agreements[4/]

Explanatory Description.
Outsourcing can be described as an agreement where a third party, such as a marketer, takes over the entire gas supply function of an LDC. This can include operation of gas supply, transportation, and storage assets. Outsourcing could entail the use of a request for proposal or competitive bidding process to choose the contractor.

Pros:
The marketer's operations are typically national in scope, often having a presence in many different states. The marketer could have a broader knowledge of the industry or particular opportunities not known to the LDC. Smaller companies, such as small municipal systems may not have the resources to handle all the facets of obtaining natural gas supply and transportation. Outsourcing offers economies of scale in purchasing. Since a marketer probably would be operating in many different geographical regions, there may be savings due to the diversity of demands in the marketer's portfolio.

Cons:
Disclosure of contracting information becomes an issue because the marketer may not be subject to disclosing aspects of its gas portfolio. Since a large portion of the responsibility for procuring gas supply has been passed on to the marketer, there may be some weakening of the general obligations of the LDC regarding adequacy of gas supply. There could be a loss in experience away from the LDC as key gas supply personnel leave the company. There is a certain loss of control of key assets of the LDC, including storage, gas supply, and transportation. There is a lack of continuity with the various changes in management of the gas supply assets. Reliability may be adversely affected because of the unknown reliance on the flexibility of other jurisdictions, or the possible defaulting by the third party. There may be an incentive to compromise reliability for profit.

Consensus of the Subgroup Regarding Outsourcing and Agency Agreements
The subgroup believes that the outsourcing option might be more viable and efficient from a small LDC's perspective because of the limited resources usually available to handle all aspects of the gas procurement function.

[4/] By David Sommerer, Task Force Group 3. Mr. Sommerer is a member of the Staff of the Missouri Public Service Commission and actively involved in the investigation and review of purchased gas costs and contracts by local distribution companies.

Group 4 Option Papers: Incentive/Performance Plans

I. Summary Statement of Group 4

Group 4 was responsible for evaluating various options relating to the use of targeted incentive plans, performance based rate-making and other measures, as alternatives or supplements to the current gas cost recovery process and as a method for encouraging energy efficiency. Although the group was unable to reach a consensus on any specific plan or procedure, it did reach general agreement on four broad principles that were submitted to the task force for its consideration. The items that the task force was asked to vote on included the following:

- **4.a)** Targeted incentive programs that are properly structured in accordance with the principles set forth on pages 50 through 57 of this subsection of the task force report should be utilized in the gas cost area;
- **4.b)** Performance Based Regulation (PBR), with rate or bill caps, as described on pages 46 through 50 of this subsection of the task force report, should not be implemented in the gas cost area at this time;
- **4.c)** The Commission should pursue incentive measures for encouraging energy efficiency that make financial sense for the utility and the consumer;
- **4.d)** An expanded exchange of information by LDCs with Staff and OPC relating to procurement plans and strategies should be pursued in an effort to reduce disincentives in the gas cost area.

Group 4 also attempted to describe, and enumerate the pros and cons of, various alternatives that have been implemented, proposed or considered in each of these areas. (See Section VII for a discussion of targeted incentive plans, Section V for a discussion of PBR mechanisms, Section VII (2) for a discussion of energy efficiency incentive mechanisms, and Section VIII for discussion of one proposal for expanding the exchange of information in the gas cost recovery process). Once again, however, it should be emphasized that the group did not reach a consensus on the merits of any of the specific approaches or plans outlined in these sections and did not ask the task force to endorse any specific approach.

II. *Introduction*

Public utilities have historically been considered "natural monopolies" that, through large-scale production, can achieve greater efficiencies and lower per unit cost than firms in most other industries. For society to gain from these efficiencies and at the same time to protect against the potential abuses associated with monopoly power, public utilities traditionally have been regulated under rate of return (ROR) regulation combined with an obligation to serve in an exclusive service territory. In this way, rate of return regulation acts as a surrogate for competition and also allows the public utility to achieve financial integrity.

The proponents of rate of return regulation suggest that it simulates competitive outcomes to promote efficiency in the product market and promotes the social goal of ubiquitously available service at just and reasonable rates. Specifically, they argue that under traditional rate of return regulation:

(a) shareholders, through the efficient operation of the firm, are offered the opportunity to earn a reasonable return on prudently incurred investments based on normalized historic performance;

(b) increased efficiencies and innovation are encouraged by allowing firms to retain any profits associated with such advances that occur between rate reviews; and

(c) consumer welfare is maximized by the guaranteed availability of essential services (heating, cooling, lighting, etc.), lower price levels attributable to lower cost, and restraints on the monopolist's ability to exercise market power.

The critics of rate of return regulation argue that, under some circumstances, rate of return regulation suffers from weaknesses that diminish its ability to simulate beneficial competitive effects. Specifically, they contend that under traditional rate of return regulation:

(a) firms are less likely to accept potentially cost reducing risk or pursue innovation because costs are not pre-approved and must be incurred prior to a determination of the prudence of allowing recovery of those costs on an ongoing basis;

(b) firms are less likely to maximize savings and revenues because the frequent rebasing of rates based on historical revenue and expense levels prevents the firm from realizing any longer-term financial benefit from such activities; and

(c) firms tend to devote an excessive amount of their resources to explaining, documenting, and defending their activities to regulators -- resources that could be more productively used to achieve additional efficiencies in the management of their assets. Instead, they suggest that alternative forms of performance-based regulation or additional monetary incentives targeted at enhancing efficiency gains would be more effective in achieving desirable outcomes for consumers and society.

III. Overview

The primary focus of this section of the task force's report is to explore the pros and cons of alternative regulatory and incentive structures in an effort to identify meaningful methods to minimize the cost of natural gas to Missouri consumers and to promote more efficient use of this limited natural resource.

Section IV provides a brief history of developments in the natural gas industry and identifies areas of contention regarding the current PGA/ACA process.

Section V explores performance-based regulation (PBR) as a regulatory alternative to rate of return regulation. Rather than frequent reviews of utility costs and rates set to reimburse utilities for prudently incurred costs, PBR takes a long-term, goal-oriented approach to the utility's performance.

While in a broader sense ROR and PBR are methodologies for the determination of rates, targeted incentives offer an alternative for promoting superior efficiencies or specific goals such as energy efficiency.

Section VI provides a recommended set of parameters for the structure of incentives.

Section VII provides an overview of gas purchasing related incentives currently used by Missouri's LDCs. It also examines the pros and cons of those incentive mechanisms and describes existing and possible incentives targeted at improving demand side energy efficiency.

Section VIII addresses the significance of information and verification to issues of regulatory oversight of gas purchasing, consumer protection, and incentive design. This Section also addresses the task force's proposal for an integrated gas-purchasing plan.

Option 4.a) INCENTIVE/PERFORMANCE BASED MECHANISMS WITH SYMMETRICAL REWARDS AND PENALITES, POSSIBLY WITH VOLATILITY PROVISIONS

IV. Risk, Incentives and Disincentives of the PGA/ACA Process

As discussed in the task force report, the Commission adopted the PGA/ACA process in 1962. It fundamentally changed the traditional regulatory treatment for costs incurred by natural gas utilities. While some costs remained subject to the traditional method of rate of return regulation, under the PGA/ACA process LDCs could pass through to customers, dollar-for-dollar, the prudently incurred wholesale cost of natural gas adjusted for any price mitigation measures. Like traditional rate of return regulation, the PGA/ACA process was criticized as a mechanism that provides disincentives for LDCs to assume sufficient risk to secure lower gas related costs.

The natural gas operations of an LDC fall into an annual cycle. Typically, an LDC will inject natural gas into storage from April through October to bolster the supply of natural gas available during the heating season months of November through March. LDCs and natural gas pipelines need storage gas to supplement the gas available from the natural gas wells in the winter. The storage gas also serves as a physical hedge of lower summer prices against higher winter prices. The carrying costs of buying, transporting, and storing natural gas for periods of up to nine or ten months before use are recovered by estimating those costs in a general rate case and providing for cost recovery through base rates. The cost of the actual gas, transportation, and storage is recovered through the PGA/ACA process. The current PGA/ACA process was developed in an era when the source of natural gas supply was entirely regulated by the federal government. The LDCs bought gas for their entire needs and delivered it to their local systems at a price regulated by the Federal Power Commission, now the FERC. Under these circumstances, there was little room for disagreement about the source of gas supply or its cost in the PGA/ACA process.

In 1978, in the face of national natural gas shortages, Congress began the process to deregulate the price of natural gas. Throughout the 1980s and early 1990s, the movement progressed by fits and starts as the FERC grappled with implementing changes and dealing with market reactions to its orders. By late 1993, the price of natural gas at the wellhead had been completely deregulated. Interstate pipeline companies were converted to common carriers of natural gas with no merchant function, that is, pipelines no longer bought gas in the field areas and sold gas to LDCs. This process is usually referenced as "unbundling". Until the natural gas season of 2000-01, natural gas prices remained relatively stable in the range of $1.75 to $2.25/Mcf with occasional short spikes.

The advent of markets for natural gas, transportation, and storage required LDCs to make choices with consequences to both reliability and price. These price and reliability risks are affected by many factors, including variations in the weather. Warmer than normal weather reduces the volumes of natural gas needed, exposing LDCs to the consequences of excess capacity. Colder than normal weather often both drives up gas prices and causes increased consumption that exposes the LDCs and their customers to the vagaries of the spot market. Prior to unbundling, the LDCs faced only limited exposure to after-the-fact reviews of these factors because they were essentially captive to the FERC-regulated pipelines and prices. After unbundling, the LDCs each year face the consequences of market movements in gas costs that can dwarf their annual non-gas income and approach the levels of the net worth of the company. Minimizing these risks becomes a critical factor; it is only natural that LDCs seek to shift that market risk either to customers or regulators. The consequences of this market risk have increased dramatically for all players with the jump in natural gas prices to historical highs in the 2000-01 winter heating season.

An issue primary to the discussion of disincentives and risk is the pre-approval of costs. Some LDCs suggest that pre-approval would, under various circumstances, have positive results for consumers. For example, it might encourage the LDC to take favorable hedging and other actions that it might otherwise avoid because of concerns over prudence disallowances. Moreover, they suggest that if the actions for which pre-approval are sought are sufficiently flexible (for example, a range of potential actions rather than a single, pre-determined action is approved), much of the risk disincentives can be potentially avoided while still minimizing the amount of regulatory involvement in day-to-day management decision.

Regulators and consumer advocates also face disincentives with respect to pre-approval in the new natural gas marketplace. While LDCs press the Staff, OPC, and the Commission to pre-approve gas price levels or hedging strategies in an effort to shed market risk, regulators and consumer advocates do not feel that they have full and immediate access to all of the private information driving the LDC's gas purchasing decisions. By granting pre-approval to specific market prices or strategies, absent a comprehensive review of all relevant information they may be inappropriately sanctioning actions that could later prove detrimental to consumers if ultimately there were adverse changes in the price of natural gas. The result of this controversy is that attempts to gain regulatory approval for changes to pre-approved levels may be met with delays while regulators gather and analyze the provided market data.

Furthermore, to compound the increased risk noted above, LDCs now must take a far more active role in securing the natural gas needed by customers. LDCs now must actively seek and analyze the costs and reliability of gas supply and transportation. Yet under the traditional regulatory compact they are entitled to no return for their efforts in these areas. Particularly when compared to natural gas producers and marketers who have a strong profit motive for similar efforts, the lack of any potential for earnings may pose a disincentive to regulated LDCs.

Prior to implementation of the PGA/ ACA process, gas costs were considered together with non-gas cost in traditional rate of return proceedings. This provided a strong, albeit contentious, incentive for LDCs to minimize gas costs. Under the direct pass through environment afforded by the PGA/ACA, most of the risk of market volatility was shifted from the LDC to consumers. In exchange, however, any benefits resulting from cost reductions relative to the wholesale cost of gas also flowed directly through to consumers diminishing any efficiency incentives afforded by permitting the LDC to retain a portion of the financial benefits produced. While some would argue that the LDCs conceded financial gains from gas procurement in order to shed the risk of market volatility; others would argue that the lack of a financial incentives pose a barrier to encouraging LDCs to assume additional risk in pursuing cost reductions.

Proponents of gas cost incentives suggest that the introduction of incentive-sharing arrangements as a supplement to the current structure can replicate at least a portion of the cost reducing incentives that existed in the rate case environment. However, critics point out that providing additional incentives to the LDC outside the scope of a rate review may alter the LDC's objectives concerning risk if there is not reasonable assurance that the savings achieved will exceed the incentive premium paid to the LDC and any additional expenses related to the operation of the incentive program.

In summary, the current gas cost recovery system - the PGA/ACA process with or without incentives – provides disincentives for any of the parties involved to shoulder the risk of natural gas price movements. This is a factor that can have a favorable or unfavorable impact on consumers depending on where prices go. While the task force recognizes that it is not likely that these disincentives can be eliminated entirely, they should be explicitly recognized and addressed as best they can. Additionally, while allowing monetary incentives outside the scrutiny of a rate review may lead to additional efficiencies it also poses additional risk to consumers.

Option 4.b) PERFORMANCE BASED REGULATION (PBR) IN THE FORM OF RATE OR BILL CAPS

V. Performance Based Regulation (PBR)

As it is usually envisioned, PBR is actually a form of cost-based regulation. The difference is that standard cost-based, or rate of return, regulation seeks to ascertain the cost of service more precisely and then set rates at levels approximating that cost. In other words, a "tighter" relationship exists between rates and actual costs. PBR, on the other hand, envisions a somewhat "looser" relationship over time, with the potential difference between rates and actual cost acting as an incentive for better performance. In a well-designed PBR, good performance in meeting the goals set out by regulators should lead to higher profits. Poor performance should lead to lower profits.

PBR usually involves some sort of price (or revenue) adjustment formula. The initial year's level is based on cost. Each subsequent year's price (or revenue) is determined by the previous year's level, as adjusted to reflect some exogenous (but relevant) general price change. In some cases, earnings sharing mechanisms, rebasing and off-ramps may be used to ensure that prices do not diverge too much from costs.

Price cap regulation is an example of PBR that has been used extensively as an alternative to rate of return regulation in the area of telecommunications. While it is too early to say whether PBR will emerge as the primary alternative to traditional rate-making for natural gas LDCs, it is not too early to expand our thinking about what PBRs are and what it takes to do them and do them well.

Creating or evaluating a PBR consists of three basic steps:

1) Identify the goals
2) Get the structure right
3) Get the numbers right

1) Identify the Goals. The first step of any successful PBR is to identify the goals to be achieved for the LDC and the consumer. These might include:

Cost cutting- Regulators can substantially increase the incentives for utilities to reduce their costs, with a significant portion of the savings passed through to customers.

Streamlining regulation- Simplifying the regulatory process allows utility management to turn its full attention to improved performance in all areas of its business and away from managing regulatory relationships.

Restructuring risk exposure-In many cases, there is a wide difference between utility management's perception of a risk and the actual financial consequences resulting from a decision. Management may worry whether cost will be disallowed as imprudent. Customers, on the other hand, rarely care whether a decision is prudent as long as it turns out to be smart. PBRs can allow a more thoughtful allocation of risk between utilities and customers.

Insuring good non-financial performance- PBRs can meet non-financial performance goals, such as energy efficiency programs that result in a decrease in energy consumption and sales, achieving an acceptable level of reliability and providing strong and effective customer service.

2) Get the Structure Right. The structure of a PBR defines the incentives that a PBR produces. Once the goals are set a PBR structure can be created to focus on those goals. For example, one of the major choices (discussed more fully below) is whether a structure should be centered on fuel prices or utility bills. Proponents of PBR suggest that a structure focused on prices produces powerful incentives to cut costs, increase sales and reduce cost-effective energy efficiency. As an alternative, they suggest that structuring the PBR around bills, on the other hand, does not diminish the incentive to cut costs but creates an incentive for cost-effective energy efficiency.

3) Get the Numbers Right. Even if the structure is right, if the numbers are wrong, there is a good chance that customer bills will be unreasonably high or utilities' financial health will be threatened. The right PBR structure, for example, might be $X per customer plus inflation minus productivity. Getting the numbers right means starting with the right "X" and using the right inflation index and productivity factor.

<u>Pros</u>

- PBR can provide opportunities to align the interests of utilities and consumers to advance energy policies that are in the public interest. It is not by chance that the PBR *discussion is occurring amid the debate over increased competition in the utility* industries, both gas and electric.
- The PBR route gives regulators the responsibility and the opportunity to define objectives for the industry. This can set the groundwork for just what is expected in a more competitive environment and can provide a vehicle to articulate what, in addition to low-cost energy services, is important for the industry to provide customers.
- Even in the absence of competition, PBR may offer a simpler and speedier regulatory process; one that emphasizes measurable results and does not depend on the myriad of inputs needed to conduct a full cost-of-service study.
- PBR provides an incentive to cut costs. Fuel adjustment clauses or PGAs, on the other hand which, for the most part, allow utilities to recover every dollar they spend on fuel or natural gas may leave the utility with less incentive to control costs.

<u>Cons</u>

- Getting the structure right will require trial and possible error. Regulatory oversight should remain intact to ensure that consumers are not in a worse position after PBR than they were before.
- Implementing PBR often turns out to be more difficult than expected, because stakeholders disagree on elements of the adjustment formula and protective measures. Getting the numbers right might prove to be very difficult.
- Absent a rate case conducted prior to implementation of a PBR, LDCs could receive a windfall at the expense of customers.

Bill Cap Versus Rate Cap

A carefully designed PBR can create mechanisms to achieve non-financial goals, including energy efficiency. Bill caps and rate caps, however, produce very different incentives.

Rate caps or "price caps" are already in use in Missouri. The three largest local exchange telephone companies Southwestern Bell, Verizon and Sprint are currently regulated under a price cap mechanism. Bill caps are not currently utilized in Missouri.

A simple bill cap PBR can be determined in the following manner:

In a rate case which looks at the usual cost items and customers served, an allowed base revenue per customer (RPC) is set at a reasonable level. This level, with certain adjustments, remains in place for a number of years, thus stretching out the regulatory lag period. Once a year, the RPC is adjusted by setting a growth rate. The simplest approach allows a growth rate based on some broad inflation measure, less adjustment for productivity improvements.

One example would be to let the RPC rise by the annual change in the Consumer Price Index less two percent for productivity improvements. Other approaches might base the increase on the change in other utilities' costs. The utility may also be allowed to directly pass through certain costs, typically referred to as "exclusions" or "Z-factors." These costs are generally desirable expenditures and/or outside the utility's control. An example might be the costs of demand side management (DSM). Adjustments can be made to accommodate changes in customer usage. For example, to the extent customer use under a cap falls (rises) outside a specified range, there would be a rebate (surcharge).

By following these steps, the net effect is that the utility will have a specified amount of money to serve customers' needs. If they spend less, their profits rise, but profit will hinge on cost control, not customer usage. This reduces the disincentive for DSM and increases the incentive for efficiency improvements. While proponents argue that rate caps provide strong incentives to cut per-unit costs, they may also provide utilities with very powerful incentives to promote energy use and equally strong disincentives to efficiency or demand side management (DSM). This tendency toward pro-sales and anti-DSM is a bias similar to that produced by a rate of return regulatory structure, under which a LDC can profit from increased sales volumes. However, if rate caps are reviewed and adjusted less frequently than a traditional rate case would otherwise occur, the window of opportunity for profit under rate caps, and in turn the disincentive to promote demand reductions, would be even greater than that produced by traditional rate of return regulation.

Additional Considerations Regarding PBR

Gas Procurement vs. Delivery Charges

The role of PBR in gas procurement may be quite different from the PBR role related to delivery costs for a LDC. A LDC's delivery costs are fairly predictable; the hope is that PBR will create incentives to reduce those costs below the level occurring under traditional regulation. For gas supply costs, however, volatility is a concern that is as big as (or bigger than) price level. Hedging can reduce volatility, but in the long run, it is debatable whether it will reduce the price level. And there is a trade-off, in that stable prices can be achieved by paying a premium over expected market prices. Hence, "success" may be harder to define in terms of gas procurement results.

Elective Hedging

The choice between hedged and unhedged gas prices is not an "all or nothing" proposition. Utilities could offer longer-term stabilized prices (e.g., for one-year, two-year or three-year periods) to customers as an option and acquire corresponding hedges for customers who want that option. This probably works best for commercial customers, but if the cost of administration is low, residential customers could be offered a similar option.

Stabilizing Delivery Costs

Commodity-based delivery charges can have an undesirable effect in colder-than-average winters. Delivery charges are usually based on normal weather. In cold winters, customers buy more gas and pay more for delivery charges, even though such costs are essentially fixed in nature.

Offering customers a fixed annual charge, based on normal weather volumes, would be a way of avoiding unnecessarily high bills during very cold winters. The price, of course, is that in warmer-than-average winters the fixed charge bill would be higher than the commodity-based charges. However, in warm winters customers would still benefit because they purchased *lower-than-average volumes of gas.*

VI. Recommended Parameters For Incentive Design

The task force believes that there are potentially additional efficiencies that may be gained from properly designed incentives for gas related costs and energy efficiency. Further, the task force agrees to the following general parameters for the design of incentive mechanisms.

- Incentives should be targeted to areas of operation in which the LDC's actions have a meaningful impact in reducing costs, enhancing net revenues, or in providing other benefits that are in the customers interest, such as energy efficiency programs.
- Additional profit from an incentive plan should only be awarded for cost reducing or net revenue enhancing actions by the LDC, and efficiency gains in excess of those that the LDC should reasonably be expected to undertake absent the incentive.
- Incentive mechanisms may be an effective tool when the level of compensation required by the LDC, for engaging in cost reducing actions does not exceed the net benefit consumers receive for the level of cost reductions that can be reasonably anticipated to result.

- Incentives should be structured to allow the LDC sufficient flexibility to respond to changing market conditions.
- Incentives should be structured to promote a portfolio targeted at mitigating overall cost or improving energy efficiency.
- Incentives should be structured to ensure that consumers receive benefits by aligning rewards to the LDC with outcomes desirable to consumers.
- Incentives should be structured to align the risk to the LDC with the risk faced by consumers in an effort to ensure that consumers are made no worse.
- Baselines should be considered for components of the incentive plan where inherent levels of performance exist. Factors relevant to establishing a particular baseline may include historic performance, changing market conditions, comparisons to similarly situated firms, or desired public energy policies.
- Consumers have expressed a strong preference for more stable natural gas prices. In the area of procurement, incentives should be targeted toward stabilizing prices by mitigating upward price volatility.
- An incentive mechanism should allow a relatively lower reward to the LDC when information linking the LDC's actions with beneficial outcomes cannot be clearly verified and a relatively higher reward to the LDC when information linking the LDC's actions with beneficial outcomes can be clearly verified. Even if provided at lower levels, however, the case for utilizing incentives as opposed to prudence reviews may be strongest where a link exists but it is difficult or costly to evaluate the precise extent of the link.
- Incentives should be structured to avoid creating a situation where the firm's management has less incentive to perform efficiently from either a customer or shareholder perspective.
- The total incentive package should be structured to ensure that when individual components are implemented together they do not produce undesirable results.

VII. Current Incentive Programs and Alternative Incentive Programs

Currently, MGE, Laclede Gas Company and AmerenUE have approved Gas Supply Incentive Plans. The incentive programs that currently apply for Missouri's LDCs are focused on providing an incentive for the LDC to reduce the cost associated with specific components of performing the merchant function. Individual incentives that are believed to contribute to overall cost mitigation apply to the areas of gas procurement, transportation related services and off-system sales. In contrast, however, some suggest that ultimately an incentive program should only reward the LDC's efforts in the event that the overall delivered cost of gas falls below some benchmark performance. The benchmarks may be based on historic performance, expected price or costs, and/or comparisons to other LDCs.

VII (1) (A) Incentive Programs that focus on rewarding activities believed to mitigate overall cost.

Pros

This approach creates a more direct and therefore, arguably, a more effective link between the reward and the preferred action than does a program under which the opportunity for reward depends on exogenous factors such as the achievement of other LDCs or the exact relationship at a point in time between current and historic price levels.

Cons

Under this type of Program the LDC can receive additional profit even when consumers are paying more than they have historically or are paying more than consumers served by other LDCs.

Individual Components

Providing Incentives For Options and Fixed Price Futures Contracts

When fixed price or options contracts are utilized, the Company determines its involvement in the design, timing, and amount of activities intended to mitigate market volatility and escalating gas costs. These contracting practices provide the opportunity through financial instruments to cap or lock-in a future price for natural gas when it appears favorable. The use of these instruments also does not necessarily require that the LDC take delivery of physical supplies in order to cap or lock-in prices.

Pros

- These pricing arrangements ensure gas costs do not exceed a specified maximum rate that appears favorable based on the information known and available when the decision was made.
- Because these instruments do not necessarily require delivery of physical supplies, they can act as a complementary mitigation technique to physical hedging measures.
- These instruments can be used to mitigate the commodity cost of gas which is by far the largest component of a consumer's bill. Therefore, depending on the volumes covered these instruments have the potential to significantly mitigate rate shock.

Cons

- What appeared to be a prudent decision when executed may result in financial benefit or detriment based on future market conditions. When capping or locking-in a predetermined future price, LDCs have no assurance of what the *spot market price* will be at the later date. Therefore, a detriment will occur at the later date if the locked-in price exceeds the actual market price or if incurring the cost of an options contract was unnecessary.
- Public utilities do have an obligation to attempt to mitigate overall costs and price spikes. LDCs must analyze all methods available to achieve these goals, including financial instruments, fixed price contracts, and storage among others.

Providing Incentives For Demand Charges
LDCs have the ability to negotiate with suppliers to lower the fixed monthly charge for reserving the availability of firm gas supplies. These charges do vary significantly but typical values are around 2-5% of total gas costs.

Pros

- Although these charges tend to rise as the cost of the commodity rises, a LDC has a greater ability to reduce, through negotiations and other strategies, the level of demand charges it actually pays. Any reduction is beneficial to customers and incentives can ensure that such reductions are maximized.
- Absent an incentive mechanism, it is difficult to determine whether the LDC has done the best job possible in minimizing the level of demand charges it pays, consistent with maintaining reliable service.
- Non-regulated firms performing identical functions are routinely allowed to profit from their successful negotiation of favorable demand charges.
- The negotiation of gas supply demand charges is a relatively new function and may not necessarily be an essential component of an LDC's public utility obligations.
- Since the potential savings to be achieved through the successful reduction of gas supply demand charges are significantly greater than the savings opportunities available in connection with most of the LDC's non-gas costs, it is important that incentives be provided in this area so that a commensurate proportion of the LDC's limited resources will be allocated to such efforts.

Cons

- Demand Charges constitute a small fraction on the total cost of gas. Rewarding efforts in this area of procurement may detract from efforts in areas that could produce more meaningful results.
- Some effort in this area should be expected. It may be difficult to ascertain the LDC's effort in this area and to design a reward that does not over compensate.
- Since demand charges constitute a relatively small proportion of a customer's bill, if this reward applies to volumes bought at volatile spot prices, there may be a perception that the LDC is profiting without meaningfully containing costs.
- Non-regulated firms do not have the benefits and obligations of the regulatory compact.

Providing Incentives For Pipeline Discounts
LDCs have the ability based upon competitive factors to negotiate reductions in the maximum transportation or storage rates established by the FERC or the MoPSC.

Pros

- Pipeline Discounts can constitute a significant savings to ratepayers.
- LDCs can, through hard bargaining, the creation of leverage and other strategies influence the level of pipeline discounts they are able to achieve. Since pipelines must provide evidence to FERC in recovering costs associated with discounts to specific customers, there is some reasonable assurance that the LDC's efforts contributed to any discounts achieved.

- It is difficult to determine, through an after-the-fact audit, whether the LDC obtained the most favorable pipeline discounts possible.
- Non-regulated firms are routinely allowed to profit from their successful efforts to negotiate favorable pipeline discounts.
- In the event baselines are established in this area, they should not be set so high that they effectively eliminate any practical incentive.
- The negotiation of pipeline discounts is a relatively new function and may not necessarily be an essential component of an LDC's public utility obligations.
- Since the potential savings to be achieved through the successful negotiation of pipeline discounts are significantly greater than the savings opportunities available in connection with most of the LDC's non-gas costs, it is important that incentives be provided in this area so that a commensurate proportion of the LDC's limited resources will be allocated to such efforts.

<u>Cons</u>

- LDCs are obligated to attempt to achieve cost reductions and should therefore pursue pipeline discounts in the normal course of business.
- Pipelines that are not fully subscribed have an incentive to increase subscription through the use of discounts.
- Large LDCs may have leverage as a buyer allowing them to enjoy relatively larger discounts than smaller pipeline customers.
- If this incentive is utilized a reasonable baseline should be established. Baselines that are set too low will provide an unnecessary windfall to the LDC.
- Just as it may be difficult to gauge whether the LDC's have maximized the efficiencies that can be potentially achieve in this area, it may also be difficult to identify a direct link between the LDCs actions and the ultimate level of cost reductions obtained.
- Non-regulated firms do not have the benefits and obligations of the regulatory compact.

Providing Incentives For Mix Of Pipeline Services

Altering the mix of pipeline services refers to renegotiating or restructuring pipeline supplier service contracts

<u>Pros</u>

- In some cases, LDCs can reduce their overall transportation costs by pursuing strategic changes in the mix and level of their transportation services from various pipelines. In some cases, there may be moderate price risks associated with such initiatives. The availability of an incentive can promote favorable results in this area by ensuring that the LDC devotes a level of resources to pursuing such opportunities that is commensurate with the potential benefits to be achieved. It also makes it more likely that the LDC will take more risks to achieve such savings by providing it with an opportunity to benefit if taking those risks produces favorable results.
- Absent an incentive mechanism, it is difficult to determine whether the LDC has devoted the right level of resources to pursuing such opportunities or has, in fact, maximized the efficiencies that can be potentially achieved in this area.

- A mix of pipeline supplier incentives may also be helpful in preventing any perverse incentives to obtain lower gas commodity costs at the expense of higher transportation costs.

Cons

- Ratepayers have financially contributed to the level of reliability contained in a LDC's existing pipeline transmission and storage services and should not incur additional costs when such contracts are renegotiated or restructured based on changing market conditions.
- Providing any substantial incentive in this area may reduce the LDCs focus on areas that can provide more meaningful reductions in customer bills.

Providing Incentives For Capacity Release

When purchasing capacity, an LDC is reserving a maximum amount of pipeline space to be made available for use in serving the potential demand in its service area. Capacity release provides the LDC the ability to release (i.e. market) unutilized capacity and receive revenues to mitigate pipeline reservation charges. Capacity release was implemented by the FERC as a result of FERC Order No. 636.

Pros

- In some cases, LDC can increase their overall revenues from capacity releases by devoting additional resources to the task and by pursuing strategies designed to take advantage of market conditions. In some cases, there may be risks associated with such initiatives. The availability of an incentive can promote favorable results in this area by ensuring that the LDC devotes a level of resources to pursuing such opportuniities that is commensurate with the potential benefits to be achieved for its customers. It also makes it more likely that the LDC will take more risks to achieve such savings by providing some upside potential if it does.
- To the extent that an incentive promotes greater capacity release the LDC gains the opportunity to recapture a portion of its sunk costs.
- It is difficult to determine through an after-the-fact audit whether the LDC obtained the most capacity release revenue possible.
- The release of pipeline capacity is a relatively new function and may not necessarily be an essential component of an LDC's public utility obligations.
- Non-regulated firms are routinely allowed to profit from their successful efforts to release capacity.
- The percentage of capacity release revenues that the LDC is permitted to retain, the volatility of such revenues, and the potential elimination of any effective incentive if baselines are set too high, are all appropriate factors to consider in determining whether and to what extent any baseline should be established for such revenues.

Cons

- Capacity release should occur as a normal method of reducing costs.
- Just as it may be difficult to gauge the whether the LDCs have maximized the efficiencies that can be potentially achieved in this area, it may also be difficult to identify a direct link between the LDC's actions and the ultimate level of cost reductions obtained.
- There may be a tradeoff between off-system sales and capacity release which provides an incentive to unduly favor one over the other. Off-system sales and capacity release should be addressed together in a rate case.
- Of particular concern would be the possibility of selling product via "capacity release" and creating an unreasonable profit at the expense of the consumer for product actually used.
- If this incentive is utilized a reasonable baseline should be established. Baselines which are set too low will provide an unnecessary windfall to the LDC.
- Non-regulated firms do not have the benefits and obligations of the regulatory compact.

Providing Incentives For Off-System Sales

Off-system sales are any sales of natural gas, or natural gas bundled with pipeline transportation service, to parties other than the LDC's transportation customers or their agents.

Pros

- In some cases, LDC's can increase their overall revenues from off-system sales by devoting additional resources to the task and by pursuing strategies designed to take advantage of market conditions. In some cases, there may be risks associated with such initiatives. The availability of an incentive can promote favorable results in this area by ensuring that the LDC devotes a level of resources to pursuing such opportunities that is commensurate with the potential benefits to be achieved for its customers. It also makes it more likely that the LDC will take more risks to achieve such savings by providing some upside potential if it does.
- To the extent that an incentive promotes greater off-system sales the LDC gains the opportunity to recapture a portion of its sunk costs.
- It is difficult to determine, through an after-the-fact audit, whether the LDC maximized off-system sales revenues.
- The sale of gas to off-system customers is a relatively new function and may not necessarily be an essential component of an LDC's public utility obligations.
- Non-regulated firms are routinely allowed to profit from their successful efforts to sale gas.
- The percentage of off-system sales revenues that the LDC is permitted to retain, the volatility of such revenues, and the potential elimination of any effective incentive if baselines are set too high, are all appropriate factors to consider in determining whether any baseline should be established for such revenues.
- Any concern regarding a potential bias toward capacity releases or off-system sales can be easily addressed by establishing identical sharing percentages for both transactions in the PGA process.

Cons

- Off-system sales should occur as a normal method of reducing costs.
- Just as it may be difficult to gauge the whether the LDCs have maximized the efficiencies that can be potentially achieved in this area, it may also be difficult to identify a direct link between the LDCs actions and the ultimate level of cost reductions obtained.
- There may be a tradeoff between off-system sales and capacity release which provides an incentive to unduly favor one over the other. Off-system sales and capacity release should be addressed together in a rate case.
- If this incentive is utilized a reasonable baseline should be established. Baselines which are set too low will provide an unnecessary windfall to the LDC.
- Non-regulated firms do not have the benefits and obligations of the regulatory compact.

VII (1) (B) Incentive Programs that focus on rewarding outcomes.

Pros

- Ensures that LDCs can only receive profit in connection with their gas supply and transportation management efforts when customers pay less than historic rates or less than customers of other LDCs.
- This option may be more understandable and palatable from a customer's perspective because it focuses on what matters to customers - the overall cost of delivered gas.
- This option diminishes the potential for the LDC to pursue profit opportunities that do not result in cost savings on the bottom line of a customer's bill.
- This option reduces concerns regarding perverse incentives created by interrelationships that may exist between individual components of an incentive plan that rewards individual actions targeted at reducing costs.

Cons

- Focus on pure outcome, without regard to impact of market forces or the degree of the LDCs ability to affect outcome, may reduce or eliminate any tie between the incentive being provided and the actions that management can actually take to produce favorable results.
- Removing an incentive for the LDC when market prices are rising will eliminate incentives to efficiency and innovation when they are most needed.
- Basing incentives on how an LDC performs on an absolute basis or over time compared to another LDC is inappropriate if the uncontrollable factors affecting that performance vary significantly from one LDC to the next.
- Efficiency gains and cost reductions may be meaningful and beneficial even when they do not lower cost below historic levels or the rates charged by other LDCs.

Option 4.c) CONSERVATION/EFFICIENCY INCENTIVES

VII (2) Incentive Programs that focus on energy efficiency.
Energy efficiency is often viewed as an energy resource like coal, oil or natural gas. In contrast to supply options such as drilling for more natural gas or mining coal, energy efficiency helps contain energy prices by curbing demand instead of increasing supply. Balanced portfolios that address demand reduction in addition to increased supply can be designed to be good for the consumer (through lower energy costs) and the utility company (through incentives that do not reduce profits from a reduction in sales).

Missouri ranks in the top 5 states in terms of total potential energy savings and energy savings per home based on a 1998 Alliance to Save Energy study of states that have not adopted an energy code.

Effective energy efficiency programs can address the barriers that inhibit customers from making investments in energy efficiency improvements – lack of money or competing demands for available funds, up-front costs are more real than long-term savings and lack of technical expertise. Energy efficiency programs can address low-income weatherization, low-cost customer financing for energy efficient building improvements and appliances, information, new home construction practices, reduced air infiltration, heating system rebates, domestic hot water, lighting and windows. Efficiency programs may be funded by earmarking a percentage of a utility company's revenues for the purpose of providing consumers with rebates and low-cost financing for energy efficient improvements or by offering consumers direct tax incentives.

For example, in addition to low-income weatherization, some of UtiliCorp's energy efficiency programs in Iowa are listed below. (UtiliCorp d/b/a Peoples Natural Gas (PNG) in Iowa).

<u>Customer Financing for Energy Efficiency</u> – This program offers Peoples Natural Gas residential customers the opportunity to purchase and receive the advantages of an energy efficient furnace and other high efficiency products at a competitive interest rate. To qualify, residential customers must own and live in a home that is occupied year round, and have a good credit history and utility payment record. Application for financing is processed in a day or so, payment is included as part of the monthly gas bill and remains the same for the term of the loan. No down payment is required, there is no penalty for early pay off, interest rate is currently at 8 percent, and the term of the loan can be set at 24, 36, 48, 60, 72 or 84 months depending on equipment efficiency.

Residential Efficiency-Heating System Rebates – The program is designed to encourage residential customers to install high efficiency natural gas heating systems by providing financial incentives to replace standard equipment. Rebates are provided for the following qualifying equipment: set-back thermostats (up to $75), gas furnace with set-back thermostat (93-93.9% annual fuel utilization efficiency up to $275; 94% or greater up to $375), high efficiency gas boilers (90% annual fuel utilization efficiency $200), mid-efficiency gas boilers with set-back thermostats (83% annual fuel utilization efficiency up to $275) and integrated space and water heating systems (84-90% combined annual efficiency $300-500). Rebate amounts vary depending on product efficiencies and are issued to the person invoiced for the equipment. Homeowners and renters are eligible to participate in the program.

Domestic Hot Water for the Residential Sector – This program includes retrofitting of existing gas water heaters with a series of low-cost measures including water heater tank insulation wrap, water heater pipe insulation, low-flow showerheads, faucet aerators and water heater temperature set back to 120 degrees. This program is provided at no additional cost to the residential customer living in single and multifamily units. Renters must have owner approval to participate. Customers apply for these services by filling out and returning bill inserts that go out regularly to promote the program or call a toll free number to schedule an appointment. A contractor calls the customer within 4 to 6 weeks.

Residential New Construction – This program promotes energy efficient new home construction practices by providing incentives to residential customers based on the specification and installation of energy efficient measures to reduce air infiltration. Rebates are provided for roof insulation (R48) $0.125/sq.ft.; wall insulation (R24) $0.20/sq.ft.; windows (double or triple pane low E) $14/opening; reduced air infiltration (0.5 air change per hour) $250. Applications require an itemized invoice, verification of R-values from builder, blower door test results if applicable and a scaled down copy of the new home blueprint.

Trees Program -- Communities and non-profit organizations that sponsor energy-saving tree planting programs as environmental projects can receive grants from Trees Forever on behalf of PNG and PNG works with the Iowa Department of Natural Resources to sponsor Trees for Kids and Trees for Teens Programs. Trees Forever is responsible for evaluating requests to fund a project and distributing funds provided by PNG.

Commercial and Industrial Customer Rebates -- This program provides commercial and industrial customers with a financial incentive to replace standard equipment with energy efficient systems. The rebate amount is based on a portion of the incremental cost between a standard product and a high efficiency unit and depends on the peak demand reduction, annual energy use reduction and annual energy cost savings.

Pros

- Energy efficiency programs provide assistance to customers in helping to reduce their energy usage and utility bills. This is particularly important when energy prices are higher and more volatile.
- Long-term costs to the system may be lower by reducing the distribution companies' costs to upgrade their systems.
- Lower energy costs improve the economy and the competitiveness of businesses and increase customers' discretionary income, raising their standard of living.
- Using energy efficiently provides additional economic value by preserving natural resources and reducing pollution.

Cons

- Use of ratepayers' money to pay for participating customers' savings may cause concerns among non-participating ratepayers.
- Incentive programs may limit customer investment to those energy efficiency products that are supported by the program.
- Incentive programs may encourage customer investment in energy efficiency products only when funding is available from the programs.

In addition to the customer impacts, another issue that must be addressed in establishing workable programs targeted at energy efficiency is the impact of such programs on the LDC. An LDC may have little incentive to facilitate programs designed to reduce energy use because in doing so the LDC may be reducing its revenue base.

There may be ways to attain the benefits of energy conserving initiatives while also mitigating the potential negative impact on an LDC. For example, in cases of over-earnings, a portion of the revenue reduction could be retained in exchange for the establishment or expansion of programs targeted at energy efficiency. In instances in which a more ubiquitous program is desired, LDCs could be offered an incentive to offset some portion of lost revenues.

While this section of the task force report is intended to provide a general discussion of incentives designed to promote energy efficiency and the pros and cons of providing such incentives, The task force believes that this subject warrants a more comprehensive review. Therefore the task force recommends that the Commission direct its Staff to initiate an investigation into currently utilized energy efficiency programs, the effectiveness of those programs and the financial impact of those programs on the participating LDCs.

Option 4.d) INTEGRATED GAS PURCHASING PLANS

VIII. The Roles of Information and Verification

Central to the issues of regulatory oversight of gas purchasing, consumer protection and incentive design are the roles of information and verification. In this section of the task force report we first summarize the differing perspectives regarding the significance of information and verification and address the task force's proposal for an integrated gas purchasing plan.

Under the existing ACA review process, reviews are to be based on information that was available at the time a LDC made purchasing decisions. Despite Staff's, OPC's and intervenor's obligation to limit reviews in this way, LDCs have suggested that the timing gap coupled with disadvantageous market events may inspire greater or unfair scrutiny during the review process. On the other hand, Staff and OPC have expressed frustration with the level of documentation and the availability of information to them in fulfilling their respective roles in the review process.

A related issue arises in the context of incentive design. Asymmetric information is inherent in the interaction between the parties. The LDC participates in the market on a daily basis, interacting with suppliers and pipelines, negotiating new contracts, and monitoring weather forecasts and other exogenous factors that impact the LDC's purchasing strategies and activities. Without thorough tracking of these factors, some believe there can be no easily discernable link between specific incentive mechanisms, the LDC's actions and the ultimate impact of those mechanisms and actions in lowering gas costs.

In an effort to address the issues of information and verification, the task force has proposed implementation of an integrated gas-purchasing plan. An integrated gas-purchasing plan is not, per se, an incentive plan. Rather, it is a process by which an LDC explicitly documents its expected natural gas demands for the ensuing year; the supply, transportation, and storage options available to meet those expected needs; its expectations for the market price of gas for the ensuing period, as well as the relative costs of the necessary physical hedges and optional financial hedges; and the possible courses of action available if, as it frequently does, the natural gas market changes. Thus, integrated gas purchasing plans are not fixed at a single point in time, but are flexible planning tools that must adapt to changing market conditions. The process also provides for the LDC to provide the plan to Staff and OPC for review and comment. Staff and OPC would comment early in the gas supply year on the effects of plans on both reliability and cost, in the hopes of reducing the likelihood of adverse results and ACA audit adjustment disputes. No LDC in Missouri currently has such a program in place. AmerenUE and UtiliCorp, which operates Missouri Public Service Company and St. Joseph Light & Power, are in the process of establishing such practices.

Pros

- The integrated gas supply plan should promote an improved quality and timeliness of information provided to the Staff and OPC enhancing their ability to fulfill their respective roles in the regulatory process.
- The integrated gas supply plan should help reduce disincentives faced by LDCs in their gas purchasing functions. These disincentives are addressed elsewhere.
- Additional positive financial incentives for securing natural gas on terms favorable to consumers can be added as a separate element in the gas supply process, if deemed desirable. The design of such incentives is also discussed elsewhere by this subgroup.
- This proposal would help to provide evidence of the link between any incentive mechanism, the LDC's actions and the ultimate impact on gas prices.
- An integrated gas-purchasing plan should contain contingency alternatives in the event of extraordinary variances in price or availability.
- An integrated gas-purchasing plan would provide advance information to the Staff and OPC, thus making the "prudence review" less onerous.
- An integrated gas-purchasing plan substantially limits, as a practical matter, the possibility of Staff or OPC using hindsight in prudence reviews.

Cons

- This proposal may unreasonably limit the LDC's ability to respond to changing market conditions and involve the state to an excessive degree in determining the procurement strategies followed by the LDCs they regulate.
- The recommendations given by Staff and OPC as a result of this process are likely to be the determinative factor in the procurement strategy ultimately pursued by Missouri LDCs since few are likely to pursue courses of action that are inconsistent with those recommendations given the likelihood of a prudence disallowance if the alternative course of action results in an unfavorable result.
- Innovation by individual LDCs may be discouraged through the potential adoption of whatever standards and practices are deemed most suitable by Staff and/or OPC. Under such circumstances, the impact of detrimental practices on customers would be magnified.
- This proposal may result in additional labor hours and expense to the LDC and ultimately customers.
- Even though the process exposes the LDC to a greater risk of prudence disallowance if it does not follow the recommendations of Staff or OPC, the proposal does not provide any firm assurance that prudence reviews will not be sought by someone even if the LDC does follow their recommendations.
- The implementation of an integrated plan review process is contrary to the Commission's previous rejection of similar proposals.
- This proposal does not sufficiently restrict the Staff or OPC from raising issues in the ACA process.

5. What Happened This Winter

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

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

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

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

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

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

In equation form,

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

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

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

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

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

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

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

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

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

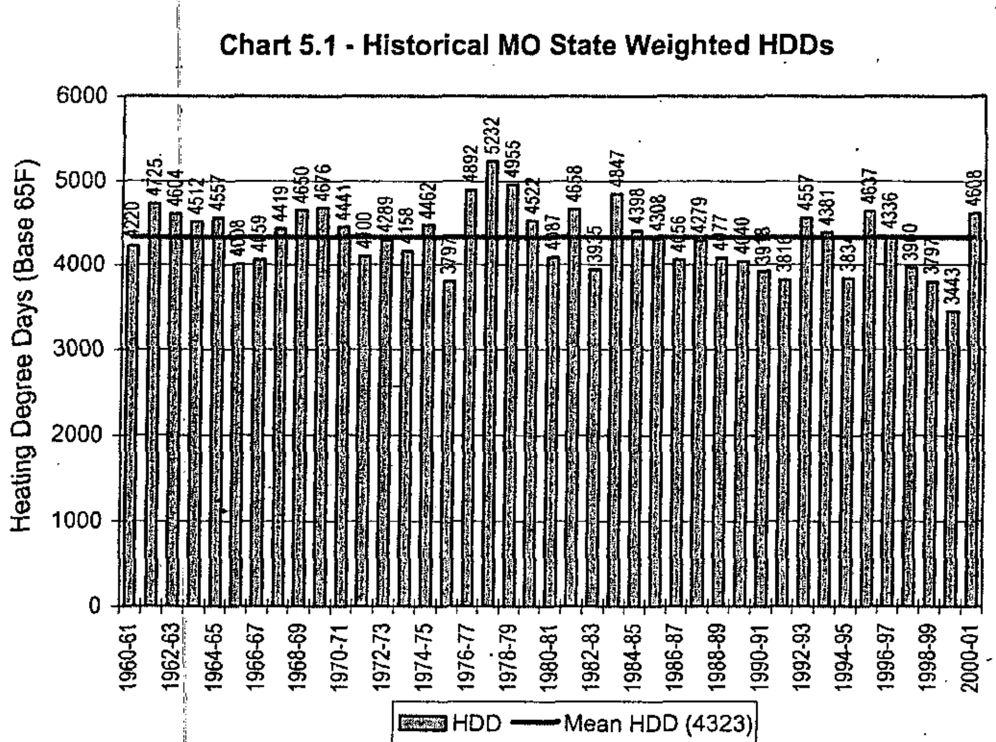


Chart 5.2 -Monthly MO Weighted Heating Degree Days

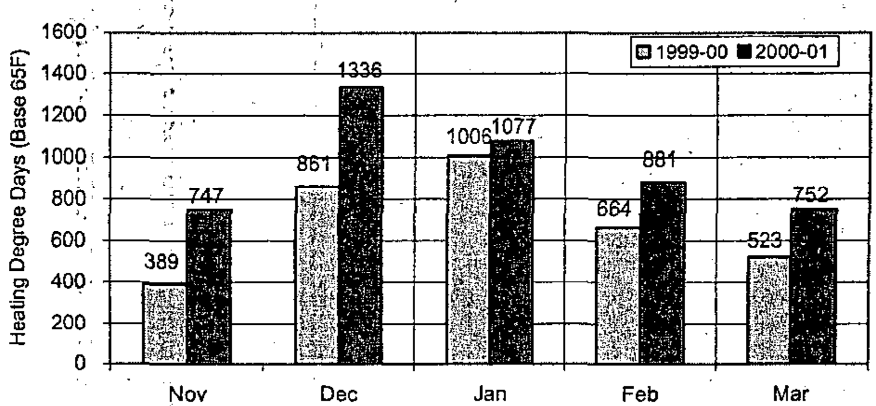
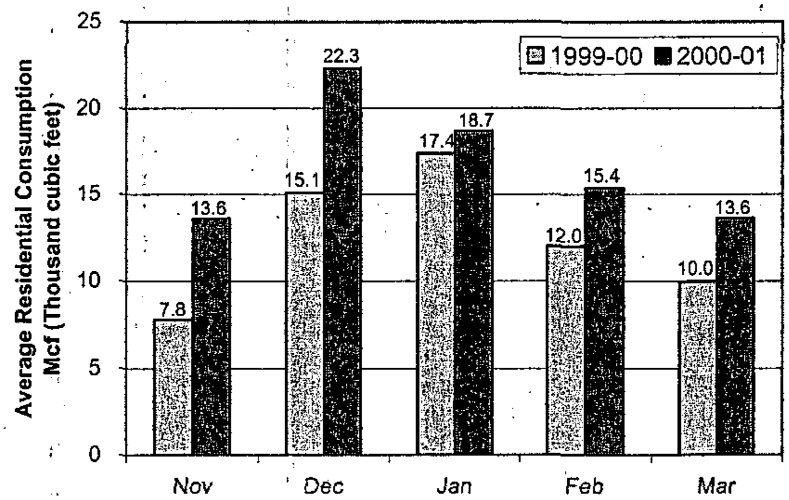


Chart 5.3 - MO Residential Natural Gas Customer Heating Season Monthly Usage



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

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

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

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

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

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

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

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

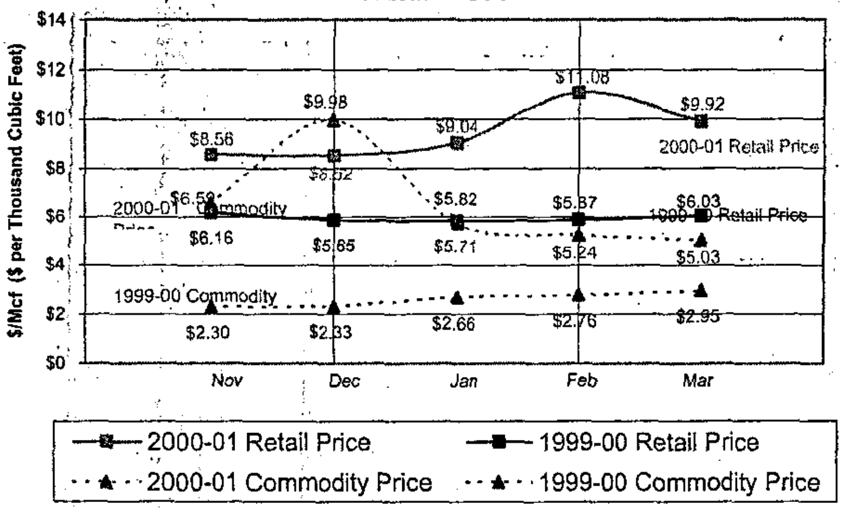
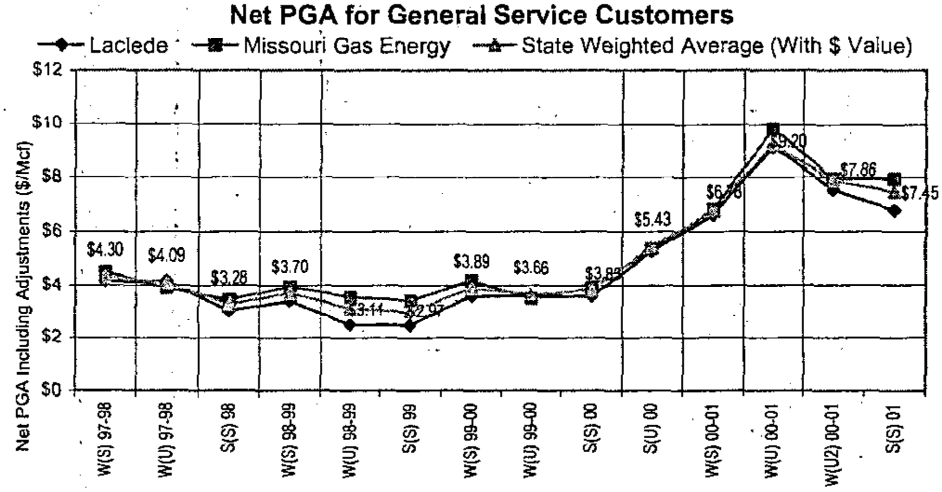


Chart 5.5 - MO Regulated Gas Utilities Net PGA for General Service Customers



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

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

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

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

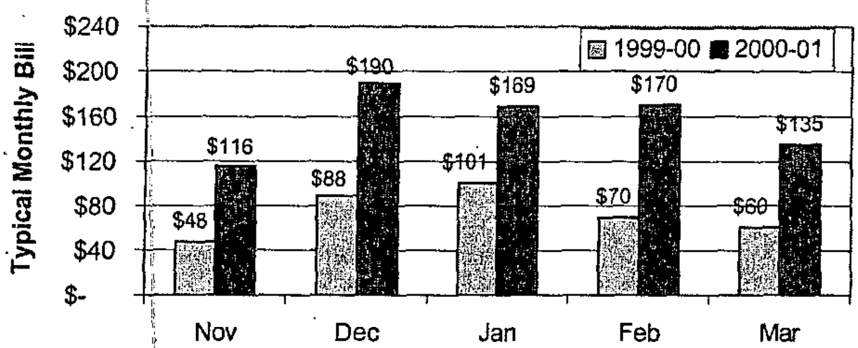
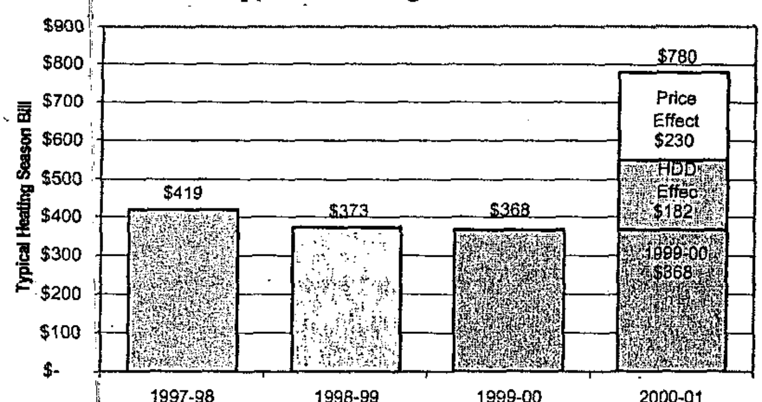


Chart 5.7 - MO Residential Natural Gas Customer Typical Heating Season Bill



Heating Seasons (November - March)

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

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

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

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

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

Gas supply costs are usually described as the cost of the wellhead supply and are usually paid to producers or marketers. Various pricing provisions can apply to this supply, but the market for the commodity is the most volatile part of the PGA and makes up the largest portion of the costs that are included in the PGA. The United States Congress in the Natural Gas Policy Act of 1978 (NGPA) set up various categories of gas production and associated ceiling prices in an effort to encourage further production. Natural gas flowing in interstate commerce was deregulated in stages by Congress, which adopted a phased-in deregulation for gas discovered after 1977. The Natural Gas Wellhead Decontrol Act of 1989 (NGWDA) removed NGPA price controls. On January 1, 1993, all remaining price controls were lifted and wellhead natural gas prices became fully deregulated.

Gas transportation costs are paid to interstate or intrastate pipeline companies for delivering the gas commodity from production areas to the city-gates of the LDCs. The FERC regulates the maximum transportation rates for interstate pipeline companies. The MoPSC regulates the rates of Missouri's intrastate pipeline companies. These rates are usually composed of primarily fixed charges based upon a contracted maximum daily capacity, and a smaller per unit charge for delivered quantities. Prior to 1993, interstate pipelines offered a "bundled" service, which included both gas supply and transportation as part of a delivered product to the LDC. In April of 1992 the FERC issued Order 636, which required interstate pipelines to "unbundle " and move away from the selling of gas supply. At this time, the regulated portion of interstate pipeline companies does not hold title to the gas itself. These interstate pipeline companies operate as transportation businesses.

Pipeline storage costs are paid to interstate pipelines for storage services that are also regulated by the FERC. The rates paid are often based upon a combination of daily delivery capability from storage and capacity levels reserved for storage. Another alternative to interstate pipeline storage is "off-system" storage where rates are negotiated between parties. When an LDC owns its storage facilities, the facility's operational costs and plant costs are typically recovered outside of the PGA Clause in a general rate case process.

Generally speaking, the PGA Clause recovers "gas costs" that are necessary to get the gas from the wellhead to the LDC distribution system. The PGA Clauses in Missouri are contained in the PSC approved tariffs for each LDC.

Before 1997, LDCs were authorized to make monthly PGA filings. After the winter of 1996-1997, most LDCs revised their tariffs so that only 2 scheduled filings, a summer and a winter filing, were authorized per year. An unscheduled filing was allowed if certain thresholds were met. PGA rates are estimates of the gas costs at the time the filings are made and include the effects of storage withdrawals and any over or under recovery that the LDC may be experiencing. The estimated PGA rates are trued-up, or reconciled, to actual gas costs on an annual basis. This reconciliation involves a comparison between what the Company actually paid for gas versus the amounts it has billed to customers through PGA rates. The return of any over-recovery starts in the fall of the year, just subsequent to the end of the applicable annual Actual Cost Adjustment (ACA) period. The regular adjustments of each LDC's PGA rates are directed at achieving a dollar-for-dollar match of gas costs expenses and revenues.

PGA rates typically include several subcomponents. The ACA rate is simply the result of the annual comparison of actual gas costs the LDC paid versus the estimated gas costs that were billed out to customers through the PGA. This residual factor is added or subtracted to the current PGA factor. The refund factor is developed by taking into account refunds received from interstate pipelines for overcharges in their authorized FERC rates. In some instances an additional rate is separately identified for take-or-pay and transition costs which resulted from FERC actions to restructure parts of the gas industry.

PGA filings are subject to an expedited review and are often effective in less than 30 days from when they are filed. The Commission's approvals are made on an "interim" basis and subject to review and refund. Prudence reviews are not conducted on these estimates but are subsequently performed on the actual gas costs when the LDCs make their annual ACA filings.

5.c) Actual Cost Adjustment (ACA) and Prudence Audit Process:

The Actual Cost Adjustment (ACA) audit was first implemented in the early 1980s. It was designed to reconcile actual gas costs to revenues recovered through the PGA Clause. The ACA uses a 12-month time frame for the reconciliation. The total actual gas costs from gas supply, transportation, and pipeline storage invoices, is accumulated and compared to the billed revenues for the corresponding time period. The closing date is typically in the summer when natural gas usage is at a minimal level.

When a LDC incurs more expense than it has recovered in PGA revenues, an "under-recovery" occurs. If the LDC collects more PGA revenues than its actual expenses for the period, an "over-recovery" occurs. The ACA factor is calculated by taking the under or over recovery and dividing it by an annual volume of sales. This factor, or rate, is then applied to billings over a subsequent 12-month period in order to refund, in the case of an over-collection, or charge, in the case of an under-collection.

Under the traditional ACA process, the goal was to ensure that the LDC passed-through the actual cost of gas, no more and no less. Since PGA rates are established based upon estimates, and weather and price almost always vary from estimates, it is necessary to true-up to actual. The ACA filing is developed once per year and is submitted as part of the annual winter PGA filing.

This annual ACA filing is audited to establish that the expenses and revenues claimed are in compliance with authorized PGA tariffs and reflect accurate levels of expenses and revenues supported by underlying source documentation. This audit includes a review of invoices, allocations among customer classes, allocations among other jurisdictions, storage accounting, billing records, and other supporting data and workpapers. Compliance adjustments, such as error corrections, can result from this review.

Another critical aspect of the audit is a reliability review. Each LDC must plan to meet a colder than normal winter period and extreme weather conditions on peak days. This requires a careful evaluation of usage characteristics and temperature data. This demand data is compared to supply and transportation/storage resources available to determine if an excess or shortage of capacity exists. Usually, reliability is related to cost in that the greater the reliability, the greater the costs for a particular supply or transportation service.

Finally, a prudence review is performed as part of the audit. Since the expenses incurred in an ACA are separate and apart from the normal rate case review, the expenses must be reviewed to ensure they are reasonable. The review is retrospective. It is not designed to be a hindsight review but is guided by the Commission's "prudence standard". This standard has been established for quite some time and has been clarified in several cases.

To test the reasonableness of a company's costs, the Commission uses a standard of prudence. This standard was discussed in the Commission's Report and Orders in the cases concerning the Callaway and Wolf creek nuclear power plants. In the Callaway case the Commission determined "that the appropriate standard was enunciated by the New York Public Service Commission in Re: Consolidated Edison Company of New York, Inc., 45 P.U.R., 4th, 1982". In that case on page 331, the New York Commission rejected an earlier 'rational basis' standard in favor of a reasonable care standard:

> "More recently, and in cases more directly on point, we have articulated the standard against which a utility's conduct in circumstances such as these should be measured as follows: '...the company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company. Case 27123, Re: Consolidated Edison Company of New York, Inc., Opinion 79-1, January 16, 1979."

The Missouri PSC went on to state: "The Commission will assess management decisions at the time they are made and ask 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 assessed the situation?'" The Commission did not adopt a standard of perfection and would not rely on hindsight.

In Kansas Power and Light Company Case No. GR-89-48 the Commission indicated that the Company "has the burden of showing its proposed rates are just and reasonable." The Company "has the burden of showing the reasonableness of costs associated with its rates for gas." Further it stated, "The standard is that when some participant in a proceeding creates a serious doubt as to the prudence of an expenditure, then the company has the burden of dispelling those doubts and proving that the questioned expenditure was prudent."

Finally, in Western Resources Case No. GR-93-140 the Commission decided to clarify the parameters of gas costs prudence reviews. It stated:

> "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. In addition, evidence about the particular controversial expenditures is needed for the Commission to determine the amount of 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 LDC had acted in a prudent manner. The critical matter of proof is the prudence or imprudence of the decision from which expenses result."

5.d) Why Did Natural Gas Prices Start High & Spike in January 2001

Despite the recent decline in natural gas prices (in August 2001, a little over $3/Mcf), soaring 2000-01 winter heating bills vividly reminded Missouri energy consumers of how quickly natural gas prices can change. Industrial, commercial and residential consumers across the state felt the sharp increases in wholesale natural gas prices that fluctuated between $2 to $3/Mcf in the 1999-00 winter and than suddenly more than quadrupled to nearly $10 during 2000-01 winter. The end of the 1999-00 winter marked the beginning of an unprecedented increase in natural gas prices that was fueled by a "perfect storm" of circumstances that impacted the supply and demand of natural gas. These factors included extraordinary weather, electric generation, storage levels, the economy and how natural gas supplies had grown in the years previous to last winter. Speculation purchases by market participants may have also played a role. To better understand what happened in the 2000-01 winter, attempts should first be made to understand the circumstances leading to the price increases that occurred.

Basic Economics – Supply and Demand

Natural gas wholesale prices are generated by activities in an unregulated market where supply and demand largely dictate the outcome. The supply and demand imbalances of last winter's national natural gas markets were largely the result of previous years where relatively low demand and natural gas prices dampened interest in the commodity's exploration and development. Regarding domestic natural gas supplies, it is important to note that the U.S. DOE reports that natural gas resource basins are considered adequate to meet most domestic demand for several more decades. The tightness of supplies last winter was largely the result of relatively low natural gas prices and the associated lack of exploration and production of these natural reserves to keep up with potential demand. Transportation capabilities of pipelines to national demand centers and some supplies also played a role. Chart 5.8 displays the gradual increase in natural gas consumption over the 1990's through which time the commodity's prices remained relatively stable and low while imports increased to offset flat natural gas production. Thus, supply constraints emerging steadily over the years, the relatively recent increase in demand for natural gas, and extraordinarily cold weather all resulted in a market price increase for natural gas as suppliers raised the wellhead price to what the market would bear in what some would call a "seller's market". Chart 5.8 depicts flat natural gas production during the 1990's while consumption and net imports of the commodity increased.

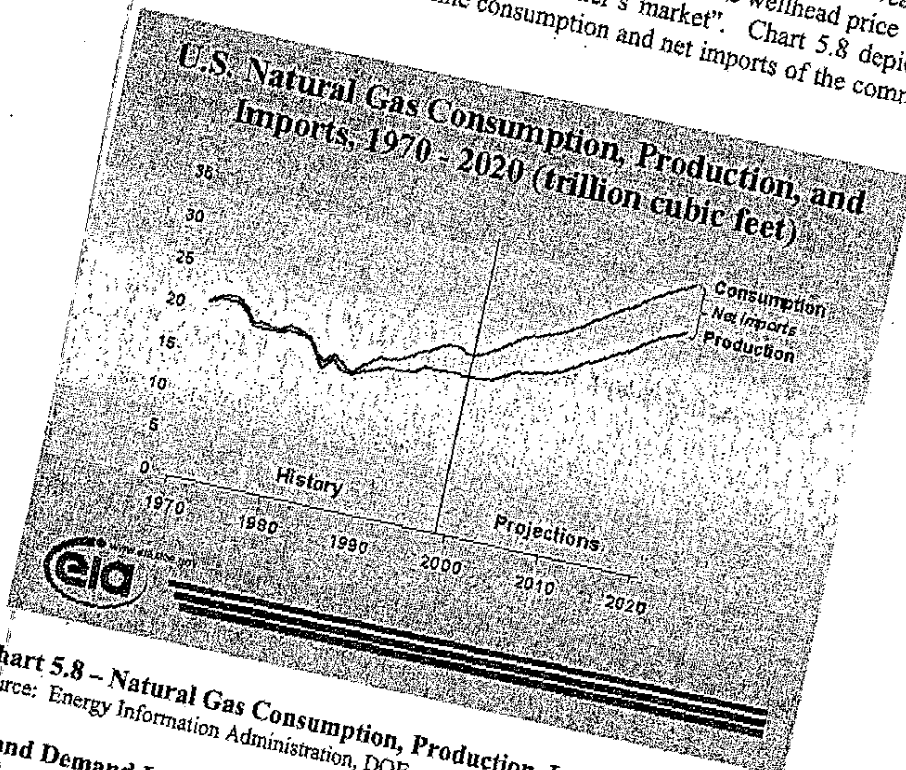


Chart 5.8 – Natural Gas Consumption, Production, Imports
Source: *Energy Information Administration, DOE*

Missouri Supply and Demand Issues

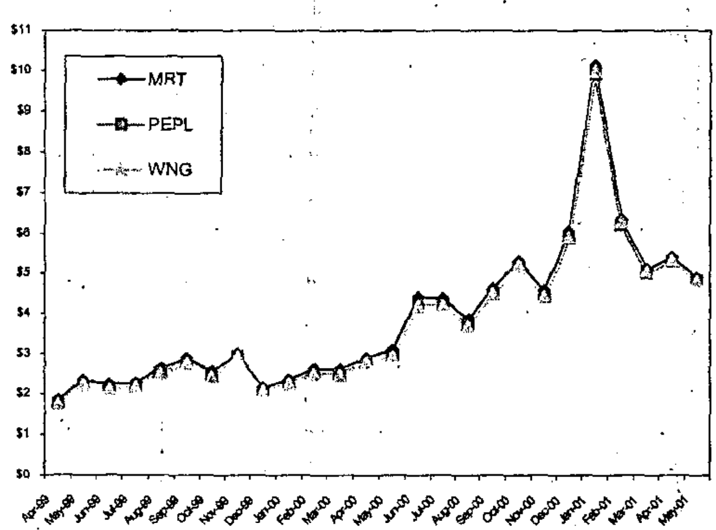
Missouri does not have any natural gas production of significance. For all practical purposes, Missouri's natural gas demand is met through supplies transported to Missouri via interstate pipelines. Three major interstate pipeline companies, Mississippi River Transmission Corporation (MRT), Williams Gas Pipelines Central, Inc. (WNG) and Panhandle Eastern Pipe Line Company (PEPL), transport into Missouri the majority of natural gas consumed by the State.

The pipeline index prices (see Chart 5.9) of these three interstate natural gas carriers show the commodity cost incurred by LDCs for the portion of their supplies that are tied to the index prices associated with these pipelines. As Chart 5.9 shows, the indexes associated with these major pipelines do not vary significantly. In Missouri, interstate pipeline companies transport natural gas directly to most of our LDC's city-gates. The FERC regulates interstate pipelines. Some of our smaller LDCs and municipalities are served by intrastate natural gas pipelines that are regulated by the MoPSC.

The MoPSC approves all rates that LDCs charge their customers. This includes non-gas costs and gas costs. Non-gas costs are addressed in general rate cases where all factors associated with the LDC's costs of doing business, including a reasonable rate of return, are addressed. Gas costs are addressed through the PGA rate. The PGA includes commodity gas costs, transportation costs, and storage costs. The high-spiking index prices in Chart 5.9, which immediately impacted the state's LDCs this past winter, will eventually be paid by Missouri's natural gas consumers who were exposed to index based contracts. The price spike in Chart 5.9 coincides with the up-trend in national consumption/demand, shown in Chart 5.8 and the end of the coldest combined 2 months in Missouri's history.

The EIA notes that the rapid run-up in prices last winter actually started in the summer of 2000 when electric generation demands caused by above average temperatures kept demand high while market participants delayed some gas purchases while waiting for the market price to drop. Continued electrical generation demand, storage demand, and market concerns kept summer prices above normal and contributed to a rapid price spike when much colder than normal weather arrived in November of 2000 and continued for 2 months.

Chart 5.9 - First of Month Pipeline Index Prices for MRT, PEPL, and WNG



The strong economy of the 1990s steadily increased the demand for electricity, but little new development in electric power generation occurred to meet this growth. Instead, operating margins between electrical supplies vs. anticipated peaks were slowly eroded. Environmental issues, market uncertainties, public opinion, and associated construction cost were, at different levels, all barriers for electric utility companies to construct large generating facilities, i.e., coal-fired or nuclear plants. Alternatively, in recent years, construction of electric generation facilities using gas-fired turbines, which can be installed and fully operable in as little as 18 months, has risen in efforts to satisfy national peak and even, to some degree, base electrical demands. The abundance, clean-burning properties, and relatively low price of natural gas made it an environmentally favorable fuel source for these turbine engines, and therefore dramatically contributed to the popularity of, and demand for, natural gas. Many of these single and combined cycle combustion turbine plants are built by unregulated entities to sell electricity on the open market.

As of May 2001, eleven new electric generating plants in Missouri have been announced with eight already under construction. In fact, the Aries plant near Kansas City recently went online. When all are online, their generating capacity could total to approximately 5,000 additional MW. Out of the eleven plants, ten will utilize natural gas as a major fuel source, which will further increase Missouri's future need for natural gas. Environmental, siting, and construction costs and schedule issues will likely continue to result in a large percentage of new electrical generation coming from natural gas.

U.S. Working Gas Storage Levels

Relatively low U.S. working gas storage levels prior to entering the 2000-01 winter also contributed to the increase in natural gas commodity prices since this helped drive up mid-winter demand. Demand for electric generation for the year 2000 cooling season (April – October), helped sustain natural gas prices above recent year's averages. At this same time, purchases of natural gas were made to replenish working gas storage levels used to hedge against generally higher winter natural gas prices. Spring 2000 U.S. gas storage levels, shown in Chart 5.10, had fallen to average levels ❶ following the previous moderate winter. Natural gas utilities and other market participants slowly replenished their gas storage resources, anticipating prices would flatten or decrease from their unusually high levels. Natural gas prices contrastingly continued to rise and total U.S. working gas storage levels ❷, levels maintained prior to winter heating months, were filled to near a five-year low.

The estimated total U.S. Working Gas Storage Capacity is 3,248 Bcf, and year 2000 storage levels peaked at an estimated 2,748 Bcf, or approximately 85 percent of estimated total capacity. In the previous five years, the highest estimated storage capacity occurred in 1998 at approximately 3,094 Bcf ❸, or 95 percent of capacity. Although easily overshadowed by the annual national commodity consumption rate of 20-plus trillion cubic feet, working natural gas storage plays a critical role in hedging against price spikes and must not be overlooked. The American Gas Association (AGA) estimates natural gas storage accounts for about 20 percent, on average, of the commodity's consumption during the winter heating season. Beyond just displacing gas needs that would be met by purchases from the wellhead in the winter, storage also plays a critical role in daily balancing requirements for a number of our LDCs.

Over 85 percent of Missouri's residential natural gas consumers are served by four investor-owned LDCs, each utilizing gas storage in gas supply portfolios. Gas storage plays an important role as a hedging tool for Missouri's LDCs attempting to mitigate market volatility and achieve some price stabilization. Laclede Gas Company, Missouri's largest LDC with over 600,000 customers, owns and operates over 6,000 MMcf of Missouri's in-state 7,800 MMcf total working gas storage. Most storage gas supplies purchased by our LDC's are stored outside of Missouri under firm contracts with interstate pipelines.

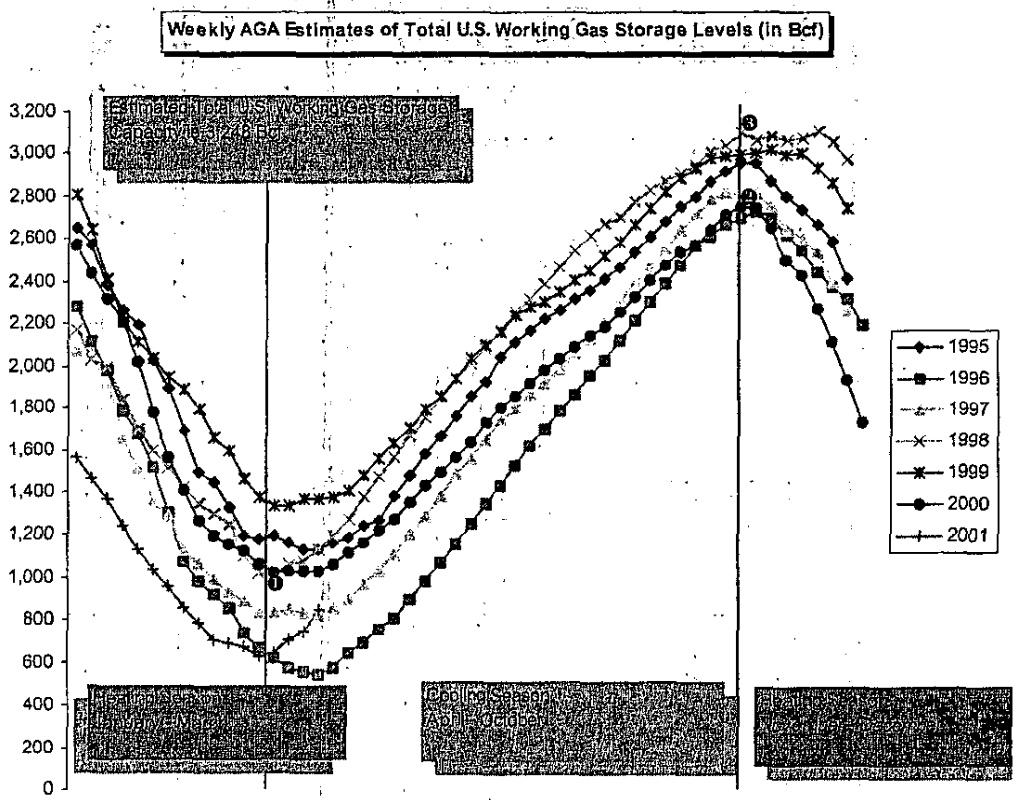


Chart 5.10 - Estimated Average Storage of Natural Gas

Weather Conditions
Abnormally warm summer months in the year 2000 cooling season helped keep natural gas prices higher than customary and played a significant part in pre-winter working gas storage levels being filled to near a five-year low. Record cold weather conditions in November and December 2000 only worsened matters, converging with low storage, increased demand and already high natural gas prices to create a dramatic spike in natural gas heating bills.

Comparing an average Missouri residential consumer's 1999 and 2000 winter heating usage of natural gas signifies last winter's record cold average temperatures affect on consumption, especially in November and December 2000. November 2000 average usage per consumer (136 Ccf) increased 74% from November 1999's comparable average consumption (78 Ccf). In other words, considering only increased consumption resulting from the record cold winter and holding November 2000 natural gas prices at the November 1999 price of approximately $3.89/Mcf, the end-consumers' heating bill dollars (before taxes) just for natural gas increased from $30.34 to $52.88, on average. Factoring both increased quantities and higher prices into heating bill dollars, the average Missouri residential consumer paid 142% and 116% more for natural gas used during November and December 2000 than during the same period in 1999, respectively.

This double impact of greater wholesale natural gas prices and greater consumption laid a heavy burden on natural gas consumers' budgets during the 2000-01 winter. Last winter's experiences have broadened natural gas consumers' perspectives on topics such as price stabilization, deregulation, and energy conservation, but the market's volatility and the unpredictability of the weather still leaves many uncertain of what's to come in 2001-02 winter.

5.e) Gas Supply Contracts and Index Pricing

One of the key provisions in every natural gas supply contract is the pricing provision. There are many different types of pricing provisions that may appear in natural gas contracts. Of all the numerous variations, many fit under two broad categories: fixed price and formula/indexed-based price.

A fixed price means that the absolute price that will be paid is already known and directly stated in the contract. An index price may reference an outside publication that independently calculates the price at some point in the future.

Index pricing grew in popularity in the 1980s with the emergence of a spot market for natural gas. Independent industry newsletters base the calculations upon actual gas supply deals for the applicable period. In a typical situation, the index is based upon a period of time know as "bid-week". This is the week prior to the delivery month where gas supply deals are finalized and nomination deadlines on the pipelines are met. Pricing points are usually in the production area at the beginning of an interstate pipeline's mainline system. Weighted averages are derived from a sample of the deals that are conducted at these various pricing points. The prices developed are for deals of 30 days or less and are known as "first-of-the-month indexes". Formula/indexed-based price contracts often refer to one of, or an average of several of, these indexes for each month's per unit pricing.

Examples of these market publications include: Inside FERC Gas Market Report, Natural Gas Intelligence Report, Gas Daily, etc. Methodologies are described at the following websites:
http://www.platts.com/gas/specification.shtml
http://www.intelligencepress.com/methodology.html
http://www.ftenergyusa.com/gasdaily/gdguide.asp

According to an AGA Report titled "LDC System Operations and Supply Portfolio Management During the 1999-00 Winter Heating Season":
"Many LDCs continue to price gas based on numerous indexes during the winter heating season. In fact some LDCs refer to their pricing strategies as a basket of indices. Of the LDCs that purchased mid-term supplies during the 1999-00 winter, the majority (92 percent) used first-of-the-month pricing for at least a portion of their gas purchases."
The study further indicated that at least 75% of winter heating "mid-term" supplies were based on a first-of-the-month index.

Index pricing is often considered to be market based since it tracks current market conditions. Indexes are not known until very close to the time period they relate to. In other words, if a contract referred to a "first-of-the-month index" for December, the price of gas for that month would not be known until December 1. Index pricing can be volatile, as first-of-the-month indexes have varied between $1 and $10/MMBtu over the last decade. In the span of 2 months last winter certain indexes moved from $4.50 to $10/MMBtu.

Pricing of natural gas futures contracts on the NYMEX is now widely monitored for gas price data. These prices are tied to a particular delivery location, the Henry Hub in Louisiana. Henry Hub is a major interconnect for several pipelines with connections to many demand centers. Index prices vary from NYMEX pricing due to location differences and other factors but have historically moved in the same general pattern as movements in the futures markets at expiration of a particular delivery month. Basis differences can be defined as the difference between the closing NYMEX prices and the cash price (index price) at a specified location.

Indexes have been used as benchmarks for the incentive plans of Missouri's two largest LDCs. For MGE the benchmark was in place for three winters starting with the winter of 1996-97. For Laclede the benchmark was also effective with the winter of 1996-97 and was still in place last winter.

It is the task force's understanding that Missouri's LDCs generally made use of storage resources during the year 2000 and the winter of 2000-01 as they have in years past. The task force was not made aware of any significant changes in LDC's use of storage. Therefore due to the summer-winter pricing differential during the year 2000 and the winter of 2000-01, storage gas constituted a physical hedge for gas supply costs (and also provided reliability assurances) for those LDCs with storage resources.

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, 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. 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.

5.f) What Can We Expect Next Winter & Beyond

Higher than long-term average natural gas prices and volatility continue to be the reported forecast by industry analysts with near-term predictions being heavily weather-driven. Summer heat is a primary driver for natural gas demand for electrical generation and winter cold is a primary driver for space heating demand for natural gas. Several forecasts in January 2001, when wholesale prices spiked at over $10/MMBtu, cautiously predicted lower natural gas prices to come, which has been the current trend, but expectations of returning to January 2000 prices ($2.00 to $2.50/MMBtu) were very low. July 2001 prices ranging near $3/MMBtu, around 27 percent below prices paid at the same time in 2000, have had a major influence on gas storage. For over 3 months, the AGA has been reporting record national storage injections each week. This will likely help stabilize prices to consumers during 2001-02 winter. Generally speaking, natural gas prices for the 2001-02 winter are not expected to return to the low prices of 1998 or 1999 or reach the high prices of the 2000-01 winter.

The EIA continues to note that several factors will play key roles in where natural gas prices go in the future. These factors include opening currently protected areas for gas exploration and production (like ANWR, Rocky Mountains, east Gulf of Mexico, Atlantic coast, etc...); emission permits availability and costs (driving electrical growth toward natural gas fueled combustion turbines); delivery pipeline expansions into Canada and/or Mexico; Liquefied Natural Gas (LNG) terminal expansions; and others. Economic factors associated with a recession would also impact these projections. These same EIA forecasts indicate that the market may have a new average of about $3.50/Mcf. This price level seems consistent with a number of outcomes associated with pipeline expansions into Canada and/or LNG terminal expansions. At least in the near term, an average of about $3.50/Mcf is recognized to be a rough guess, but subject to a number of factors that will result in the market being lower than this price at times and much higher than this price at other times.

Significant concerns are currently being expressed regarding EIA estimates. These concerns include beliefs that the EIA's supply forecast is too optimistic. Recent reports on high rig counts and continuing sluggish growth in supplies despite this extraordinary exploration and production effort are pointing to an issue that will continue to be of great concern to those interest in natural gas supplies and prices. Even if $3.50/Mcf is accepted as a near term average, it is anticipated that well before 2020, as available reserves are smaller, more difficult to develop, and harder to transport to demand centers, prices will steadily rise.

Economic Factors

The implications of last winter's high natural gas prices on household incomes and large energy-consumer budgets are not completely known at this time, but obviously reduced consumer's disposable income and may have contributed to a slumping economy. The U.S. is currently in an economically uncertain period and this uncertainty contributes to a broad forecast range for natural gas prices. Both electric and natural gas project announcements have risen in light of the current emphasis on potential blackouts and a widespread energy crisis, but how many of these projects will actually reach operation remains to be seen. Higher average natural gas prices in the future cast some uncertainty on the prudence of total reliance on natural gas fueled electrical generation and other sources of electrical generation must continue to be part of every utility's planning effort to meet the needs of its customers. On the other hand, future higher average natural gas prices will be a powerful incentive for further exploration and production of natural gas, which will tend to help moderate prices. In the near-term, lower market prices could limit investment to fund high-capital natural gas projects. Also, low economic growth could create uncertainty about actual demand. If these factors are significant, they could lead to postponements of projects. Overall though, industry reports anticipate slow project development into 2002, but picking up thereafter to reflect forecasted growth.

Long-term economic growth is projected to increase natural gas demand and in turn increase future average wellhead natural gas prices; by how much will vary. The EIA reports projected wellhead prices to increase on average between 1.2 and 2.8 percent per year for the next 20 years under low and high economic growth scenarios, respectively. Discovery efforts and production operations will directly affect this upward trend in prices but technological advances and cost-savings in these areas will hopefully suppress dramatic long-term price spikes. Generally speaking, increased costs will likely be reflected in a gradual long-term increase of average end-consumer costs for natural gas, given current and rising future demand.

Electrical Generation

There is a growing inter-dependency between the gas and electric industries. Electric generation is projected to grow in the short-term and long-term projections remain optimistic about continued market growth. Natural gas consumption for electric generation in 2000 was less than half the amount of the industrial sector, the current leader in natural gas consumption. However, electric generation is projected to lead all sectors in natural gas consumption within 15 to 17 years. Growth in projected total domestic consumption of natural gas, therefore, will be greatly influenced and lead by electric energy demands in the western, particularly the California market, and eastern regions.

Comparably lower initial set-up costs, environmental advantages, shorter ground-breaking-to-operational time periods, and significant efficiency improvements have popularized the use of gas-fired turbines and combined-cycle facilities for electric generation in both the regulated and non-regulated sides of the electric industry. The current advantages of natural gas have heavily influenced the use of these generation facilities to meet growth in electrical demand. Until newer pipeline facilities are built, increased use of natural gas for electric generation may place utilization levels on existing facilities that have never been experienced before. If forecasted growth materializes, additional pipelines will be necessary or capacity constraints, bottlenecks, and end-consumer supply shortages may become a real possibility.

Missourians are seeing first hand the Nation's emphasis on energy production growth. As noted earlier, ten electric generation plants utilizing natural gas as a major fuel source have been announced, with some nearing construction, while others are already operating. Depending on plant locations, pipeline expansions may be required to deliver services with adequate capacity. This capacity will be essential as a large electric generation facility can require a level of natural gas capacity equivalent to a city the size of Columbia at peak load.

As a non-gas-production state, Missouri relies on interstate pipelines for delivery of natural gas from gas production states such as Texas, Oklahoma, Louisiana, and Kansas. Production excess in the Central Region has been reported but exporting pipeline capacity has limited the availability of the commodity to end-consumer markets. Other states, like Missouri, will also be bidding for these gas supplies to serve their increasing electric generation needs and dependency upon current natural gas pipeline capacities could become even more strained unless expansions develop. A number of potential expansion projects are currently being looked at by different interstate pipelines, and the Staff of the MoPSC will continue to watch these projects with great interest. It is essential that Missouri's LDCs continue to regularly assess their projected peak demands and determine which expansions they must participate in to meet the needs of their customers.

Natural Gas Storage

As noted earlier, commodity price drops through July 2001 have led to heavy volume purchases of natural gas during this year's storage injection season and reflect an inverted market from the same time last year when prices were on the rise. As of mid 2001 working gas storage totals trailed only 1998 and 1999 storage totals for the same given time periods, when comparing the past six-year averages. The volumetric rate of gas injections during the 2001 injection season, however, exceeds both 1998 and 1999.

Sluggish economic growth and mild summer-weather energy demand have contributed to the market's downward trend and have provided better than expected buying opportunities for replenishing storage levels. Although unpredictable weather-related-demands can allure market volatility, a continuation of the current market through the end of the injection season will hopefully play a major role in stabilizing end-consumer natural gas costs during the 2001-02 winter.

Increased Natural Gas Imports

To balance the nation's natural gas consumption dependency with domestic production, commodity imports from Canada and Mexico are expected to grow. The EIA reports "net natural gas imports are expected to grow … from 15.8 percent of total gas consumption in 1999 to 16.7 percent in 2020." Availability of imports is expected to add to the supply factor, especially in the eastern region of the United States, but insufficient pipeline facility development could be a constraint to expanding markets in need. Sufficient pipeline capacity will be a key component for imports to keep pace with expected national demand and bringing to the energy-fuel market a supply level that's effective to moderate prices. Increased imports into the western and eastern regions add gas supplies that ultimately can aid in minimizing nation-wide commodity price spikes.

6. How Missouri Compared to Other Parts of the Country – PGA Rates &Typical Heating Bills

Last winter's rise in natural gas prices in Missouri was a reflection of market variables that affected the price of energy nationwide. The increase in natural gas prices that occurred over the 2000-01 winter was the result of several critical factors within the industry. The wellhead price of natural gas is a deregulated commodity and largely driven by supply and demand. The supply situation involved relatively flat growth in supplies since about 1995 with storage levels, at the beginning of the winter, that were somewhat below average. Relatively low demand and prices in the natural gas market did not make it attractive for exploration and production in the years immediately preceding the 2000-01 winter. The demand situation included extraordinarily cold winter weather throughout a large part of the US, a significant growth in demand for natural gas for electrical generation, and higher than normal demand for residential, commercial and industrial customers. Market speculation on natural gas prices may have also played a role. These factors combined to create a "seller's market" by mid-winter as prices climbed to near $10/MMBtu in late December and early January of the 2000-01 winter. It should be noted that national supplies for natural gas were not the problem, the EIA continues to indicate that domestic proven and speculated reserves of natural gas will meet most of our needs for several more decades. If international supplies transported as LNG are included, reserves may well last for over a century. The price spikes of the 2000-01 winter were more closely associated with tightness of supply deliverability to demand centers than natural gas reserves. Pipeline constraints presented significant challenges in some parts of the country. Missouri was not significantly impacted by pipeline constraints but areas like California were impacted by transmission constraints. During a number of market price jumps in the 2000-01 winter the Southern California market exceeded $50/MMBtu when Henry Hub was near $10/MMBtu. Some of this difference was due to transmission constraints on the El Paso line. A number of investigations are ongoing regarding this difference in pricing.

While nationally 53% of U.S. households use natural gas for heating, it is estimated that 60% of Missouri households utilize natural gas as their primary heating source (1990 census data). In an effort to examine how Missouri residential customers fared this past winter regarding natural gas prices in comparison to other Midwest states, a survey of neighboring states regulating natural gas was performed. The results of this review are shown in Table 6.1. Findings indicate that while Missouri residents experienced similar spikes in natural gas prices as the rest of the country, prices in mid-winter were not as elevated as in some other areas of the Midwest. In comparing the prices for Missouri's two largest LDCs to LDCs in other states, average prices effective January 1, 2001 were less than most other states surveyed. Although this comparison is of interest, it must be noted that estimated January 2001 natural gas bills cannot necessarily be directly compared to Missouri's natural gas bills as usage calculated in the monthly billing varies from state to state due to geographic location and temperatures experienced. Also, some of the observed differences in rates are the result of differences in when PGA rates can change and how much under recovery in gas costs the noted LDCs were willing to accept before filing for changes in rates.

Table 6.1, Comparison of Midwest Regulated PGAs and Bills				
State	**LDC & Effective Rate on 1/1/01 ($s/Mcf)**		**Average**	**Estimated Jan. 2001 Bill**
Arkansas	Arkla	$7.60	$5.60	$143
	AWG	$3.59		$100
Illinois	Peoples Gas	$9.77	$9.64	$327
	NIGas	$9.50		
Iowa	Mid-American	$10.51	$10.00	$224
	IES	$9.49		$206
Kansas	Kansas Gas Service	$8.68	$8.68	$178
Kentucky	Louisville G & E	$6.44	$7.28	$147
	Columbia Gas	$7.67		$209
	Western Ky Gas	$7.74	—	$163
Missouri	Laclede Gas Company	$6.45	$6.63	$200
	Missouri Gas Energy	$6.80		$196
Oklahoma	Oklahoma Natural Gas $7.89	$7.89	$7.89	$192
South Dakota	MidAmerican Energy	$10.50	$8.65	$247
	Montana - Dakota Util.	$6.80		$171
Tennessee	Nashville Gas	$7.03	$7.17	$229
	United Cities Gas	$7.31		

A number of other reasons may have also contributed to these differences in rates between states. In fact, significant differences in rates exist between different LDCs within the state of Missouri. These differences can include, but are not limited to a) overall system size and mix of the LDCs customer base, b) availability and use of storage capacity, c) how LDCs choose to participate in index priced, fixed priced, and transportation contracts, and d) the LDCs hedging strategies as well as the different percentages of supplies from these sources. Changes in PGA rates can also be a result of differences in regulatory practices in states and how much under or over recovery an LDC is able, and/or willing, to incur before requesting changes in rates. In comparing bills it is also necessary to recognize that distribution charges vary among different LDCs.

7. Other Options for Changing How Consumers Pay for Natural Gas Service

During the deliberations of the task force, groups briefly discussed a number of non-gas cost issues and options. The task force group as a whole did not deliberate on these "other" options because these other issues and options did not specifically deal with gas commodity costs, which were the focus of this task force. The task force group briefly discussed how to address these other issues and options and decided that they should be noted in the final report of the task force for the benefit of decision makers who may wish to consider options that were not considered by this task force. These "other" options were as follows:

- Reduce, cap or eliminate gross receipts taxes (GRT)
- Weather Normalization Adjustment Clause
- Base (margin) revenue distribution charge rate design revision

Each of these options and their associated pros and cons are noted in more detail below. It is important to note that utility and OPC interests were very different in this section. This resulted in a number of pro and con statements that one party or the other strongly disagreed with. In fact, some argued that this section should not be included in the task force report. No effort was made to resolve these differences in opinion, as this was not the focus of the task force. The summary statements and associated pros and cons below are the result of editing of comments received from utility, OPC, and other representatives by the chair of the task force and do not necessarily represent the opinions of Staff, the utilities, OPC, or others but do include most of the pro and con statements provided by interested parties.

Reduce, cap or eliminate gross receipts taxes
Description: Under this option, gross receipts taxes would be reduced or capped during the winter months. Alternately it could be converted to another form, such as a flat monthly $/customer charge, or eliminated entirely. To the extent that a viable option might be consumer choice of gas suppliers, GRT becomes a complicating factor. At least one state, Pennsylvania, has recently eliminated GRT on gas sales/distribution.

<u>Pros</u>
- Reduction to customer's total bill.
- If capped, a partial reduction of the bill will result from the portion of the bill that is not taxed.
- Could eliminate negative aspects of tax windfall to municipalities during colder than normal weather.
- Possible savings by LDCs of costs associated with processing GRT.

Cons

- Does not reduce the volatility of gas costs, only reduces the total bill by the amount of reduced taxes on the gas plus distribution charges.
- If GRT are eliminated, loss of revenue source to municipalities may force them to reduce services or make-up for the tax revenue loss through increases in other taxes. If capped, loss of tax windfall revenues during abnormally cold weather could result in less available funds for associated increases in snow removal, road salt, and increased municipal operating costs during colder than normal weather.
- The Commission lacks authority to reduce or cap GRT and this would need to be addressed by state and local governments.

Weather Normalization Adjustment Clause

Description: A Weather Normalization Adjustment clause allows a utility to true-up for weather, the recovery of non-gas distribution costs on an annual on-going basis. On a regular basis (usually with some lag or via deferral) a customer's bill is adjusted so that the revenue generated for base rate (margin) revenue is tried up to normal weather. Forty-four LDCs in 22 states have implemented them.

Pros

- Slight to moderate reduction in both the volatility and financial impact of weather variations upon the recovery of non-gas (distribution) costs for both consumers and LDCs.
- Identified by NARUC as an option that public service commissions "may want to consider".
- May decrease the frequency of rate case filings.
- Would have been beneficial, in terms of reduced natural gas bills, in the 2000-01 winter when there was a coincidental price spike for commodity gas at the same time as extremely cold weather. Would result in higher bills for consumers during warmer than normal winters with associated recovery of distribution costs by LDCs that they would not have received otherwise.
- Reduced weather risk for utility may bring about lower costs.

Cons

- Applicable to approximately 20 to 35 percent of total gas bill so potential impact on volatility of overall bill is limited.
- The MoPSC has previously rejected a weather adjustment clause, stating it was "single-issue ratemaking." See: In Re: Missouri Gas Energy GT-95-429 October 27, 1995.
- Customers will have a wide range of opinions on this type of methodology. Some will like it and others will not.
- Consumers may not benefit from any cost reductions associated with reduced weather risk to LDCs.
- Decreased incentive to conserve energy since charges on distribution costs would be adjusted based on actual weather. Price signal incentive for conservation from PGA portion of costs would still be in place.
- Customer education necessary to address confusion/questions on adjustment charges.

- Utility may incur one-time costs due to additional programming if billing system needs to be upgraded to accommodate changes.
- Obtaining uniformity in developing and applying a standardized weather measure may be difficult.

Base (margin) revenue distribution charge rate design revision

Description: Redesign of base rates for fixed (non-commodity related) distribution charges, placing more or all costs in the monthly service charge and less or none in the commodity charge. Carried to full implementation, such a rate design may be a full fixed variable design (like Georgia) or complete elimination of the commodity related portion for recovery of distribution costs so the service, or distribution charge, is a flat monthly fee considered as a system access fee. Under the access fee structure, rate class revenues are divided by annual number of bills and the customer pays that flat monthly fee each and every month. Distribution costs recovery is currently about 20 to 35 percent of a customer's average monthly bill for natural gas service.

Pros

- Less seasonal volatility of customer's bill (winter bill reductions of approximately $9 to $18/month with corresponding increases in summer bills, based on normal weather – lower when warmer, higher when colder).
- Distribution charge component of customer's bill is more predictable the closer the rate becomes to an access fee.
- Less risk and more stable revenue stream for utility with possible lower costs.
- Recommended as one of six areas to "review for possible long-term solutions" in Attorney General Jay Nixon's Report on natural gas price spikes to Governor Bob Holden, dated February 26, 2001.
- Some have argued (utility) that distribution costs do not vary significantly with customer usage but, rather, are based on the number of customers served, and should be recovered on a customer related access fee basis. Some have also argued that monthly service charges, or access fees, are commonly accepted in today's consumer market.

Cons

- Applicable to approximately 20 to 35 percent of total gas bill (non-gas or distribution portion) so potential impact on volatility of overall bill is limited.
- Slight to moderate reduction of price signal since the non-gas or distribution portion of the total natural gas bill may no longer be a function of the quantity consumed.
- Some have argued (OPC) that this type of rate design helps insulate the utility from (1) competition with electric utilities for space heating loads and (2) competition from distributed generation resources such as photovoltaics.
- Small users (in terms of consumption) may be subsidizing large users.
- Low load factor customers may be subsidizing high load factor customers.
- The utility has an incentive to add customers rather than load. Depending on line extension policy, this may be less beneficial to existing customers.

8. Appendices

Appendix A: Transcripts from Public Meetings

The transcripts from the task force's public meetings are available on the Internet at http://www.psc.state.mo.us/publications.asp under "Natural Gas" with the following titles:

Task Force April 26th Public Meeting Transcript
Task Force May 4th Public Meeting Transcript
Task Force May 10th Public Meeting Transcript
Task Force May 24th Public Meeting Transcript.

The task force's 5th and 6th public meetings, held in Sikeston and Joplin respectively, were not well attended and no transcripts were taken in these meetings.

Appendix B: Glossary of Natural Gas Industry Terms

ACA – Actual Cost Adjustment - The annual proceeding before the Missouri Public Service Commission in which a gas utility's actual gas costs are reconciled against the amounts it has collected from customers through its PGA charges during the year.

Base Gas – The portion of gas in a storage basin that is typically not considered for withdrawal, as it is important that some base gas be left in certain types of storage facilities for reliable operation of the storage basin.

Baseload contract – A gas supply contract that requires the buyer to purchase and receive a levelized volume of gas throughout a specified time period.

Benchmark – A standard against which a local distribution company's performance in utilizing its gas supply assets in meeting the requirements of its customers can be measured.

Bcf – Billion Cubic Feet – A unit of measure for large natural gas users or storage facilities.

Btu – British Thermal Unit - A measure of the heat content of natural gas. One cubic foot of natural gas is typically equivalent to about 1,000 Btu.

Capacity release – The sale and assignment of firm transportation capacity by a primary capacity holder such as a gas utility to a third party.

Call option - A financial instrument which permits the owner the right but not the obligation to purchase a specified quantity of gas at a specified strike price in a future period. It can be used to establish a ceiling price for natural gas purchasers but does require that the owner pay a price equivalent to an insurance premium to have the right.

Ccf – One hundred cubic feet, which is a standard measure of the quantity of natural gas. See also Mcf, therm, dekatherm, and MMBtu.

City gate – The point at which an interstate or intrastate delivery pipeline is interconnected to and delivers gas to the local distribution company.

Commodity charge – A per unit charge for gas purchased or transported during a month.

Contract Demand – The maximum amount of gas deliverable by a natural gas producer or pipeline to a utility, as specified by contract during any gas day, i.e. during any 24-hour period commencing at 9:00 a.m., prevailing Central Time.

Costless collar – A cost-free financial instrument which creates a ceiling price for a specified quantity of natural gas, in exchange for a floor price for the same quantity. It stabilizes the price for the specified quantity of gas between the floor and ceiling prices.

Dekatherm – Equivalent to one million Btu.

Demand charge – A fixed monthly charge to reserve and assure the availability of firm gas supplies. This charge does not vary based on the actual volume of gas purchased, within contract demand limits, during the month.

Demand Side Management (DSM) – A program typically designed to reduce natural gas usage (or electrical demand for an electric utility) as part of an effort to minimize need for growth in supplies (or electrical generation) with delivered costs objectives and/or to achieve particular energy efficiency goals.

FERC – Federal Energy Regulatory Commission, which is the federal agency charged with the responsibility of regulating the rates and terms of service for interstate natural gas pipelines.

Futures Contract - A supply contract between a buyer and seller, whereby the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of a commodity at a predetermined price at a specified location. Futures contracts are traded exclusively on regulated exchanges and are settled daily based on their current value in the marketplace.

Gas producers – Owners of gas producing wells and reserves who explore for, drill, develop, produce and sell gas at unregulated prices.

Gas storage – Underground reservoirs used to store natural gas for withdrawals in future periods. Typically used for daily and monthly balancing, seasonal load shaping, and price arbitrage. Can be constructed as underground salt domes in deep salt deposits or in aquifers with an impermeable dome rock structure or depleted oil and/or gas fields. Can also be stored as liquefied natural gas but this is much less common.

GSIP – Gas Supply Incentive Plan, which is a Missouri Public Service Commission-approved plan, whereby a gas utility is provided financial incentives to encourage it to devote additional resources to optimize the use of various gas supply options for its customers.

HDD – Heating Degree Day – A measure of the "coldness" of a given time period. Usually defined as the difference between the average temperature in a day and 65 degrees Fahrenheit. If a day had an average temperature of 25 F, the day could be referred to as having had 40 HDDs. Weekly, monthly, and annual HDD numbers are typically just the sum of the daily HDDs recorded in the period of interest.

Hedge – A mechanism which can be used to mitigate the volatility of gas prices, such as gas storage or the purchase of various financial instruments or fixed-price contracts.

Index Price – The daily or monthly price of natural gas in a particular location set forth in industry publications such as Gas Daily and Inside FERC.

Interstate pipeline – Any FERC-regulated pipeline that transports gas from production fields to local distribution companies and end users in different states.

LDC – Local Distribution Company - Is the local gas utility that distributes gas from the interstate or intrastate pipeline to end use consumers of natural gas. Rates and services of Missouri's regulated LDCs are regulated by the Missouri Public Service Commission.

Mcf – One thousand cubic feet, which is a standard measure of the quantity of natural gas. See also Ccf, therm, dekatherm, and MMBtu.

Missouri Public Service Commission – The State agency charged with the responsibility of regulating the rates and terms of service of the local regulated gas utility.

MMBtu – One Million Btu - Is a standard measure of the quantity of natural gas approximately equivalent to a Mcf. See also Ccf, therm, dekatherm, Mcf.

MMcf – One Million Cubic Feet – a common unit of measure for large customers.

Office of the Public Counsel – The State agency charged with the responsibility of representing consumers in proceedings before the Missouri Public Service Commission.

Off-system sales – The sale of gas by a gas utility to customers outside its service territory in Missouri.

Peak Design Day – The coldest possible day anticipated for a specified gas supply planning period.

PGA Clause – Purchased Gas Adjustment Clause, which is the provision in each local distribution company's tariff that permits it to recover gas supply, transportation and storage costs, on a dollar-for-dollar basis, from customers.

Pipeline discounts – Reductions in the maximum transportation or storage rates established by the FERC or the Missouri Public Service Commission negotiated between gas pipelines and their utility customers based upon competitive factors.

Put – A financial instrument that permits the seller to sell a specified quantity of gas at a specified price. It can be used to establish a floor price for natural gas sales.

Reservation charge – A fixed monthly charge to reserve firm pipeline transportation or storage capacity.

Strike price – The price at which a call option permits the owner to purchase gas.

Swing contract – A gas supply or transportation contract which permits the flexibility to purchase or transport amounts of gas between zero and a maximum amount specified in the contract.

Therm – Equivalent to 100,000 Btu. This is also approximately equivalent to 1 Ccf. See also Mcf, MMBtu and dekatherm.

Throughput – The amount of gas transported through specified facilities over a specified period of time.

WACOG – Weighted Average Cost of Gas, which is a method used to calculate an average price of a portfolio of gas supplies including the cost of gas inventory held in gas storage reservoirs.

Working Gas – The amount of natural gas in a storage basin that can be removed and replaced in each injection/withdrawal cycle.

Appendix C: List of Natural Gas Commodity Price Task Force Members

Natural Gas Commodity Price Task Force Members

Name	Organization	Name	Organization
Robert J. Amdor	UtiliCorp United/Energy One	Jan Marcason	Mid-America Assistance Coalition
David Beier	Fidelity Natural Gas	Mary K. Matalone	Interested Consumer
Jim Browning	*Palmyra City Mayor*	*Tim Maupin*	*Interested Consumer*
Pat Childers	Atmos Energy Corporation	Rep. Carol Jean Mays	Representative - District 50
Stuart W. Conrad	Finnegan, Conrad & Peterson	Anne McGregor	MC^2 Consultants
Charles H. Day	Interested Consumer	Cathleen Meyer	City Utilities of Springfield
Mark Drazen	Drazen Consulting Group	Michael C. Pendergast	Laclede Gas Company
Jeremiah D. Finnegan	County of Jackson - Counsel	Anita C. Randolph	DNR Energy Center
Jim Fischer	Fischer & Dority, P.C.	Joseph Schulte	Gas Workers Union Local 5-6
Bill Guinther	Interested Consumer	Tim Schwarz	MOPSC
Robert J. Hack	Missouri Gas Energy	Amy Sheridan	
Martha S. Hogerty	Office of the Public Counsel	David Sommerer	MOPSC
Rep. Rod Jetton	Representative - District 156	Sen. Sarah Steelman	Senator - District 16
Chris Kaitson	Kansas Pipeline - Counsel	Rich L. Taylor	Interested Consumer
Robert E. Kindle	Interested Consumer	Diana M. Vuylsteke	MO Indust. Energy Consumers
Richard J. Kovach	Ameren Services	Vicki Walker	Interested Consumer
Charles D. Laderoute	*Independent Consultant*	*Joyce White*	*Interested Consumer*
Joyce Lucas	Interested Consumer	Gary W. Wood	Bethany Muni. Gas
		Warren Wood	MOPSC
Peope Who Attended on Behalf of Others or As Interested Parties:			
Tom Byrne	Ameren Corp.	Brenda Wilbers	DNR Energy Center
Scott Glaeser	Ameren Corp.	Lesa Jenkins	MOPSC
Phil Lock	MOPSC	Shawn Gillespie	UtiliCorp United Inc.
Mark Martin	Atmos Energy	Barbara Meisenheimer	Office of the Public Counsel
Doug Micheel	Office of the Public Counsel	Jim Busch	Office of the Public Counsel

Summary of Missouri Energy Utility
Energy Efficiency and Renewable Energy Services

The Missouri Energy Center, the state's energy office operating within the Missouri Department of Natural Resources' Outreach and Assistance Center, conducted an energy efficiency and renewable energy program survey of all Missouri electric, natural gas and steam utilities.

The survey was distributed on December 21, 2001 and requested the companies' response by January 31, 2002; however, information was received through August 2002 through follow-up contacts. This survey summary reports responses received from the companies. The Energy Center did not review program implementation information such as funding or participation.

Of those utilities responding to the statewide survey, the Energy Center identified utility-based energy efficiency, alternative and renewable energy programs and services offered by each company to their residential, commercial and industrial customers or proposed to be offered in the near future.

Table 1. Survey Summary

Utility Type	Surveys Mailed	Responses	Percent	Energy Efficiency Programs	Percent	Alternative/ Renewable Energy Programs	Percent
Investor-owned electric and natural gas *	16	7	44%	7	44%	2	13%
Municipal electric and natural gas *	108	29	27%	5	5%	5	5%
Rural electric cooperatives**	47	19	40%	40	85%	0	0%
Other --							
Investor-owned steam	3	0	0%	0	0%	0	0%
University of MO-Columbia	1	1	100%	1	100%	0	0%
TOTAL	175	56	32%	53	30%	7	4%

*As of January 2002
**As of August 2002

Energy Efficiency

Of the 175 energy utilities surveyed (16 regulated investor-owned electric and natural gas utilities, 108 municipal utilities, 47 rural electric cooperatives, 3 regulated investor-owned steam and the University of Missouri-Columbia power plant) 53 or 30% responded that they offered an energy efficiency program or service to their customers. Details regarding energy efficiency, renewable energy and alternative energy programs and services are presented in Appendix I.

Investor-Owned Electric and Natural Gas Utilities

Seven (7) of 16 investor-owned electric and/or natural gas utilities offer energy efficiency program services:

AmerenUE – Ameren Energy Marketing, an affiliate of AmerenUE, and AmerenUE offers residential, commercial and industrial energy efficiency products or services to their customers in Missouri including low-income residential weatherization assistance services and energy management services to their commercial and industrial clients.

Missouri Public Service – Offers energy audit services to its residential, commercial and industrial customers and provides resource assistance to support low-income residential weatherization assistance services.

St. Joseph Power & Light Company – Promotes low-income weatherization assistance services in their service territory by providing financial assistance to the local chapter of United Way and resource contributions to Community Services, Inc., the area's low-income energy assistance program.

The Empire District Electric Company – Empire provides energy audit services to its residential, commercial and industrial customers upon request.

Great Plains Energy, Inc. (KCPL) – KCPL is a partner with Heartland for Energy Efficiency, a consortium of utilities in promoting energy efficiency services in western Missouri. The company also provides low-income weatherization assistance through local community action agencies and the City of Kansas City.

Laclede Gas Company – Offers a low-interest finance program to purchase and install insulation in homes and low-income weatherization assistance programs with the assistance of local community action agencies.

Missouri Gas Energy – MGE provides local support for low-income residential weatherization assistance and also joined with other area energy utilities to form the Heartland for Energy Efficiency (HUEE). HUEE will promote energy awareness and education initiatives for the residential market within the Greater Kansas City area. Other HUEE members include KCPL, Independence Power & Light, and Aquila (UtiliCorp). Together, the companies have donated approximately $40,000 to support the program.

Rural Electric Cooperatives

Forty (40) of 47 rural electric cooperatives offer a variety of energy efficiency services. All 39 distribution cooperatives and 1 distribution/transmission cooperative offer energy efficiency customer service programs – automatic meter reading, residential energy audits, low-interest loan programs and financial rebates for the purchase and installation of ground-source heat pumps, air source heat pumps and high efficiency electric appliances. See Appendix 1 for additional information.

Municipal Electric and Natural Gas Utilities
Five (5) of 108 municipal electric and natural gas utilities offer services or information on energy efficiency:

Columbia Water and Light
Independence Water & Light
City Utilities of Springfield
Carrollton Municipal Utilities
City of Sikeston

These municipal utilities offer energy efficiency outreach and assistance services that include energy audits, lighting programs, load management programs, and energy education and awareness programs. See Appendix 1 for additional information.

Other

The University of Missouri – Columbia administers an internal energy conservation program for campus facilities that provides lighting audits and recommended upgrades and building energy audits that address heating and cooling improvements.

Renewable and Alternative Energy

The following summarizes utility responses to renewable and alternative energy programs and services. Of the 175 utilities surveyed, 6 or 3% offer or will offer a renewable or alternative energy program or service:

Marshall Municipal Utility – Electricity generated from pelletized paper.

Chillicothe Municipal Utility – Electricity generated from pelletized paper.

City of Lamar – Electricity generated from waste wood materials (Under consideration).

City of West Plains – Electricity generated from waste wood materials and wood gas (Under consideration).

City Utilities of Springfield – Electricity is available to its customers generated from wind generation systems located in Kansas.

Missouri Public Service Company and St. Joseph Light and Power, divisions of UtiliCorp, are offering Missouri customers wind-produced electricity from a facility jointly built with Westar Energy.

Appendix 1. Description of Energy Efficiency and Renewable/Alternative Energy Programs and Services by Individual Utility

The following presents brief summaries of the energy efficiency and renewable energy programs or services offered by those utilities responding to the utility survey:

Investor-Owned Electric and Natural Gas Utilities

AmerenUE (Electric and Natural Gas)
Low-income weatherization assistance project. In cooperation with local community action agencies, AmerenUE continues to offer weatherization assistance to low-income residential customers. Under a formal agreement with the Missouri Public Service Commission, the Office of Public Counsel and the Department of Natural Resources, the company provides funds of up to $125,000 annually to support this energy efficiency program.

The company offers 5 programs for their commercial and industrial customers. Ameren's Abacus wireless metering information system tracks energy use by process, facility or equipment. This is an Internet-based software system allowing customers to view data in table or graphical format. The service provides customers with access to their energy use information on a daily basis and can be used by customers as a tool to monitor and manage their energy use.

A Customer Energy Exchange Internet-based notification and response system is offered for voluntary load curtailment. Customers are offered a financial incentive ($/kWh) to reduce their energy load below established baseline levels. The program assists AmerenUE in reducing its system peak in times of system constraints and allows customers to avoid unnecessary exposure to fluctuating market prices for power during peak energy demand periods.

AmerenUE offers Internet-based (12 month or hourly usage data) access to customer energy use information. Commercial and industrial customers may access historical usage data via ameren.com and may access their account information.

A Compressed Air Program is offered to the utility's industrial customers as a referral service to a local provider of compressed air energy audits. This service provides industrial customers with a reliable source of energy efficiency assistance with compressed air use (improved efficiency for air compression motors).

AmerenUE distributes upon customer request copies of the US Department of Energy's Motor Master Plus software as part of the US DOE OIT Allied Partner Program. This service provides a tool to commercial and industrial customers that will help them make educated decisions on the procurement of energy efficient motors.

Missouri Public Service Company (Electric and Natural Gas)

Missouri Public Service Company (MPS), a division of UtiliCorp (now Aquila) offers a "do-it-yourself" mail-in residential audit. The audit includes questions that focus on the age and construction of the home, appliances used, occupancy patterns, and lifestyle variables. MPS combines the survey results with the customer's billing data to generate an audit report that is sent back to the residential customers. The report includes an estimate of energy usage by appliance and end-use, and a list and description of energy efficiency measures to be considered by the customer for possible installation and operation. Since inception of the program in April 1999, MPS has received over 9,000 audit requests.

MPS offers a walk-through "Class B" energy audit for its small commercial and industrial customers. The audits focus on customer energy consumption and operations and provide recommendations for efficiency improvements. The audit is performed by utility-qualified energy auditors designated by MPS and based on customer profile, may include the use of industry experts for selected types of facilities and process operations.

MPS offers a comprehensive "Class A" energy audit to its large commercial and industrial customers. The audits focus on customer energy consumption and operations and provide recommendations for efficiency improvements. Assessments are conducted by utility qualified energy auditors and may include the use of industry experts for selected types of facility and process operations. Energy systems examined by the audit include chillers, refrigeration compressors and other types of equipment.

MPS offers a low-income weatherization assistance program developed by the utility in order to provide non-profit agencies in their service territory funding for improvements made to low-income residential units. These utility funds are intended to supplement existing federal weatherization assistance funds used by these agencies.

MPS is working with Habitat for Humanity organizations in their service territory to provide incentives for energy efficient measures in Habitat homes. The utility also supports the Mid-America Assistance Coalition in offering a voluntary program for customers to provide emergency energy assistance to low income individuals. The program is called "Energy Aid" and is promoted under the company's "EnergyOneCares" theme. Energy Aid pays for utility bills or emergency repairs to vital heating equipment.

MPS is an active member of the US Department of Energy's Energy Star Program that promotes the purchase and use of high energy-efficiency consumer products such as computers, refrigerators and heating and cooling systems.

MPS has also joined with other area energy utilities to form the Heartland for Energy Efficiency (HUEE). HUEE will promote energy awareness and education initiatives for the residential market within the Greater Kansas City area. Other HUEE members include KCPL, Independence Power & Light, and Missouri Gas Energy. Together, the companies have donated approximately $40,000 to support the program.

MPS is a member of the Midwest Energy Efficiency Alliance (MEEA) and is currently promotes the Change A Light program, providing greater lighting efficiency standards in the Kansas City area.

Missouri Public Service Company in a joint venture with Westar has constructed two 750 kW variable-speed wind turbines designed and built by Zond Development Corporation at Westar's Jeffery Energy Center located near St. Marys, Kansas and produces approximately 2.9 million kilowatt hours of electricity annually.

This is enough electricity to meet the annual power needs of more than 300 households. Each turbine is mounted on tubular towers that stand more than 170 feet high.

A portion of the power is sold to Missouri electricity customers in the Kansas City area as well as Springfield through its municipal utility system, City Utilities.

MPS's parent company, UtiliCorp United Inc., received the 2001 Missouri Governor's Environmental Excellence and Pollution Prevention Award for providing alternatively generated electric power to their customers in Missouri.

On December 17, 2001, UtiliCorp United and Florida Power and Light (FPL) Energy officials dedicated the largest wind farm ever constructed in Kansas. The FPL Energy Gray County Wind Farm near Montezuma is owned and operated by FPL Energy.

Construction of the 170 turbines at the wind farm, each about 295 feet high to the tip of the rotor, began in June and was completed ahead of schedule in late November 2001. The facility is capable of generating 110 megawatts of electricity, enough to power 33,000 homes. UtiliCorp purchases all the power produced at the wind farm.

All of the electricity from the wind farm serves UtiliCorp's WestPlains Energy customers in Kansas as well as its Missouri Public Service and St. Joseph Light & Power customers in Missouri.

<u>St. Joseph Light & Power Company (SJLP)</u> (Electric and Natural Gas)
St. Joseph Light & Power, a division of UtiliCorp United, is involved in two low-income residential energy assistance programs. Through the SJLP Energy Assistance Program, utility customers may contribute funds to support this project. All proceeds are provided to the United Way and distributed to area agencies to help people pay their utility bills. SJLP also works with Community Services, Inc., the local federal weatherization assistance agency. SJLP provides energy saving devices and educational tapes from product manufacturers to those participating in the program.

<u>Laclede Gas Company</u> (Natural Gas)
The company will soon offer a low-income weatherization assistance program in coordination with local community action agencies.

Laclede offers a program designed to provide low-interest loans to qualified residential customers to finance the purchase and installation of insulation. The program offers payment terms of up to seven and one-half years. A portion of the program is funded through rate-base. Initiated in 1981, the company has issued over 9,000 loans.

Energy Wise Dealer Program – This program provides financing through authorized HVAC contractors for the purchase and installation of energy-efficient natural gas heating and gas or electric cooling equipment and other natural gas appliances. A portion of the program cost is rate-based. Since May 1997, the program has issued about 2,500 loans.

Missouri Gas Energy (Natural Gas)
MGE offers a low-income residential assistance program and provides $340,000 annually to local community action agencies to administer the program. Partners include the City of Kansas City, Community Services, Inc., Economic Security Corporation, Missouri Valley Human Resources, and Ozark Area Community Action Corporation.

MGE has also joined with other area energy utilities to form the Heartland for Energy Efficiency (HUEE). HUEE will promote energy awareness and education initiatives for the residential market within the Greater Kansas City area. Other HUEE members include KCPL, Independence Power & Light, and Missouri Public Service. Together, the companies have donated approximately $40,000 to support the program.

Kansas City Power & Light Company (Great Plains Energy) (Electric)
KCPL has joined with other area energy utilities to form the Heartland for Energy Efficiency (HUEE). HUEE will promote energy awareness and education initiatives for the residential market within the Greater Kansas City area. Other HUEE members include Independence Power & Light, MGE, and UtiliCorp. Together, the companies have donated approximately $40,000 to support the program.

The Empire District Electric Company (Electric)
Upon request, Empire provides a walk through energy audit service for their residential, commercial and industrial customers to identify opportunities to improve energy use.

Municipal Utilities

Carrollton Municipal Utilities (Electric)
Administers an outreach and education program for 5th and 6th grade students regarding energy conservation tips and safety topics through videotapes and hard-copy handouts.

Chillicothe Municipal Utilities (Electric)
The utility is reducing its use of fossil fuel by using pelletized paper processed at a local sheltered workshop to fuel its electric generation system. The system provides a relatively inexpensive fuel source and reduces the amount of waste to the local landfill, as dedicated municipal waste is recycled at the utility's electric generation facility.

Columbia Water and Light (Electric)
Columbia Water and Light offers several energy efficiency and renewable energy services to its customers. Among those services include a Junior High School Calendar contest held annually to encourage students to design artwork promoting energy efficiency and renewable energy. Calendars are provided to Water and Light customers.

Columbia also installs and operates direct load control devices on central air conditioners to reduce summer peaking demands.

A commercial and industrial load shedding program provides reduced rates to commercial/industrial customers to voluntarily reduce electric demands during summer peak periods.

Customers under the Large General service agreement or industrial service rate that have at least 500 kW of load that can be interrupted by Columbia Water and Light are eligible for the Interruptible Service Rate. Customers on this rate have a contracted firm demand charge.

The Water and Light department manages the City of Columbia's Government access channel. The utility hosts a segment every two weeks covering a variety of energy-related topics including outside water conservation tips to attic insulation requirements.

Energy audits are available to residential, commercial and industrial customers. A variety of systems are used depending upon the customer type.

Columbia is a participating member of the American Public Power Association's Tree Power program. The program encourages the use of shade trees to help cool buildings during summer months, reducing air conditioning demand.

A low-interest loan program is available to all electric customers, for energy efficient improvements such as insulation, HVAC upgrades and heat pumps.

Distributed Generation is currently under consideration by Columbia. DG provides customers with back-up power in the event of a power outage or other emergency and also provides the utility with peaking capacity as needed.

Columbia Water and Light hosts Saturday Science which allows three different groups of 8th grade science students to spend a Saturday morning learning how science applies to the world of electric utilities. Students spend 4 hours discovering how electricity is produced and distributed, how water is treated or how insulation affects home energy efficiency.

The Energy Challenge for Columbia Public Schools is a multi-faceted program that allows users to determine where and how well their energy is being used within their homes. The program is designed as a curriculum supplement for the 9th grade natural sciences program in the schools. It consists of a computerized energy audit, and classroom presenters that talk about ways in which they can remedy some of the energy problems in their homes.

Columbia offers a free infrared thermography to its industrial rate customers four times each year or as required. This service covers all demand-side electric infrastructures – power distribution, load centers, motor control centers, control cabinets, manufacturing equipment, boilers, air compressors, HVAC and research and development. A pilot program, Power Quality Assistance, will soon start offering recommendations to improve energy use to the utility's industrial customers. Both services are/or will be offered to residential and commercial customers.

Independence Water & Light (Electric)
Independence offers an on-site residential energy audit that examines energy usage and provides general recommendations to improve energy use.

The utility also offers information about energy conservation and renewable energy through pamphlets, newspaper and other forms of media.

A Key Accounts Program offers large commercial and industrial customers with services to increase the energy efficiency of their operations.

Energy conservation kits consisting of weatherization materials, compact fluorescent lamps and other energy saving items are provided at no charge to selected low-income residential customers.

A residential electric water heater, heat pump and air conditioner rebate program is offered by the utility to encourage the purchase and installation of high efficiency equipment.

City of Lamar (Electric)
Lamar is examining the potential for alternative electric generation through a cooperative project with O'Sullivan, a wood product manufacturer. The utility is considering building and operating a 5 to 10 MW combined-cycle generator using waste saw dust which is currently disposed at their local landfill.

Sikeston (Electric)
Sikeston is a member of the national Tree Power Program. This is a public power (municipal) project that promotes tree planting in their community as an energy conservation and environmental awareness effort.

City Utilities of Springfield (Electric and Natural Gas)
City Utilities offers its WindCurrent program to customers as an opportunity to invest in renewable energy through an agreement to purchase 100 kWh blocks of wind-generated electricity at $5.00 each per month in addition to the monthly metered electric service. The wind energy is produced at Westar's Jeffrey Energy Center noted earlier. Since October 2000, City Utilities had 139 participants with a total of 251 blocks sold.

The Home Sense Energy Audit assists City Utilities' customers in reducing energy and water use and increasing comfort by pinpointing air leaks with a blower door test, conducting a complete house evaluation and providing a list of house specific cost-effective retrofit measures.

Other

University of Missouri – Columbia Campus Power Plant (Electric)
The University of Missouri – Columbia administers an internal energy conservation program for campus facilities that provides lighting audits and recommended upgrades and building energy audits that address heating and cooling improvements. The program focuses on measures that reduce energy consumption by 1% per year through efficiency improvements with a simple payback of five years or less.

Municipal utilities - Energy efficiency and renewable energy activities

Municipal Utility	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Carrollton					x											
Chillicothe	x															
Columbia		x	x		x		x		x	x		x	x			x
Independence				x	x		x				x			x	x	
Lamar		x														
Sikeston																x
Springfield						x	x	x								

1. Alternative generation - biomass fuel used
2. Alternative or/distributed generation - studying potential
3. Commercial energy audit
4. Commercial customer assistance - other
5. Education and information programs
6. Green pricing offerings
7. Home energy audit
8. Home energy audit -- blower door
9. Interruptible service rates - commercial
10. Load control - AC
11. Low-income assistance
12. Low interest loans
13. Peak load reduction - commercial/industrial
14. Rebates -- heat pump
15. Rebates -- other (water heater, AC, etc.)
16. Tree planting program

1. Automatic Meter Reading
2. Distributed Generation – Fuel Cell Installed
3. Heat Pump – Sizing
4. Heat Pump – Dual Fuel
5. Heat Pump – Installed
6. Home Energy Audit
7. Home Energy Audit – Blower Door
8. Home Energy Audit – Infrared Camera
9. Home Energy Rating
10. Insulation Installation
11. Low-Income Weatherization Assistance
12. Load Control – Air Source Heat Pump
13. Load Control – Air Conditioning
14. Load Control – Ground Source Heat Pump
15. Load Control – Water Heater
16. Low Interest Loans
17. Rebates – Ground Source Heat Pump
18. Rebates- Air Source Heat Pump
19. Rebates – Other (Water Heater, Dual Fuel, etc.)

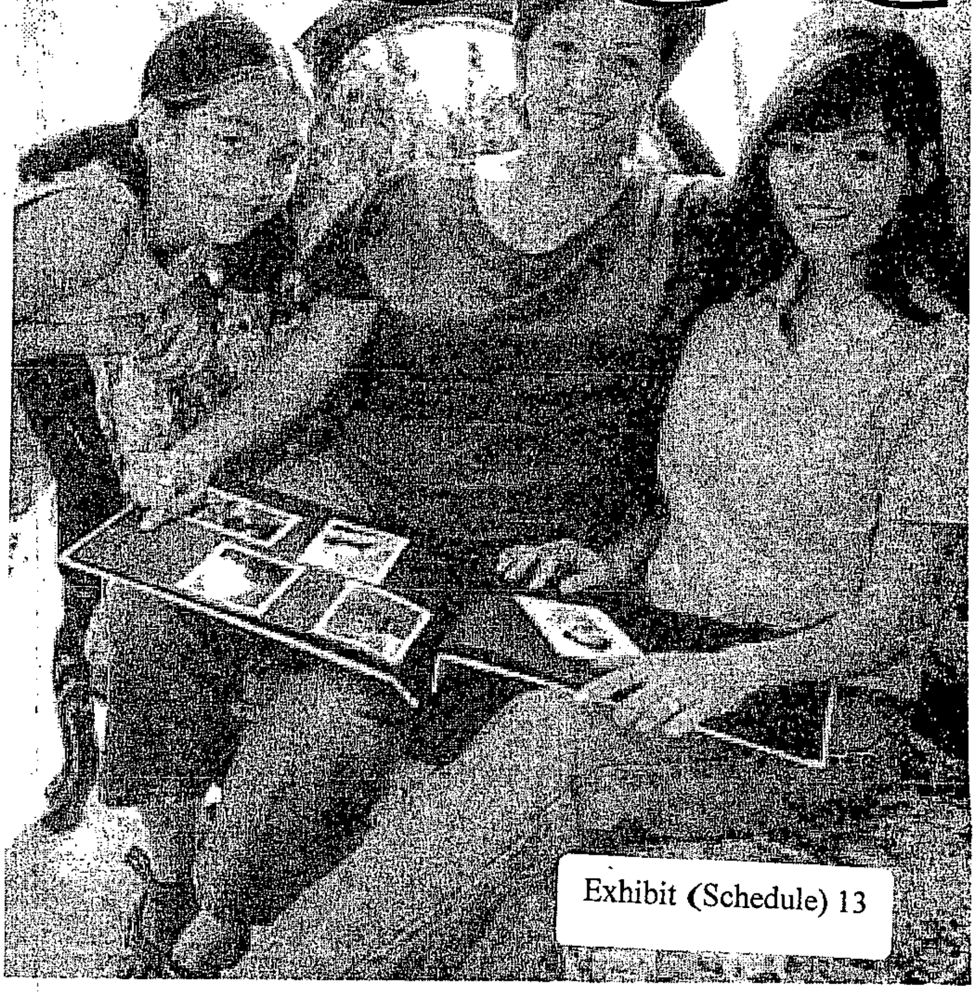
Rural Electric Cooperatives

Energy Efficiency Service or Program

Cooperative	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Atchison-Holt																	*	*	*
Barry	*					*					*						*		*
Barton County																*			
Black River				*		*											*		*
Boone	*			*		*	*					*			*	*	*		
Callaway			*			*										*	*		*
Central Missouri																			*
Citizens Electric Corporation						*													
Co-Mo	*		*			*		*									*		*
Consolidated						*										*	*		*
Crawford	*			*		*										*	*	*	*
Cuivre River	*				*	*		*								*		*	*
Farmers'	*			*														*	*
Gascosage																	*		*
Grundy	*			*		*			*				*		*	*	*	*	*
Howard				*												*	*	*	*
Howell-Oregon																*			*
Intercounty						*			*							*	*	*	*
Laclede						*	*		*					*			*	*	*
Lewis County				*												*	*	*	*
Macon				*	*	*									*	*	*	*	*
Missouri				*													*		*
New-Mac	*			*												*	*	*	*
North Central				*		*			*							*	*		*
Osage Valley	*			*								*	*	*	*	*	*	*	*
Ozark	*					*											*	*	*
Ozark Border						*											*	*	*
Pemiscot-Dunklin								*									*	*	*
Platte-Clay	*	*		*		*										*	*	*	*
Ralls County			*			*				*						*	*		*
Sac Osage																*	*		*
SEMO						*		*									*	*	*
Se-Ma-No				*													*	*	*
Southwest			*			*													
Three Rivers	*		*			*										*	*		
Tri-County						*										*	*		*
United Electric						*	*					*	*	*	*	*	*	*	*
Webster	*			*		*		*									*	*	
West Central					*												*	*	*
White River Valley	*					*										*	*	*	*

Opportunity Lost

Better Energy Codes for Affordable Housing and A Cleaner Environment



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ALLIANCE TO
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Exhibit (Schedule) 13

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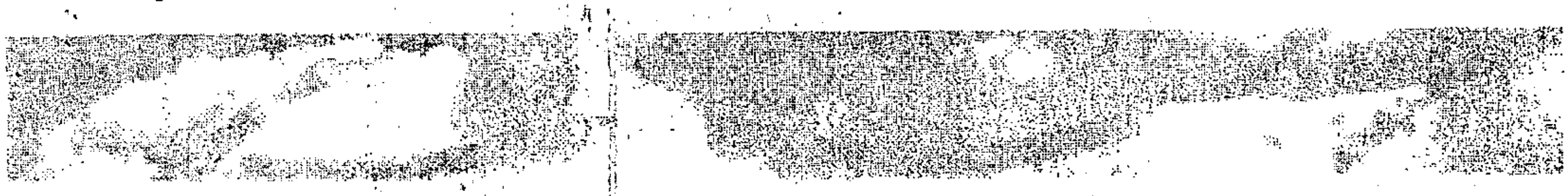
The Alliance to Save Energy is a coalition of prominent business, government, environmental, and consumer leaders who promote the efficient and clean use of energy worldwide to benefit consumers, the environment, economy, and national security.



Opportunity Lost

Better Energy Codes for Affordable Housing and A Cleaner Environment

A National and State Analysis Of the 1993 Model Energy Code

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List of Tables

Executive Summary

This report shows that modern building energy codes save consumers money and energy, making housing more affordable while reducing air pollution. It is the result of a major Alliance to Save Energy study that conducted a detailed analysis of the costs and benefits of adopting the International Code Council's Model Energy Code (MEC), 1993 version, in the states whose codes are less stringent. The study developed information on the energy, dollar, and air pollution emission savings that would occur if these states upgraded their codes to the 1993 MEC. It compared these benefits with the added construction costs involved in complying with the 1993 MEC.

ENERGY CODES ARE A ONCE-IN-A-LIFETIME OPPORTUNITY

The states in this study—which do not yet use the MEC—are hosts to more than half a million new homes a year. Every year we have a unique chance to build these half-million homes right. Once they are built, it is very expensive and often impossible to achieve the energy efficiency that can be built in so economically at the time of construction. This is an opportunity that we cannot afford to lose. Today's homes may last 75 to 100 years or longer. We should not deny either half a million homebuyers each year, or their children and grandchildren, the chance to live in homes that save energy, money, and pollution.

BETTER ENERGY CODES SAVE ENERGY AND MONEY, AND PREVENT AIR POLLUTION

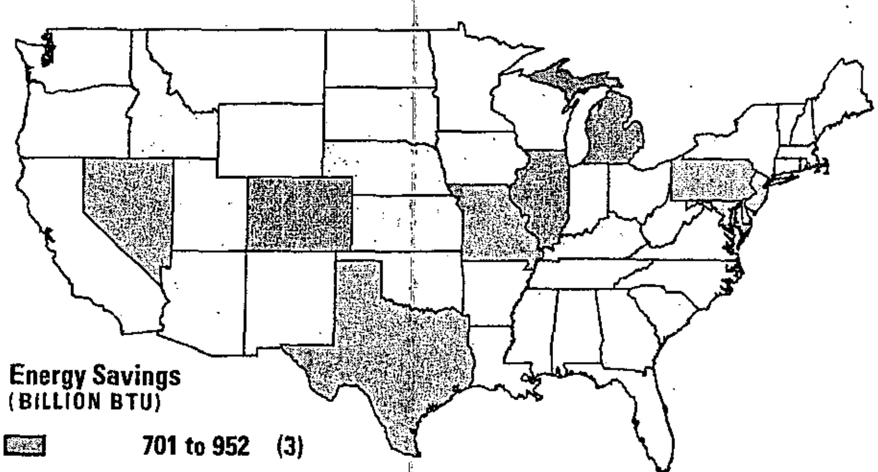
The study found that if the states in the analysis used the 1993 MEC, American homebuyers would save 7 trillion Btu, $81 million, and almost 226,000 tons of air pollution each year. These energy savings are enough to serve the energy needs of all the new homes built in a typical year in Michigan and Pennsylvania combined.

The energy and pollution savings can be attained very cost-effectively: the typical homebuyer enjoys positive cash flow within two years. That is, the energy bill savings

Category	Savings	
	Nationwide	Per Home
Energy	7.4 trillion Btu/year	10 million Btu/year
Money	$81 million/year	$122/year
Air Pollution	226,000 tons/year	588 pounds/year
Housing Affordability	Homeowner sees positive cash flow within two years	

Annual Energy Savings Potential

BY STATE



Energy Savings
(BILLION BTU)

- **701 to 952 (3)**
- **481 to 700 (3)**
- **241 to 480 (3)**
- **0 to 240 (28)**
- **not in the study (14)***

***Alaska and Hawaii not in study. District of Columbia included in study.**

(about $122/year) typically exceed the small increase in mortgage payments. So the 1993 MEC makes housing more affordable for the initial homebuyer.

Over 30 years, the net present value of the dollar savings is $529 million for each year's production of new homes built to the 1993 MEC, or about $800 per home. So the nation's homebuyers as a whole benefit from the 1993 MEC, as well as the first buyer of the home.

SOME STATES STAND OUT IN SAVINGS POTENTIAL

The maps illustrate the leading states on various measures of benefit for adoption of the 1993 MEC. The leaders in total energy savings potential are Michigan, Illinois, and Colorado. Total dollar savings are greatest in Texas, Illinois, and Arizona. The potential for cutting air pollution emissions is highest in Texas, Kentucky, and Missouri.

ENERGY CODES ARE ESSENTIAL FOR CONSUMER PROTECTION

Special interests in the building industry are mounting political campaigns in some states to roll back energy codes as too expensive for builders and homebuyers. While their efforts in most cases have failed, they did succeed in repealing the 1993 MEC in Michigan, giving Michigan the dubious distinction of being the *only state ever to go backward on energy* codes.

These special interests have touted their involvement in voluntary programs, such as the U.S. Environmental Protection Agency's (EPA) Energy Star Homes program and the electric utility industry's E-Seal program, as evidence that codes are not needed. While the Alliance is a staunch supporter of these voluntary programs as vital to the future of energy efficiency in the housing market, so far they have reached only a small fraction of the market. The total estimated participation in these programs combined in 1996 was less than 30,000 homes, which is less than 2 percent of total housing starts.

In light of these market realities, energy and other building codes are essential for the protection of the average consumer against substandard construction and needlessly high energy bills. Until the time that voluntary programs dominate the market, codes will be needed to protect consumers and ensure that they and society as a whole receive the dollar savings and environmental protection they deserve. Even then, codes will continue to be needed to protect consumers against poor-quality products.

Some building industry organizations claim that home builders cannot afford to build homes to the MEC, yet the voluntary programs they embrace, such as Energy Star Homes, are based on the MEC and in fact exceed the MEC by 30 percent or more. So it is simply contradictory to say that codes are bad for homebuyers and programs with higher energy standards are good. The truth is that codes like the MEC are good for buyers, and the voluntary programs are better.

ENERGY CODES ARE VITAL TO HOUSING AFFORDABILITY

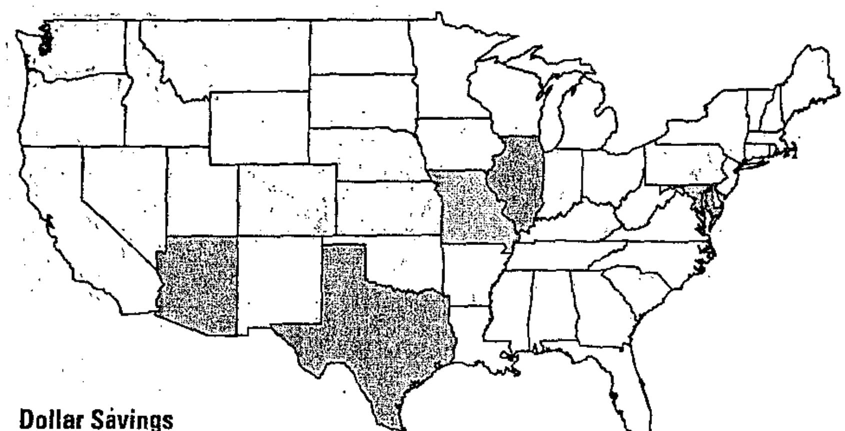
The MEC makes housing more affordable. No homebuyer has ever been denied a mortgage loan because the home met MEC standards. In fact, the nation's two mortgage programs aimed at helping low- and moderate-income homebuyers—FHA and VA—require homes to meet the MEC. The MEC does add first cost to the home, but since buyers nearly always finance their home purchases through mortgages, these costs show up as small increases in monthly payments, typically less than $10. Our study shows that energy bill savings typically exceed $10 per month, so the buyer is better off financially with an MEC-built home. Mortgage lenders recognize this value in their underwriting through energy-efficient mortgage (EEM) policies. The nation's largest mortgage institution, Fannie Mae, recognizes MEC compliance software as a tool to qualify for its EEM program.

ENERGY CODES IMPROVE AIR QUALITY

While the MEC improves the finances of homebuyers, it also protects all citizens from air pollution by preventing the emission of 250,000 tons of carbon dioxide, sulfur dioxide, and other gases. Protecting the health and property of its citizens alone gives governments an imperative to adopt modern energy codes; when doing so is also economically beneficial, as shown in our study, failure to take this step is indefensible.

Beyond the immediate benefits of improved air quality, the MEC provides

Annual Dollar Savings Potential
BY STATE

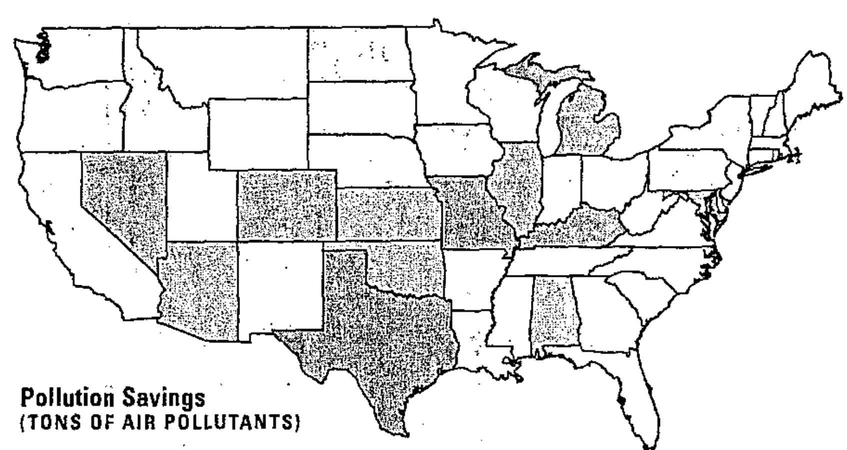


Dollar Savings
(NET PRESENT VALUE)

- 54,400,001 to 81,500,000 (3)
- 27,200,001 to 54,400,000 (2)
- 0 to 27,200,000 (32)
- not in study (14)*

*Alaska and Hawaii not in study. District of Columbia included in study.

Annual Pollution Savings Potential
BY STATE



Pollution Savings
(TONS OF AIR POLLUTANTS)

- 34,001 to 46,000 (3)
- 23,001 to 34,000 (4)
- 11,501 to 23,000 (5)
- 0 to 11,500 (25)
- not in study (14)*

*Alaska and Hawaii not in study. District of Columbia included in study.

sensible, low-cost insurance against the potential effects of climate change. Scientists generally agree that energy consumption is the greatest cause of increased carbon dioxide in the atmosphere, and that the resulting increase in the "greenhouse effect" is having an effect on our climate. While the severity and timing of the effects of climate change are hard to predict, it is easy to see the value in taking out "insurance policies" against climate change damage through proven, cost-effective policies, such as modern energy codes.

Introduction

In September 1991, the Alliance to Save Energy published a study of the energy, economic, and environmental benefits of adopting the 1989 version of the Council of American Building Officials' (CABO) Model Energy Code (MEC) for residential buildings. The study compared MEC-1989 energy standards to current code criteria in 34 states that had not recently updated their building codes. The 1991 report's findings included:

- If the 34 states had adopted the 1989 MEC, 7.2 trillion Btu would have been saved annually, or enough to meet the *total* energy needs of 65,000 to 70,000 single-family homes;

- 565,000 tons of energy-consumption-related air pollution would have been eliminated per year;

- The benefit-cost ratio of MEC adoption equaled 3.0, with a net present value to consumers of $687 million; and

- Average savings per home per year equaled $130. With the average $874-added-home-cost typically financed through the mortgage, the average homebuyer would enjoy an immediate $60 per year positive cash flow.

The need for the present study arose with the updating of the MEC by CABO in 1993. (The MEC was also updated in 1995, but the changes affecting energy efficiency were minor compared to the efficiency gains in the 1993 version.) By the end of 1994 only three states—Michigan, Ohio, and Virginia—had adopted the 1993 MEC. Michigan, however, reversed itself in 1995, rescinding its adoption under severe pressure from home builders. Because the 1993 MEC was available for adoption by every state in 1994, we chose to use the 1993 version in the present study.

In addition, in 1996 and 1997 the U.S. Department of Energy (DOE), under its authority in the Energy Policy Act of 1992 (EPAct), required all states to consider adopting the 1993 and 1995 versions of the MEC, respectively. In EPAct, all states were initially required to consider adopting the 1992 version of the MEC. DOE was also mandated to review later versions of the MEC and, if it determined that a later version was significantly more energy efficient, to require states to consider adopting the later version. DOE determined that the 1993 and 1995 versions of the MEC would achieve greater energy efficiency in residential buildings. Consequently, many states are now involved in reviewing their codes and responding to DOE's reporting requirement. This study provides strong support for adopting the 1993 MEC in those states that have not yet done so.

The scope of the present study is similar to the original. For each state that had *not* adopted the 1993 MEC during the 1994 calendar year, we estimated the lost opportunities in energy and dollar savings as well as reductions in air pollution. We also estimated the magnitude (in present dollars) of the lost savings from two perspectives: the individual consumer and society as a whole.

UPDATE ON ADOPTION OF 1993 AND 1995 VERSIONS OF THE MEC

As of summer 1997, eight of the 31 states in the study had begun adoption of the 1993 or 1995 versions of the MEC. In various stages of implementing the 1995 MEC are Massachusetts, Georgia, Rhode Island, Maryland, and South Carolina. The 1993 MEC has been adopted in Delaware, Kansas, and North Dakota.

These changes occurred too recently to include in this analysis; in some cases the code has not yet taken effect, and in others training and other forms of administrative support are still being developed. The decisions of these eight states do not affect the overall findings of the study—that the MEC saves significant energy and pollution and is very cost effective. In fact, they support these conclusions by proving that states are indeed finding the newer MEC versions attractive. They demonstrate an encouraging trend that other states could follow by adopting the MEC's 1993 or 1995 versions.

Findings

This section presents the potential energy, environmental, and economic benefits of adopting the 1993 MEC. Findings are broken out by energy type, housing type (single-family versus multi-family) for the United States as a whole, and for each state in which the 1993 MEC is cost effective but had not been adopted by the end of 1994.

NATIONAL-LEVEL BENEFITS

Homeowner's Perspective

Energy Savings Benefits

Table A (next page) shows 1994 national energy savings if all states for which the 1993 MEC is cost effective had adopted it. From the homeowner's perspective, energy savings are valued at the consumer's retail price—the price they would have paid for the energy they saved. The discount rate used in the homeowner's perspective calculation is that of the prevailing mortgage rate in 1994, under the assumption that a new mortgage is the predominant funding vehicle for home purchases.

Total energy savings are 7,419 billion Btu: 7,093 billion Btu for single-family (SF) and 326 billion Btu for multi-family (MF). These savings occur in 716,400 SF homes and 129,590 MF dwellings built in 1994 in the affected states. The Btu savings are equivalent to the energy used by 70,705 single-family homes. Combined (SF and MF) savings by fuel type are: 5,023 million cubic feet of natural gas, 457 million kWh of electricity, and 4.3 million gallons of heating oil. On a per SF home basis (averaged from state values), the savings by fuel type are: 12,689 cubic feet natural gas, 2,309 kWh, and 106 gallons of oil.

Greenhouse Gas and Other Air Pollution Prevention

Greenhouse gas emissions savings (in tons of carbon equivalent) occur primarily as carbon dioxide (CO_2) savings (99.7 percent), which result primarily from savings in electricity use (123,885 tons carbon, or 56.1 percent), followed by natural gas (84,492 tons carbon, or 38.3 percent). Prevention of other air pollutants derives almost exclusively from savings in coal-fired electric generation; electricity (in total) accounts for 94.4 percent of other air pollution savings. Table B (next page) shows pollution avoidance by greenhouse gas and air pollutant. As can be seen in Table B, adoption of the 1993 MEC would help mitigate global climate change across the board by fuel type but would primarily reduce other air pollution where savings in electric heating and cooling occurred.

Economic Benefits

Table C (see page 5) shows the benefits for the average homeowner of adopting the 1993 MEC.

Table A. Potential National Energy Savings—1994
(Homeowner's Perspective)

Btu

Savings / Dwelling Type	Energy Per Home (MMBtu)	Energy Total (BBtu)	Natural Gas Per Home (MMBtu)	Natural Gas Total (BBtu)	Electricity Per Home (MMBtu)	Electricity Total (BBtu)	Oil Per Home (MMBtu)	Oil Total (BBtu)
Single-Family	9.90	7,093	12.68	5,063	7.65* 23.02†	1,443* 4,349†	12.51	595
Multi-Family	2.64	326	3.09	213	4.02* 12.10†	113* 342†	0.13	0.04
Totals		7,419		5,276		1,556		595

Note: Per home figures are averages of state values; thus, total Btu savings do not equal the sum of Btu savings by fuel type.
*Equals Btu of electricity saved per home as measured at the point of consumption.
†Equals Btu of electricity saved per home as measured at the source of generation.

Energy Units

Savings / Dwelling Type	Energy Per Home (MMBtu)	Energy Total (BBtu)	Natural Gas Per Home (Cu. Ft.)	Natural Gas Total (MMCF)	Electricity Per Home (kWh)	Electricity Total (MkWh)	Oil Per Home (Gallons)	Oil Total (M Gal)
Single-Family	9.90	7,093	12,689	4,815	2,309* 6,953†	423* 1,274†	106	4.3
Multi-Family	2.64	331	3,046	208	1,205* 3,629†	34* 101†	1	0.0
Totals		7,424		5,023		457		4.3

Note: Per home figures are averages of state values.
*Equals Btu of electricity saved per home as measured at the point of consumption.
†Equals Btu of electricity saved per home as measured at the source of generation.

Table B. Potential National Pollution Prevention—1994
(SF and MF—Homeowner's Perspective)

	Electricity	Natural Gas	Oil	Totals
Greenhouse Gases (as tons of carbon):				
Carbon Dioxide (CO_2)	123,331	84,364	12,271	219,996
Nitrous Oxide (NO_x)	538	94	39	617
Methane	16	34	14	64
Total	123,885	84,492	12,324	220,701
Air Pollutants (in tons):				
Sulfur Dioxide (SO_2)	3,363	0	64	3,427
NO_x	1,620	0	160	1,780
Carbon Monoxide (CO)	73	0	71	144
PM-10 (Particulates)	59	0	8	67
Total	5,115	0	303	5,418

Table C. Potential National Economic Savings—1994
(Homeowner's Perspective)

	Added First Year Cost of MEC Adoption	Incremental Annual Dollar Savings	Benefit/Cost Ratio (at 7.5%)	Net Present Value (at 7.5%)	Consumer Affordability Index*
Average Home:†					
SF	$1,161	$122	1.8	$804	1.8
MF	340	40	2.2	285	2.2
Total (Millions)					
SF	$720	$77	—	$500	—
MF	37	4	—	29	—
Total	757	81	—	529	—

*Years to positive cash flow—added down payment plus added mortgage payment minus energy bill savings.
†Average home values equal the average of the state values.

It shows that the 1993 MEC is very cost-effective and makes housing more affordable for homebuyers. Because home purchasers typically finance with a mortgage, and because the added first cost of the home will be included in the mortgage (less the portion going to the down payment), the Consumer Affordability Index (down payment plus added mortgage payment minus energy bills savings) equals 1.8 years and 2.2 years, respectively, for SF and MF homeowners. This means the added investment (as represented by the added cost of their mortgage) pays back in two years or less. All remaining years (years 3 through 30), the families living in MEC-built homes will experience a positive cash flow. On a benefit-cost basis, adoption of the 1993 MEC produces a benefit/cost ratio of 1.8 for SF homeowners and 2.2 for MF homeowners.

The average added cost per home to meet the 1993 MEC is $1,161 and $340, respectively, for SF and MF homes. But the added energy efficiency embodied in the home saves the household $122 and $40 in annual energy costs for SF and MF dwellers, respectively. These savings streams over 30 years provide each SF and MF household a net benefit of $804 and $285, respectively, on a present value basis at a 7.5 percent discount rate. Total dollar savings to consumers in the 842,000 homes affected by this study equal $529 million on a net present value basis.

Societal Perspective

The above results are based on the consumer's point of view. The consumer's perspective uses the marginal (retail) energy price paid by the homeowner as the value of the benefits of the energy savings. In addition, we calculated the benefit/cost ratio and net present value of energy cost savings from the 1993 MEC at the homeowner's marginal cost of capital, which we assume to be the prevailing mortgage rate on 30-year mortgages. For 1994, the average mortgage rate was approximately 7.5 percent.

An alternative way to evaluate the economics of the 1993 MEC is from the "societal" perspective. This perspective analyzes the MEC as if all new home purchasers—or all consumers—could act together. In such a case, the societal group would use a lower discount rate, close to the risk-free rate on U.S. government securities. This "society" would evaluate economic benefits based on the marginal costs of fuel supply and the value of reduced air pollution and climate change costs. The environmental benefits are based on the estimated avoided costs of air pollution damage and the costs of mitigating global climate change.

We use a discount rate of 6.28 percent—the average 1994 rate on 30-year T-bills—as the proxy for the risk-free discount rate. Marginal cost of production—as a percent of retail energy prices—for the purposes of this study are 53 percent for natural gas, 51 percent for oil, and 62 percent for electricity, based on national energy industry statistics.

Mid-range estimates of the cost of air pollution—expressed also as a percentage of fuel price—were obtained from the work of Viscusi[1] and are 0.5 percent for natural gas, 13 percent for oil, and 261 percent for coal used in electric generation. Mid-range estimates of the cost of global climate change mitigation based on carbon dioxide emissions—again expressed as a percent of fuel price—were obtained from Nordhous[2] and are 14 percent for natural gas, 21 percent for oil, and 79 percent for coal. By adding the two percentages to each fuel price, we derived combined monetized social costs for each energy type: 15 percent for natural gas, 34 percent for oil, and 340 percent for coal.

These percentages were directly applied to natural gas and oil prices where these fuels were burned directly in homes. For electricity, the percentages were applied based on each state's electric generation fuel mix. The effects on retail prices of natural gas and oil used by homeowners are $.09/therm for natural gas and $.20/gallon for heating oil. For these fuels, the added environmental costs are well below their current retail price; "social-cost" pricing raises their base prices by 15 to 34 percent.

For electricity, however, the percentage of "social cost" prices accounted for by environmental costs is much greater. Where power plants are mostly coal-fired, environmental costs can dramatically increase electricity prices. The inclusion of environmental costs results in substantial variations state-by-state in the relationship of electricity's social marginal costs (SMC) to its private marginal costs (PMC). The ratio of SMC to PMC varies for 1994 from a high of 4.376 in Kentucky, Montana, North Dakota, and Wyoming, to a low of 1.015 in Vermont. However, because fuel costs are not the only cost of producing electricity, the percentage impact of social costs on retail electricity prices is less than the impact on fuel costs alone. For example, while Kentucky, Montana, North Dakota, and Wyoming each would see fuel costs increase 337 percent because of the inclusion of environmental damage costs, the total impact on retail electric prices was 106 percent for Kentucky, 77 percent for Montana, 173 percent for North Dakota, and 255 percent for Wyoming. In contrast, because very little electricity in Vermont is generated by coal, the impact of the inclusion of environmental damage costs on the retail price of electricity is only 1.5 percent.

Energy Savings Benefits

Table D shows 1994 potential national energy savings from the societal perspective if all states for which the 1993 MEC is cost effective had adopted it. The energy savings projected from this perspective are very similar in magnitude to the energy savings from the homeowner's perspective. The societal perspective was used to analyze the potential savings from 694,140 SF homes and 119,890 MF dwellings. Total energy savings are 7,158 billion Btu from the societal perspective compared to homeowner-perspective savings of 7,424 billion Btu. This finding indicates that energy savings potential is not very sensitive to the perspective used for analysis.

SF energy savings equal 6,851 billion Btu compared to homeowner-perspective SF savings

[1] See Viscusi, W. Kip, Wesley A. Magat, Alan Curlin, and Mark Dreyfus. 1994 "Environmentally Responsible Energy Pricing." *The Energy Journal*. Vol 15, No. 2.

[2] Nordhaus, William D. 1994. *Managing the Global Commons*. Cambridge and London: The MIT Press.

Table D. Potential National Energy Savings—1994
(Societal Perspective)

Savings / Dwelling Type	Energy Per Home (MBtu)	Energy Total (BBtu)	Natural Gas Per Home (MBtu)	Natural Gas Total (MCF)	Electricity Per Home (MBtu)	Electricity Total (MkWh)	Oil Per Home (MBtu)	Oil Total (M Gal)
Single-Family	9.87	6,851	13.33	4,715	7.99* 24.06†	419	13.40	3.3
Multi-Family	2.56	307	2.49	189	3.67* 11.04†	32	0.11	0.0
Totals		7,158		4,904		451		3.3

Note: Per home values are average of state values; thus total energy per home does not equal the sum of fuel types per home.
*Equals Btu of electricity saved per home as measured at the point of consumption.
†Equals Btu of electricity saved per home as measured at the source of generation.

Table E. Potential National Pollution Avoidance—1994
(SF and MF—Societal Perspective)

	Electricity	Natural Gas	Oil	Totals
Greenhouse Gases (as tons of carbon):				
Carbon Dioxide (CO_2)	121,886	82,381	9,712	213,979
Nitrous Oxide (NO_X)	532	92	31	655
Methane	16	33	11	60
Total	122,434	82,506	9,754	214,694
Air Pollutants (in tons):				
Sulfur Dioxide (SO_2)	3,323	0	51	3,374
NO_X	1,600	0	127	1,727
Carbon Monoxide (CO)	72	0	56	128
PM-10 (Particulates)	58	0	6	64
Total	5,053	0	240	5,293

of 7,093 billion Btu, and MF savings are 307 billion Btu compared to homeowner-perspective savings of 331 billion Btu. These Btu savings are equivalent to the annual home energy used by 68,293 SF households. Combined (SF and MF) savings by fuel type are 4,904 million cubic feet of natural gas, 451 million kWh of electricity, and 3.3 million gallons of heating oil. On a per SF home basis (averaged from state values), the savings by fuel type are: 12,951 cubic feet natural gas, 2,343 kWh, and 109 gallons of oil.

Greenhouse Gas and Other Air Pollution Avoidance

Greenhouse gas emissions savings (in tons carbon) occur primarily as CO_2 avoidance (99.7 percent), which in turn results primarily from savings in electricity use (122,434 tons carbon, or 57.0 percent), followed by natural gas (82,506 tons carbon, or 38.4 percent). Emissions avoidance of other air pollutants derives almost exclusively from savings in coal-fired electricity generation. Electricity savings account for 95.5 percent of other air pollution savings. Table E shows the emissions savings by greenhouse gas and air pollutant. As can be seen in Table E, adoption of the 1993 MEC would help mitigate global climate change across the board by fuel type, but would primarily reduce other air pollution where savings in electric heating and cooling occurred.

Economic Benefits

Table F summarizes the economic benefits of adopting the 1993 MEC from the societal perspective. It shows that the MEC is very cost-effective and makes housing more affordable. Because home purchasers typically finance with a mortgage, and because the added first cost of the home will be included in the mortgage (less the portion going to the down payment), the Consumer Affordability Index (down payment plus added mortgage payments minus energy bill savings) equals 4.1 years and 6.4 years, respectively, for SF and MF homeowners. This means the added investment (as represented by the added cost of their mortgage) pays back in four to six years. All remaining years (years 4 or 6 through 30), the homeowner will experience a positive cash flow.

The average added cost per home to meet the 1993 MEC is $1,156 and $336, respectively, for SF and MF homes. But the added energy efficiency embodied in the home saves the homeowner $102 and $40, respectively, for SF and MF dwellers, in annual energy costs. These savings streams over 30 years provide SF and MF homeowners a net benefit of $765 and $384, respectively, on a present value basis at a 6.28 percent discount rate. On a benefit-cost basis, adoption of the 1993 MEC produces a benefit/cost ratio of 1.8 for SF homeowners and 2.7 for MF homeowners. Total dollar savings to consumers equal $544 million on a net present value basis.

Discount Rate Sensitivity Analysis

We conducted a sensitivity analysis to determine how our findings might have been affected by different discount rate assumptions. Mortgage rates—the proxy for the discount rate for the homeowner's perspective—were varied from a low of 5.54 percent to a high of 9.75 percent. From the homeowner's perspective, we ran the analyses for both the high and low case to determine the impact on our results.

As Table G shows, the magnitude of the energy savings results are largely insensitive to discount rates on the low end. For discount rates above the base case, however, cost-effective energy savings drop—by about 25 percent of the base case for the highest discount rate. Still, even with higher discount rates, adoption of the 1993

Table F. Potential National Economic Benefits—1994
(Societal Perspective)

	Added First-Year Cost of MEC Adoption	Incremental Annual Dollar Savings	Benefit/Cost Ratio ([illegible])	Net Present Value ([illegible])	Consumer Affordability Index
Average Home:					
SF	$1,156	$102	1.8	$765	4.1
MF	336	40	2.7	384	6.4
Total (Millions)					
SF	$689	$64	—	$506	—
MF	34	4	—	38	—
Total	723	68	—	544	—

...lus added mortgage payments minus energy bill savings.

Table G. Sensitivity of Findings to Discount Rates—Homeowner's Perspective

Savings (1994 National)	Low—5.54 Percent	Medium—7.50 Percent	High—9.75 Percent
Btu (Billions)	7,557	7,424	5,068
Natural Gas (Million CF)	5,115	5,022	3,268
Electricity (Million kWh)	465	456	347
Oil (Thousands Gallons)	4,312	4,228	3,285
Dollars (Millions - NPV)	871	529	276

MEC remains economical for many of the states that had not updated their energy codes.

STATE-BY-STATE SAVINGS

This section reports state-by-state energy savings, air pollution avoidance, and economic benefits of MEC adoption for the states that had not adopted the 1993 MEC by December 31, 1994, and for which the 1993 MEC was cost-effective given our economic assumptions.

While three states (Michigan, Ohio, and Virginia) had adopted the 1993 MEC by December 31, 1994, only two carried through their decision (Michigan rescinded its adoption in 1995 under pressure from home builders). While not officially adopting the 1993 MEC, another five states had adopted state and/or local codes that were at least as stringent as the 1993 MEC. These states were California, Florida, Minnesota, Oregon, and Washington. An additional six states—Alaska, Hawaii, Montana, Vermont, West Virginia, and Wyoming—were left out of the analysis due to lack of available complete data or too few housing starts. One state, North Carolina, was left out of the study because it failed to be cost effective for both single-family and multi-family housing. Overall, 36 states and the District of Columbia were analyzed. They had either (a) not adopted the 1993 MEC, and/or (b) did not have state codes as stringent as the 1993 MEC. The 1993 MEC proved cost effective for single-family construction in 31 out of these 37 states. For multi-family construction, the MEC was cost effective in 30 states.

The fact that states "fell out" of the analysis indicates that their residential code requirements were stringent enough to make adoption of the 1993 MEC non-cost-effective. In every case, this occurred in states that had recently adopted the 1992 MEC. Also, as mentioned earlier, eight states have begun adoption of the 1993 or 1995 MEC since this analysis began. If the analysis were to be rerun, these states would also drop out. However, this does not invalidate the current study; it simply means that some states are beginning to take advantage of the benefits identified in this analysis.

Potential Energy Savings

Table H (next page) shows the state-by-state energy savings potential by Btu and fuel type from the homeowner's perspective. Several observations are apparent from examination of the table. First, housing start activity, as one would expect, is concentrated in large states, popular retirement areas, and major metropolitan areas. Second, in only a handful of states is fuel oil a major home heating energy source; the dominant fuel for heating is natural gas. Correspondingly, electricity is the dominant fuel for air conditioning. Less obvious, because it requires calculating millions of Btu saved per newly constructed home, is the potential savings from the adoption of the 1993 MEC.

Table H. State-by-State Potential Energy Savings—1994
(Homeowner's Perspective)

	Housing Starts		Btu (Billions)		Natural Gas (Millions Cubic Feet)		Electricity (Millions kWh)		Oil (Thousands Gallons)	
	SF	MF	SF	MF	SF	MF	SF	MF	SF	MF
Alabama	21,490	2,890	164	6	67	1	26	1.5	52	0
Arizona	43,370	7,480	164	8	86	4	19	1.0	64	0
Arkansas	15,680	4,920	10	14	6	10	1	0.8	0	0
Colorado	30,990	6,760	645	25	534	18	23	1.9	52	0
Connecticut	8,520	—	16	—	7	—	<1	—	54	—
DC	90	10	1	<1	<1	<1	<1	<0.1	0	0
Delaware	4,610	210	63	<1	40	<1	6	0.1	0	0
Georgia	66,910	6,850	52	9	25	<1	7	2.6	0	0
Idaho	9,880	2,370	208	9	168	7	8	0.7	33	0
Illinois	37,760	7,760	914	38	656	29	31	2.3	859	0
Indiana	—	7,190	—	19	—	14	—	1.1	—	0
Iowa	—	3,090	—	13	—	8	—	1.3	—	0
Kansas	12,900	2,440	224	9	169	6	12	1.0	37	0
Kentucky	20,930	4,450	197	12	82	2	31	2.7	21	0
Louisiana	15,910	2,290	67	3	51	2	4	0.3	0	0
Maine	6,030	330	184	2	84	2	5	0.1	581	<1
Maryland	29,580	2,770	280	5	189	<1	24	1.4	0	0
Massachusetts	17,440	—	152	—	60	—	2	—	589	—
Michigan	36,700	9,240	741	46	623	35	23	2.7	58	0
Mississippi	12,230	1,300	81	2	36	<1	12	0.5	16	0
Missouri	27,210	3,470	567	14	419	9	30	1.5	183	0
Nebraska	—	1,500	—	5	—	3	—	0.6	—	0
Nevada	23,330	—	474	—	350	—	25	—	167	—
New Hampshire	5,020	300	145	2	54	2	2	0.1	594	<1
New Jersey	17,370	3,000	271	11	154	10	19	0.4	314	0
New Mexico	—	2,010	—	4	—	3	—	0.3	—	0
New York	24,700	—	141	—	82	—	7	—	220	—
North Dakota	—	1,280	—	6	—	3	—	0.6	—	0
Oklahoma	13,950	1,490	213	5	146	4	18	0.3	0	0
Pennsylvania	36,370	—	258	—	184	—	17	—	36	—
Rhode Island	2,790	—	26	—	9	—	<1	—	108	—
South Carolina	23,090	—	100	—	48	—	14	—	28	—
South Dakota	3,050	1,010	9	3	6	2	<1	0.3	3	0
Tennessee	35,760	5,670	22	10	7	2	4	2.3	0	0
Texas	91,010	30,320	599	45	398	28	47	4.5	143	0
Utah	—	3,190	—	7	—	5	—	0.5	—	0
Wisconsin	21,730	—	102	—	74	—	4	—	74	—
Totals	716,400	125,590	7,093	331	4,815	207	423	33.2	4,288	<1

Table I. Ranking of States by Potential Energy Savings Per Newly Constructed SF Home—1994

Potential Energy Savings (Millions Btu per SF Home)	States
25–29.9+	ME
20–24.9	CO, ID, IL, MI, MO, NV
15–19.9	KS, NJ, OK
10–14.9	DC, DE
5–9.9	KY, MA, MD, MS, NY, PA, RI, TX
0–4.9	AR, AZ, CT, GA, LA, SC, SD, TN, WI

State Btu savings ranged from a high of 914 billion for Illinois to a low of 9 billion for South Dakota (and 1 billion for the District of Columbia). Energy savings per SF home varied from a low of 0.6 million Btu in Tennessee to a high of 30.1 million Btu in Maine. SF home savings average 9.9 million Btu per home.

Table I shows states ranked according to potential energy savings per home. Maine, Colorado, Idaho, Illinois, Michigan, Missouri, and Nevada all have average savings of 20 million Btu per home or greater. The high potential savings in these states likely stem from the (a) cold winters and/or (b) substantial codes improvement potential. Kansas, New Jersey, Oklahoma, and Delaware along with the District of Columbia show average savings potential of 10 to 19.9 million Btu per home. Kentucky, Massachusetts, Maryland, Mississippi, New York, Rhode Island, Texas, Pennsylvania, Arkansas, Arizona, Connecticut, Georgia, Louisiana, South Carolina, South Dakota, Tennessee, and Wisconsin exhibit very low levels of potential energy efficiency improvement either due to (a) their warm climate, and/or (b) their codes being very similar to the 1993 MEC.

Table J. Ranking of States by Potential Pollution Prevention Per SF Home—1994

Potential Pollution Prevention: Greenhouse Gases Plus Other Air Pollutants (Tons per SF Home)	States
2.01+	NH
1.51–2.0	CO, DE, IL, KS, KY, ME, MI, MO, NV, OK
1.01–1.5	AL, DC, ID, NJ
0.51–1.0	MA, MD, MS, PA, RI, TX
0–0.5	AR, AZ, CT, GA, LA, NY, SC, SD, TN, WI

Potential Pollution Avoidance

Table B showed potential pollution avoidance in total tons per year by pollutant. As discussed before, the primary pollutant is carbon dioxide, which affects global climate change. The other major pollutants are sulfur dioxide and nitrous oxide. The total pollution avoidance per state depends on both the number of housing starts and the dominant heating fuel. The highest levels of potential pollution avoidance are found where housing starts are numerous, heating energy use is high, and heat is supplied by fuel oil or coal-fired electricity.

We also compared states in terms of potential pollution avoidance per home; the results are displayed in Table J. It shows that high potential pollution savings per home are available in Colorado, Delaware, Illinois, Kansas, Kentucky, Maine, Michigan, Missouri, Nevada, New Hampshire, and Oklahoma. In these states the combination of large energy savings potential and a high proportion of more-polluting fuels create the greatest pollution avoidance potential (1.51 tons per home per year or more). Arkansas, Arizona, Connecticut, Georgia, Louisiana, New York, South Carolina, South Dakota, Tennessee, and Wisconsin—because of relatively stringent existing codes and/or less-polluting fuels—exhibit very low levels (less than 0.5 tons per home per year) of potential pollution prevention from the adoption of better building codes.

Table K. Potential Economic Benefits to Individual Homeowners by State—1994

State	Added First Cost	First Year Savings	Benefit/Cost Ratio (at 7.5%)	Net Present Value (at 7.5%)	Years to Positive Cash Flow
AL	$881	$130	2.2	$1,073	0.6
AR	100	13	1.6	84	1.8
AZ	248	88	5.2	1,046	0.3
CO	1,814	145	1.1	643	2.9
CT	123	19	1.5	201	1.7
DC	1,398	133	1.4	744	0.7
DE	2,155	203	1.4	1,054	1.7
GA	134	14	1.3	67	0.8
ID	1,819	158	1.2	863	0.6
IL	2,206	219	1.6	1,477	1.3
KS	1,752	204	1.6	1,285	2.1
KY	1,587	113	1.1	162	4.4
LA	250	47	2.7	401	0.6
MA	1,307	80	1.0	101	6.9
MD	1,036	125	1.7	905	0.7
ME	2,169	304	2.1	3,062	0.5
MI	2,094	160	1.1	572	4.6
MO	1,718	205	1.8	1,409	1.4
MS	551	126	3.8	1,315	0.4
NH	2,114	248	1.5	2,237	0.5
NJ	2,101	209	1.6	1,291	3.2
NV	2,687	175	1.1	338	5.2
NY	459	77	2.3	827	0.4
OK	1,152	159	2.1	1,205	1.0
PA	1,353	98	1.1	246	4.0
RI	1,121	83	1.0	353	2.6
SC	630	76	2.2	482	1.4
SD	117	26	1.2	291	0.1
TN	108	12	1.6	66	0.9
TX	414	89	3.6	837	0.5
WI	385	41	1.6	301	1.8
AVERAGES	$1,161	$122	1.8	$804	1.8

Table L. Top 10 States Ranked by Total Energy Savings, Savings Per Home, and Economic Measures (SF Homes)—1994

Total Energy Savings (Billion Btu)	Energy Savings Per Home (Million Btu)	Benefit/Cost Ratio	Net Present Value	Consumer Affordability Index (years to positive cash flow)
1. IL 914	1. ME 30.6	1. AZ 5.2	1. ME 3,062	1. SD 0.1
2. MI 741	2. NH 28.9	2. MS 3.6	2. NH 2,237	2. AZ 0.3
3. CO 645	3. IL 24.2	3. TX 3.6	3. IL 1,477	3. NY 0.4
4. TX 599	4. ID 21.2	4. LA 2.7	4. MO 1,409	4. MS 0.4
5. MO 567	5. MO 20.8	5. NY 2.3	5. MS 1,315	5. TX 0.5
6. NV 474	6. CO 20.8	6. AL 2.2	6. NJ 1,291	6. NH 0.5
7. MD 280	7. NV 20.3	7. SC 2.2	7. KS 1,285	7. ME 0.5
8. NJ 271	8. MI 20.2	8. ME 2.1	8. OK 1,205	8. LA 0.6
9. PA 258	9. KS 17.4	9. OK 2.1	9. AL 1,073	9. AL 0.6
10. KS 224	10. NJ 15.6	10. MO 1.8	10. DE 1,054	10. ID 0.6

Potential Economic Benefits

Table K shows the potential economic benefits to homeowners if all states in which it is cost-effective had adopted the 1993 MEC. By virtually all economic measures, investment in better building codes is economical to homebuyers. First, the benefit/cost ratios for *all* states are greater than 1.0, indicating benefits exceed costs on a present value basis (at a 7.5 percent discount rate). In fact, 9 out of the 31 states have benefit/cost ratios of 2.0 or greater.

Second, all states in the study show a positive net present value (again at a 7.5 percent discount rate). From the homeowner's point of view—when taking mortgage financing into account—in most states the Consumer Affordability Index (years to positive cash flow) is less than 1.0, meaning that the savings in energy costs exceed the added mortgage cost in the first year of homeownership.

SUMMARY STATE-BY-STATE COMPARISONS

Table L lists the top ten states by total energy savings, savings per home, benefit/cost ratio, net present value, and Consumer Affordability Index. A review of the table leads to the following observations:

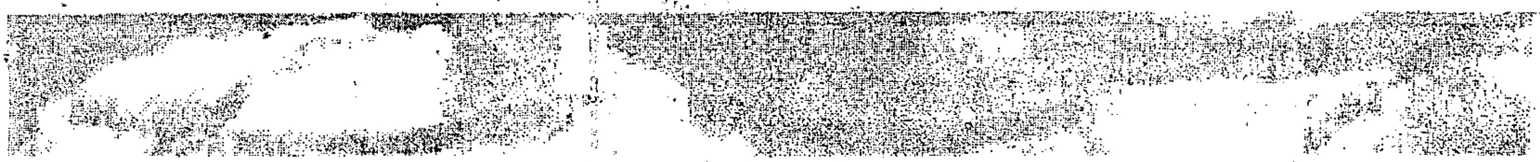
- As one would expect, the larger states dominate the ranking of total potential energy savings. Seven of the top 10 are large or moderately large states in terms of population. These states are Illinois, Michigan, Colorado, Texas, Missouri, Pennsylvania, and New Jersey. The other states—Nevada, Maryland, and Kansas—are smaller, but are experiencing high rates of housing starts.

- For potential savings per home, Maine and New Hampshire top the list with savings above 25 million Btu per home. Illinois, Idaho, Missouri, Colorado, Nevada, and Michigan contain potential savings between 20 million and 25 million Btu per home. The remaining states, Kansas and New Jersey, have per home savings of 17.4 million Btu and 15.6 million Btu, respectively. A common characteristic of these states is that they all experience cold winters.

- The top-ranked states according to benefit/cost ratio are predominantly southern or western states where the added cost of meeting the 1993 MEC is low, but potential savings are relatively high, resulting in high benefit/cost ratios. Arizona has a benefit/cost ratio of 5.2, Mississippi and Texas have ratios of 3.6, and the rest of the states have ratios between 1.8 and 3.0. The northern states in the group are New York and Maine, which experience severe winters.

- Examination of the net present value top ten shows this list is dominated by states that have high potential Btu savings per home (5 out of the top 10). They are also states with relatively high energy prices. Thus where energy savings per home and energy prices are high, consumers benefit most from MEC adoption.

- The states having low Consumer Affordability Index values, like those with high benefit/cost ratios, include both southern and northern states. In the south, the MEC boosts affordability because its compliance costs are relatively low. In northern states like Maine, the large energy bill savings are more important factors.



Methodology

As a first step in the study, we updated all of the data sets used in the 1991 study. These included marginal fuel prices, marginal fuel costs, housing starts, furnace and air conditioning equipment characteristics, technical criteria in the MEC, current state building code technical criteria, and such economic assumptions as mortgage interest rates.

We next assigned the data on housing starts, fuel prices and costs, new equipment sales, new construction characterization, building code practice, and other data for 131 cities/ Standard Metropolitan Statistical Areas (SMSAs). This city-level database was used as the basis for calculations we developed for 44 states and the District of Columbia.

The city/SMSA-level data were fed into a mainframe computer model that optimizes building design for both current code criteria and the 1993 MEC for 33 residential home prototypes. The model produced a number of outputs, including energy savings, cost savings (marginal and average), and economic analysis results.

MARGINAL FUEL PRICES

Retail energy prices determine the consumer's perceived economic benefits from more stringent building energy codes. Marginal retail energy prices were estimated for oil, natural gas, and electricity (both summer cooling and winter heating). For heating oil, we used data on No. 2 distillate prices to residences (reported by state in DOE/EIA's *Monthly Energy Review*) averaged for the months December 1993–February 1994. For natural gas, we used the space heating rates reported in *Residential Gas Bills: Winter 1993–94*, by the National Association of Regulatory Utility Commissioners (NARUC). For electric heating, we used winter rates reflecting a monthly usage level of 1,000 kWh for December-February as reported in NARUC's *Residential Electric Bills: Winter 1993–94*. For electric cooling, we used rates reflecting monthly usage of 1,000 kWh for June–August as reported in NARUC's *Residential Electric Bills: Summer 1994*.

MARGINAL FUEL COSTS

Marginal fuel costs to energy suppliers, as distinct from retail prices to consumers, serve to determine the cost-effectiveness of better building codes from the societal perspective. The 1994 average No. 2 fuel oil refiner price (for resale) was used as a proxy for the marginal cost of fuel oil. A ratio of this price to the average 1994 residential heating oil retail price was used to estimate the refiner price for each state. The 1994 average city gate (wholesale) price of natural gas was used as the marginal natural gas cost. As with fuel oil, a ratio of the city gate cost to the 1994 average natural gas retail price was calculated and used to estimate city gate gas costs by state. For electricity, a similar procedure was followed using the cost of all fossil fuels of steam electric utility plants as the guide. The oil, gas, and electric fossil fuel cost data were obtained from DOE/EIA's *Monthly Energy Review*.

Based on these data, marginal fuel costs, as a percentage of average residential retail prices during 1994, were 51.1 percent for oil, 52.8 percent for natural gas, and 61.8 percent for electricity.

In order to take into account environmental externalities, we also estimated the cost of air pollution damages, which were then added to the above marginal fuel costs. To estimate air pollution damage costs, we relied on work by Kip Viscusi performed for the U.S. Environmental Protection Agency. Viscusi (Viscusi, et al., "Environmentally Responsible Energy Pricing," *The Energy Journal*, Vol. 15, No. 2, 1994, pp. 23–42) used the scientific and economics literature and EPA research to estimate environmental damage costs associated with energy use. This work resulted in estimates of "full social cost" prices for the following fuels: petroleum, wood, coal, gasoline, diesel, aircraft fuel, heating oil, and natural gas. Each fuel contributes varying degrees of the following seven externalities: residual lead in gasoline, emitted particulates, sulfur oxides (excluding and including mortality), ozone, visibility, and air pollution toxics from motor vehicles.

Viscusi's estimates are based on the assumption that existing compliance costs have achieved a 25 percent reduction in emissions. Thus, he assumes the current compliance costs need to be multiplied by a factor of three to measure the cost of achieving *zero* emissions (the other 75 percent). This estimate is very conservative, since experience shows that the incremental cost of reducing additional percentages of pollutants tends to increase dramatically.

We also obtained mid-range estimates of the cost of air pollution—expressed as a percent of fuel price—from the work of Viscusi. These are: 261 percent for coal, 13 percent for oil, and 0.5 percent for natural gas. In addition, we also incorporated estimates for global climate change costs. Mid-range estimates of the cost of global climate carbon emissions—expressed as a percent of fuel price—were obtained from the work of Nordhaus (Nordhaus, W. D., "An Optimal Transition Path for Controlling Greenhouse Gases," *Science*, 258, November 20, 1992, pp. 1315–1319). These are 79 percent for coal, 21 percent for oil, and 14 percent for natural gas. The combined environmental costs, thus, equal 240 percent for coal, 34 percent for oil, and 15 percent for natural gas. We applied the natural gas and oil percentages directly to 1994 fuel prices. For electricity, we applied fuel-based environmental cost percentages state-by-state based on each state's generation fuel mix.

HOUSING STARTS

For 1994, housing starts data were available only at the national level. *Housing Starts: April 1995*, U.S. Department of Commerce, reported 1.2 million single-family (SF) and 244,000 multifamily (MF) starts in 1994. We also consulted *New Construction Report: Insulation: 1993–1997*, by the F. W. Dodge Residential Product Demand Group for estimates of SF and MF housing starts by state. Because the F. W. Dodge data totaled fewer starts than the Commerce data, we adjusted the F. W. Dodge state estimates upward in each state proportionally for congruence with Commerce's national totals.

Within each state we assigned the SF and MF data to the 131 city/SMSAs used in the computer model by applying weights developed from new construction permit data available in *Housing Units Authorized by Building Permits: December 1994*, U.S. Department of Commerce. Where SMSAs crossed state boundaries, breakouts into the respective states were estimated. In this procedure, the permit data and the cities were simply used as a convenient way to assign housing starts to weather regions.

FURNACE AND AIR CONDITIONING EQUIPMENT SHARES

The 1992 F. W. Dodge Residential Statistical Services report, *New Construction Report: Heating, Venting, & Air Conditioning*, provided forecast information we used to estimate 1994 new construction market shares for oil, gas, and electric furnaces, electric resistance heating, heat pumps, and air conditioning on a state-by-state basis.

THE 1993 MEC

The most widely accepted model energy code in the United States is the Model Energy Code of the Council of American Building Officials (CABO), now administered by the International Code Council (ICC). The MEC translates the advisory language of building energy standards into building codes, which are intended to be implemented and enforced. The MEC, first developed in 1982, has been maintained by CABO and now ICC and is revised each year through an annual code change cycle.

The following components were evaluated in this analysis for single-family and multi-family residential buildings: walls, roof/ceilings, floors, heated and unheated slabs, crawl space walls, and basement walls. The thermal performance criteria for these components in the 1993 MEC, broken out by the 131 cities/SMSAs in our model, were provided electronically by the Department of Energy's Pacific Northwest National Laboratory.

CURRENT STATE CODE CRITERIA

Most states do not use the 1993 MEC as their official residential building code, though many use earlier versions. In fact, at the beginning of our analysis only three states did—Ohio, Michigan, and Virginia. (Note: because Michigan never truly enforced the 1993 MEC and rescinded it in 1995, we added them to the list of states *not* having adopted the 1993 MEC in 1994.) The rest of the states fall into one of four code categories:

- a state-written code;
- a code that references or adopts language in one of the regional codes, such as the Building Officials and Code Administrators International (BOCA), the Southern Building Code Congress International, Inc. (SBCCI), or the International Conference of Building Official (ICBO);
- a prior version of the MEC or American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) standards; or
- no code at all.

For the purpose of analysis, we compared each state's current code criteria to the MEC 1993 on a building component level. Some state-written codes are more stringent than the MEC, while others are less stringent. Of the three regional model codes, only the 1996 version of BOCA is more stringent than the 1993 MEC (it includes the 1995 MEC). Where an earlier MEC version was in force, we simply compared component thermal performance values. In cases where a state did not have a code, we made estimates of current practice using ASHRAE Standard 90-A, or average builder practice in the state if this data was available. Current residential code data was collected at the building component level by the

Alliance to Save Energy by surveying state building code offices. Both housing start data and residential building code energy requirements were later verified by the Alliance.

ECONOMIC ASSUMPTIONS AND MODELING

The primary economic assumptions required for the analyses were setting the mortgage interest rate and the cost of capital for the different analytic points of view. During 1994, fixed-rate, 30-year mortgage interest rates averaged 8.325 percent and at year's end fell between 9.125 and 9.250 percent. In 1995, mortgage rates fell and by autumn ranged between 6.875 (at 3 points) and 7.250 (at 2.5 points). We chose a rate reflecting the "middle" ground of the 1994 rates—8.325 percent (at 3 points)—to reflect current mortgage economics.

We also used the following assumptions when analyzing mortgage cash flow economics from the point of view of individual homeowners: 1.46 percent property tax rate, 15 percent down payment, and 28 percent federal income tax bracket. The inflation rate was set at 2.6 percent.

Other interest rate assumptions used in the analysis were 5.54 percent (yield on 5-year CDs), 6.28 percent (yield on 30-year T-bills), and 9.75 percent (prime + 1 percent on home equity loans). The 30-year T-bill rate was used to reflect society's cost of capital. The other rates were used as alternative consumer discount rates for sensitivity analyses.

We updated the computer model—called ASE and developed by Owens Corning—that was used in the 1991 study. The ASE model consists of a FORTRAN source program and three major subroutines. ASE—the main program—reads the data, performs calculations, calls the subroutines, accumulates the results, calculates averages, and prints the output. The program calculates the heating and cooling load savings using envelope factors. The load savings are converted into energy savings using distribution loss factors and HVAC equipment efficiencies. Finally, the program converts the energy savings into annual cost savings using either marginal average prices (for consumer savings) or marginal fuel costs (for societal savings). In addition, the program calculates the costs to construct homes to meet the 1993 MEC. These calculations also take into account the ability to downsize HVAC systems based on better insulated building shells. All savings (load, energy, and dollars) are statistically weighted by housing starts, house type saturation, foundation type saturation, HVAC equipment saturation, and fuel type.

The three major subroutines are: DESIGN, WALCOMP, and ECON. The DESIGN subroutine calculates the heating and cooling design loads for sizing HVAC equipment. The WALCOMP subroutine searches for the lowest cost wall construction package that meets the overall U-value (U_o) criteria. The ECON subroutine calculates the economic and affordability tests: B/C ratio, NPV, and Consumer Affordability Index (years to positive cash flow for the homeowner).

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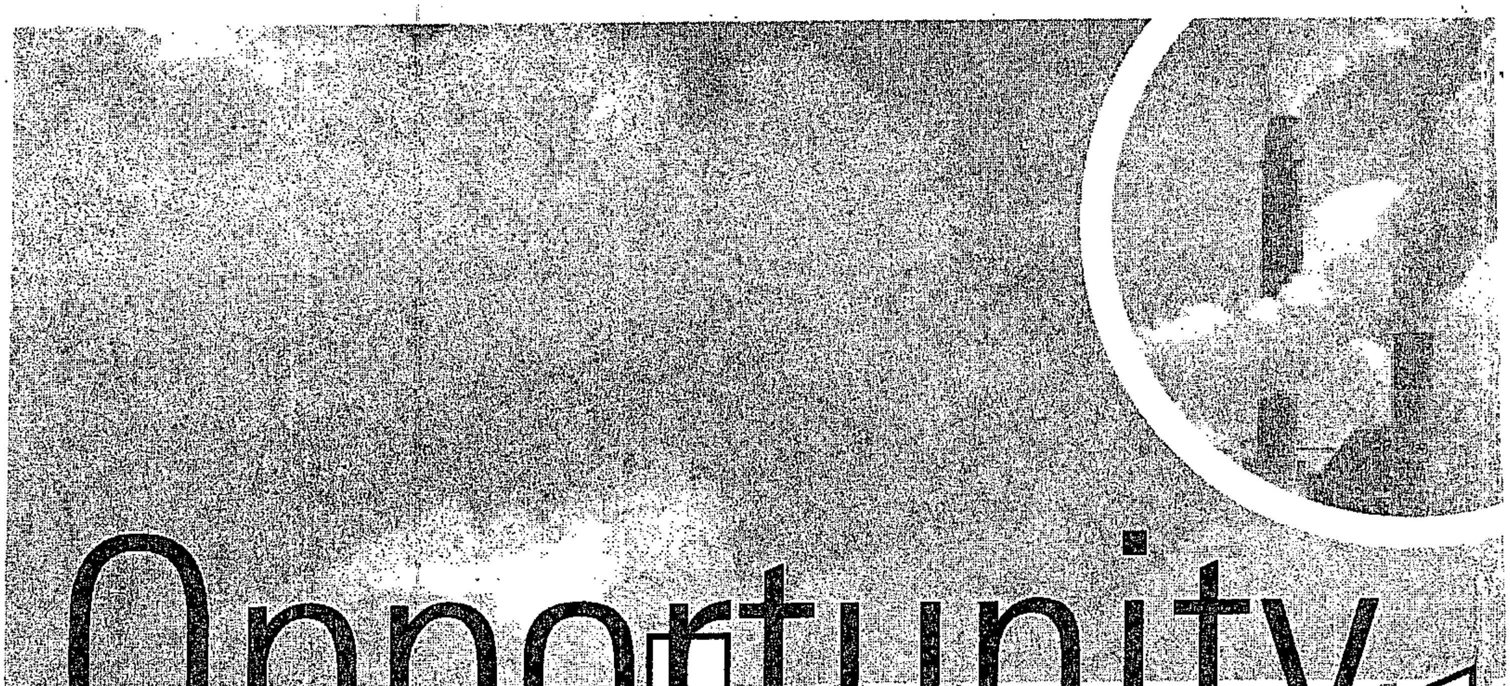
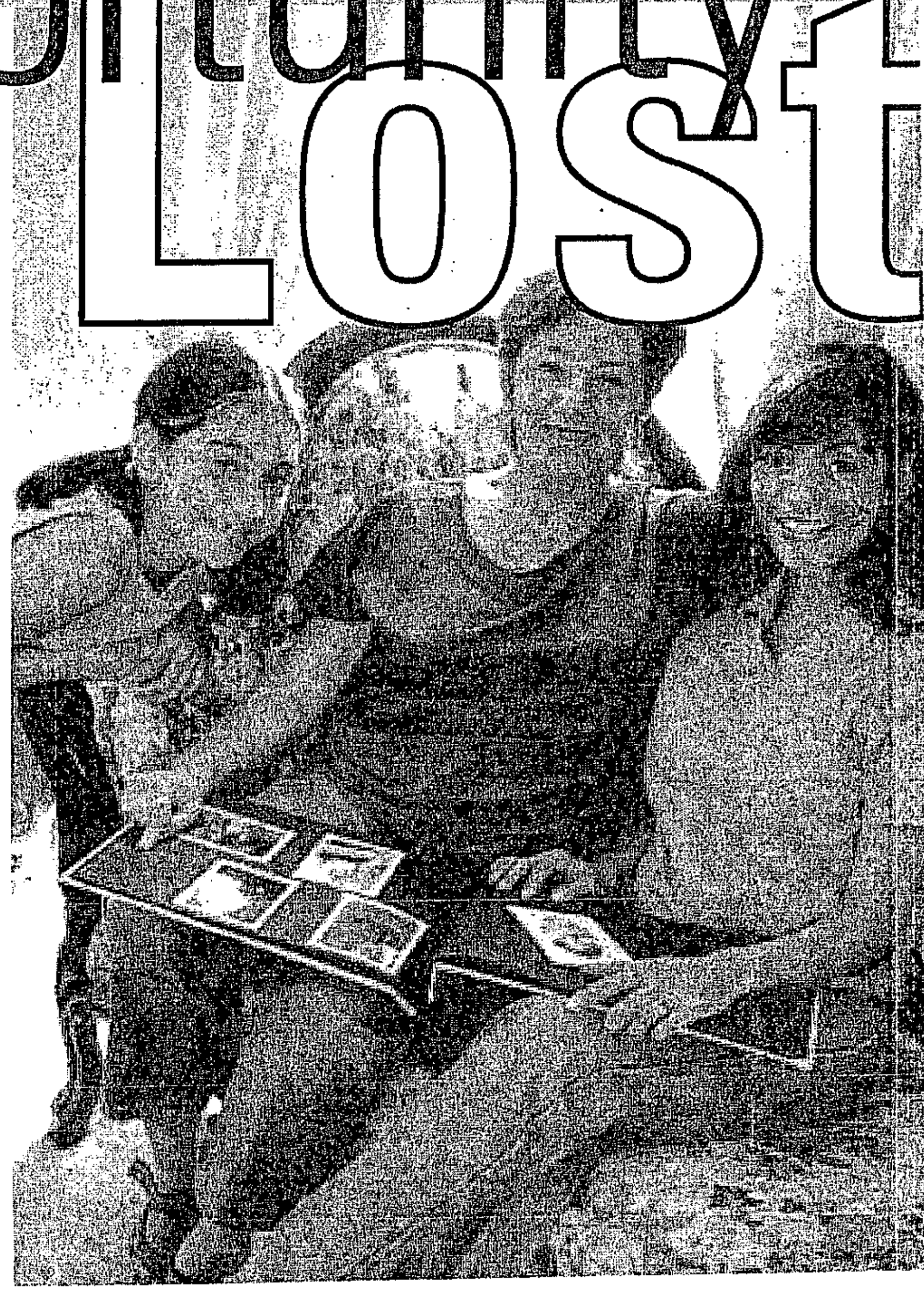


Opportunity Lost



Better Energy Codes for Affordable Housing and A Cleaner Environment

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