Impact of Higher Natural Gas Prices on Local Distribution Companies and Residential Customers

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This report examines some of the problems faced by natural gas consumers as a result of increasing heating bills in recent years and problems associated with larger amounts of uncollectible revenue and lower throughput for the local distribution companies (LDCs) supplying the natural gas. The report also discusses Federal, State, and utility assistance programs for consumers, and focuses on various innovative rate mechanisms used by LDCs, along with the use of physical and financial hedging as a risk-mitigating strategy. Lastly, the report analyzes the risk of LDCs and how the risk has changed since regulatory reform in the utility industry. Questions or comments should be directed to Lejla Alic at lejla.alic@eia.doe.gov or (202)586-0858.

Executive Summary

Natural gas prices increased for all end-use market sectors between 1999 and 2006, rising between 73 and 128 percent since 1999. These higher natural gas prices have had a significant impact on natural gas consumers as well as the local distribution companies (LDCs) supplying their natural gas. Residential natural gas consumers have been particularly affected by higher natural gas prices, which coupled with other economic factors, pose payment difficulties for a number of customers.

LDCs report that nonpayment of natural gas bills was most common for low-income customers during 2004. The increase in customer accounts past due (in arrears) translates to higher net write-offs for LDCs. Increased appliance and building efficiencies, as well as politically- or economically-induced conservation have all adversely affected the cost recovery plans for many LDCs. In an effort to mitigate the effects of decreased delivery volumes, some LDCs have tried to implement changes in how rates and bills are determined.

- The number of LDC natural gas customers in arrears and the dollar value of the overdue accounts have been rising since at least 2001. Past-due accounts and terminations are becoming more prevalent even during periods of mild weather, as energy price increases have outpaced growth in household incomes.[1] The average percentages of accounts in arrears and number of terminations as a share of total residential accounts increased by 4.5 and 2.0 percentage points, respectively, between 2001 and 2006. Related to these problems, more households are seeking assistance in paying their utility bills.
- There are a number of programs that provide assistance to consumers in need, such as the Low Income Home Energy Assistance Program (LIHEAP), a federally-funded program administered by State agencies to provide funds to help consumers pay their energy bills. The number of households eligible for LIHEAP has increased since the early 1990s, from 25.4 to 35.4 million households in 2004. With the increase in LIHEAP funds appropriated in 2005, from \$1.9 billion in 2004 to \$2.2 billion in 2005, the number of households receiving assistance climbed from 5 million to 5.8 million households.
- In addition to LIHEAP, there are many State, local and charitable assistance programs that also provide direct assistance for households that struggle with energy costs. For example, many LDCs have programs to provide payment assistance or debt relief to eligible customers. Utility assistance programs generated \$1.3 billion in funds in 2005, according to the American Gas Association (AGA). These funds often are recovered through a special fee in the bills of LDC customers, but in some instances utility shareholders cover at least a portion of the costs.
- Many States have established laws and/or regulations to shield natural gas customers from service disruptions. In particular, States have attempted to establish protections for elderly, disabled and low-income customers. For example, 41 States have policies that protect ill and disabled customers from service shut-offs, in addition to restrictions that pertain to households with elderly members or young children. Thirty-seven States have policies that protect consumers from service cut-offs based on specific dates, most of which fall during the heating season (November 1 to March 31). Finally, 24 States have policies for low-income households and 16 States have consumer protection based on temperature,

[1] Howat, John, McKim, Jerry, Harak, Charlie, and Wein, Olivia, *Tracking The Home Energy Needs Of Low-Income Households Through Trend Data On Arrearages And Disconnections*, National Energy Assistance Directors' Association (May 2004).

which generally applies to instances when the temperatures fall below 32 degrees in an LDC service area.

- Efficiency gains coupled with higher prices have resulted in decreasing residential natural gas per customer throughput and diminishing markets for natural gas utilities, thus jeopardizing full LDC cost recovery. Since the 1990s, natural gas usage per residential customer has declined across the Lower 48 States. According to Energy Information Administration (EIA) data, the average volume of natural gas delivered per residential customer in 2005 was 10.9 percent lower than in 1990. EIA data also show that the declines in natural gas use per customer were apparent in all Census divisions except the Middle Atlantic between 1990 and 2005.

- Several LDCs have proposed or adopted various methods to mitigate the impact of market changes on revenues and returns. The proposals aim to separate revenue collection from the volume of gas delivered to customers. In effect, consumers enter into a contract with the LDC and agree to pay a specific amount each month, regardless of the amount of natural gas consumed. These approaches tend to protect the LDC from the risk of under collection of revenue and protect the customer from the risk of over collection during periods of increased consumption, such as severe weather events. The number of LDCs with revenue decoupling programs is expected to grow in the near future as support for these programs grows among public agencies.

- Some rate implementation plans incorporate tracking mechanisms to monitor LDC receipts, or use another benchmark, to assess the LDCs' revenue collections relative to the approved revenue requirement based on cost of service. Once the tracking value exceeds an established threshold or range, the LDC can adjust rates or bills to compensate for the difference and recover revenue or refund excess receipts. Thirty-three alternative rate design programs with tracking mechanisms have been adopted or proposed in seventeen States. At least 15 LDCs initiated or proposed some form of rate-tracking mechanisms in 2005 and 2006.

- In addition to innovative rate structures, LDCs can utilize physical and financial hedging strategies to mitigate some of the price risk and to protect themselves and their customers from price fluctuations.

- The passage of the Energy Policy Act of 1992 and the removal of restrictions that previously dictated the ownership structure and operating requirements of LDCs resulted in a corporate realignment within the industry. Diversification away from their core business has increased LDCs' market risk. Increased risk was observed across the set of companies analyzed and proved to be far less related to the size of the companies than the percentage of revenues derived from regulated LDC operations. Based on an analysis of 49 companies, there was an inverse relationship between the percentage of company sales from LDC operations and the increase in market risk over time.

Introduction

Since 1999, natural gas prices have trended upward as continuing natural gas demand pressure, much stemming from expanded capacity for electric power generation, has left the industry operating near full capacity. Additionally, tight demand and supply balance has made the natural gas market susceptible to extreme price swings when unexpected changes occur in the market, such as weather-related spikes in demand or supply constraints caused by hurricane damage.

The U.S. annual average natural gas wellhead price was $6.23 per thousand cubic feet (Mcf) in 2006, the second-highest average annual wellhead price ever recorded, and second only to the 2005 wellhead price of $7.55 per Mcf. In the early and mid-1990s, prices were generally low, ranging between $1.89 and $2.73 per Mcf.[2] Since 1999, however, when the average wellhead price was $2.60 per Mcf, wellhead prices have roughly tripled. Similarly, the Henry Hub spot price has been trending upward, consistently exceeding $4 per Mcf since late 2002, a significant change from the average of $2.08 during the 1990s. Price spikes have been even more pronounced in shorter periods. The Henry Hub spot price reached as high as $19.43 per Mcf ($18.85 per MMBtu) on February 25, 2003, and more recently, as much as $15.85 per Mcf ($15.40 per MMBtu) on December 13, 2005.[3] Although the Henry Hub spot price has decreased from the post-Katrina/Rita peak of late 2005, it remains above the historical average price of $4.10 per Mcf that was observed between 1999 and 2002.

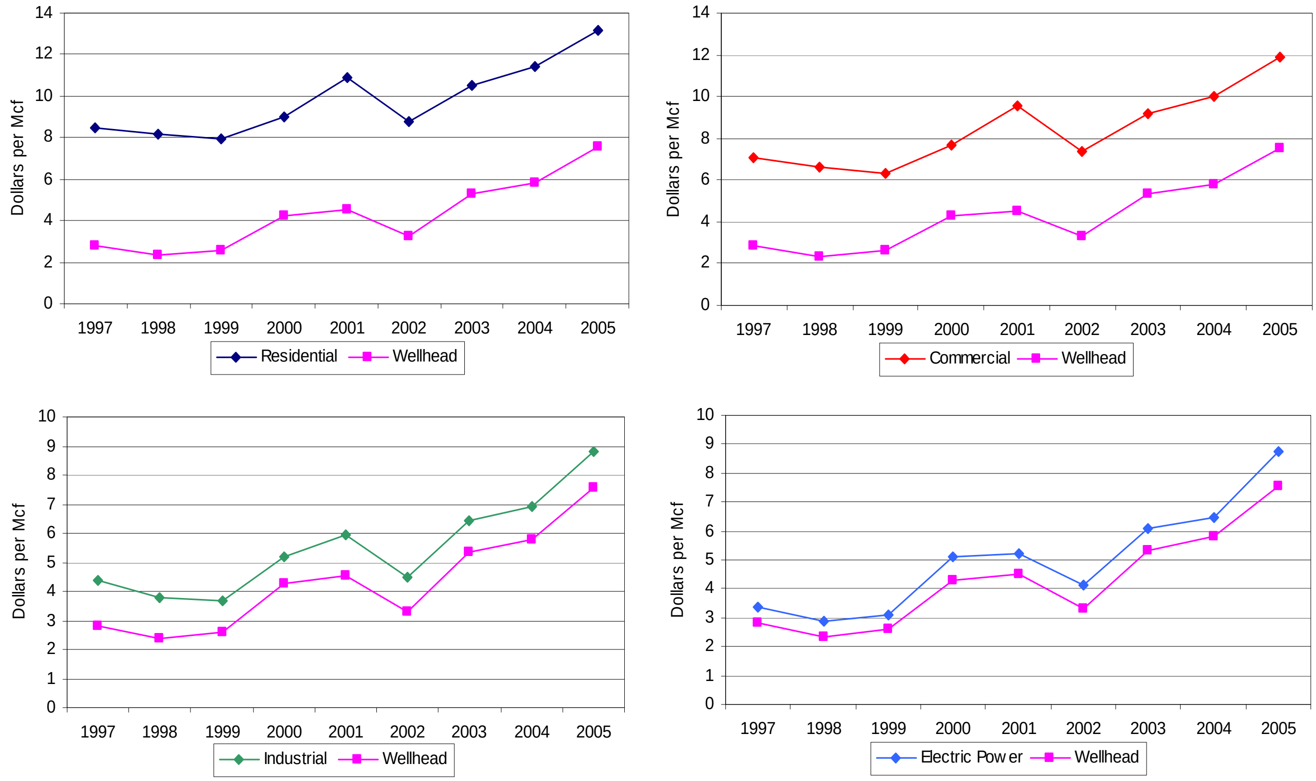
Natural gas prices increased in all end-use consuming sectors of the natural gas market between 1999 and 2006, reflecting the large increase in wellhead prices. Prices in the end-use sectors rose between 73 and 128 percent since 1999 (Figure 1). In the 1990s, residential natural gas prices averaged $8.05 per Mcf (constant 2006 dollars), increasing nearly 71 percent by 2006 to an annual average price of $13.76 per Mcf. Similarly, prices in the commercial and industrial sectors also increased, averaging $11.97 and $7.89 per Mcf, respectively, in 2006, compared with $6.32 and $3.70 in 1999.

Although the recent price trends may be an appropriate market response to prevailing demand and supply conditions, the shift to higher prices affects both consumers and suppliers of natural gas. This report addresses the impact of higher natural gas prices on residential households and the local distribution companies (LDCs) supplying their natural gas. Higher natural gas prices expose both consumers and LDCs to higher risks. Some residential customers face difficulties in trying to meet the increasing cost of energy. Some of these customers benefit from assistance programs based on Federal funding, State-sponsored programs, or programs provided by the LDCs. Adding to the complexity, LDCs have been confronted by nonpayment problems and shrinking markets caused by greater efficiencies in consumption and either politically- or economically-induced conservation. The falloff in consumption per customer, or outright reduction in market volumes has hindered the LDCs' cost recovery plans. To that end, this report concludes with an examination of the financial returns to LDCs in recent years with respect to the potential impact of recent market trends.

[2] All prices are in constant 2006 dollars. Unless otherwise stated, natural gas price and quantity data are from EIA's *Natural Gas Monthly* and *Natural Gas Annual*.

[3] Prices in Mcf were derived using conversion factors as published in Appendix B, Table B2 in EIA's *Natural Gas Annual 2005*.

Figure 1. Natural Gas End-Use and Wellhead Prices, 1997-2006
(constant 2006 dollars per thousand cubic feet (Mcf)



Source: Price data derived from Energy Information Administration's *Natural Gas Monthly*. Gross domestic product deflator information from the U.S. Department of Commerce, Bureau of Economic Analysis.

2. The Impact of High Prices on Consumers

The effect of sudden, unexpected surges in commodity prices on residential consumers depends on several factors, such as the consumer's economic status and the degree to which their suppliers, both LDCs and marketers rely on spot markets to purchase natural gas. The economic status of residential consumers in recent years was notably affected by the 2001 recession and its aftermath. Personal bankruptcies increased by 67 percent between 2000 and 2005, reaching an all-time high in 2005 of more than 2 million non-business bankruptcy filings.[4] The unemployment rate in the United States increased from roughly 4 percent in 2000 to around 5 percent in subsequent years.[5] Debt payments as a percentage of disposable income also increased to 14.5 percent for the fourth quarter of 2006 compared with 12.9 percent for the same quarter in 2000.[6] These economic factors suggest that higher prices for essential household goods or services may have become a considerable economic burden. Increased accounts in arrears for many residential consumers, particularly those who are at low-income levels, are one indication of economic difficulty.

Consumers whose suppliers, either LDCs or marketers, rely heavily on spot markets usually will incur significantly higher/lower fuel costs during periods of rapid, unexpected price increases/decreases compared with those whose suppliers rely on long-term arrangements for natural gas acquisitions. LDCs can mitigate some of this incremental cost by relying on longer-term contracts for supply acquisition or by using successful hedging strategies. However, both strategies incur risk. Inflexible pricing terms in a contract or the purchase of futures contracts as a hedging tool, while serving as protection when market prices rise, do not allow the LDCs to capture the benefits of declining prices. In such cases, volumes under these arrangements would be more costly than spot market purchases.

The number of LDC natural gas customers in arrears and the dollar value of the overdue accounts have been rising. Past-due accounts (arrearages) and terminations are becoming more sprevalent even during periods of mild weather, as energy price increases have outpaced growth in household incomes.[7] The average percentage of accounts in arrears and number of terminations as a percentage of total residential accounts based on an industry sample, increased by 4.5 and 2.0 percentage points, respectively, between 2001 and 2006.[8] Related to these problems, more households are seeking assistance in paying their utility bills.

Customer Assistance Programs

A number of programs provide assistance to consumers in need. LIHEAP is a federally-funded program administered by State agencies to provide funds to help consumers pay their energy bills. In addition to LIHEAP, there are State and local energy assistance programs funded through taxpayer initiatives, as well as charitable programs funded by private donations that provide direct assistance. Lastly, many LDCs have programs to provide payment assistance or debt relief to eligible customers.

The U.S. Department of Health and Human Services reported that during fiscal year 2004, average natural gas expenditures for all households were $1,645 and the mean individual energy burden was 6.5 percent of income. Low-income households had natural gas expenditures of $1,433, which was 14.5 percent of household income, more than twice the percentage for all households. LIHEAP-recipient households had energy expenditures of $1,598, which was about 12 percent higher than for all low-income households. The energy share for LIHEAP recipients was 19.8 percent of income, excluding assistance, which was more than 13 percentage points higher than the share for all households and more than 5 percentage points higher than for low-income households.[9]

The number of households eligible for LIHEAP has increased since the early 1990s, however, funding has not kept pace with the rise in LIHEAP eligibility and the

[4] American Bankruptcy Institute, *Annual Business and Non-business Filings by Year (1980-2006)*, http://www.abiworld.org/AM/AMTemplate.cfm?Section=Home&TEMPLATE=/CM/ContentDisplay.cfm&CONTENTID=46621, May 10, 2007.

[5] Bureau of Labor Statistics, *Labor Force Statistics from the Current Population Survey*, April 2007.

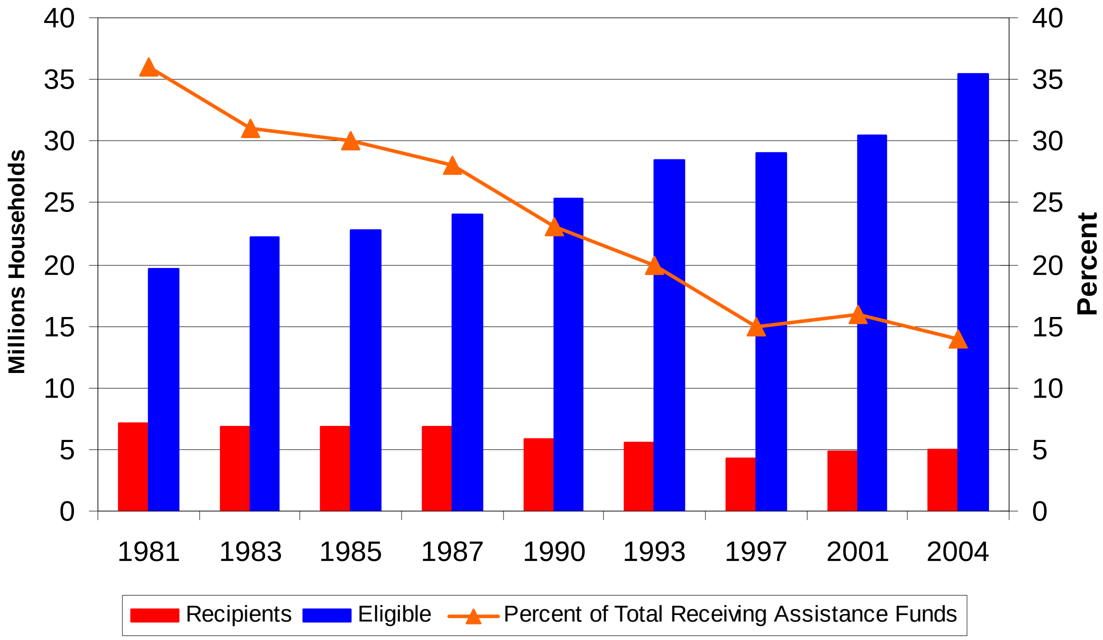
[6] Federal Reserve Board, *Survey of Consumer Finances*, http://www.federalreserve.gov/releases/housedebt/ March 13, 2007.

[7] Howat, John, McKim, Jerry, Harak, Charlie, and Wein, Olivia, *Tracking The Home Energy Needs Of Low-Income Households Through Trend Data On Arrearages And Disconnections*, National Energy Assistance Directors' Association (May 2004).

[8] National Regulatory Research Institute, *Analysis of Responses to Collections Survey* (March 2007).

[9] U.S. Department of Health and Human Services, *LIHEAP Home Energy Notebook, FY 2004* (June 2006).

Figure 2. Number of LIHEAP-Eligible Households and Number and Percent of Eligible Households Receiving LIHEAP Assistance, Selected Fiscal Years, 1981-2004



Note: Data are based on individual State eligibility criteria, which are reported to the Department of Health and Human Services and aggregated for publication in the annual *LIHEAP Home Energy Notebook*.

Source: U.S. Department of Health and Human Services, *LIHEAP Home Energy Notebook, FY 2004* (June 2006).

percentage of households receiving assistance has declined in recent years (Figure 2). The number of increased by 18 percent between 1999 and 2004.[10] LIHEAP provided $2.2 billion to more than 4.9 million households in 2005, according to the National Association of State Energy Officials. However, as of the beginning of the 2005-2006 winter, only about 20 percent of the eligible population received funds through the program, with an average payment of $311 per household.[11] Additionally, despite several years of increases recently, LIHEAP funding in fiscal year 2005 was only $720 million higher than in 1999, while the number of eligible households increased by nearly 20 percent over the same time period. Funding per eligible household increased, but the increase was not large enough to offset the increase in natural gas expenditures per household over the same time period.

By the end of the 2005-2006 winter season (March), the number of households receiving LIHEAP heating assistance had increased by 12 percent from the year-earlier level to nearly 5.8 million households, the highest number in 13 years, according to the National Energy Assistance Directors' Association. Eight States and the District of Columbia reported increases of at least 25 percent in the number of households receiving heating assistance in the 2005-2006 winter compared with the number the previous winter as detailed: Louisiana (46.2 percent), Arizona (33.7 percent), Florida (33 percent), Kansas (32.2 percent), Arkansas (30 percent), the District of Columbia (27.2 percent), Nevada (26.3 percent), California (25 percent), and Oklahoma (25 percent).[12]

In addition to customer assistance programs, over the past few years, LDCs have established numerous programs to help customers keep their accounts current and maintain natural gas service. Some LDCs, at times mandated by the public utility commission (PUC) in their States, have set up payment plans. Examples include the option for customers to pay their winter heating bills over the period of a year (or longer), and debt forgiveness for customers agreeing to pay their outstanding bills in a timely manner for a set period of time. Some LDC assistance programs also include various discounts, fee waivers, debt

[10] U.S. Department of Health and Human Services, LIHEAP Home Energy Notebook, FY 2004 (June 2006).

[11] The $2.2 billion includes administrative costs associated with the program.

[12] National Energy Assistance Directors Associations 2006 National Energy Survey (June 2006).

forgiveness, and efficiency and weatherization programs. In California, for instance, the California PUC approved a 10/20 plan for Pacific Gas and Electric Company (PG&E) that offers a 20-percent discount for customers who reduce their natural gas usage by 10 percent or more.[13] Overall, in the United States, according to the AGA, utility assistance programs generated $1.3 billion in 2005 The funds are often recovered through a special fee on the bills of LDC customers, but in some instances utility shareholders cover at least a portion of the costs.[14] These funds were distributed in the form of discounts, waivers, forgiveness of arrearages, and weatherization programs. The $1.3 billion generated through utility assistance programs are not included in the $2.2 billion in LIHEAP funds appropriated in 2005.

Disconnection Protection Measures

Many States have laws and/or regulations that shield natural gas customers from service disruptions. For instance, some States do not allow LDCs to impose late fees on customers, while others require LDCs to exhaust other ways of trying to recover the charges from the customers before they can disconnect service. LDCs also prefer to keep their customers connected and often consider disconnections as a last resort because they result in additional costs. These costs include the extra field personnel required to notify customers in person of impending shut-offs and the personnel needed to suspend the service and restore it when the outstanding debt has been resolved. Generally, LDCs will reconnect customers with outstanding debt once a payment has been made, or once the customer and the LDC have established a payment plan through which the LDC expects to recover all or most of the outstanding debt.

Most State PUCs have established certain restrictions that serve as additional protection measures for customers deemed in need. Some PUCs prohibit disconnections at times when temperatures drop to a certain level. Furthermore, there are special service protection measures for households with young children, elderly, disabled, or ill members and households that are classified as low-income.[15] Twenty-four States have special policies for low-income households. However, protections for seriously ill and disabled persons are most common. Forty-one States have special policies that protect households from service shut-offs that have an ill or disabled member, in addition to restrictions that pertain to households with elderly or young children.

Thirty-seven States have policies in place that protect consumers from service cut-offs based on specific dates, most of which are during the period of peak consumption (November 1 to March 31). However, a few States extend the date-based protection through mid-April. Sixteen States have consumer protection based on temperature, which generally applies to instances when the temperature in an LDC service area falls below 32 degrees. Cut-off restrictions can also apply in times of extreme heat. Only four States (Colorado, Florida, Hawaii, and Virginia) have no policies in place that protect consumers from shut-offs (Table 1). Both the number of States that provide protections and the number of restrictions have increased over the past few years, coinciding with the increase in natural gas prices. This was especially the case during the 2005-2006 winter season, as a number of States added special protection for those consumers enrolled in a deferred payment plan or who have arranged payment plans with their LDCs to alleviate some of the hardship caused by higher natural gas prices.

There appears to be some geographical explanation for the different service termination restrictions across the United States. Generally, States in the northern half of the country (New England, Middle Atlantic, East North Central, West North Central, South Atlantic and Mountain Census Divisions) have date-based protections against service termination in place, particularly between the months of November and April, reflecting the general expectation of cold winter weather. Alternatively, several States in the southern part of the country, such as those in the West South Central and East South Central Census Divisions, have temperature-based protection measures that stipulate that LDCs cannot cut off service to customers during extreme cold or heat. This measure is undoubtedly a result of the milder winters that generally occur in these regions of the country.[16]

[13] California Public Utilities Commission, *Preparing for High Natural Gas Prices This Winter*, Winter 2005.

[14] These costs do not include past-due customer debt that the utility eventually writes off as uncollectible.

[15] The low-income considerations are determined by States and vary across the board. Some States set the threshold at 100 percent of the Federal poverty line, while other States may consider residents in the low-income category up to 250 percent of the Federal poverty line.

[16] This statement is based on the analysis of historical gas customer-weighted heating degree-days (HDDs). According to the historical data, the normal number of HDDs in the West South Central and East South Central are fewer than normal HDDs for the Census divisions in the northern half of the country. Source: National Weather Service, National Oceanic and Atmospheric Administration.

Table 1. Disconnection Policies for 10 Largest Consumer States (Based on Residential Volume)

	Protection Based On		Special Protection For			
State	**Temperature**	**Date**	**Elderly**	**Low Income**	**Seriously Ill / Disabled**	**Deferred Payments**
CA	--	Winter Months	--	--	No disconnect year round if detrimental to health or safety of household member	No disconnect if customer on payment plan
IL	Less than 32 degrees	12/1 - 3/31	--	--	30-day delay if adverse effect to health with physician certification	--
NY	--	12/23 – 1/5	No disconnect	--	No disconnect with life support equipment; up to 90-day delay for certified medical condition. No disconnect if blind or disabled.	Utilities must offer a payment plan suited to customer's financial situation.
MI	--	11/1 - 3/31	Winter protection plan	Winter Protection Plan (below 200 percent FPG)	21-day delay if adverse effect to health with medical certificate	--
OH	--	11/1 - 4/15	--	Winter protection	30-day delay if dangerous to health as certified by medical professional; No disconnect if medical or life support equipment is necessary	No disconnect for PIP customers as long as they remain current with their PIP payment.
PA	--	12/1 - 3/31	--	--	30-day delay with medical certificate; No disconnect if health adversely affected	No disconnect if customer on payment plan
NJ	--	11/1 - 3/15	--	No disconnect for unemployed or customers receiving Lifeline, LIHEAP, TANF, SSI, PAAD or GA	2-month delay if physician certifies health adversely affected; No disconnect if (greater than $50) or (fewer than 3 months charges)	--
TX	Less than 32 degrees;	--	No disconnect	No disconnect for low-income	--	--

	During Heat Advisory		for low-income elderly with deferred plan	elderly with deferred plan		
IN	--	12/1 - 3/15	--	No disconnect for LIHEAP certified or WAP (150 percent FPG)	10-day delay with medical certificate	No disconnect for financial hardship
WI	Heat Advisory	11/1 - 4/15	21-day delay if certified. Only if customer is on a payment plan.	No disconnect if below 250 percent FPG	21-day delay if certified. Customer must agree to payment plan.	Protection for customers entering payment plans; special notice and links to assistance agencies.

Note: States in the table are ranked based on the volume of natural gas consumed in the residential end-use sector. A complete table, including notes, is available in the Appendix A.

Source: U.S. Department of Health and Human Services, *LIHEAP Clearinghouse*, November 2006.

Under current PUC policies, LDCs generally are allowed to disconnect natural gas service only to seriously delinquent customers, such as those who are more than 2 months behind on payment, outside times that are considered protection periods, and have made no effort to pay their outstanding amounts. LDCs are at times allowed to disconnect service to customers after all other legal measures of collection have failed. Customers who enter payment arrangements with the LDCs are protected under most PUC policies.

Only 12 State PUCs collect and publish data on accounts in arrears and account disconnections, so data are not available for a complete analysis of overdue account balances and account disconnections by State.[17] According to the National Regulatory Research Institute's (NRRI) *Non-Payment of Energy Bills by Low-Income Customers*, California reported the highest percentage of natural gas residential accounts in arrears as of March 31, 2004,[18] with more than 34 percent, or 1.7 million accounts of the State's residential accounts in arrears (Table 2). The high percentage of accounts in arrears in California is mostly likely due to the small number of service disconnections in the State and the State's regulatory environment. Illinois, the second-largest natural gas consuming State (by residential volume consumed in the end-use sectors in 2005) reported that 0.6 million accounts or 21.4 percent of the State's 2.6 million residential accounts were in arrears in 2004. The lowest percentage of accounts in arrears of the 12 States reported was in Tennessee, where about 10 percent of the State's 0.3 million residential customers were in arrears.

Despite having the highest percentage of accounts in arrears, California reported the lowest percentage of disconnections (1.0 percent) between April 1, 2003, and March 31, 2004, followed by Pennsylvania (2.9 percent) and Connecticut (3.2 percent). The highest percentage of natural gas residential account disconnections was reported by Indiana, where 8.4 percent of residential accounts were disconnected during the same time period.

The low disconnection rate in California likely reflects regulations in place that include special protections from service shut-offs during winter months. For example, California utilities are prohibited from shutting off service during the winter to residential customers who make regular payments of at least 50 percent of their bills. Furthermore, the California PUC imposes a shut-off moratorium for individual customer accounts regardless of the season if the disconnection is deemed detrimental to health or safety of a household member or if a customer consents to a deferred or extended payment agreement. Utilities may require such customers to comply with a levelized payment plan to avoid shut-offs or otherwise must provide such customers with 9-month repayment plans starting at the end of the winter.

[17] The 12 States that publish these data are: California, Colorado, Connecticut, Delaware, Illinois, Indiana, Maine, Missouri, Nevada, Ohio, Pennsylvania, and Tennessee.

[18] The National Regulatory Research Institute defines accounts in arrears as those that are at least 30 days overdue.

Table 2. Residential Natural Gas Accounts by State, April 1, 2003 – March 31, 2004

State	Number of Residential Accounts	Number of Accounts in Arrears	Percentage of Accounts in Arrears	Dollar Amount of Residential Accounts in Arrears (Thousand)	Number of Disconnections	Percentage of Disconnections
California	5,044,640	1,733,163	34.4	52,280	51,732	1.0
Colorado	208,747	20,534	9.8	940	8,134	3.9
Connecticut	465,311	151,675	32.6	97,350	14,179	3.0
Delaware	24,687	3,134	12.7	490	1,061	4.3
Illinois	2,622,689	560,764	21.4	194,370	111,126	4.2
Indiana	760,059	141,906	18.7	38,760	64,218	8.4
Maine	18,069	2,456	13.6	590	890	4.9
Missouri	1,266,962	209,802	16.6	37,310	61,725	4.9
Nevada	539,796	121,129	22.4	13,320	42,632	7.9
Ohio	3,020,085	519,851	17.2	45,130	161,559	5.3
Pennsylvania	1,530,131	270,201	17.7	123,250	44,449	2.9
Tennessee	295,708	28,688	9.7	5,940	21,206	7.2

Source: National Regulatory Research Institute, *Non-Payment of Energy Bills by Low-Income Customers*, June 2005.

Recently-enacted Federal legislation has made it easier for LDCs to collect the overdue amounts from their customers who have filed for bankruptcy protection. The Bankruptcy Abuse Prevention and Consumer Protection Act of 2005 has made it more difficult for consumers to erase debt by forcing more people to file under Chapter 13 rather than Chapter 7. Under Chapter 13, consumers are required to pay their creditors, including utilities, provided the LDCs have taken appropriate action, such as turning the account over to a collection agency and placing a claim for the amount owed (Box 1, Bankruptcy Abuse Prevention and Consumer Protection Act of 2005).

On the other hand, the Fair Credit Reporting Act and similar State laws have placed restrictions on the Fair Credit Reporting Act and similar State laws have placed restrictions on how aggressively LDCs can pursue customers with accounts in arrears. All bills sent to customers must include: (1) an explanation that the utility has the right to report a customer's credit history to a credit rating agency, including the right to report a customer who is more than 30 days delinquent; (2) an explanation of what a credit report is and which Federal and State laws govern credit reporting; and (3) an explanation of the consequences for their credit of not paying or paying late. Some States also require LDCs to give their customers a 30-day written notice before reporting their delinquency to a credit rating agency, so that customers have an opportunity to take necessary steps to pay their bills and avoid being reported to the credit bureaus.

The Impact of Delinquent Payments on LDCs

Residential customers' payment difficulties directly affect the financial health of many LDCs. According to NRRI, average arrearages for natural gas utilities have trended upward since 2001, with account terminations as a percentage of total residential accounts steadily increasing over the same time period.[19] The analysis further shows that the average percentage of accounts past due for LDCs increased from 16.5 percent in 2001 to 21.0 percent in 2006. At the same time, the average amount of past due accounts rose 26.7 percent from $263.30 in 2001 to $333.61 in 2006.

In one instance, according to representatives from a trade association representing publicly-owned natural gas utilities, Philadelphia Gas Works billed $42 million more than it collected from the beginning of the 2005-2006 heating season (November 1) through February 2006. In Kentucky, utilities during the 2005-2006 winter witnessed their highest ever number of complaints and the greatest number of payment-related problems for customers.[20]

[19] National Regulatory Research Institute, *Analysis of Responses to Collection Survey* (March 2007).

[20] U.S. Government Accountability Office, *Natural Gas: Factors Affecting Prices and Potential Impacts on Consumers* (February 2006).

Box 1. Bankruptcy Abuse Prevention and Consumer Protection Act of 2005

The Bankruptcy Abuse Prevention and Consumer Protection Act of 2005 made significant changes to U.S. bankruptcy laws. It was passed by the 109th United States Congress on April 14, 2005, and signed into law by President George W. Bush on April 20, 2005. Most provisions apply to cases commenced on or after October 17, 2005. The act reforms some of the bankruptcy filing practices in the United States. Some of the new aspects of the law include:

- Increasing the amount of paperwork which must be filed by every debtor, requiring pre-filing credit counseling and post-filing financial education for debtors whose debts are primarily consumer debts, increasing filing fees, and increasing attorney obligations in a manner that, collectively, will increase the cost of filing for bankruptcy.
- Making it more difficult for individuals to receive a Chapter 7 discharge.
- Making Chapter 13 less attractive by, among other things, requiring 5-year payment plans (for above median debtors) rather than the 3-year plans that were previously the norm.
- Allowing creditors to pursue collection remedies without court permission in various circumstances such as offsetting tax refunds, pursuing tax and domestic relations litigation in all respects except the final turnover of assets from the estate, and repossessing vehicles and personal property.
- Requiring that debtor counsel conducts an investigation of their clients' filings and be personally liable for them, which was not present under prior law. In addition, bankruptcy filings are now subject to audit in a manner similar to tax returns.
- Tightening the standards under which debts could be discharged in bankruptcy.
- Requiring a 730-day waiting period before a debtor may use his State's exemptions.
- Combining the 3.3-year homestead requirement with the 2-year in-State provision, which is intended to prevent consumer debtors from moving assets and domicile to a State with more favorable exemptions and filing.
- Increasing the bureaucratic compliance obligations in and shorter deadline for Chapter 11 reorganizations involving small businesses.
- Changing the treatment of complex financial contracts, including many derivative contracts used by hedge funds.

When LDCs cannot recover their costs, they have to write off these accounts.[21] According to anecdotal evidence, net write-offs for LDCs have increased as natural gas prices rose. Furthermore, industry sources report that the percentage of utility industry write-offs to overall revenue has exhibited concurrent increases with the rising prices. For example, in 2002 (the latest year for which data are available) the percentage of net write-offs to total revenue was 0.59 percent, increasing from 0.39 percent the year before.[22] In some instances, LDCs are allowed to account for their net write-offs in the tariffs they file with the PUCs in an attempt to recover their costs of doing business.[23] These write-offs filed with the PUCs are based on their past bad debt.

However, past trends in customer nonpayment may be a poor harbinger of future conditions. When natural gas prices increase beyond anticipated levels, the resulting bad debt may exceed expected levels that were the basis of the current LDC service rates. Since rate cases can be very costly and lengthy processes, LDCs sometimes have to pass on the increase in net write-offs to their shareholders instead. Recently, however, some State PUCs have allowed adoption of alternative rate structures that LDCs can implement to recover bad debt without having to go to a new rate case. The new alternative rate plans are discussed in the next section.

[21] Generally Accepted Accounting Principles (GAAP) require that a determination be made between receivables deemed to be collectible and those considered not economically collectible (including those not collectible at all). According to GAAP, uncollectible accounts cannot be considered part of accounts receivable after a certain period of time, and thus have to be written off.

[22] Chartwell, *Credit and Collections in the Utility Industry 2004* (November 2003). The report covers both electric and natural gas utilities. Chartwell reported that the 26 utilities that took part in the survey wrote off an estimated $100 million in uncollectible revenues in 2002.

[23] Some States allow LDCs to file changes only to a portion of their tariff. In this case that would be the portion that deals with the net write-offs. Other States may require LDCs to file new tariffs altogether.

3. Local Distribution Companies

LDC deliveries to end users have declined in recent years. Total natural gas deliveries to end-use sectors in 2006 were 1.3 percent below the 1997 level. Deliveries peaked in 2000 and generally declined thereafter, as prices began to increase. Declines were observed in volumes consumed by all end-use sectors except for electric power. Declining consumption by core customers is problematic because LDC systems are designed to meet core customer demand on peak days. A key factor behind the decline in aggregate residential gas consumption since 1997 is the decline in average consumption per residential household, which began in the late 1980s (Figure 3). Variation in the generally downward trend occurs because residential consumption is especially responsive to temperatures. A weather-normalized average consumption per customer series was developed to account for temperature fluctuations.[24] Without the variability in year-to-year average consumption caused by temperature variation, the long-term decline is even more apparent.

Factors behind the decline in average residential consumption include greater appliance and building efficiencies. The magnitude of the decline may have been enhanced recent years by the large increase in prices. A recent analysis report published by AGA, included estimates of short- and long-term price elasticities.[25] The negative value of the price elasticities conform to the expected inverse relation between price and consumption based on economic theory. AGA found that the annual
ate of decline in weather-normalized consumption in 2000-2006 was more than double the rate in the period from 1980 to 1999. Additionally, the downward trend in weather-normalized average consumption per customer is present across the Lower 48 States. Although short-term declines in volume are troublesome (Box 3, Weather Effects on LDCs' Operating Incomes), the impact is transitory, and the financial impact on the LDC should balance out over time. However, long-term consumption declines may erode cost recovery gradually and cause concern about the potential for market growth. Although an LDC can file for new rates that reflect the lower consumption per residential customer, this process can be lengthy and costly.

The recent price surges have exacerbated market-related problems confronting LDCs. The rather consistent increase in natural gas prices since 1999 correlates with the increase in delayed payments and nonpayments by residential customers. Late payment or nonpayment of bills increases costs to the LDC and may result in net writeoffs when bill resolution or collection efforts are unsuccessful. In light of these difficulties, some LDCs have tried to change rate determination in an effort to mitigate some of the effects of decreased delivery volumes.

Although prices may be expected to decline from the historically high average levels of 2005 and 2006, they seem to have shifted to a range significantly above that of the 1990s.[26] As higher natural gas prices persist, the issues of shrinking natural gas markets, a decline in natural gas consumption per customer, and payment problems are expected to continue. Additionally, as prices have increased, the magnitude of daily price fluctuations also has grown, which increases the price risk faced by LDCs.

This chapter provides an overview of traditional ratemaking principles and cost-of-service rate determination as background for understanding rate design issues. Furthermore, this chapter examines some of the changes to traditional rates and nontraditional approaches to service rates that LDCs have proposed to mitigate revenue shortfalls. Some companies have proposed rate design changes that make revenue collection less dependent on customers' consumption levels, while others have encouraged tracking mechanisms that periodically adjust rates or billings in response to changes in consumption levels or other benchmark values. Some of these proposals have been adopted, but State regulatory agencies differ in their acceptance of the various alternative rate mechanisms. The chapter concludes with a discussion of price hedging strategies, which are used by some LDCs to manage price risk and mitigate the potential impact of price volatility.

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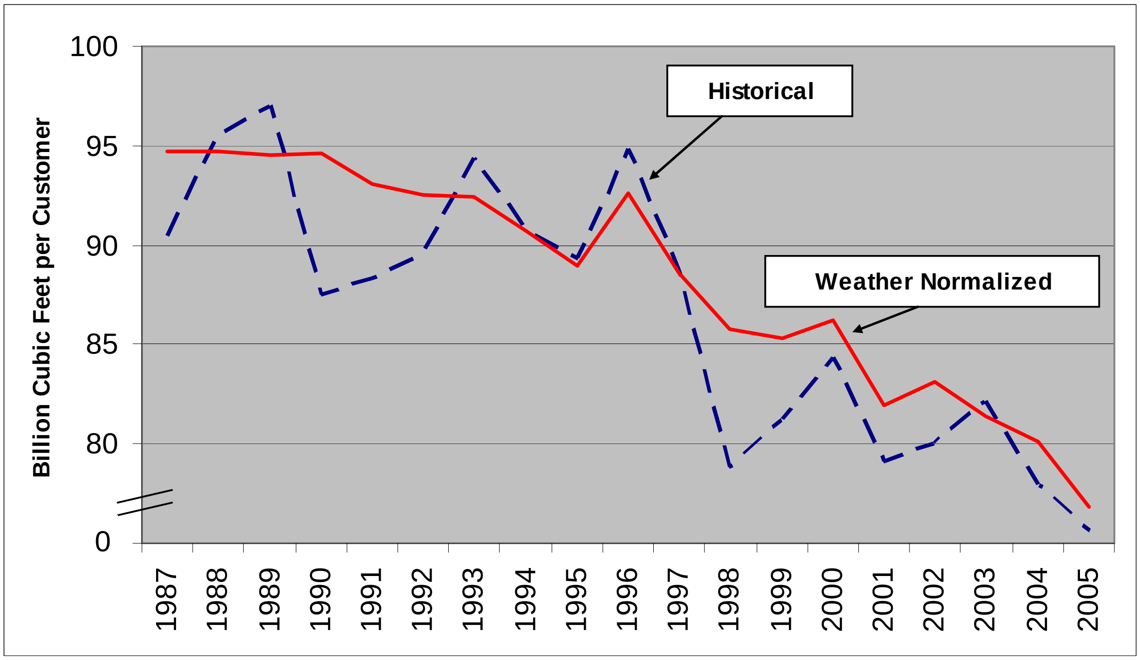
[24] The description of the method to develop the weather-normalized series is available in Appendix C of this report.

[25] Joutz, Frederick, and Trost, Robert. P., *An Economic Analysis of Consumer Response to Natural Gas Prices*, American Gas Association (March 2007).

[26] According to the Energy Information Administration's *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (February 2007), natural gas wellhead prices are expected to remain above $5 per thousand cubic feet (measured in 2007 dollars) despite declining through 2015.

Figure 3. Average Consumption per Residential Household, 1987-2005



Source: Energy Information Administration, Natural Gas Division, derived from EIA data published in the *Natural Gas Monthly* (consumption) and *Natural Gas Annual* (number of customers); and EIA's Short-Term Integrated Forecasting System (heating degree-days and normal heating degree-days).

Box 3. Weather Effects on LDC Operating Incomes

Under traditional ratemaking approaches, LDCs only make a return on the delivery service that they provide. When an LDC's rates are tied to throughput volumes, its financial returns will vary along with deliveries, which are influenced heavily by the weather. Several LDCs reported a decline in profitability for the first 6 months of 2006, because of the drop in gas consumption brought on by the warm winter in 2005-2006. While operating revenues generally rose because gas prices were higher, operating income and net income for gas distribution operations fell as delivery volumes declined and higher gas costs offset the higher prices.

- Pittsburgh-based Equitable Resources Incorporated, which operates LDCs serving about 270,000 customers in Pennsylvania and West Virginia, reported that its gas distribution volumes fell by 13 percent in the 6 months ended June 30, 2006. This occurred amid a 10-percent drop in heating degree-days during the period, which resulted in a decrease in residential energy use. Operating income from its gas distribution business fell by almost 25 percent to $29.6 million.
- The Laclede Group Incorporated, owner of the largest LDC in Missouri, serves about 630,000 customers near St. Louis. The company reported that net income from its gas distribution operation fell 10.5 percent to $35.1 million in the 9 months ending June 30, 2006, resulting from higher expenses and lower volumes. While the Missouri Public Service Commission approved a rate increase for the company in October 2005, the rate increase failed to offset the lower throughput during the 2005-2006 heating season.
- Energen Corporation's Alabama Gas Corporation, Alabama's largest LDC with 460,000 customers, recorded a net income decrease of 8.3 percent (to $36.8 million) during the first half of 2006, resulting from weak gas demand; the company's gas delivery volumes during the same time period decreased by 8.4 percent.
- UGI Corporation, owner of an LDC serving 307,000 customers in Pennsylvania, reported a 2.6 percent decline in operating income from its gas division in the 9 months ending June 30, 2006, to $82.2 million. The company cited high gas prices and warm winter weather as causal factors.

Some LDCs, however, have been able to mitigate the effects of high prices and warm weather through PUC-approved rate increases. Nicor, Incorporated in Illinois, for example, which operates the third-largest LDC in the United States, reported increased operating net income during the first 6 months of 2006, stating that a rate increase that was approved in October 2005 offset the potential losses associated with the warm weather and higher natural gas prices. Similar to Nicor, Oneok, Incorporated, also posted an increase in operating net income over the same time period.

Source: Standard & Poor's *Industry Survey: Natural Gas Distribution*, September 2006.

An Overview of LDC Ratemaking

State PUCs regulate the rates that LDCs may charge for services. Rates are determined in a rate case, which is a legal procedure that is overseen by the PUC. One objective of ratemaking is to protect consumer interests by establishing just and reasonable rates. In addition, the rates are intended to enable the LDC to earn a fair return on its investment. While there are a number of methods used to design specific rates, in general a traditional cost-of-service approach is used to estimate an LDC's revenue requirements for providing specific services and earning a fair return. The objective of cost-of-service ratemaking is that aggregate consumer payments will produce sufficient revenues to cover the utility's expenses of operation, including depreciation, income taxes, and all other taxes, and allow the firm to earn a fair return on its rate base.[27] The PUC reviews and approves the distribution of the revenue requirement among the LDC's services and customer classes, and the billing units through which the LDC revenues are collected.[28]

Under the traditional regulatory process, LDCs cannot change rates to address variations in consumption or expense levels except through formal rate case proceedings, which can be time consuming and costly. For this reason, LDCs frequently keep rates in effect for several years. Some LDCs have proposed alternative forms of ratemaking that make revenue collection less dependent on realized consumption levels. Other alternative rate design proposals allow rate modification while the rates are in effect without requiring a full rate case. These proposals generally implement tracking mechanisms that indicate the need for periodic rate adjustments to ensure the target revenue is collected. Each ratemaking approach has advantages and disadvantages for LDCs and their customers.

The approaches differ in their ability to handle problems such as declining markets or increasing amounts of uncollectible revenues. In addition, the different approaches affect the consumers' and the LDC's incentives regarding certain policy objectives, such as promoting increased conservation by its customers.

[27] Suelflow, James E., *Public Utility Accounting: Theory and Application*, Institute of Public Utilities, Michigan State University (1973), p. 159.

[28] A *billing unit* is the basic measure of an item or service for which customers are charged an approved fee. Examples of billing units relevant to ratemaking include the volume of the commodity consumed on average, peak-day volumes, and number of customers.

Regulatory Concepts and Objectives

State regulatory agencies oversee various aspects of LDC activities, including the total amount that an LDC may charge and the specific rate structure for its services. The regulatory agency's goal is to ensure that services meet certain quality standards, are reasonably priced, are provided on a non-discriminatory, and provide the LDC the opportunity to earn a fair return on equity. In this manner, price regulation governs market competition where it otherwise might be limited or nonexistent. These general principles apply whether the LDC acts as a merchant or merely transports natural gas on behalf of the customer.[29]

At the core of any ratemaking procedure is the determination of expected costs for the LDC to provide service to its customers. This cost estimate along with the approved return on the rate base is used as the target value for revenue that should be generated by LDC activities (Box 4, Components of the Rate Base).

Box 4. Components of the Rate Base

Rate Base = Net Plant + Working Capital – Accumulated Deferred Income Taxes

Where,

Net Plant = Gross Plant in Service + Allowance for Funds used During Construction
- Accumulated Depreciation, Depletion, and Amortization

Working Capital = Cash Working Capital + Prepayments (payments for services in advance such as insurance premiums) + Materials and Supplies

Accumulated Deferred Income Taxes refers to the amount of income taxes collected by the pipeline but not yet needed to pay current income taxes.

[29] When operating as a *merchant*, the LDC procures natural gas for resale to the customer. When the natural gas is resold, the cost of delivery is an ancillary service fee intrinsic to the sale. In other cases, LDCs operate as *open-access transporters* that ship and deliver natural gas on behalf of third parties. Additional information on States with unbundling programs, in which the LDC transportation services have been separated from the merchant function, is available at EIA's web page, *Natural Gas Residential Choice Programs*.

In the simple model of traditional ratemaking, expected costs and quantities are estimated in the initial proceedings. During the period for which rates are effective, if costs and quantities are relatively static, the LDC would recover its costs and a return on the rate base that is close to the approved rate. Service-related costs and quantities tended to be relatively stable in earlier years, when the entire natural gas industry from wellhead to burner tip was characterized by heavy regulation and long-term contracts. However, as wholesale markets became more dynamic, an LDC's costs and throughput quantities became more variable, and revenues and profit became more uncertain.[30]

The LDC must account for a number of factors in the ratemaking process, including the identification of service costs associated with the (1) number of customers, (2) demand (capacity to serve) functions, and (3) commodity (daily consumption) functions. The LDC apportions the costs among the various customer types or classes (e.g., residential, commercial, industrial, and electric power generators; or large-volume and small-volume consumers), among the types of services offered (sales, transportation, and storage), and between the quality of service categories (firm or interruptible). These calculations result in LDC rates that are designed to recover costs for services provided to each of its types and classes of customers based on quality of service.

The commodity cost of natural gas has been handled differently from other costs in the rate-setting process. Even under traditional ratemaking procedures the LDC typically is allowed to adjust customer rates regularly as the cost of natural gas varies.[31] This provision, often referred to as a Purchased Gas Adjustment (PGA), achieves updates that account for the actual purchased natural gas costs while avoiding the need for a more complete rate case. This treatment reflects the volatile nature of the commodity cost and its relative importance to the overall cost of delivered natural gas. The direct pass-through of commodity costs has become a fairly universal ratemaking approach to resolve issues caused by commodity price fluctuations. LDCs receive compensation for the commodity cost, but they do not make any profit on the sale of natural gas.

Components of Cost of Service

There are a number of methodologies by which LDC rates may be set, but all begin with the determination of costs, billing units, and rates of return. The cost of service that is used to develop just and reasonable rates consists of the estimated costs incurred by the LDC to provide service to its customers, as adjusted for expected changes, plus a reasonable return on investment. The cost of service establishes the revenue requirement that a regulated company must collect from its customers as compensation. Failure by an LDC to achieve its annual revenue requirement may jeopardize its ability to operate profitably and attract capital for future growth. On the other hand, collection of revenues exceeding the revenue requirement generally is considered an unacceptable outcome as a matter of public policy. The LDC develops its cost-of-service estimate by starting with values from a recent historical period (base period) and making adjustments based on a test period immediately following the base period to arrive at the forecasted annual revenue requirement.

Major components of the cost-of-service include:

- Operation and maintenance (O&M) expenses, which are the direct costs of operating and maintaining the system in an operational status. These costs are made up of labor and material expenses.
- Depreciation, depletion, and amortization expenses, which represent charges that account for the decrease in value of assets over time.
- Allowances for income and other taxes.
- Other operating expenses, which include taxes other than income taxes, revenue credits, deferred income taxes, and other such miscellaneous expenses.
- The allowed return on the rate base.

Many of the cost components are derived through standard accounting practices and may be adjusted to account for expected changes. Some components on occasion might require greater analysis of historical and current trends to support expected values in the proposed costs. For example, an LDC will adjust historical values of O&M and general and administrative (G&A) expenses to reflect anticipated measurable changes. The changes may include expected changes in employee wages, operating expenses associated with new facilities, rent, and other cost components. The LDC also calculates test period values for return, depreciation, taxes, and credits and combines these with the O&M and G&A expenses to arrive at the test period cost of service.

[30] Although regulatory reform has reached most aspects of the present natural gas industry, LDC delivery service to residential customers remains subject to a considerable degree of regulation.

[31] Early in their history, LDCs recovered natural gas costs from customers by including the costs as a line-item in their general rate proceedings. By the 1960s, LDCs began using PGA clauses to pass along the costs of purchased natural gas without entering into a full rate proceeding. A PGA clause was instituted for Laclede Gas Company in 1962. Source: Final Report of the Missouri Public Service Commission's Natural Gas Commodity Price Task Force, Case No. GW-2001-398, August 29, 2001, p. 70.

Box 5. Calculating the Cost of Service

Cost of Service = Return
+ Operation and Maintenance Expense
+ Administrative and General Expense
+ Adjustments to Estimate Expected Expenses
+ Depreciation Expense
+ Taxes
+ Other Allowances
- Revenue Credits

Where,

Return =Rate Base * Overall Rate of Return

and

- Operation and Maintenance Expenses are the funds expended for non-capital items, such as labor, rent, and materials. This is the cost of running the physical distribution system.
- Administrative and General Expenses include salaries and wages, office supplies, outside services, regulatory commission expenses, rents and general plant maintenance.
- Adjustments to Estimate Expected Expenses are entered to adjust the historical period for changes in revenues and costs that are known and are measurable with reasonable accuracy at the time of the rate filing.
- Depreciation Expense is the return of investment in the LDC facilities over the useful life of the facilities.
- Taxes include income and non-income taxes such as property taxes or ad valorem taxes, franchise taxes, and employment taxes.
- Revenue Credits refers to a reduction to the cost-of-service. If the LDC receives payment from leased facilities, a credit to the cost-of-service for these amounts may be recommended. Another example is if the LDC has collected excessive revenue from the imposition of penalties, it could be recommended that these monies be credited to the cost-of-service.

A key component of an LDC's cost of service is the return on rate base, which is calculated by multiplying the allowed rate of return by the company's rate base. Under the traditional cost-of-service approach, an LDC earns a return on its undepreciated capital investment. The rate base is generally calculated as net plant in service (gross natural gas plant in service plus construction work in progress less the accumulated depreciation, depletion, and amortization) plus prepayments and inventory items, less accumulated deferred income taxes. Some factors have a natural tendency to influence rates over time. For example, depreciation of the LDC facilities will tend to reduce rates over time by reducing the rate base on which return is computed. This reduction is offset by the LDC's investment in capital improvements and facility expansions. A listing of the components of the cost-of-service is available in Box 5, Calculating the Cost of Service.

The determination of costs is the first step towards establishing an LDC's rates. The cost estimate becomes the LDC's annual revenue requirement. The translation of the total revenue requirement into acceptable rates to charge the customers is the next step in determining the rate design.

Rate Determination

There are five steps involved in cost-of-service ratemaking.

- *Cost-of-Service Determination*. Using historical values from the base period, an LDC establishes the actual costs for providing natural gas delivery to its customers. Then, costs are estimated for the test period that may include adjustments for expected changes and a fair return on investment.

- *Cost-of-Service Allocation by Function.* The test-period cost of service is separated by LDC functions, such as transportation and storage. Common costs that are not associated with a specific function, such as administrative costs, are apportioned among the activities carried out by the LDC. The separation of costs into LDC functions is intended to avoid cross-subsidization by which revenue received for one type of service compensates for all or a part of the LDC activities dedicated to other services.

- *Cost Classification*. Costs are classified according to an LDC's rate structure, which can contain up to three rate components: demand charges, customer charges, and commodity rates. Demand and customer charges tend to be stable for a given month. The actual charges may be based on the customer, meter, or number of days—each of which is constant for a given month. The commodity rate is volumetric and applied to the amount of delivered gas. The commodity rate (per unit) may vary as the delivered volume passes stated thresholds. As a result, the actual commodity charge paid by customers varies widely as the delivered volume fluctuates between months. There is considerable latitude in classifying costs between the rate components, regardless of whether the costs themselves might be considered variable or fixed. Ratemaking goals (e.g., promoting conservation) influence the amount of fixed or variable costs allocated among the customer, demand, and commodity components.

- *Cost Allocation by Service Level*. Demand costs often are allocated among the service levels offered by the LDC based on customer capacity requirements. Commodity costs often are allocated among the service levels offered by the LDC based on customer annual or seasonal consumption. The allocation process also may incorporate the distance natural gas travels to the customer.

- *Service Rate Design*. Rates can be designed to incorporate a one-, two-, or three-part rate structure for billing. A one-part rate is designed to recover demand and commodity costs in a single monthly charge or a volumetric charge in which the customer is billed based on the number of gas units it receives. In a two- or three-part rate structure, reservation rates are designed to recover demand capacity costs; costs based on the number of customers served; and a volumetric rate to recover costs associated with the amount of natural gas delivered. Unit rates are developed by dividing the allocated demand and commodity costs by billing units for the respective services.

The rate-design process yields LDC rates that are tailored to the services rendered to each customer type so that the rate structure and revenue collection are appropriate for each customer service category. For example, firm-service small-volume customers, such as residential customers, may pay two-component rates that include customer and commodity charges only, while firm-service industrial and other large-volume customers normally pay rates with the three distinct rate components of customer, demand, and commodity. Customers using interruptible service, which has no capacity reservation rights, normally pay only customer and commodity charges without a demand fee.

Each PUC has considerable latitude in establishing rates. It is not required to conform to a simple economic or accounting framework based on fixed and variable costs. A PUC may promote various classification and allocation procedures to achieve goals that are pertinent to prevailing market or political concerns. The classification of costs between fixed or variable fees to the customer often affects an LDC's incentives, even though the expected total costs paid by each customer group remain unchanged. For example, increasing the share of costs collected in the commodity component provides an incentive for the LDC to increase throughput and extend its market by achieving higher per-customer natural gas consumption or including more customers. The economic incentive for the LDC to encourage increased consumption may run counter to other policy goals such as encouraging conservation. Shifting costs to the demand or customer rate components would mitigate this incentive for increasing consumption.

Rate Performance in Practice

The actual volume of natural gas delivered to customers generally does not match the billing units estimated for the test period in the rate case. In the short term, weather variation can cause fluctuations in energy consumption, which result in both positive and negative deviations in LDC revenue collection. As long as the consumption deviations are not significant or offset each other, there should be no appreciable net effect on cost recovery. However, if the offsets do not occur within a relatively short period, such as a year, the lingering revenue reconciliation issues may become a problem. Additionally, a prolonged period of significant temperature differences from levels on which rates were based can cause a sustained under- or over-collection of revenues. This imposes considerable risk for both the LDC and customers.

Longer-term influences on residential natural gas consumption include a trend toward warmer heating seasons, new consumption technology that improves energy efficiency, and price-induced conservation as prices have increased since 2000. Each of these factors motivates customers to reduce their individual use of natural gas. As consumption falls, the portion of fixed costs incorporated into the commodity rate will not be fully recovered, so the LDC could fail to meet its revenue requirement.

A long-term trend of declining volumes can jeopardize the LDC's ability to earn its allowed return by directly reducing revenue below expected levels. The overall revenue impact to the LDC of a reduction in natural gas deliveries can be partially mitigated to the extent that some of the LDC's fixed costs may be collected through fixed monthly demand and customer charges. Also, an increase in the number of customers served can offset a decline in per-customer consumption. In addition, an LDC may be able to mitigate the impact of volume reduction by cutting costs and improving efficiencies in operations. However, the potential to increase customers or lower costs tends to be limited in practice, thus constraining their potential to avert the need for rate adjustments.

An additional longer-term impact on cost recovery occurs in the form of delinquent payments or nonpayments, which have become more common as natural gas prices have increased in recent years. Higher commodity prices for natural gas increase customer bills. Revenue collection problems become more frequent because customers have difficulty paying larger bills. Even when delinquent payments eventually are collected, the delayed payments result in higher costs to the LDC, which hurt its financial position. Nonpayment of bills has a two-fold impact: it causes revenues to be deficient, and it adds to costs associated with additional collection efforts.

Responses to Revenue Shortfall

An LDC can address revenue under-collection issues by filing a new rate case. As previously mentioned, a rate case can be time-consuming and costly, and can expose all LDC ratemaking issues to review and possible challenge. Also, since traditional ratemaking changes are only prospective, the LDC cannot recover past uncollected revenues. LDCs recently have proposed different methods to avoid the otherwise lost revenues associated primarily with serving residential customers.

Various methods to resolve or at least mitigate the impact of market changes on LDC revenues or returns have been proposed. Approaches to modifying rates for LDC services continue to evolve, and they differ between States and even between LDCs within States. The attempts to address these issues tend to either alter aspects of current rate structures through changes such as a reclassification of costs between monthly and volumetric charges, or modifying the operation of given rates to allow for rate or billing adjustments without a full rate hearing.

The proposals aim, to various degrees and with varying methods, to decouple revenue collection from the volume of natural gas delivered to customers. Some LDCs have proposed rate design approaches to mitigate revenue under- or over-collection, while others have proposed tracking mechanisms that would automatically adjust rates to compensate for variations in specified benchmark values.[32] These approaches tend to protect the LDC from the risk of under collection of revenue and protect the customer from the risk of over collection during periods of increased consumption, such as in the case of severe weather events.

Rate Design Approach to Revenue Shortfall

LDCs have been permitted, in some cases, to alter their rate design to increase the likelihood of collecting fixed costs of distribution and the allowed return. Although redesign efforts often have attempted to shift a larger or total share of fixed costs to the relatively stable monthly fees, some LDCs have dealt with their revenue problems while retaining volumetric rates. One rate design approach was to alter the rate structure of declining block rates, so that the LDC collects most of the fixed costs, including return, on the first units of natural gas consumed. For instance, the Missouri Public Service Commission (PSC) approved rates for Laclede Gas Company that included two block rates for the distribution charge, a fixed customer charge, and two block rates for a purchased gas adjustment. The distribution charge is collected on the basis of units consumed in the first block. There is no distribution charge in the second block. By setting the volume in the first block to a relatively low level, the risk to the LDC related to under collection of costs caused by weather variation is mitigated. An advantage to the rate structure is that there is less financial disincentive for the LDC to promote conservation.

Another rate design approach is for the LDC to recover all or at least more of its fixed costs, including return, through the regular monthly customer and demand charges. Customers under this rate design generally pay higher year-round base charges than they otherwise would. This results in larger total bills during the summer months and smaller total bills than would have been otherwise during the winter months. As one example, Northern States Power Company in North Dakota charges a monthly fixed fee to residential customers for service. This cost recovery mechanism reduces the risk of not meeting revenue requirements for the LDC. This shift in payment structure also reduces the variation in bills between seasons, which is appealing to some consumers.[33]

[32] Detailed information on revenue decoupling programs using tracking mechanisms is available in Appendix B of this report.

[33] A uniform monthly charge has not been adopted in all

The key difference in the new rate designs is that the collection of revenue is structured so that cost recovery of some share or even all fixed costs remains independent of the volume of natural gas delivered to the customer. These rate programs are intended to ensure cost recovery is complete. In other cases, the rates conform generally to a traditional rate structure and changes are made to the collection process to address the adequacy of revenue recovery.

The Tracking Mechanism Approach to Revenue Shortfall

Tracking mechanisms appear under a variety of names, such as Weather Normalization Adjustment, Normal Temperature Adjustment, Customer Utilization Tracker, Revenue Normalization Adjustment, and others. While the specifics differ from case to case, generally these mechanisms track the differences between the values of an agreed performance measure and those estimated in the last formal rate case. The agreed measure differs from case to case, but measures in existing rate plans include LDC revenues, return on equity (ROE), or volumes delivered. Once the tracking value passes an established threshold or is outside a pre-established range, the LDC can adjust rates or bills to compensate for the difference and recover foregone revenue or refund excess receipts.

The permitted frequency of adjustments triggered by tracking mechanisms varies by LDC. Some LDCs apply the adjustments monthly, usually by the second billing cycle after the revenue difference has been calculated. Other LDCs apply the adjustments quarterly, semi-annually, or annually. In addition, depending on the LDC, the tracking mechanism could be in effect throughout the year or for only selected months, such as during the winter heating season.

Tracking mechanisms in ratemaking are not a new concept, although they are becoming more common.[34] At least 15 LDCs initiated or proposed some form of rate-tracking mechanism in 2005 and 2006. An example of a revenue-tracking plan is the revenue normalization plan for Maryland customers served by Washington Gas Light Company. Revenue is examined each month, and any differences owing to over- or under-collection are incorporated into the distribution charges 2 months later.

Another approach is to monitor the ROE and adjust rates or customer billings when ROE levels are outside an allowable range. As one example, CenterPoint Energy, which operates in service areas in Louisiana, Mississippi, and Oklahoma, has a PUC-approved rate with a ROE tracker in each of these States. When the realized returns are lower than the approved ROE by more than a specified tolerance, the LDC can increase rates. If the ROE exceeds the approved level plus the tolerance amount, CenterPoint is required to share the excess return with customers. Although CenterPoint must file for the changes in rates or billings, the hearing is limited and not as burdensome as a full rate hearing. Many of the key issues in a rate hearing, such as the allowable ROE, depreciation rates, cost allocation, and rate design, are not open to discussion.

As a third option, excess or deficient volumes delivered may trigger the LDC rate or billing adjustments. Cascade Natural Gas Corporation has a plan approved for its Oregon customers based on deviations from baseline volumes. Volume differences are attributable to either weather or conservation. Weather-induced volume differences, which are considered a result of normal business risk, are based on a comparative analysis of actual weather relative to normal. The remainder is attributed to conservation, and these volumes trigger billing adjustments. Accounts for each customer are settled every 12 months, with cost recovery or revenue dissemination occurring during the subsequent 12 months.

In all cases reviewed, the amount of adjustment is tracked and applied to each rate subject to the tracking mechanism. This approach is used to prevent cross-subsidization between services for the under- or over-collection of revenues. Tracking mechanisms generally are applied to those customer classes and services that tend to experience large variations in deliveries related to temperature variation. For example, virtually all of the tracking mechanisms reviewed apply to residential customers, with only a few applying to interruptible services.[35] Beyond that, a customer class or service subject to a tracking mechanism depended on the services offered by the LDC and how the respective LDC identified its customer classes.[36] In those cases where the

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cases. As one counter example, the Atlanta Gas Light Co. (AGL) received approval to collect its fixed charges in a monthly demand charge in the late 1990s. However, its customers were used to receiving higher bills in the colder months and lower in the summer. A uniform monthly fee was judged to be less acceptable, so the total annual fee was scheduled as monthly fees with a seasonal quality that yielded higher rates in the winter and lower rates in the summer. Source: American Gas Association, "Exploring the Philosophy of Rate Design," *American Gas*, November 2006.

[34] For example, the Baltimore Gas and Electric Co. has been applying a monthly rate adjustment under Rider 8 of its Gas Service Tariff since at least May 1998.

[35] As one example of a program that includes more than firm residential customers, the Washington Gas Light Co. Revenue Normalization Adjustment plan includes monitoring and adjustments of all rate schedules. See Appendix B.

[36] LDC services are typically titled somewhat generically, such as General Service, Firm Service, or Basic Firm Sales

LDC offered unbundled service, the tracking mechanism was applied to residential transportation service.

The tracking mechanisms generally track and adjust rates for changes in deliveries, but the mechanisms also may account for changes in the number of customers so that the LDC is not unduly rewarded or penalized for changes to usage per customer or its number of customers.

Issues Related to Tracking Mechanisms

With tracking mechanisms, differences between the actual deliveries and the estimates used to develop rates become less important to the LDC's ability to recover its approved costs. The LDC revenue collection becomes more volume neutral in that it is less affected by whether it reaches or exceeds certain delivery levels. However, the LDC still endeavors to achieve an accurate estimate of expected volumes in rate cases to avoid significant shifts in rates. One advantage of tracking mechanisms often touted by supporters is that they can lessen the cost of regulation by allowing rate modifications without a full rate hearing. This reduces the regulatory costs to LDC, its customers, and the public agencies.

Many PUCs have embraced tracking mechanisms as the appropriate method to mitigate the revenue impact of consumer conservation and other variations in deliveries, while some have decided that tracking mechanisms may not be appropriate for their circumstances.[37] When reviewing proposals, PUCs must carefully consider how tracking mechanisms will affect LDCs and their customers. Potential impacts of tracking mechanisms include:

- The customer's ability to save money through conservation. The tracking mechanism is designed to stabilize LDC revenues for service when consumption varies. The lower savings limit the perceived incentives for consumers to conserve, because a customer using fewer units saves only on the cost of the commodity itself without a reduction in service costs.
- More timely reduction in rates as the LDC customer base increases. An LDC will pass along the reduction in rates much faster through a tracking mechanism than would otherwise occur through a traditional rate case.
- More stable and consistent earnings for LDCs.
- A possible reduction in the allowed return to LDCs associated of reduced operating risk. As a matter of PUC policy, the rate of return that determines the LDC's profit level is related to the risk experienced by like, non-regulated businesses. It is argued by some that application of a tracking mechanism reduces the chances that the LDC will under-collect revenue and, thus, reduces its business risk. However, others argue that LDCs still face substantial business risk and reducing allowable rates of return is inappropriate and provides a disincentive for investors.
- Profit earnings in excess of an LDC's authorized rate of return. When tracking mechanisms track revenues not earnings, an LDC may reduce costs while revenues are maintained.[38] This situation could result in the LDC earning a return in excess of its allowed level. An LDC would have little incentive to file a new rate case under these conditions.

Alternative rate design has been accepted for LDCs in a number of States, although its use is far from universal. Even where implemented, the details of each program vary. There are 33 alternative rate design programs with tracking mechanisms that have been adopted or proposed in 17 States.[39] These programs include 12 that are "weather-tracker" programs based on temperatures. Another 11 programs track revenues directly and make rate adjustments when receipts differ from target levels by more than an allowed threshold. Many of the benchmark values in the revenue-tracker programs are adjusted to account for weather variations, which are generally considered part of normal business risk. There are nine programs that focus on the LDC returns or "margins," where the margin is a form of net revenue, and one program (Laclede in Missouri) that rewards customers when they reduce their natural gas usage by at least 10 percent from a prior period.

The number of LDCs with revenue decoupling programs is expected to grow in the near future. In addition to the programs identified as active or proposed, other programs are under consideration. As one recent example, the New York State PSC directed the State's major natural gas (and electric) utilities to develop proposals for a true-up process for revenues based on revenue decoupling

Service, and the consumption requirements of the customer usually determine the service that applies. As such, one often cannot identify a specific customer class to which a tracking mechanism may apply.

[37] For example, the Iowa Utilities Board determined that energy efficiency measures are not interfering substantially with Iowa's natural gas utilities' opportunity to earn their authorized rate of return. State of Iowa Department of Commerce Utilities Board, Docket No. NOI-06-1, Order Addressing Issues and Closing Docket, December 18, 2006.

[38] Since the tracking mechanism rate adjustments rely on designed rates, volumes, and number of customers, it does not reflect actual operating costs over the tracking period.

[39] Some of the LDCs have multiple programs. A detailed listing of the 33 programs appears in Appendix B of this report.

mechanisms. The commission did not encourage adoption of any particular approach, but it will require revenue decoupling proposals in ongoing and new rate cases.[40] In a similar action, the Senate Energy and Natural Resources Committee in early May 2007 included language that encouraged State regulators to allow utilities to decouple revenues from gas volumes. Although the language, which was included in S.B. 1115, was endorsed by interested groups, such as the AGA, it is not binding on State agencies. However, it is expected that congressional endorsement of the concept may build support among the States.[41]

Since not all State PUCs have allowed alternative rate design, inevitably shareholders bear some of the loss associated with bad debt and net write-offs. States that allow alternative rate designs for the purpose of lowering the impact of uncollectibles to the LDC differ in how much may be recovered through these mechanisms. Some States allow full recovery, while others allow only partial recovery. For example, the Michigan PSC approved an uncollectible expense true-up mechanism in the form of a customer surcharge for Michigan Consolidated Company. However, in an attempt to provide an incentive for the utility to keep uncollectibles as low as possible, the PUC allowed a 90 percent recovery level under the mechanism.

LDC Price Hedging

LDCs build and manage a portfolio of supply, storage, and transportation services that include a diverse set of contractual agreements to meet consumer consumption requirements during high-demand months. The use of storage through much of the history of the industry has been to provide enhanced supply security during peak demand periods. The large price increases in recent years, along with the associated volatility, has motivated increased interest by LDCs to protect themselves and their customers from high and volatile prices through the use of physical and financial hedging strategies. Hedging generally refers to a strategy that is designed to minimize or limit exposure to price risk. Physical hedging can consist of storage use or forward physical commodity purchases, while financial hedging is conducted using any combination of derivative contracts traded in the market.[42]

Most, if not all, LDCs utilize storage to help ensure supply security during peak demand periods and for load balancing. Some LDCs operate their own storage facilities, while others, such as those that may not have the required geological formations in their service territories to develop on-system storage fields in a cost-effective matter, rely on third-party storage facilities. Natural gas in storage serves as a reserve for critical demand days and for balancing against unforeseen load variance. Storage facilities, often located close to major consuming markets, are well situated to provide more supply security than other natural gas supply sources during peak demand periods. Utilizing storage facilities allows the LDCs to avoid potential congestion along long-haul pipeline systems. In addition to the benefit of supply security, storage utilization also serves as a physical hedge against price risk by mitigating the impact of price swings experienced in the wholesale market.

Another type of physical hedging strategy includes the forward physical purchase of natural gas, in which an LDC enters into a longer-term contract, usually between 1 and 5 years, with a supplier. Depending on terms of these contracts, the LDC may be able to lock in a specific price for the natural gas it receives from the supplier for the duration of the contract. With prices that are set or subject to limited flexibility, the risk of spot market price fluctuations is reduced. Further, if natural gas spot prices are expected to exceed prices under the longer-term contract, the LDC can expect to receive natural gas throughout this period at an average cost that would be lower than if the LDC had relied solely on spot market transactions. Additionally, the purchase of natural gas using a forward physical contract gives the LDCs a degree of supply security.

Financial hedging is another strategy LDCs use to guard against volatile price movements and protect their business through risk mitigation. LDCs can engage in trading of swap, futures, put option, and call option contracts to achieve their objective.[43] Financial hedging instruments are not expected to be devices through which physical supply is delivered, although some of them include obligations for physical delivery under certain conditions. They are instruments that are intended to manage price risk by locking in prices, or establishing price ceilings, floors, or both. For commercial traders, these transactions have an associated physical transaction at some point in the future. An LDC that uses these financial instruments to lock in a price or establish a price

[40] State of New York Public Service Commission, "PSC Seeks more Efficient Energy Use," 07027/06-G-0746 (April 18, 2007).

[41] "Senate Panel Adopts Bill Urging LDC Rate Decoupling," *Gas Daily*, Platts, May 7, 2007, p. 7.

[42] In finance, a derivative is a financial instrument that is derived from an underlying asset's value. Rather than trade or exchange the asset itself, market participants enter into an agreement based on the underlying asset to exchange money, assets, or other value at some future date(s). There are many types of derivative contracts, but futures, options, and swaps are the most common ones.

[43] A detailed discussion of different financial hedging tools is beyond the scope of this paper. For more information on futures, options, and swaps, see for example, Bodie, Zvi and Merton, Robert, *Finance*, pp. 284-317.

ceiling and/or floor will have an offsetting position in the natural gas physical markets.

Physical and financial hedging strategies benefit an LDC and its ratepayers by providing cost stability and may result in lower prices than those incurred by relying on the spot market. However, if the objective of the LDC is to procure natural gas at the lowest possible price, using a hedging strategy involves the risk that prices may move counter to expectations upon which the hedging strategy was formulated. As the price terms become more restrictive to limit the impact of adverse market price movements, the ability of a participating LDC as a natural gas purchaser to capture gains from favorable price movements will diminish.

According to an AGA report, as of 2005, companies reporting for at least 107 separate jurisdictions stated that PUCs have officially addressed the use of financial hedging mechanisms in their respective States, with regulators allowing hedging in 98 jurisdictions.[44] PUCs have approved the use of financial derivatives to hedge against natural gas supply price increases and to protect the consumers from significant price fluctuations.[45] Furthermore, PUCs have allowed in most cases that costs and benefits associated with hedging be accounted for under purchased gas adjustment (PGA) or gas cost recovery (GCR) programs and passed through to the customer.

In a 2006 AGA survey, 87 percent of companies responding to the survey indicated that they used financial instruments to hedge at least a portion of their supply purchases for the 2005-2006 heating season, increasing significantly over the 70-percent level in the previous year. Financial tools used most often were options, fixed-price contracts, swaps, and futures contracts to hedge natural gas volumes. For the same heating season, nearly all LDCs reported using storage as a primary hedging tool, with about 50 percent of companies reporting that they hedged between 26 and 50 percent of their winter heating season supplies.[46] When asked about the timing of hedging strategies, 79 percent of the responding companies indicated that they employ a 6-month or less strategy for a portion of their hedges, while only 21 percent of companies used a 7- to 12-month strategy. (See Box 6, Example of an Alternate Hedging Scenario)

While hedging does not guarantee an LDC that it will attain the lowest price, hedging offers the opportunity to mitigate the risk associated with price volatility. Besides price risk, LDCs are exposed to systematic and other types of risk that cannot be mitigated by hedging, and the next section discusses this in detail.

[44] A company can have more than one jurisdiction in its service territory. Source: American Gas Association, "AGA Rate Inquiry: Regulatory Hedging Policies, Summer 2005."

[45] According to an American Gas Association survey, 59 percent of all responding LDCs stated that PUCs in their areas were equally concerned with lowest possible price and price stability. About 24 percent reported that PUCs were concerned with lowest possible price and the remaining 17 percent reported that price stability was the most important objective for PUCs. Source: American Gas Association, *LDC Supply Portfolio Management During the 2005-2006 Heating Winter Season* (September 2006).

[46] American Gas Association, *LDC Supply Portfolio Management During the 2005-2006 Heating Winter Season* (September 2006).

Box 6. Example of An Alternate Hedging Scenario

To illustrate a possible outcome of hedging strategies over the past 5 years, an analysis of actual data between 2002 and 2006 compares the actual spot market price for heating season months to a price that could have been achieved under alternate hedging strategies and outcomes. For the purpose of the example, there are two possible hedging schedules, a 6-month hedge and a 12-month hedge. The 6-month hedge assumes that the upcoming heating season natural gas supply price is established through hedging decisions made at some point during the immediately preceding 6-month period (April through September). Therefore, all hedging decisions for all months of the heating season are made prior to November. The 12-month hedge assumes that hedging decisions are made over a longer period of time preceding the heating season.

The potential for acquiring higher or lower prices through hedging is represented in the table below. The "low hedge" outcome assumes that the price hedged for the heating season was the lowest possible price during the hedging period. The "average hedge" outcome assumes that the price achieved during the hedging period was an average price, while the "high hedge" outcome assumes the worst possible timing of securing a price and that the hedged price turned out to be the highest recorded spot price during the time period. The following tables present the outcome of the analysis. Positive differences in the (Cost) or Benefit section of the tables indicate the hedge price was lower than the actual spot price, producing a lower cost to the consumer.

6-month Hedges				
Heating Season	2003-2004	2004-2005	2005-2006	2006-2007
Average Spot Price During the Heating Season ($/MMBtu)	5.49	6.38	9.29	7.15
Average Hedged Price for Contracts for Delivery During Heating Season ($/MMBtu)	5.67	6.63	9.42	9.99
Lowest Possible Hedged Price for Contracts for Delivery During Heating Season ($/MMBtu)	4.62	5.44	6.99	5.39
Highest Possible Hedged Price for Contracts for Delivery During Heating Season ($/MMBtu)	6.86	8.03	14.99	12.48
(Cost) or Benefit Achieved Using				
Average Hedge ($/MMBtu)	(0.18)	(0.25)	(0.13)	(2.84)
Low Hedge ($/MMBtu)	0.87	0.94	2.30	1.76
High Hedge ($/MMBtu)	(1.37)	(1.65)	(5.70)	(5.33)

12-month Hedges				
Heating Season	2003-2004	2004-2005	2005-2006	2006-2007
Average Spot Price During the Heating Season ($/MMBtu)	5.49	6.38	9.29	7.15
Average Hedged Price for Contracts for Delivery During Heating Season ($/MMBtu)	4.62	5.54	7.44	10.37
Lowest Possible Hedged Price for Contracts for Delivery During Heating Season ($/MMBtu)	3.75	4.59	5.86	8.74
Highest Possible Hedged Price for Contracts for Delivery During Heating Season ($/MMBtu)	5.64	6.72	10.49	11.87
(Cost) or Benefit Achieved Using				
Average Hedge ($/MMBtu)	0.87	0.84	1.85	(3.22)
Low Hedge ($/MMBtu)	1.74	1.79	3.43	(1.59)
High Hedge ($/MMBtu)	(0.15)	(0.34)	(1.20)	(4.72)

Source: EIA, derived based on spot and futures data from Natural Gas Intelligence, *Daily Gas Price Index*.

From the preceding analysis, it is evident that the hedging related benefits of a near-term hedging strategy are smaller than the benefits of a longer-term strategy. This was true for all years with the exception of the 2006-2007 heating season, as both futures and spot prices during the latter part of 2005 increased significantly as a result of the hurricane-induced shut-ins and production disruptions. While the benefits of a longer-term strategy are bigger, so is the risk associated with it. Both need to be considered in evaluating alternative financial hedging strategies.

4. LDC Operations and Risk

Over the past decade, several powerful trends have led to a realignment of the highly fragmented natural gas distribution industry in the United States. The number of companies operating in the distribution sector shrunk from about 2,000 in the mid-1990s to less than 300 companies that own and operate LDCs by 2006. Legislative and regulatory changes, higher natural gas prices, energy efficiency gains, as well as increased competition, have created new risks and potential rewards for LDCs. Furthermore, creation of merchant services has allowed LDCs to take advantage of more business opportunities. Responding to this new environment, previously independent natural gas utilities have combined with other regulated utilities, and also with new, unregulated energy-related businesses, in an attempt to manage and to profit from these new risks. As a result, today's LDCs often are part of a holding company that operates several different businesses. In some instances, LDC operations are the holding company's primary business, which may include other commercial activities such as wholesale natural gas marketing, unregulated power generation, oil and natural gas exploration and production, interstate pipeline transportation and storage, or non-energy-related businesses such as timber or even shipping. In other cases, LDCs may be relatively small parts of large multi-utility or holding companies (see Box 7, Utility Holding and Multi-Utility Companies).

Despite the business mix of individual energy holding companies, the basic business model of an LDC has remained unchanged. While regulatory reform took place allowing for the playing field of LDC-operating companies to change, LDCs continue to operate in a regulated industry. An LDC's ability to recover its investment as well as to realize its allowed rate of return depends in large part on its throughput of natural gas. A decline in natural gas consumption since at least the mid-1990s reduced natural gas delivery volumes and eroded profits for many LDCs, jeopardizing the cost-of-service recovery (see Chapter 3). The emerging long-term trend of reduced throughput is a major concern to all companies that operate LDCs. Both EIA data and industry-published data have provided insight into the magnitude of declining throughput. This chapter discusses some of the perceived reasons behind this trend and its effect on LDCs. The chapter also discusses the market risk of LDCs and the impact of structural changes in the market on the LDCs' risk.

LDCs and Declining Throughput

Efficiency gains coupled with higher prices have resulted in decreasing throughput and diminishing markets for natural gas utilities. Since the 1990s, although there is some evidence that the declines started even earlier, usage per residential customer has declined across the Lower 48 States. The trend toward smaller markets is widespread; lower throughput was observed for all types and sizes of utilities (investor-owned, municipal, cooperatives, privately-owned).

According to industry sources, efficiency gains in space-heating equipment and other natural gas appliances account for about 60 percent of the per customer reduction in throughput since 1990.[47] The National Appliance Energy Conservation Act (NAECA) of 1987 mandated minimum energy efficiency standards for several types of household appliances and equipment such as air conditioners, furnaces, water heaters, and heat pumps. This followed earlier voluntary appliance-efficiency targets in the Energy Policy and Conservation Act (EPCA) of 1975 and various State efficiency standards. In response to these various standards, manufacturers have improved the energy efficiency of household appliances and equipment over the past 30 years. Other contributing factors to declining throughput included more efficient homes (28 percent), as well as a reduction in the number of natural gas appliances in homes served by natural gas (6 percent).[48]

Box 7. Utility Holding and Multi-Utility Companies

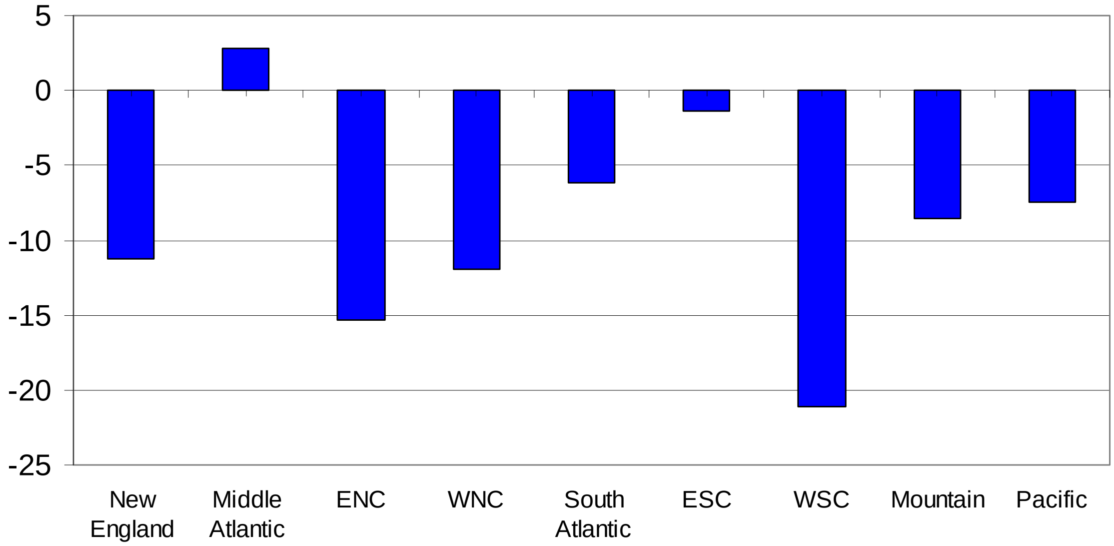
A holding company is a company that owns part, all, or a majority of other companies' outstanding stock. It usually refers to a company that does not produce goods or services itself but instead exists for the sole purpose of owning shares of other companies. Holding companies allow the reduction of risk for the owners and can allow the ownership and control of a number of different companies. Eighty percent or more of voting stock must be owned before tax-consolidation benefits such as tax-free dividends can be claimed.

Multi-utility companies refer to (1) companies that were formed as a result of mergers of utility network companies (such as natural gas LDCs and electric utilities) and (2) multi-utility supply companies, principally the dual-fuel companies. The merging of utility services offers benefits to customers in terms of reduced prices and improved services, which may not be achieved otherwise. To the extent that there are such benefits, the PUC regulators generally try to ensure that some are passed on to customers.

[47] American Gas Association, *Patterns in Residential Natural Gas Consumption, 1997-2001*, June 2003.

[48] American Gas Association, *Patterns in Residential Natural Gas Consumption, 1997-2001*, June 2003.

Figure 4. Percentage Change in Residential Per Customer Deliveries byCensus Division, 1990-1992 and 2003-2005 (3-Year Averages)



Note: Because of the significant variations in weather, 3-year averages are used in the analysis in order to reduce the influence a significantly warmer than normal winter may have on consumption in a given year.

Source: Energy Information Administration, derived from data collected on the EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition."

According to EIA data, the average U.S. residential per-customer volume delivered in 2005 was 10.9 percent lower than in 1990.[49] EIA data also show significant declines in the use per customer in all Census divisions except the Middle Atlantic between 1990 and 2005 (Figure 4). Even during periods of colder-than-normal winter weather, as measured by natural gas customer-weighted heating degree-days, per customer deliveries in 2005 were lower than in the 1990s.

The largest decreases in per customer consumption were recorded in the West South Central Census Division, which includes the mostly producing States of Arkansas, Louisiana, Oklahoma, and Texas, where declines reached 20.2 percent between 1990 and 2005. Similarly, per customer throughput in the West North Central Census Division declined 18.2 percent. The large consuming areas of the East North Central Division, which includes Chicago and other large population centers, had per customer consumption decreases of 13.7 percent. Similar findings were reported in a June 2003 study by the AGA, which stated that natural gas use per customer declined by 16.0 percent from 1980 through 1996, followed by an additional 6.4-percent decline from 1997 through 2001.[50] Furthermore, the AGA reported that use per customer declined in all regions of the country, as per-customer use declined 1.74 Mcf per year in the Northeast between 1997 and 2001, while declines in the South and the West amounted to 2.17 Mcf and 4.31 Mcf per year, respectively.

On the State level, the EIA data show that nearly all States had lower throughput in 2005 than in 1990, with the exception of Connecticut, Hawaii, Maryland, Maine, New Jersey, and New York, where the average per-customer consumption in 2003 to 2005 was higher than in 1990 to 1992. The decreases in throughput ranged between 3 and 29 percent, with the highest decreases in Texas and Arizona.

LDCs and Market Risk

Because their returns are regulated and their industry is mature, LDCs traditionally have had limited growth

[49] The comparison of consumption data includes all investor-owned, municipal, privately-owned, and cooperative LDCs that responded to the EIA-176 survey. A complete list of respondent LDCs can be obtained from the EIA-176 query system at http://www.eia.doe.gov/oil_gas/natural_gas/applications/eia176query.html. According to EIA's *Short Term Energy Outlook* degree-day data, heating and cooling degree-days were 6.0 and 8.3 percent higher, respectively, in 2005 compared with 1990.

[50] American Gas Association, *Patterns in Residential Natural Gas Consumption, 1997-2001*, June 2003.

prospects. Historically, earnings for LDCs have grown at rates comparable to population growth rates, usually about 1 percent to 2 percent annually, and share prices tend to lag shifts in the larger market. Until the 1990s, there was little that managers of LDC companies could do to raise their growth rates and boost shareholder returns. That changed, however, during the latter half of the decade, when regulatory reforms took effect that allowed LDCs to form holding companies that could invest in other unrelated businesses that offered stronger growth prospects.[51] However, the opportunity for enhanced growth was accompanied by greater risks.

Box 8. Capital Asset Pricing Model and Beta Coefficient

The Capital Asset Pricing Model (CAPM) is used in finance to determine a theoretically appropriate required rate of return of an asset. The CAPM takes into account the asset's sensitivity to non-diversifiable risk (market risk), referred to as the beta-coefficient in the financial industry, as well as the expected return of the market and the expected return on a risk-free asset.

The beta coefficient, which is a key parameter in the CAPM, is calculated using regression analysis. It measures the part of the asset's statistical variance that cannot be mitigated by the diversification, because the return on the asset is correlated with the return of the other assets in the market.

The model differentiates between market risk and specific risk. Market risk is common to all securities, and cannot be diversified away, while the specific risk is associated with an individual asset and thus can be reduced with diversification. In theory, for a well-diversified portfolio, the specific risk can be reduced to 0, limiting the exposure of the portfolio to market risk only. By definition, the market itself has a beta of 1.0, and individual stocks are evaluated based on how much they deviate from the market. Assets with higher betas imply a greater volatility and are thus considered riskier, but in return provide a potential for a higher return. Lower-beta assets pose less risk, but also lower returns.

More specifically, a stock that has a beta of 2 follows the market in an overall decline or growth, but does so by a factor of 2, meaning that when the market has an overall decline of 3 percent a stock with a beta of 2 would fall by 6 percent. Betas can also be negative, implying the stock moves in the opposite direction of the market. A stock with a beta of -3 would decline 9 percent when the market goes up 3 percent and conversely would climb 9 percent if the market fell by 3 percent.

Source: Bodie, Zvi, and Merton, Robert, *Finance*, pp. 343-359 (June 2001).

The passage of the Energy Policy Act of 1992 and the removal of restrictions that previously dictated the ownership structure and operating requirements of LDCs resulted in a corporate realignment within the industry. The outcome of the numerous mergers and acquisitions that followed during the latter half of 1990s was an industry made up of fewer companies operating in the market than before, many of which were holding companies that owned utilities along with non-utility businesses.

The corporate realignment of the 1990s slowed greatly in 2001, when the Enron Corporation bankruptcy and the power crisis in California undermined investor confidence in the benefits of asset diversification. During 1998 and 1999, a total of 18 mergers involving LDCs were announced. In contrast, between 2000 and 2004, there were only 6 announcements. The confidence of the market recently, though, seems to have returned as mergers and acquisition activity within the natural gas distribution industry increased dramatically during 2006. LDCs seeking combinations are looking to drive earnings growth by cutting overhead, duplicated functions, and other costs, and by expanding into areas of stronger demand growth. Several large transactions were announced during the first 7 months of 2006.

The mergers and formation of holding companies have had a significant impact on the risk exposure for LDCs. Companies diversifying away from their core LDC business in the post-1992 environment may acquire more risk overall. Despite potential cost or efficiency advantages resulting from a merger, the diversified company may be exposed to additional non-diversifiable risk associated with LDCs and their holding companies.

To evaluate the market risk of LDCs and how it has changed, a regression analysis was performed. The LDCs' sensitivity to non-diversifiable risk (market risk), referred to as the beta-coefficient in the financial industry (see Box 8, Capital Asset Pricing Model and Beta Coefficient),

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[51] Passage of the Energy Policy Act (EPACT) of 1992 eliminated most restrictions on utilities' mergers and acquisitions as previously set forth in the Public Utilities Holding Company Act (PUHCA) of 1935. In 2006, however, the EPACT of 2005 repealed PUHCA, completely removing any restrictions with respect to mergers, acquisitions, diversification, and overall business strategies placed on the utility industry. For more information on PUHCA, see http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/pubutility.html.

was compared across companies as well as with the market. For simplicity purposes, the Standard and Poor's 500 Index was used as a proxy for the market as a whole. A sample of 49 companies was chosen with their month-end stock closing prices between January 1999 and February 2007, taking into account all dividends paid during the time period.[52] The beta coefficients were estimated using the Capital Asset Pricing Model (CAPM).

Based on the regression results, LDCs' betas have increased significantly over time, implying that the LDCs are more exposed to market risk than in the past.[53] Particularly striking were some of the increases in beta coefficients for LDCs between 1999 and 2002 compared with the coefficients for the companies between 2003 and 2007 (Table 3). This increase in beta coefficients coincide with the impacts of regulatory changes in the natural gas utility industry in the early to mid-1990s and the almost doubling of average prices between the two periods. With the 1992 repeal of certain Public Utility Holding Company Act (PUHCA) of 1935 restrictions on regulated utilities, many LDC operating companies entered various unregulated lines of business.[54] Previously, investors were willing to accept a lower growth rate and a lower return on their investment in return for a lower risk. With the structural changes that came about in the post-1992 utility industry, the formerly low-risk companies transformed into companies whose risk was significantly higher and closer to that of the overall market.

All but 4 of the 49 companies in the sample exhibited a higher degree of market risk after 2002 than between 1999 and 2002. LDCs' mergers, building and buying new unregulated, merchant energy power generation assets, acquiring overseas operations, and establishing (and funding) trading desks, as well as expanding into novel areas such as telecommunications, construction, and even healthcare, undoubtedly contributed to the increase in the market risk of the utility holding companies. However, this strategy of diversification, at least during the period of marked increases in natural gas prices, did not result in the same growth rates for stock prices as that of the overall market. Very few matched and exceeded the 247-percent growth of the Standard and Poor's (S&P) 500 fund between 1992 and 2006, and stock prices for the sample of companies increased by an average of 84 percent during the same period. Bond ratings reflect some of the increased risk of these companies, albeit with a lag. In 2006, the average credit rating of LDCs was A-, ranging widely between AA- and BB-. The financial industry deems the credit outlook for this industry to be slightly negative and expects that on average, bonds will be downgraded in the future. The estimated beta coefficient for the S&P LDC Index was 0.8054 for the time period between 1999 and 2002 and 0.6251 for 2003 to 2007.

The increasing risk between the two analysis periods is evident for LDCs of varying sizes (Table 4). However, the risk of the companies appears to be less clearly related to their size than the percentage of revenues derived from regulated LDC operations. Based on the analysis of 49 companies grouped by dollar value of total sales, there was a relationship between the percentage of company sales from LDC operations and the increase in market risk over time. It is evident that the higher the percentage of regulated operations of a holding company, the smaller the increase in the market risk. Conversely, companies that derived a very small percentage of sales from regulated LDC operations experienced the highest increases in their betas.

Clearly, the degree of risk for LDCs in the analysis increased between the two periods, 1999 to 2002 and 2003 to 2007. The expanded risk reflects the influence of a number of factors. Natural gas prices increased greatly between periods, and this trend tends to discourage consumption, thus jeopardizing LDC cost recovery. In addition, corporate structures have evolved with a shift toward more operations in non-regulated commercial activities outside regulated natural gas, which may offer opportunities for higher returns albeit with greater risk.

Lastly, LDCs have been experiencing an increasing trend of overdue accounts, as well as a rise in the average amount of accounts in arrears. Despite efforts to maintain service when payments are overdue, there has been an increase in LDCs' net write-offs. The increase in beta coefficients for the LDCs, along with the expectation of downgrading of bond ratings for these companies at least partially reflected the combined influence of these significant industry conditions.

[52] While there are many more LDC-operating companies in the industry, only 49 were chosen for the sample. The criteria for sampling included choosing companies that are publicly traded on the New York Stock Exchange and the American Stock Exchange and companies that were in existence between January 1990 and February 2007.

[53] For more information on the regression model, see Appendix C.

[54] The Energy Policy Act of 1992 eliminated many of the PUHCA restrictions. However, PUHCA was completely repealed with the passage of the Energy Policy Act of 2005.

Table 3. Beta Coefficients for a Sample of 49 Companies and LDC Index, 1999-2007

	Raw Beta Coefficients		Adjusted Beta Coefficients		Change in Beta Coefficients	SE of Beta Coefficients	
Company Number	1999-2002	2003-2007	1999-2002	2003-2007		2003-2007	1999-2002
1	0.1925	0.4849	0.4590	0.6549	0.1959	0.4849	0.4590
2	-0.1762	1.1178	0.2119	1.0789	0.8670	1.1178	0.2119
3	-0.2653	0.3306	0.1522	0.5515	0.3993	0.3306	0.1522
4	0.1033	0.4897	0.3992	0.6581	0.2589	0.4897	0.3992
5	-0.2980	0.6178	0.1303	0.7439	0.6136	0.6178	0.1303
6	0.0938	0.2806	0.3928	0.5180	0.1252	0.2806	0.3928
7	-0.0343	0.9808	0.3070	0.9872	0.6801	0.9808	0.3070
8	0.0154	0.4848	0.3403	0.6548	0.3146	0.4848	0.3403
9	0.0136	0.3072	0.3391	0.5358	0.1967	0.3072	0.3391
10	0.4499	1.8516	0.6314	1.5706	0.9392	1.8516	0.6314
11	-0.0987	0.4186	0.2639	0.6105	0.3466	0.4186	0.2639
12	0.2488	0.2704	0.4967	0.5112	0.0145	0.2704	0.4967
13	0.0150	0.3025	0.3401	0.5327	0.1926	0.3025	0.3401
14	0.1894	0.8725	0.4569	0.9146	0.4577	0.8725	0.4569
15	0.1951	0.3091	0.4607	0.5371	0.0764	0.3091	0.4607
16	0.1372	0.4622	0.4219	0.6397	0.2178	0.4622	0.4219
17	-0.0563	0.1996	0.2922	0.4638	0.1715	0.1996	0.2922
18	0.5502	0.4193	0.6986	0.6109	-0.0877	0.4193	0.6986
19	0.0719	0.9812	0.3782	0.9874	0.6093	0.9812	0.3782
20	-0.1543	0.3924	0.2266	0.5929	0.3663	0.3924	0.2266
21	0.1330	0.3869	0.4191	0.5892	0.1701	0.3869	0.4191
22	0.0961	0.6620	0.3944	0.7735	0.3791	0.6620	0.3944
23	0.3266	0.3576	0.5488	0.5696	0.0208	0.3576	0.5488
24	0.0446	0.6304	0.3598	0.7524	0.3925	0.6304	0.3598
25	0.0100	0.4361	0.3367	0.6222	0.2855	0.4361	0.3367
26	0.1635	0.2346	0.4395	0.4872	0.0477	0.2346	0.4395
27	-0.1304	0.4007	0.2427	0.5984	0.3558	0.4007	0.2427
28	0.1097	0.2790	0.4035	0.5169	0.1134	0.2790	0.4035
29	0.0655	0.5218	0.3739	0.6796	0.3057	0.5218	0.3739
30	0.2509	0.6134	0.4981	0.7410	0.2429	0.6134	0.4981

31	0.0239	0.5281	0.3460	0.6838	0.3378	0.5281	0.3460
32	0.5634	0.6182	0.7075	0.7442	0.0367	0.6182	0.7075
33	0.2692	0.1204	0.5104	0.4107	-0.0997	0.1204	0.5104
34	-0.0144	0.5787	0.3203	0.7177	0.3974	0.5787	0.3203
35	0.1047	0.0954	0.4001	0.3939	-0.0062	0.0954	0.4001
36	0.2145	0.6016	0.4737	0.7331	0.2594	0.6016	0.4737
37	0.1636	0.3722	0.4396	0.5794	0.1398	0.3722	0.4396
38	-0.0292	0.3613	0.3104	0.5721	0.2616	0.3613	0.3104
39	-0.2504	1.5206	0.1622	1.3488	1.1866	1.5206	0.1622
40	0.2333	1.8866	0.4863	1.5940	1.1077	1.8866	0.4863
41	0.0771	0.3125	0.3817	0.5394	0.1577	0.3125	0.3817
42	0.1301	0.4280	0.4172	0.6168	0.1996	0.4280	0.4172
43	-0.2007	0.4052	0.1955	0.6015	0.4060	0.4052	0.1955
44	0.0615	0.4316	0.3712	0.6191	0.2479	0.4316	0.3712
45	0.2098	0.5616	0.4705	0.7063	0.2358	0.5616	0.4705
46	0.1815	0.3730	0.4516	0.5799	0.1283	0.3730	0.4516
47	-0.2325	0.4701	0.1742	0.6450	0.4708	0.4701	0.1742
48	0.1012	0.3582	0.3978	0.5700	0.1722	0.3582	0.3978
49	0.0255	-0.1648	0.3471	0.2196	-0.1275	-0.1648	0.3471
LDC Index	0.6056	0.4700	0.7357	0.6449	-0.0908	0.1625	0.3420

Note: The LDC Index (LDC S&P 500 Index) comprises companies whose main function is to distribute and transmit natural and manufactured gas. It excludes companies primarily involved in natural gas exploration or production, as well as diversified midstream natural gas companies.

Source: *Global Financial Database.*

Table 4. Average Adjusted Betas and Percentage of Sales Revenues from LDC Operations, 1999-2007

		Average Adjusted Beta Coefficients		
Company Total Sales	**Number of Companies**	**1999-2002**	**2003-2007**	**Average Percentage of Sales from LDC Natural Gas Operations**
Less than $1 billion	8	0.1783	0.3250	70.1
$1 billion - $3 billion	17	0.3028	0.6249	52.0
$3 billion - $6 billion	10	0.3712	0.7852	22.2
Greater Than $6 billion	14	0.3717	0.7932	37.8

Note: the number of companies in each size class is based on 2006 SEC filings.

Source: Company-specific financial information: Hoover’s, Incorporated. Betas were derived using the CAPM (see Appendix C for more information).

5. Summary

Recent higher natural gas prices have had a significant impact on natural gas residential consumers as well as LDCs supplying their natural gas. Residential consumers have been particularly affected by the higher prices, which coupled with other economic factors, pose difficulties for a number of customers. Problems with payment have been especially prevalent among low-income customers. According to most recent data, the number of LDC natural gas customers in arrears and the dollar value of the overdue accounts have been rising since at least 2001. Past-due accounts and terminations are becoming more common even during periods of mild weather, as energy price increases have outpaced growth in household incomes. As a result of these problems, more households are seeking assistance in paying their natural gas bills.

There are a number of programs that provide assistance to consumers, such as LIHEAP, a federally-funded program administered by State agencies to provide funds to consumers. The increase in eligible households for LIHEAP funds has outpaced the increase in appropriations. Still, in 2005, 5.8 million households received funding, which was an increase from the previous year's level of 5 million households. In addition to LIHEAP, a number of State, local and charitable assistance programs also provide direct assistance for households that struggle with energy costs. For example, utility assistance programs generated $1.3 billion in funds in 2005, which are often recovered through a special fee in the bills of LDC customers, but in some instances utility share holders cover at least a portion of the costs.

Most State public utility commissions have established regulations to shield natural gas customers from service disruptions when assistance programs are not sufficient to cover the gap between household incomes and energy costs. In particular, States have attempted to establish protections for elderly, disabled and low-income customers. For example, 41 States have policies that protect ill and disabled customers from service shut-offs, in addition to restrictions that pertain to households with elderly members or young children. In addition, 37 States have policies that protect consumers from service cut-offs based on specific dates, most of which fall during the heating season (November 1 to March 31). Finally 24 States have policies for low-income households and 16 States have consumer protection based on temperature, which generally applies to instances when the temperatures fall below 32 degrees in an LDC service area.

LDCs have also been experiencing problems resulting from higher natural gas prices. These problems have manifested themselves in increased customer past-due accounts, which have resulted in higher net write-offs for LDCs. Additionally, the long-term trend of increased appliance and building efficiencies, as well as politically- or economically-induced conservation, have all adversely affected the cost recovery plans for many LDCs. According to EIA data, since the 1990s, natural gas usage per residential customer has declined across the Lower 48 States. Even when adjusted for weather, there is clear evidence that the higher prices have supported conservation, which in turn have led to diminishing markets for LDCs. Since the LDCs' cost recovery depends on the volume throughput, the long-term trend of decreased per customer usage jeopardizes LDC cost recovery.

In an effort to mitigate the effects of decreased delivery volumes, some LDCs have tried to implement changes in how rates and bills are determined. Several LDCs have proposed or adopted various methods to mitigate the impact of market changes on revenues and returns. The proposals aim to separate revenue collection from the volume of natural gas delivered to customers. These approaches tend to protect the LDC from the risk of under collection of revenue and protect the customer from the risk of over collection during periods of increased consumption, such as during severe weather events. The number of LDCs with revenue decoupling programs is expected to grow in the near future as support for these programs grows among public agencies.

Some rate implementation plans incorporate tracking mechanisms to monitor LDC receipts, or use another benchmark, to assess the LDCs' revenue collections relative to the approved revenue requirement based on cost of service. Once the tracking value exceeds an established threshold or range, the LDC can adjust rates or bills to compensate for the difference and recover revenue or refund excess receipts. Thirty-three alternative rate design programs with tracking mechanisms have been adopted or proposed in seventeen States. At least 15 LDCs initiated or proposed some form of rate-tracking mechanisms in 2005 and 2006. In addition to innovative rate structures, LDCs can utilize physical and financial hedging strategies to mitigate some of the price risk and to protect themselves and their customers from price fluctuations.

In addition to higher prices, changes in the industry over the past decade have also affected the performance of LDCs. The passage of the Energy Policy Act of 1992 and the removal of restrictions that previously dictated the ownership structure and operating requirements of LDCs resulted in a corporate realignment within the industry.

Diversification away from their core business has increased LDCs' market risk. Increased risk was observed across the set of companies analyzed and proved to be far less related to the size of the companies than the percentage of revenues derived from regulated LDC operations. Based on an analysis of 49 companies, there was an inverse relationship between the percentage of company sales from LDC operations and the increase in market risk over time.

Appendix C. Calculating Weather Normalized Use per Customer

Step 1. Calculate the weather normalization factor, which is the ratio of normal heating degree-day to actual heating degree-days.

Step 2. Calculate the average consumption of July and August for each year. This is the proxy for base natural gas consumption per customer for a year.

Step 3. Subtract the base consumption from actual consumption for the next 10 months (September through June). This is referred to as "temperature-driven" consumption. For example: the average of July and August 1999 will be subtracted from September 1999 through June 2000.

Step 4. To calculate the weather normal consumption per customer series, multiply the temperature-driven consumption variable by the weather normalization factor. Intuitively, a very cold winter will have relatively high levels of consumption. The very cold weather means that the denominator in the weather normalization factor is large relative to the normal heating degree-days. Multiplying the large consumption variable times the factor, which is less than one, will bring back or reduce consumption towards the normal temperature-driven consumption level.

Step 5. Add the base consumption per customer back into the September through June normal temperature-driven consumption levels.

Source: Adopted by Energy Information Administration based on Joutz, Frederic, and Trost, Robert, *An Economic Analysis of Consumer Response to Natural Gas Prices*, American Gas Association (March 2007).

Appendix D. Estimation of Beta Coefficients

The capital asset pricing model, with assumptions about no transaction costs or private information, examines an investor who holds a portfolio that includes every traded asset in the market. The risk of any investment is the risk added on to this "market portfolio." The expected return from the model is

Expected Return = Riskfree Rate + bjM (Risk Premium on Market Portfolio)

The beta for an asset can be estimated by regressing the returns on any asset against returns on an index representing the market portfolio, over a reasonable time period where the returns on the asset represent the dependent variable, and the returns on the market index represent the independent variable. The regression equation is as follows:

Rj = a + b RM

where Rj is the return on investment j, and RM is the return on the market portfolio, otherwise called a market index. The slope of the regression "b" is the beta, because it measures the risk added on by that investment to the index used to capture the market portfolio. In addition, it also fulfills the requirement that it be standardized, since the weighted average of the slope coefficients estimated for all of the securities in the index will be 1.

Estimation of beta-coefficients necessitated using a proxy for the market portfolio, as in practice there are no indices that can measure the actual market portfolio. Instead, there are equity market indices and fixed income market indices that measure the returns on subsets of securities in each market. This analysis relied on the Standard and Poor's (S&P) 500, which is the most widely used index for beta estimation for U.S. companies. The S&P 500 includes only 500 of the thousands of equities that are traded in the U.S. market. However, the rationale for the use of the S&P 500 is that it is market-weighted.

The time period (January 1999 to February 2007) for the analysis was chosen so that there would be enough observations. However, over an extended period, the companies themselves may have changed their characteristics in terms of business mix and leverage over the period. To account for the latter, the (adjusted) betas in Table 3 were estimated over two time periods: 1999 to 2002 and 2003 to 2007.

Another factor that affects the beta estimate is the choice of return intervals, which can be measured daily, weekly, monthly, quarterly, or annually. For this analysis, monthly returns were chosen, which are generally deemed to provide sufficient observations for companies listed for more than 3 years.

This analysis presents both raw and adjusted beta coefficients. The adjusted beta coefficients reflect the assumption that, over time, there is a tendency for betas of all companies to move towards one. This is based on the rationale that for firms to survive in the market, they tend to increase in size over time, become more diversified, and have more assets in place. All of these factors push betas towards 1.[55] This analysis used the Bloomberg beta adjustment:

Adjusted Beta = Regression Beta (0.67) + 1.00 (0.33)

[55] See, for example, Damodaran, Aswath, *Estimating Risk Parameters*, or Jarnecic, Elvis, McCrory, Michael, Winn, Roland, *Periodic Return Timeseries, Capitalisation Adjustments, and Beta Estimation* (February 1997).

Appendix A. Disconnection Policies by State

	Protections Based On		Special Protections For			
State	**Temperature**	**Date**	**Elderly**	**Low Income**	**Seriously Ill / Disabled**	**Deferred Payments**
AL	32	--	--	--	--	--
AK	--	--	15-day delay	--	15-day delay	No disconnect if customer on payment plan
AR	32 / 95	11/1 (temperature-based) or 12/1 (income-eligible) to 3/31	No disconnect for elderly when temp > 95 or medical emergency	No disconnect for certain income-eligible households **(1)**	30-day delay with physician certification	No disconnect if customer on payment plan
AZ	32 / 95	--	--	--	No disconnect for 10 days if dangerous to health, documented by physician	--
CA	--	Winter Months	--	--	No disconnect year round if detrimental to health or safety of household member	No disconnect if customer on payment plan
CO	--	--	--	--	--	--
CT	--	11/1 - 4/15	--	Low-income "hardship" policy **(2)**	15-day delay for illness with physician certification; No disconnect if life threatening	No disconnect if customer on payment plan
DC	32	--	--	--	--	--
DE	20	11/15 - 4/15	--	--	--	--

FL	--	--	--	--	--	--
GA	32	11/15 - 3/15	--	--	No disconnect if illness would be aggravated w/ statement from doctor; 30-day delay with medical certification	No disconnect if customer on payment plan
HI	--	--	--	--	--	--
IA	20	11/1 - 3/31	--	No disconnect for LIHEAP certified	30-day delay if adverse affect to health with physician certification	No disconnect if customer on payment plan
ID		12/1 - 2/29	No disconnect	--	No disconnect for infirm; 30-day delay if detrimental to health certified by health professional	No disconnect if customer on payment plan
IL	32	12/1 - 3/31	--	--	30-day delay if adverse affect to health with physician certification	--
IN	--	12/1 - 3/15	--	No disconnect for LIHEAP certified or WAP (150 percent FPG)	10-day delay with medical certificate	No disconnect for financial hardship **(3)**
KS	35	11/1 - 3/31	--		20-day delay if adverse affect to health	No disconnect under special circumstances **(4)**
KY	--	11/1 - 3/31	--	30-day delay (<130 percent FPG)	30-day delay with medical certificate	No disconnect if customer on payment plan

LA	--		--		Up to 63-day delay if detrimental to health or safety	
MA	--	11/15 - 4/30	--	No disconnect	--	--
MD	--	11/1 - 3/31	--	No disconnect payment plans (<150 percent FPG)	No disconnect if endangerment to health; 30-day delay for certified serious medical condition	--
ME	--	11/15 - 4/15	--	No disconnect if (<185 percent FPG), (< 3 months overdue) or (<$50); requires PUC approval	30-day delay if adverse affect to health with physician certification	No disconnect if customer on payment plan
MI	--	11/1 - 3/31	Winter protection plan	Winter Protection Plan (< 200 percent FPG)	21-day delay if adverse affect to health with medical certificate	--
MN	Excessive Heat issued by NWS	10/15 - 4/15	--	No disconnect under special circumstances **(5)**	No disconnect if adverse affect to health with medical certificate	No disconnect if customer on payment plan
MO	32	11/1 - 3/31	No disconnect for elderly who meet certain income guidelines and make minimum payment	No disconnect for customers who meet certain income guidelines and make a minimum payment	No disconnect for disabled who meet certain income guidelines and make minimum payment	--
MS		12/1 - 3/31	--	No disconnect	No disconnect	--
MT		11/1 - 4/1	No disconnect	No disconnect for	Delayed if detrimental to existing	Utilities are required to

				public assisted	medical condition; No disconnect for disabled customer.	offer payment plan before disconnection
NC	--	11/1 - 3/31	No disconnect	No disconnect for ECAP eligible	No disconnect for disabled	No disconnect if customer on payment plan
ND	--		30-day delay	--	30-day delay	No disconnect if customer on payment plan
NE		11/1 - 3/31	--	No disconnect with proof of eligibility for energy assistance	--	--
NH	--	12/1 - 4/1	No disconnect without PUC approval	--	30-day delay for certified medical emergency; No disconnect if (greater than $50) or more than 2 months charges	No disconnect if customer on payment plan
NJ	--	11/1 - 3/15	--	No disconnect for unemployed or customers receiving Lifeline, LIHEAP, TANF, SSI, PAAD or GA	2-month delay if physician certifies health adversely affected; No disconnect if (greater than $50) or (longer than 3 months charges)	--
NM	--	11/15 - 3/15	--	No disconnect during protection dates if LIHEAP eligible	No disconnect for seriously or chronically ill certified by medical professional	Utility must attempt to make a payment plan with the customer

						before termination. No disconnect if customer on payment plan
NV	--	--	2-day delay	--	30-day delay if medical emergency. 2-day delay for handicapped.	Disconnection is delayed if customer agrees to pay bill in installments within the next 90 days
NY	--	Two week period encompassing Christmas and New Years	No disconnect	--	No disconnect with life support equipment; up to 90-day delay for certified medical condition; No disconnect if blind or disabled.	Utilities must offer a payment plan suited to customer's financial situation. **(6)**
OH	--	11/1 - 4/15	--	Winter protection **(7)**	30-day delay if dangerous to health as certified by medical professional; No disconnect if medical or life support equipment is necessary	No disconnect for PIP customers as long as they remain current with their PIP payment.
OK	32 (daytime); 20 (night) / Heat Index > 103	11/15 - 4/15	--	20-day delay if eligible for assistance (including SSI).	30-day delay for certified life-threatening condition or for life support equipment	No disconnect if customer on payment plan
OR	--	--	--	--	6-month delay for non-chronic condition; 12-month delay for chronic condition; medical certificate required	No disconnect if customer on payment plan

PA	--	12/1 - 3/31	--	--	30-day delay with medical certificate; No disconnect if health adversely affected	No disconnect if customer on payment plan
RI	--	11/1 - 3/31	No disconnect	No disconnect for unemployed	Disconnect ban for ill / disabled; 21-day disconnect delay if household member is certified as seriously ill. Customer may request an extension.	Utilities are required to offer payment plan before disconnection
SC	--	12/1 - 3/31	--	--	31-day shut-off delay for seriously ill with medical certificate, can be renewed up to 3 times during the winter protection period	No disconnect if customer on payment plan
SD	--	11/1 - 3/31	--	--	30-day disconnect delay if physician, public health official or social service official certifies a medical emergency	No disconnect if customer on payment plan
TN	32		--	--	Disconnect postponed for medical emergency; 30-day disconnect delay if physician, public health official or social service official certifies that a household member's health would be adversely affected. Certificates may be renewed 3	Utilities are required to offer payment plan

					times.	
TX	32; During Heat Advisory	--	No disconnect for low-income elderly w/ deferred plan	No disconnect for low-income elderly with deferred plan	--	Low income electric customers under age 65 can prevent disconnection through September with a deferred plan requiring payment of no more than 25 percent of their bill. The deferred amount would be due within 5 months.
UT	--	11/15 - 3/15	--	No disconnect if customer applied for HEAP and Red Cross Energy Assistance, has an income <125 percent FPG, or becomes unemployed or income is cut by 50 percent or more.	30-day delay if detrimental to health	Utilities must offer payment plans; No disconnect if customer has written statement from utility that states that a payment plan could not be agreed upon
VA						
VT	10; 32 for elderly	11/1 - 3/31	No disconnect if temperature is less than 32 degrees		30-day disconnect delay if household member's health would be adversely affected	No disconnect if customer on payment plan

WA	--	11/1 - 3/31	--	Protection for assistance eligible hardship customers (<125% FPG) that enter payment plan	30-day delay if a medical emergency exists	No disconnect if customer on payment plan
WI	Heat Advisory	11/1 - 4/15	21-day delay if certified. Customer must agree to payment plan.	No disconnect if < 250 percent FPG	21-day delay if certified. Customer must agree to payment plan.	Protection for customers entering payment plans; special notice and links to assistance agencies.
WV	--	12/1 - 2/28	--	--	30-day delay if health adversely affected, certified by a physician and can be renewed every 30 days if illness persists. Renewals not needed if physician certifies that condition is permanent.	No disconnect if customer on payment plan
WY	--	11/1 - 4/30	--	--	22-day delay if certified disabled or seriously ill; 30-day delay if on life support equipment. Must enter into payment plan.	No disconnect if customer on payment plan

(1) If households make a minimum payment of about 50 percent of their bill, the remainder of the bill is deferred until April after which they have 7 months to pay off the balance.

(2) Customers are entitled to have gas heat and electric service turned on between 11/1 and 4/15, even if they owe the utility company money, except if gas heat service was provided during prior winter based on "hardship" and service was turned off between 4/15 and 10/31, then, to get service turned on, customer must pay the lesser of $100, minimum payments due under payment agreement, or 20 percent of debt to gas company when gas was shut off. Customers must apply for "hardship" protection at the utility every fall.

(3) Only if the customer pays the lesser of $10 or 10 percent of the overdue bill, agrees to pay the remainder within three months and agrees to pay all undisputed future bills when due.

(4) To avoid disconnect when temperature is above 35, customers must make payment schedule, meet payments and apply for aid if eligible

(5) No disconnect if income is less than 50 percent state median income; or if eligible customer pays 10 percent of income or the full amount of current bill - whichever is less

(6) If pay plan cannot be implemented the utility must delay termination for 15 days and request that social services assist in devising a plan.

(7) Winter protection adds 10 days notice before shut-off occurs. Customers below 150 percent of poverty can avoid disconnection by enrolling in and following requirements of Percentage of Income Payment plan. Customers can maintain service if they have a disconnect notice or become reconnected under the Winter Reconnect Payment Program by paying a minimum of $175 and agreeing to a payment plan for the balance. Program can only occur once during protection months.

LIHEAP: Low Income Home Energy Assistance Program

HEAP: Home Energy Assistance Program

WAP: Weather Assistance Program

FPG: Federal Poverty Guidelines

TANF: Temporary Assistance to Needy Families

SSI: Supplemental Security Income

PAAD: Pharmaceutical Assistance to the Aged & Disabled

GA: General Assistance

Source: U.S. Department of Health and Human Services, *LIHEAP Clearinghouse*, March 2007.

Appendix B. State Ratemaking Programs with Revenue Decoupling Provisions

Approved Tracking Mechanism Programs

State	LDC	Name of Program	Type of Mechanism	Response	Fixed Monthly Charge	Volumetric Delivery Charge	Affected Customer Classes or Rate Schedules	Frequency of Adjustment	Effective Date
WA	Avista Corp.	Natural Gas Decoupling Mechanism	Revenue Tracker	Annual Volumetric Rate Adjustment	$5.50	Single per unit rate	Residential and Small Commercial Customers	Annual	1/1/2007
MD	Baltimore Gas & Electric Co.	Monthly Rate Adjustment	Revenue Tracker	Gas delivery rate is adjusted to result in respective month's revenues established in latest base rate proceeding as adjusted for change in number of customers	$13.00	Single per unit rate	Residential and General Service customers - excluding Daily Metered customers and General Service Daily Metered customers	Monthly	2/1/2006
OR	Cascade Natural Gas Corp.	Conservation Alliance Plan	Margin Tracker	Surcharge (or refund) included in unit rate to collect (or refund) the accumulated difference between baseline and actual weather-normalized average margin per customer, as adjusted for the change in number of customers	$3.00	Single per unit rate	Residential and Commercial General Service Customers	Annual	5/1/2006
WA	Cascade Natural Gas Corp.	Conservation Alliance Plan	Margin Tracker	Surcharge (or refund) included in unit rate to collect (or refund) the accumulated difference between baseline and actual weather-	$4.00	Single per unit rate	Residential and Commercial Customers	Annual	1/19/2007 - 3 Year Pilot Program

				normalized average margin per customer, as adjusted for the change in number of customers					
LA	CenterPoint Energy	Rate Stabilization Mechanism	ROE Tracker	High ROE: adjust billings for refund Low ROE: modify rates	$6.50	Single per unit rate	All customer classes	Between rate stabilization filings	~~
MS	CenterPoint Energy	Rate Stabilization Mechanism	ROE Tracker	High ROE: adjust billings for refund Low ROE: modify rates	$6.50	Single per unit rate	All customer classes	Between rate stabilization filings	~~
OK	CenterPoint Energy	Rate Stabilization Mechanism	ROE Tracker	High ROE: adjust billings for refund Low ROE: modify rates	$6.50	Single per unit rate	All customer classes	Between rate stabilization filings	~~
MD	Chesapeake Utilities Corp.	Revenue Normalization Mechanism	Revenue Tracker	Quarterly adjustment included in the Gas Sales Service Rate to collect/refund the accrued monthly difference (either positive or negative) between the actual Delivery Service Revenue received per customer and the revenue requirement per customer based on the requirement established in Case No. 9062	$9.10	Declining block rate (3 block)	Residential Heating	Quarterly	10/1/2006

MD	Columbia Gas	Weather Normalization Adjustment	Weather Tracker	Gas Sales Volume Adjustment - The volumes of gas sales for the heating season shall be increased or decreased monthly by the WNA	$9.25	Single per unit rate	Residential and Commercial Customers under Rate Schedules RS, PS, and GS	Monthly during heating season November through March	4/12/2000
NJ	New Jersey Natural Gas Co.	Conservation Incentive Program	Revenue Tracker	At end of annual period, a calculation shall be made that determines for each customer class group the deficiency or excess to be surcharges or credited to customers	$6.60	Single per unit rate	Residential Sales; Residential Transportation; General Service; Small Commercial Rebundled; Comprehensive Transportation & Balancing; and Economic Development	Annual	9/30/2006 - 3 Year Pilot Program
OR	Northwest Natural Gas	Partial Decoupling Mechanism	Weather Tracker	Each month the company will calculate the difference between weather-normalized usage and the calculated baseline usage for each affected customer group. Resulting usage differential (debit or refund) shall be multiplied by the per therm distribution margin for applicable customer group	$6.00	Single per unit rate	Residential and Commercial Customers who take service under the following rate schedules: General Sales Service; Residential Sales Service; Basic Firm Sales Service-Non-Residential; and Non-Residential Sales and Transportation Service	Monthly	11/1/2006 - 3 Year Pilot Program
OR	Northwest Natural Gas	Weather Adjusted Rate	Weather Tracker	Adjustment allows the company to recover its fixed costs by either raising rates when weather is	$6.00	Single per unit rate	Residential and Commercial	Monthly during WARM	11/1/2006

		Mechanism		unusually warm or lowering rates when weather is unusually cold				period December 1st through May 15th	
CA	Pacific Gas & Electric Co.	Revenue Decoupling through Balancing Account Mechanism	Revenue Tracker	Annual True-up adjusts rates to return or recover difference between actual and authorized revenue requirement.	$0.00	Increasing block rate (2 block) residential, declining block rate (2 block) commercial and industrial structure	Residential, Commercial, Industrial	Annual True-up of Balancing Accounts	1978
PA	Philadelphia Gas Works	Weather Normalization Adjustment	Weather Tracker	WNA charge appears on bill that will either reduce the bill when colder than normal or increase the bill when weather is warmer than normal	$12.00	Single per unit rate	Residential, Commercial, Industrial, Municipal Service, and Philadelphia Housing Authority	Monthly during the period of 10/1 through 5/31	9/1/2003
NC	Piedmont Natural Gas Co, Inc.	Customer Utilization Tracker	Margin Tracker	Under-collected margin: modify rates, Over-collected margin: refund to customer	$10.00	2 seasonal single per unit rates	Residential; Small and Medium General Rate Service Classification Customers	Monthly	11/1/2005 - 3 Year Pilot Program
UT	Questar Gas Company	Weather Normalization	Weather Tracker	For customers that have not opted off, the WNA partially offsets the	Basic Service Fee	2 seasonal declining	Service used for purposes such as space heating, air	Monthly	5/1/2006

		Adjustment		effects of unusually colder- or warmer-than-normal weather by adjusting bills up or down	Ranges from $5 - $244 based on meter capacity / Monthly Minimum Bill = $7.50	block rates	conditioning, water heating, clothes drying, cooking or other similar uses		
UT	Questar Gas Company	Conservation Enabling Tariff	Revenue Tracker	At least twice per year Questar would file for a percentage adjustment to block rates according to revenue deviations	Basic Service Fee Ranges from $5 - $244 based on meter capacity / Monthly Minimum Bill = $7.50	2 seasonal declining block rates	Service used for purposes such as space heating, air conditioning, water heating, clothes drying, cooking or other similar uses	No less frequently than semi-annually, true-up	11/1/2006 - 3 Year Pilot Program
NY	Rochester Gas & Electric Corp.	Weather Normalization Adjustment	Weather Tracker	Warmer than normal weather: "weather adjustment" charge, Colder than normal weather: "weather adjustment" refund	$15.00	Declining Block Rate (4 block)	Space Heating Customers	Monthly October 1st through May 31st	1/1/2005
CA	San Diego Gas & Electric Co.	Revenue Adjustment Mechanism	Revenue Tracker	On a monthly basis actual base margin revenues are recorded to the gas core and noncore fixed cost	N/A	Increasing block rate (2 block)	Core and Noncore sales customers	Monthly	5/11/2005

				accounts and balanced against the monthly portion of authorized base margin revenue requirement. Low Revenue: modify rates, High revenue: refund customer					
NJ	South Jersey Gas Co.	Conservation Incentive Program	Revenue Tracker	This adjustment will be effectuated through a credit or surcharge applied to customers' bills during the adjustment period	$7.75	Single per unit rate	Residential Service, General Service, General Service - Large Volume	Annual	9/30/2006 - 3 Year Pilot Program
CA	Southern California Gas Co.	Revenue Decoupling Mechanism	Revenue Tracker	~~	$.16438 per meter per day	Increasing block rate (2 block)	~~	~~	~~
CT	Southern Connecticut Gas Co.	Weather Normalization Adjustment	Weather Tracker	During applicable months, WNA adjusts portion of bill to reflect normal winter weather conditions, adding a bill surcharge in warmer-than-normal weather or adding a bill credit in colder-than-normal weather	$8.25	Single per unit rate	Residential Rates, Small General Service, General Service and Large General Service with the exception of firm customers on Rate Rider ED or MED	Monthly during months of September through June	9/1/2005
CA	Southwest Gas Corp.	Fixed Cost Adjustment Mechanism	Margin Tracker	Southwest is allowed to record under- or over-collected margin in a balancing account for recovery or refund to customers in a subsequent period. The margin recorded in the balancing account is based on the difference between billed and	$5.00	Increasing block rate (2 block)	Bills for sales service under all core and noncore schedules	Annual attrition filing	8/1/2006

				authorized levels. Under-collected margin: modify rates, Over-collected margin: refund to customer					
IN	Vectren Energy Delivery of Indiana	Energy Efficiency Rider	Margin Tracker	Company shall defer 85% of the calculated differences between actual margins and adjusted order franted margins for subsequent return or recovery via the SRC	$11.00 per meter	Declining block rate (2 block)	Residential and General Sales; and School Transportation Sevice	Monthly	12/1/2006
IN	Vectren Energy Delivery of Indiana	Normal Temperature Adjustment	Weather Tracker	The NTA adjusts each customer's monthly billed amount to reverse the impact on margin recovery caused by non-normal temperatures during the billing period, as measured by actual heating degree day variations from normal heating degree days.	$11.00 per meter	Declining block rate (2 block)	Residential and General Sales; and School Transportation Sevice	Monthly during seven winter billing periods commencing with customer's first meter read date after 10/14	8/9/2006
OH	Vectren Energy Delivery of Ohio	Sales Reconciliation Rider	Revenue Tracker	By Nov. 1st of each year, Company shall reflect the accumulated monthly differences between actual base revenues and adjusted order granted base revenues. Accumulated monthly differences for each rate	$7.00 per meter	Declining block rate (2 block)	Residential Sales and Transportation Service; General Sales and Transportation Service	Annual	10/1/2006

				schedule shall be divided by projected sales volumes to determine the applicable SRR.					
VA	Virginia Natural Gas	Weather Normalization Adjustment	Weather Tracker	WNA adjusts a portion of the bill to reflect normal winter weather, adding a bill surcharge in warmer-than-normal weather or adding a bill credit in colder-than-normal weather	$9.78	Declining block rate (2 block)	Residential firm gas service, and residential air conditioning firm gas sales service customers	Monthly November through April	10/15/2002
MD	Washington Gas Light Co.	Revenue Normalization Adjustment	Revenue Tracker	Adjust customer billing 2 months later. Low revenue: modify rates, High revenue: refund customer	$10.20	Declining block rate (3 block)	Residential sales and delivery services; Commercial and Industrial sales and delivery service; group metered apartment sales and delivery service	Monthly	10/1/2005

Pending Tracking Mechanism Programs

State	LDC	Name of Program	Type of Mechanism	Response	Fixed Monthly Charge	Volumetric Delivery Charge	Affected Customer Classes or Rate Schedules	Frequency of Adjustment	Effective Date
MO	Laclede Gas	Earnings Sharing Mechanism	Offers customers the opportunity to receive rebates (up to 90% of any excess earnings) - Not a tracker	At the end of each twelve months ended September period, the Company shall accrue in an Earnings Adjustment account any revenues associated with earnings above or below authorized return. Company shall distribute any excess earnings in the form of bill credits to customers. No adjustment shall occur for deficient revenue balances.	$12.00	2 seasonal declining block rates	All customer classes	Annual	Filed request on 12/1/2006
DC	Washington Gas Light Co.	Revenue Normalization Adjustment	Revenue Tracker	An RNA factor will be computed each billing cycle month for each rate schedule to establish a credit or surcharge to the Distribution Charges contained in each rate schedule	$7.85	Seasonal Increasing block rate (2 block)	All Rate Schedules	Monthly	Filed on 12/21/2006
VA	Washington Gas Light Co.	Revenue Normalization Adjustment	Revenue Tracker	An RNA factor will be computed each billing cycle month for each rate schedule to establish a	$8.80	Declining block rate (3 block)	All Rate Schedules	Monthly	Filed on 9/15/2006

				credit or surcharge to the Distribution Charges contained in each rate schedule					
VA	Washington Gas Light Co.	Weather Normalization Adjustment	Weather Tracker	WNA will provide credits to Distribution Charges when total monthly usage is greater due to colder than normal weather. WNA will provide surcharges to Distribution Charges when monthly usage is less due to warmer than normal weather	$8.80	Declining block rate (3 block)	All Rate Schedules	Monthly	Filed on 9/15/2006 - Effective only if RNA mechanism is not approved

Uncollectible Tracking Mechanism Programs

State	LDC	Name of Program	Type of Mechanism	Response	Fixed Monthly Charge	Volumetric Delivery Charge	Affected Customer Classes or Rate Schedules	Frequency of Adjustment	Effective Date
OH	Duke Energy Ohio	Uncollectible Expense Rider	Uncollectibles Tracker	Uncollectibles expense is balanced in the form of refund or surcharge applied to gas bills	$6.00	Single per unit rate	All Sales Service and Transportation Customers	Company shall file an application with PUCO whenever an adjustment of +/- 10% occurs - no more than once per year	4/1/2006

MI	Michigan Consolidated Gas Company	Uncollectible Expense Tracking Mechanism Surcharge (UETM)	Uncollectible Tracker	Up to 90% of uncollectibles expense is balanced in form of a surcharge or refund applied to MichCon gas bills	$8.50	Single per unit rate	Uncollectibles for the following customer classes: Residential; Low Income Senior Citizens; Residential Multiple Family Dwelling Class 1&2; Non-Residential General Service; Large Volume; School; Small Volume Transportation; Large & Extra Large Volume Transportation	By March 31st of each year, MichCon will file an application comparing its actual uncollectible expense with the base level	1/1/2007

Miscellaneous and Temporarily Suspended Programs

State	LDC	Name of Program	Type of Mechanism	Response	Fixed Monthly Charge	Volumetric Delivery Charge	Affected Customer Classes or Rate Schedules	Frequency of Adjustment	Effective Date
MO	Laclede Gas	Conservation Incentive Program	Rewards customers who are able to reduce their gas usage by at least 10% from a prior period - not a tracker	Since these rewards are intended to encourage savings in the gas cost portion of customers' bills and hopefully result in reduced purchased gas costs, the PGA clause is being used to fund payments	$12.00	2 seasonal declining block rates	Residential Sales Customers	During peak heating months of December, January and February	Filed request on 12/1/2006

NJ	New Jersey Natural Gas Co.	Weather Normalization Clause	Weather Tracker	Warmer than normal weather: Increase rates, Colder than normal weather: Customer recieves credit	$6.60	Single per unit rate	Residential Sales; Residential Transportation; General Service; Small Commercial Rebundled; Comprehensive Transportation & Balancing; and General Service Demand	Monthly October through May	As of 10/1/2006, this has been suspended for the duration of the NJNG CIP mechanism also listed - 9/30/2009
NJ	South Jersey Gas Co.	Temperature Adjustment Clause	Weather Tracker	This adjustment will be effectuated through a credit or surcharge applied to customers' bills during the year	$7.75	Single per unit rate	Residential Service, General Service, General Service - Large Volume	Monthly October through May	As of 10/1/2006, this has been suspended for the duration of the SJG CIP mechanism also listed - 9/30/2009

Note: Data are current as of May 2007.

Source: Energy Information Administration, Office of Oil and Gas, compiled from various industry sources.