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DIRECT GAS PURCHASES BY GAS DISTRIBUTION COMPANIES: SUPPLY RELIABILITY AND COST IMPLICATIONS

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December 29, 1989

Dr. Harry M. Trebing
Director
Institute of Public Utilities
113 Olds Hall
Michigan State University
East Lansing, Michigan 48824

Dear Harry:

Enclosed is our latest report, *Direct Gas Purchases by Gas Distribution Companies: Supply Reliability and Cost Implications*. While the long title is self-explanatory, included in the study are the results of a survey of state commissions as to the oversight each employs regarding direct gas purchases by LDCs.

Best regards,

Doug

Douglas N. Jones
Director and Professor
of Regulatory Economics

jjs

Enclosure

P.S. — and I hear your Virginia session was another fine one!

Established by the National Association of Regulatory Utility Commissioners at The Ohio State University in 1976

EXECUTIVE SUMMARY

This study analyzes the reliability and cost implications of direct gas purchases by local distribution companies (LDCs). A direct purchase is a gas procurement arrangement entered into by an LDC and any entity other than an interstate pipeline. A direct purchase can take many forms including purchases in the gas spot market, the signing of long-term contracts with wellhead producers, and the use of gas marketers to secure gas supplies and transportation services. This study concludes that the most important aspects of the growing use of direct gas purchases by LDCs are the inducement of speedy market responses in adding gas production and transportation capacity and the increased flexibility in LDCs' supply portfolios.

This study also finds, through a telephone survey of state public service commission staff in forty-eight states and the District of Columbia, that two-thirds of the states have some kind of oversight on LDCs' direct gas purchases. Most of the oversight is conducted through the use of established procedures such as purchased gas adjustment (PGA) or rate case review. Other procedures--such as prudence review, PGA incentives, and direct risk assessment--are less common.

The reliability of gas supply to LDCs is determined by the amount of gas produced in the gas fields and the availability of transportation facilities to move the gas from wellheads to city gates. Throughout the 1980s there has been an abundant supply of natural gas. No widespread or chronic shortages have been experienced in the United States. Increasingly, however, signs indicate a possible reemergence of gas supply reliability issues even though several long-term forecasts do not foresee the occurrence of extensive and chronic gas shortage for the nation as a whole over the next twenty years. If current demand and supply trends continue, the amount of gas supply surplus is likely to decrease, and certain parts of the nation may be vulnerable to supply shortfall due to inadequate transportation capacity. Several factors contribute to the reemergence of the gas supply issue: a prolonged slump in oil and gas exploration, renewed environmental concerns about the use of primary fuels other than gas, and the prevalence of new gas transportation and procurement practices.

With a continuing shift toward relying more on competitive forces than on government regulations in the gas market, gas procurement and transportation practices have gone through significant changes in the last few years. Most changes are reflected in two areas: a drastic increase in the amounts of gas directly purchased by LDCs, and a proliferation of new gas procurement and transportation practices. The LDCs' growing involvement in direct purchases is motivated primarily by three factors: the current cost advantage of spot market purchases over long-term contracts, more readily available access to pipeline transportation facilities, and intense interfuel competition, least-cost gas purchase, and other regulatory requirements at the distribution level.

The primary cost advantages of direct gas purchase by an LDC are the access to low-cost gas supplies in the spot market and the opportunity to build a new gas supply portfolio consisting mainly of new supply contracts that are more in tune with current gas demand and supply conditions. As for the limitations of direct purchases, a typical LDC's experience and knowledge about gas procurement (especially the long-term contracts with wellhead producers) are probably less than those of a typical pipeline, at least in these initial years. However, such short-term advantages and limitations are mostly transitory and are bound to narrow over time.

Neither direct purchase nor traditional pipeline supply has clear and persistent long-term advantages in terms of the opportunity to purchase more economical gas supplies, finding and evaluating gas suppliers and transporters, and arranging transportation service. Two possible long-term advantages associated with pipeline purchase are a stronger bargaining position in gas procurement and more diversified sources of gas supply that are made possible by the large amount of gas purchased and the large number of suppliers associated with typical pipeline supply portfolios.

The supply reliability consequences of direct purchases by an LDC can be analyzed in three aspects: as a single gas procurement transaction, as a part of a total supply portfolio, and in the context of overall gas market responses in adding gas production and transportation capacity. If considered as a single gas procurement arrangement, a direct purchase--whether a spot market purchase or a long-term contract with a wellhead producer--is less reliable than a long-term purchase contract with a pipeline mainly due to the differences in the experience in gas procurement, possible constraints for LDCs in obtaining transportation and backup services, and in contract provisions in the case of spot market purchases. However, if direct purchase is viewed as a part of an LDC's overall supply portfolio, any such reliability concerns can be offset by the added flexibility and cost advantages of direct purchases, especially where the gas obtained through direct purchases is aimed primarily at providing service to noncore customers who have alternative sources of gas supply.

The reliability of an LDC's gas supply portfolio is determined not only by its procurement decisions but also by the overall market availability of gas and transportation facilities to deliver it. If an overall supply and transportation capacity shortfall exists, the incidences of supply interruption or a very costly gas supply probably are inevitable for some LDCs no matter what gas procurement strategies they use. The market responses to the increase in direct purchases have significant supply reliability implications. In this respect, direct gas purchase has several positive influences over the sole reliance on pipeline supplies. They include inducing pipelines to choose to become open-access transporters, providing spot-market price signals which are more indicative than a long-term contract price about possible imbalance of gas demand and supply, and pooling many small amounts of gas demand in a way that encourages development of gas wells and transportation facilities.

Changes in gas procurement and transportation practices are transforming the nature and tasks of state gas regulation. In the past, the main concern of state regulators has been to monitor the pass-through of the cost of gas supplies from LDCs to end-users. As direct gas purchase becomes more prevalent, the state commissions must be prepared to take on the additional tasks of evaluating the prices and reliability of direct gas purchase contracts. In addition to the review of direct purchase contracts, state regulators need to consider the options of reconciling state and federal gas curtailment policies, providing clear guidelines on the LDCs' obligation to serve to various groups of customers, and paying closer attention to the enforceability of gas purchase contracts.

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FOREWORD

The increasing involvement of local gas distribution companies in direct gas purchases rather than total reliance on conventional pipeline purchases raises cost and reliability questions for regulators. This report considers the implications of both elements. It also reports on the results of a survey of the state commissions as to the kind of regulatory oversight each currently employs with respect to direct gas purchases by jurisdictional LDCs.

Douglas N. Jones
Director
Columbus, Ohio
December 1, 1989

ACKNOWLEDGEMENTS

We wish to express our sincere thanks to the staff of the public service commissions, listed in the appendix, who responded to the survey conducted for this report. We would also like to thank Lorraine Cross of the American Gas Association and Diane Lique of the Energy Information Administration for providing information used in various parts of the report, and Rick Hornby of the Energy Systems Research Group, Inc. for his many suggestions in improving the report. Finally, we wish to express our gratitude to David Wagman for editing, and to Marilyn Reiss, Evelyn Shacklett, Jacquelyn Shepherd, and Joan Marino for typing and preparing this report.

CHAPTER 1

INTRODUCTION AND OVERVIEW

The concept of gas supply reliability is a complex one. Strictly speaking, the total amount of natural gas available for discovery is fixed even though the estimated amounts of potential gas reserves may vary from time to time.[1] Any government or business decision is unlikely to change the total amount of gas resource. But underground gas reserves need to be explored for and developed, and the gas produced must be transported to make it a useful form of energy to end-users. In that regard, government policies and business decisions can have significant effects on the amounts of gas made available to specific locations at specific times, meaning the reliability of gas supply must be measured in similar terms.

The reliability of gas service to end-users is determined by the amount of gas being produced in the gas field, the availability of transportation facilities to move the gas from wellheads to city gates, and the ability of local distribution companies (LDCs) to deliver gas to individual customers. Three distinct entities--wellhead producers, pipelines, and LDCs--each have some unique influence on the reliability of gas service. Therefore, gas service reliability needs to be evaluated in terms of a specific transactional relationship. This study focuses on the relationship between an LDC and its suppliers; that is, how an LDC can obtain and assure the production and transportation of gas so that its customers can receive uninterrupted gas service.

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[1] Natural gas resources can generally be classified as "proven reserves" (reasonably recoverable in future years from known reservoirs under existing economic and operating conditions), "probable resources or inferred reserves" (gas reserves that can be added to known gas fields through extensions, revisions, and new pay zones), and "undiscovered resources." See U.S. Department of Energy, *An Assessment of the Natural Gas Resource Base of the United States* (Washington, DC: Department of Energy, 1988), 1-41.

Gas supply reliability can be measured in several ways. For example, it can be measured by directly comparing the projected amounts of gas demand and gas supply. Alternatively, the ratio of annual gas production (equivalent to a reduction of gas reserve) and gas reserve additions can be used to indicate the speed with which gas reserves are replenished through new discoveries or adjustments. Another measure is "reserve life" that determines the availability (in years) of future gas supply in light of current gas consumption.

A common supply reliability criterion used by the pipelines and LDCs in determining their gas procurement strategies is the "design-peak-day" or "abnormal-peak-day" delivery requirement. Under this criterion, a gas delivery system must be able to meet its load requirement when the system experiences the simultaneous occurrence of the lowest temperature and the highest winds on a weekday during the heating season.[2]

Gas supply reliability is not a new issue. Wellhead gas supply shortfalls or insufficient transportation capacity to meet customers' gas requirements have occurred in the past. Various actions have been taken by the government and the gas industry to remedy these situations. For example, in addressing the extensive and chronic gas supply shortfall of the 1970s, the federal government partially decontrolled wellhead prices to spur exploration and production, while many pipelines signed long-term contracts containing high take-or-pay provisions to assure future gas supply. But with many drastic changes occurring in the gas industry and related government regulations in the last few years, the focus of gas supply reliability is likely to shift. New perspectives are required to deal with current and emerging supply reliability issues.

Given the magnitude and multitude of gas supply reliability issues, it is helpful to confine the scope of inquiry and choose a specific approach in identifying the options available to the gas industry and to government that can enhance gas supply. This study considers the gas supply issue mainly from the perspective of state regulators. It focuses on those issues

[2] American Gas Association, *Gas Rate Fundamentals* (Arlington, VA: American Gas Association, 1987), 229.

related to an LDC's ability to serve its ratepayers and the options available to LDCs and state regulators.

This study also adopts a long-term perspective. It analyzes the factors and strategies concerning gas service at reasonable cost and reliability over an extended period of time. A long-term approach to gas supply reliability is needed since both gas production and transportation capacity (as evidenced by the time lag of up to ten years from gas exploration to actual production) and demand for gas (due to the longevity of most gas-consuming appliances) tend to be fixed over time. Any government actions and business decisions aimed at influencing future gas supply reliability in any significant way require a substantial lead time.

This study can be characterized further by what it does not do. First, it is not a forecast of future gas production and transportation capacity, although the projection of future gas supply is, obviously, of great importance for LDCs in formulating gas procurement strategies. Numerous projections exist concerning the amount of gas available in the future. This study does not endorse any particular projection but reviews some of the more important ones as necessary background material. Second, this study does not deal with the issue of selecting an optimal portfolio of gas supply sources by an LDC. No new portfolio selection algorithm is proposed.[3] Third, this study does not deal with the task of optimizing the gas distribution system within the service area of an LDC nor does it suggest a particular supply reliability target to be met by LDCs.[4] In other words, it is assumed that an LDC's choices of gas supply options and transportation arrangements do not affect its distribution performance. The reason for using this assumption is to limit the LDC's task at hand to that of securing external supplies only.

[3] The models for selecting optimal gas supply portfolios are available elsewhere. See, for example, J. Stephen Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches* (Columbus, OH: The National Regulatory Research Institute, 1988).

[4] Discussions on these areas can be found elsewhere. See, for example, Jean-Michel Guldmann, "Supply, Storage, and Service Reliability Decisions by Gas Distribution Utilities: A Chance-Constrained Approach," *Management Science* 29 (August 1983): 884-906.

This report consists of seven chapters. An overview of the reemergence of supply issues, determinants of supply reliability, and several forecasts of the future availability of gas supply in the United States is provided in the remainder of this chapter. Chapter 2 deals with the rationales, mechanisms, advantages, and limitations of direct gas purchases by LDCs. The current status of state regulatory oversight into direct gas purchases is presented in chapter 3. Chapter 4 analyzes supply reliability implications, especially the market responses in adding future gas production and transportation capacity to the increased use of direct purchases by LDCs. The options available to state regulators to enhance supply reliability and reasonable costs of gas directly purchased by LDCs are identified in chapter 5. Some concluding comments are presented in chapter 6. Appendix A summarizes the responses of state regulatory commissions to a 1989 survey on direct gas purchase conducted by The National Regulatory Research Institute.

Reemergence of Gas Supply Issues

Throughout the 1980s, natural gas has been in abundant supply. No widespread or chronic gas shortages have been experienced in the United States as a whole. On the contrary, the dominant gas issue during this period seems to be the marketing and cost recovery of high-priced gas obtained under long-term contracts signed in the late 1970s. Increasingly, however, signs point to a reemergence of issues related to gas supply reliability. Most notable are the gas supply shortfalls that occurred during the 1988-1989 heating season in California, Texas, and several Northeastern states.[5] Some energy analysts have predicted an acute gas supply shortfall in the 1989-1990 heating season.[6]

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[5] See "Record Cold Causes Gas Shortages for Utilities in California, Texas," *Electric Utility Week*, 13 February 1989, 17-18; and Caleb Solomon and Dianna Solis, "Volatile Fuel," *The Wall Street Journal*, 6 February 1989, A1, A6.

[6] See, for example, John Sawhill, "Don't Count on 'Cooking with Gas'," *The New York Times*, National Edition, 26 February 1989, Section 3, 2.

Although one may argue whether the perceived or real gas supply shortfall is imminent or only in the more distant future, many recognize that the excess of gas supply over gas demand is shrinking making the prospect of gas shortages for certain parts of the nation a distinct possibility.[7]

Several factors contribute to the reemergence of gas supply issues: a prolonged slump in oil and gas exploration activities due to lower crude oil prices, renewed environmental concerns about the use of primary fuels other than gas, and the initiation of new gas transportation and procurement practices resulting from changing government regulations.

Oil and gas exploration activities declined dramatically from 1980 to 1988. The number of completed exploratory gas wells dropped from 2,300 in 1980 to 800 in 1987.[8] The average number of rotary rigs (for both gas and oil exploration) in use decreased from an all-time high of 4,530 in December 1981 to 944 in August 1988.[9] The amount of proven reserve additions (the amount of new gas discovery plus adjustments of existing proven reserves) shows a similar decline--from 14.1 trillion cubic feet (Tcf) in 1980 to 7.1 Tcf in 1987.[10] This significant shrinkage of gas reserve additions is not surprising given the low levels of gas and oil drilling activities of recent years.

Heightened environmental concerns, primarily in the areas of air quality, acid rain, and global warming (the greenhouse effect) induce additional demands for natural gas, especially in the area of electricity generation. The Gas Research Institute (GRI) estimates that the incremental gas requirement in the year 2010 due to tightened environmental regulations

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[7] See "Gas Executive Forum: Renewal of Drilling Activity," *Public Utilities Fortnightly*, 1 October 1987, 74-79; "California Report Says Curtailments Will 'Increase in Frequency'," *Inside, F.E.R.C.*, 27 March 1989, 2-3; and "Promising Demand Projections Dimmed by Anticipated Supply Crunch," *Inside F.E.R.C.*, 27 March 1989, 5-6.

[8] Cambridge Energy Research Associates, *Natural Gas Trends* (Cambridge, MA: Cambridge Energy Research Associates, 1988), 22.

[9] Ibid., 24.

[10] Ibid., 12.

could range from 1.4 quadrillion BTU (quads) to 5.3 quads.[11] Gas is commonly viewed as a "superior" fuel since it is readily substituted for other fuels and has fewer adverse environmental effects during its production, transportation, and consumption than other common fuels.

Implementation of the National Ambient Air Quality Standard at the state level may constrain the use of coal and oil by large industrial and electric generating facilities. This, in turn, should increase the demand for gas. At the same time, the federal government is now acting on the acid rain issue, meaning gas could become a more economical alternative to installing scrubbers or other clean-coal technologies.[12] Gas also enjoys some advantage by reducing carbon dioxide emissions from energy consumption, a fact of particular interest in the debate over global warming.[13]

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[11] Gas Research Institute, *Policy Implications of the 1988 GRI Base Projection of U.S. Energy Supply and Demand to 2010* (Chicago: Gas Research Institute, 1988), 10-11. Obviously, a projection of such wide range is only indicative at best, and the Gas Research Institute has made it clear that it did not incorporate the effects of tightened environmental regulations into its baseline projection due to the lack of more concrete information about new gas technology and stringent environmental constraints.

[12] On June 12, 1989 President Bush announced a series of proposals to amend the Clean Air Act of 1970. The measures were concerned with acid rain, sales of pollution rights, urban air quality, and toxic air pollution. With respect to acid rain, the President proposed a 10-million-ton reduction in sulfur dioxide emissions from coal burning power plants by the year 2000. Half of the reduction would have to be achieved by 1995. The 10-million tons represent about half of the total sulfur dioxide emissions from power plants. Companies could decide which strategies to employ (i.e., scrubbers, low sulfur coal, new technology, etc.) to meet the goals. For a description of the Bush proposals, see Philip Shabecoff, "President Urges Steps to Tighten Law on Clean Air," *The New York Times*, National Edition, 13 June 1989, section 1, 10. The President's legislation was sent to Congress on July 21, 1989 in a bill incorporating all of the major elements of the original proposals. *The New York Times* reported that all sides agreed that the administration's bill would break a deadlock on clean air legislation and that a bill would be approved before the end of the 101st Congress in 1990. See Philip Shabecoff, "President's Plan for Cleaning Air Goes to Congress," *The New York Times*, National Edition, 22 July 1989, 1, 7.

[13] The term "greenhouse effect" refers to the absorption by gases (mainly carbon dioxide and water vapor) in the atmosphere of heat from the surface of the earth. The heat, which would have gone into space if not absorbed, is then radiated back to the earth's surface. This is a naturally occurring process up to a point and helps to maintain a livable environment on the

(Footnote continues on next page)

According to one study, burning gas will generate only 50 percent of the carbon dioxide of coal combustion and 70 percent of fuel oil burning.[14] While nuclear power generation has certain advantages in reducing these adverse environmental effects, a host of other issues (including the timeliness and costs of completing nuclear plants and the problem of nuclear waste disposal) have made it unlikely that conventional nuclear technology can be a major contributor to additional United States electricity generation in the near future.[15]

The third source of the renewed interest in gas supply reliability is the structural changes in the gas industry and government regulations governing it. The traditional linkages between producers, pipelines, distributors, and end-users are altered. Important changes include voluntary open access to pipeline transportation facilities, development of a gas spot market, and the availability of transportation-only service. These changes afford new opportunities as well as new responsibilities for

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planet. Over the last few decades scientists have detected an increase in the amount of carbon dioxide in the atmosphere from 315 parts per million by volume (ppmv) in 1958 to 346 ppmv in 1985. Increasing the amount of carbon dioxide in the atmosphere could theoretically lead to a greater greenhouse effect or global warming with widespread climatic changes. The increase in carbon dioxide is attributed largely to the use of fossil fuels, with deforestation also contributing. Besides carbon dioxide, other atmospheric gases are also of concern to those monitoring global warming. These gases are methane, nitrous oxide, ozone, and chlorofluorocarbons. See "The Greenhouse Effect: Earth's Climate in Transition," *EPRI Journal*, June 1986, 4-15; Richard A. Warrick and Philip D. Jones, "The Greenhouse Effect: Impacts and Policies," *Forum for Applied Research and Public Policy* 3 (Fall 1988): 48-62; Gordon J. MacDonald, "Scientific Basis for the Greenhouse Effect," *Journal of Policy Analysis and Management* 7 (Spring 1988): 425-44; "Scientists Bare Cold Facts About Global Warming," *Electrical World*, 1 August 1989, 9-10. On the use of natural gas to counter the increase in greenhouse gases, see American Gas Association, "Natural Gas and Climate Change: The Greenhouse Effect," *Planning & Analysis Issues, Issue Brief 1989-7*, 14 June 1989.

[14] Cambridge Energy Research Associates, *Natural Gas Trends*, 8.

[15] U.S. Department of Energy, *Energy Security: A Report to the President of the United States* (Washington, DC: U.S. Department of Energy, 1987), 189-95. The DOE report also identifies three conditions that must be met in order to keep nuclear energy as a viable choice for meeting future demand: that nuclear energy should be able to compete economically with other sources of electricity supply, that the safety of nuclear power plants must continue to be satisfactorily demonstrated, and that there must be evident progress toward siting and building high-level waste management systems in a safe and publicly acceptable manner.

LDCs in securing gas supplies. For example, as an LDC converts a portion of its contracted demand to firm transportation service with its traditional pipeline supplier, the pipeline is relieved of any obligation to serve that portion of the LDC's gas requirement (consequently, the assurance for gas supply traditionally provided by the pipeline). Given the relatively limited experience of some LDCs in purchasing gas directly from producers and sources other than its pipeline suppliers, and the possible constraints in arranging transportation service (coupled with the shift toward short-term gas supply arrangements) the long-term availability of gas can become a legitimate concern in the more balanced and tighter gas market that is expected in the future.

Determinants of Gas Supply Reliability

The widespread use of gas as a primary energy source in the United States started after World War II. With the discovery of a substantial amount of natural gas reserves in the Southwest and with the advance in high-pressure long-distance pipeline transportation, natural gas is available to many regions of the nation that have little or no gas production of their own.[16] Domestic net wellhead production of natural gas has increased from 10.2 trillion cubic feet (Tcf) in 1955 to 17.2 Tcf in 1986.[17] Consumption of natural gas has increased from 8.9 Tcf in 1955 to 16.7 Tcf in 1987.[18] Gas consumption as a percentage of total energy consumption also has steadily increased from 23.1 percent in 1955 to a peak of 32.8 percent in 1970. Since then it has decreased gradually to 23.6 percent in 1985.[19]

Given the importance of gas in the nation's total energy supply, it is useful to examine the main factors that have affected reliability in the past or that could influence reliability in the future.

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[16] American Gas Association, *Gas Rate Fundamentals*, 1-11.
[17] Idem, *Gas Facts: 1987 Data* (Arlington, VA: American Gas Association, 1988), table 3-7; and *Gas Facts: 1976 Data*, table 16. The net wellhead production equals gross production less gas for repressuring.
[18] Ibid., table 10-2 and table 51, respectively. Gas liquids are excluded and the 1987 data are preliminary.
[19] Ibid., table 10-3 and table 52, respectively.

Gas supply shortage can take many forms. Gas delivery shortfall to customers in a limited area may be caused by gas main ruptures, temporary extreme weather, and gas field production stoppage. Such supply interruptions generally are short-lived and can be corrected quickly. There also are instances of chronic curtailment to existing customers or permanent moratoria for connecting new gas-using customers. Such curtailments represent a chronic condition of gas demand exceeding gas supply, which may not be alleviated with temporary measures alone. Such long-term gas supply shortfalls are the subject to be examined here.

Chronic gas supply shortfalls have two causes. One is insufficient gas production in the field. Gas exploration and production activities are affected primarily by the wellhead price of gas, and (to a lesser extent) the price of crude oil. A gas producer, like any other business, needs to obtain financing and undertake significant risks in exploration and production. An estimated three-quarters of all exploratory wells have been dry. The success rate for development wells (from confirmed discovery to actual volume production) has averaged from 76 to 80 percent since 1970.[20] The actual gas production from a particular well also may be lower than the projected amount due to insufficient gas well pressure or lower than expected gas reserves. All these factors can lead to smaller amounts of gas being produced than what was specified in long-term purchase contracts between buyers and gas producers. If no alternative supply sources can be found within a short period of time, the pipelines or LDCs may have no choice but to curtail gas delivery to end-users. For the gas market as a whole, if the prevailing price of gas cannot provide an adequate return to the producers that is compatible with the risks involved and the returns on alternative investments, the market supply of gas will decrease.

In addition to production shortfalls in the gas field, shortages can be caused by limits on gas transportation capacity. Under current gas delivery technologies, a high-pressure underground pipeline is the only economically feasible alternative to transporting large volumes of gas over long

[20] Energy Information Administration, *Drilling and Production Under Title I of the Natural Gas Policy Act 1978-1986* (Washington, DC: Energy Information Administration 1989), ix.

distances.[21] Some argue that even with today's relatively abundant gas production there is sometimes too much gas trying to force its way through too few pipelines, making the gas transmission sector the "battleground" of the natural gas industry.[22] A recent Gas Research Institute study indicates that the United States' gas transmission system may have to undergo substantial changes and expansion to deliver gas to the various gas consuming regions in order to meet projected future gas demand.[23]

During the past thirty years, there have been several instances of gas supply shortage as well as gas supply surplus experienced either by the entire nation or a significant portion. Most notable was the gas shortage that began in the early 1970s, culminating in a severe shortage in the winter heating season of 1976-1977. Several studies have detailed the causes and consequence of the 1970s' gas shortage.[24] In many respects, this gas shortage and the initiatives taken to overcome it are still affecting the current development of the natural gas industry and related government regulations.

Most studies on this subject concluded that the extent of gas shortage in the 1970s was extensive and its economic consequences severe. A 1980 U.S. Department of Energy (DOE) study indicated that the annual welfare loss due to unproduced natural gas may have ranged from $2.5 billion to $5 billion per year.[25] Another study estimated that the extent of gas shortage nationwide, as measured by unserved load, had increased from 3.4 percent in 1971 to 26.2 percent in 1976.[26]

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[21] Congressional Research Service and The National Regulatory Research Institute, *Natural Gas Regulation Study* (Washington, DC: U.S. Government Printing Office, 1982), 96-105.

[22] Solomon and Solis, "Volatile Fuel."

[23] Gas Research Institute, *The Long-Term Trends in U.S. Gas Supply and Prices: The 1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010* (Chicago: Gas Research Institute, 1988), 26-32.

[24] See Richard J. Pierce, Jr., "Natural Gas Regulation, Deregulation, and Contracts," *Virginia Law Review* 68 (1982): 63-115; Stephen Breyer and Paul W. MacAvoy, "The Natural Gas Shortage and the Regulation of Natural Gas Producers," *Harvard Law Review* 86 (1973): 941-87; and Paul W. MacAvoy and Robert S. Pindyck, "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," *Bell Journal of Economics* 4 (1973): 454-98.

[25] Pierce, "Natural Gas Regulation, Deregulation, and Contracts," 71-72, footnote 36.

[26] Ibid., 67-8, footnote 18.

Some examples may illustrate the severity of the gas shortage at that time. For example, in January 1970, 30,000 workers employed at seven-hundred companies were laid off for ten days due to gas supply shortfalls in the Cleveland, Ohio area.[27] The gas shortage reached its peak during the 1976-1977 heating season. In Ohio alone, because of drastic gas curtailment to schools and large customers, 1.4 percent of potential workdays were lost resulting in an increase in the unemployment rate from 7.15 percent to 8.1 percent.[28] For the nation as a whole, there were seventy-five gas-shortage-related deaths, and two million workers laid off.[29]

These studies also generally agreed that insufficient gas production in the gas field, rather than transmission capacity constraints, was the major cause of the gas shortage. The primary reason for insufficient production was federal regulation of wellhead gas prices. It was argued that the price ceilings imposed by the Federal Power Commission (the agency preceding the Federal Energy Regulatory Commission) were based on area-wide gas production costs, which tended to be lower than the marginal cost of adding new gas supply. As a result, many producers did not consider the exploration for and production of new gas to be profitable. Consequently, the proven reserves in the contiguous states declined 32 percent between 1970 and 1977, falling from 270 Tcf to 184 Tcf.[30]

The gas shortage was compounded further by producers' shift of supply from interstate gas markets to intrastate markets where wellhead prices were generally unregulated and gas producers could earn higher profits.[31] It was estimated that interstate gas reserve additions as a percentage of total reserve additions declined from 79 percent in 1968 to 21 percent in 1971.[32] Between 1970 and 1977, the domestic reserves committed to interstate pipelines decreased from 174.6 Tcf to 92.9 Tcf, a 46 percent reduction.[33]

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[27] MacAvoy and Pindyck, "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," 455.

[28] Jean-Michel Guldmann, "A Chance-Constrained Programming Approach to Natural Gas Curtailment Decisions," *Resource and Energy* 3 (1981): 133-61.

[29] Pierce, "Natural Gas Regulation, Deregulation, and Contract," 68, footnote 18.

[30] Cambridge Energy Research Associates, *Natural Gas Trends*, 12.

[31] Pierce, "Natural Gas Regulation, Deregulation, and Contract," 70.

[32] Ibid., footnote 27.

[33] Cambridge Energy Research Associates, *Natural Gas Trends*, 18.

Assessments of Future Gas Supply and Demand

Projections of future gas supply and demand range widely. This section reviews only the three projections that represent the four major groups of participants in the natural gas market: the federal government, gas producers, pipelines, and distribution companies. The three projections are the *Annual Energy Outlook* prepared by the Energy Information Administration (EIA) of the U.S. Department of Energy, the *Gas Energy Supply Outlook* compiled by the American Gas Association (AGA), and the *Baseline Projection of U.S. Energy Supply and Demand to 2010* published by the Gas Research Institute (GRI). These three projections do not address the gas supply issue from the same perspective nor cover the same time period of projection. So some differences in results may not necessarily indicate real divergences in gas demand and supply projections. But since it is not the main purpose of this study to forecast future gas demand and supply, no effort is made here to reconcile the differences of these projections.

EIA *Annual Energy Outlook*

The *Annual Energy Outlook* prepared by the Energy Information Administration in a sense reflects the federal government's "best judgement" about the long-term projection of the United States' energy economy.[34] It contains price, demand, and supply projections to the year 2000 for four fuel markets: petroleum, natural gas, electricity, and coal. Three basic assumptions underlie the EIA projections: the rate of economic growth, world oil price, and overall energy intensity.

The real gross national product (GNP) is assumed to grow at an average rate of 2.5 percent a year to the year 2000. This rate is slightly lower than the average real GNP growth since 1970. World crude oil prices are assumed to remain below $20 per barrel (in 1988 dollars) until 1995 and then rise gradually to $28 per barrel by the year 2000. The crude oil price is

[34] Energy Information Administration, *Annual Energy Outlook 1989* (Washington, DC: Energy Information Administration, 1989).

critical to the EIA projections since it is the largest single energy resource in the United States (40 percent of total energy consumption), and it is also generally substitutable for most other energy resources.[35] The future prices, production, and consumption of other energy resources all are significantly influenced by the price trajectory of crude oil.

The overall energy intensity of the economy, as expressed by the energy-to-GNP ratio (thousand-BTU-per-dollar-GNP), is assumed to continue declining at a rate of 1.3 percent per year until the year 2000. This rate of reduction is lower than the annual rate of 2.1 percent experienced between 1973 to 1987, and may indicate the EIA's assessment that the improvement in energy efficiency will continue into the future but at a lower rate, perhaps the result of relatively stable energy prices.

Based on these assumptions, the *Annual Energy Outlook* projects that annual gas demand will reach 20.3 Tcf by 2000, while domestic gas production will increase to 18.5 Tcf. Virtually all of the projected increase in gas demand is from the electricity generation sector; the uses of gas by residential, industrial, commercial, and transportation sectors are forecast to remain essentially unchanged. The difference in consumption and production is made up principally from increased gas imports (from 1.15 Tcf in 1988 to about 2.3 Tcf in 2000) largely from Canada through pipeline transportation and to a smaller extent (0.3 Tcf) from liquified natural gas imports. The EIA projection assumes the outlook of Canadian gas imports will not be affected by ratification of the Free Trade Agreement between the United States and Canada since significant steps already have been taken by the Canadian government to remove restrictions on the production and export of gas.

The projections of yearly natural gas supply, consumption, and prices are presented in table 1-1. In addition to this "base case" projection, the *Annual Energy Outlook* includes two alternative projections reflecting different assumptions about future world oil prices. In the "low oil price case," oil prices increase at an annual rate of 3.3 percent, versus 5.5 percent annually in the base case, reaching $21.7 per barrel by the year 2000. The lower oil price leads to a slightly higher increase in GNP,

[35] Ibid., 5.

TABLE 1-1

EIA PROJECTION OF GAS SUPPLY, CONSUMPTION, AND PRICES (BASE CASE)

	1988	1990	1992	1994	1996	1998	2000	Annual Percent Growth (1988-2000)
SUPPLY (Tcf)								
Production	16.71	16.94	16.93	17.35	17.67	18.20	18.49	0.9
Net Imports	1.15	1.44	1.61	1.79	1.98	2.15	2.31	6.0
Adjustments*	.21	.10	.10	.10	.10	.10	.10	--
Total**	18.07	18.48	18.64	19.24	19.75	20.45	20.90	1.2
CONSUMPTION (Tcf)								
Residential	4.59	4.62	4.59	4.52	4.42	4.37	4.31	-.5
Commercial	2.61	2.65	2.68	2.67	2.65	2.68	2.69	.3
Industrial	6.15	6.29	6.37	6.34	6.27	6.21	6.14	.0
Electric Util.	2.83	2.88	2.95	3.61	4.26	4.97	5.50	5.7
Others***	1.56	1.50	1.51	1.54	1.58	1.62	1.66	--
Total**	17.75	17.94	18.10	18.68	19.17	19.86	20.29	1.1
PRICE								
Avg. Wellhead Price#	1.62	1.75	2.14	2.61	3.22	3.55	3.91	7.6
World Oil Price##	14.70	15.00	15.90	18.90	22.50	26.00	28.00	5.5

Source: Energy Information Administration, Annual Energy Outlook 1989 (Washington, DC: Energy Information Administration, 1989), table A9.

* Includes supplemental gas and net storage withdrawals
**Totals may not equal sum of components due to independent rounding
***Includes lease and plant fuel and transportation costs
\# 1988 dollars per thousand cubic feet
\##1988 dollars per barrel

although it is still projected to increase on average at an annual rate of 2.5 percent. The resulting projection of gas prices, supply, and consumption is shown in table 1-2. The "high oil price case" assumes an annual increase of 7.5 percent in crude oil prices reaching $35 per barrel by the year 2000. The higher oil price leads to a lower growth of GNP; 2.4 percent annually. The gas market projections under this scenario are shown in table 1-3. The projections based on these three different scenarios are relatively close to one another. Based on these projections, the *Annual Energy Outlook* does not foresee any extended or chronic gas shortage up to the year 2000.

AGA *Gas Energy Supply Outlook*

Since 1980, the Gas Supply Committee of the American Gas Association, a trade association for regulated pipelines and distribution companies, has issued biennial reports presenting the Committee members' consensus view about future sources of natural gas supply.[36] The forecast of gas supply is based on the integration of gas supply studies made by individual Committee members. The AGA report provides forecasts of future gas supply for both the contiguous states and other sources of gas supply (mainly Alaskan gas and imports). The *Gas Energy Supply Outlook* indicates that its supply assessments do not consider the effects of demand factors such as interfuel competition, fuel switching, and historical market demand, which might constitute constraints of gas supply in a real gas market. So the *Gas Energy Supply Outlook* projections in a sense represent the highest amounts of possible gas supply at various prices. It is not necessarily the most likely amount of gas supply in the future gas markets. Three scenarios (low-price, high-price, and OPEC-dominant) based on different energy price assumptions are constructed, but no one specific scenario is chosen as the base case.

The low-price scenario assumes a decline in the real price of crude oil through 1990 with a slow rise thereafter, reaching $22 per barrel in the

[36] American Gas Association, *The Gas Energy Supply Outlook 1987-2010* (Arlington, VA: American Gas Association, 1987).

TABLE 1-2

EIA PROJECTION OF GAS SUPPLY, CONSUMPTION, AND PRICES (LOW OIL PRICE CASE)

	1988	1990	1992	1994	1996	1998	2000	Annual Percent Growth (1988-2000)
SUPPLY (Tcf)								
Production	16.71	17.17	17.22	17.53	17.96	18.35	18.82	1.0
Net Imports	1.15	1.44	1.59	1.77	1.93	2.10	2.27	5.8
Adjustments*	.21	.10	.10	.10	.10	.10	.10	--
Total**	18.07	18.71	18.91	19.40	19.99	20.55	21.18	1.3
CONSUMPTION (Tcf)								
Residential	4.59	4.64	4.63	4.57	4.51	4.46	4.39	-.4
Commercial	2.61	2.67	2.71	2.72	2.74	2.76	2.76	.5
Industrial	6.15	6.45	6.54	6.52	6.54	6.53	6.46	.4
Electric Util.	2.83	2.86	2.94	3.44	4.00	4.53	5.25	5.3
Others***	1.56	1.55	1.54	1.58	1.62	1.66	1.70	--
Total**	17.75	18.16	18.36	18.84	19.41	19.95	20.57	1.2
PRICE								
Avg. Wellhead Price#	1.62	1.69	1.99	2.40	2.79	3.14	3.52	6.7
World Oil Price##	14.70	12.89	13.80	15.80	17.70	19.50	21.70	3.3

Source: Energy Information Administration, Annual Energy Outlook 1989, table B9.

* Includes supplemental gas and net storage withdrawals
**Totals may not equal sum of components due to independent rounding
***Includes lease and plant fuel and transportation costs
1988 dollars per thousand cubic feet
##1988 dollars per barrel

TABLE 1-3

EIA PROJECTION OF GAS SUPPLY, CONSUMPTION, AND PRICES (HIGH OIL PRICE CASE)

	1988	1990	1992	1994	1996	1998	2000	Annual Percent Growth (1988-2000)
SUPPLY (Tcf)								
Production	16.71	16.85	16.88	17.08	17.56	18.05	18.35	0.8
Net Imports	1.15	1.44	1.62	1.81	2.01	2.18	2.36	6.2
Adjustments*	.21	.10	.10	.10	.10	.10	.10	--
Total**	18.07	18.38	18.60	19.00	19.67	20.33	20.81	1.2
CONSUMPTION (Tcf)								
Residential	4.59	4.61	4.56	4.47	4.36	4.31	4.23	-.7
Commercial	2.61	2.64	2.66	2.63	2.60	2.63	2.63	.1
Industrial	6.15	6.21	6.17	6.12	6.10	6.00	5.86	-.4
Electric Util.	2.83	2.86	3.18	3.71	4.47	5.20	5.85	6.2
Others***	1.56	1.52	1.49	1.51	1.56	1.60	1.63	--
Total**	17.75	17.85	18.06	18.45	19.09	19.74	20.20	1.1
PRICE								
Avg. Wellhead Price#	1.62	1.85	2.24	2.81	3.46	3.85	4.32	8.5
World Oil Price##	14.70	18.00	20.20	22.80	26.50	30.80	35.00	7.5

Source: Energy Information Administration, Annual Energy Outlook 1989, table C9.

* Includes supplemental gas and net storage withdrawals
**Totals may not equal sum of components due to independent rounding
***Includes lease and plant fuel and transportation costs
1988 dollars per thousand cubic feet
##1988 dollars per barrel

year 2000 and $29 per barrel in 2010 (in 1987 dollars). The gas price associated with the $29 per barrel oil price would be $4.88 per thousand cubic feet. Because of these relatively low oil and gas prices, it is projected that there will be few additional incentives for developing new gas fields. The resulting gas supply and price projections are shown in table 1-4.

The high-price scenario assumes a more rapid increase in oil and gas price relative to general inflation, with oil prices reaching $28 per barrel in 2000 and $40 per barrel in 2010. The corresponding gas prices would be $3.70 per thousand cubic feet in 2000 and $6.37 per thousand cubic feet in 2010. Based on the comparison of the assumptions of energy prices (both assuming oil prices close to $28 per barrel by 2000), the high-price scenario of the AGA *Gas Energy Supply Outlook* seems to correspond to the

TABLE 1-4

AGA PROJECTION OF GAS SUPPLY AND PRICES
(LOW PRICE SCENARIO)

	1990	2000	2010
SUPPLY (Tcf)			
Contiguous States	16.0	15.1	14.8
Imports	1.5	2.9	3.3
Alaskan Gas	0.0	0.0	0.7
Totals*	17.6	18.0	18.9
PRICES			
Gas#	1.69	3.03	4.88
Oil##	16.00	22.00	29.00

Source: AGA, *The Gas Energy Supply Outlook: 1987-2010* (Arlington, VA: American Gas Association, 1987), table I-1.

*Totals may not equal sum of components due to independent rounding

In 1987 dollars per thousand cubic feet

In 1987 dollars per barrel

base case of the EIA *Annual Energy Outlook*. Because of the assumption of a higher energy price, there will be more exploration and development of new gas fields and, consequently, a higher amount of gas supply (see table 1-5).

The OPEC-dominant scenario assumes the Organization of Petroleum Exporting Countries (OPEC) can return to its dominant position in the world oil market and achieve oil prices of $35 per barrel and $60 per barrel in years 2000 and 2010, respectively. The corresponding gas prices would be $4.67 and $9.55 per thousand cubic feet. Of course, the highest energy price will lead to the largest increase in natural gas supply (see table 1-6).

TABLE 1-5

AGA PROJECTION OF GAS SUPPLY AND PRICES
(HIGH PRICE SCENARIO)

	1990	2000	2010
SUPPLY (Tcf)			
Contiguous States	17.4	18.7	18.6
Imports	1.7	2.9	3.8
Alaskan Gas	0.0	0.7	1.2
Other (Synthetic & Nonconventional)	0.0	0.1	0.2
Totals*	19.2	22.4	23.8
PRICES			
Gas #	2.11	3.70	6.37
Oil ##	20.00	28.00	40.00

Source: AGA, *The Gas Energy Supply Outlook: 1987-2010*, table I-2.

*Totals may not equal sum of components due to independent rounding

In 1987 dollars per thousand cubic feet

In 1987 dollars per barrel

TABLE 1-6

AGA PROJECTION OF GAS SUPPLY AND PRICES
(OPEC DOMINANCE SCENARIO)

	1990	2000	2010
SUPPLY (Tcf)			
Contiguous States	17.4	22.7	23.5
Imports	1.7	2.7	3.2
Alaskan Gas	0.0	0.7	1.2
Other (Synthetic & Nonconventional)	0.0	0.2	0.3
Totals*	19.2	26.2	28.2
PRICES			
Gas#	2.11	4.67	9.55
Oil##	20.00	35.00	60.00

Source: AGA, *The Gas Energy Supply Outlook: 1987-2010*, Table I-3.

*Totals may not equal sum of components due to independent rounding

In 1987 dollars per thousand cubic feet

In 1987 dollars per barrel

The AGA *Gas Energy Supply Outlook* does not provide its own projection of gas demand, but compiles those made by the AGA Gas Demand Committee and four other sources.[37] These projections of total gas demand range between 16.6 and 19.8 quads in the year 2000. As a result, the AGA projection does not foresee any gas supply shortfall except where energy prices stay low during the forecast period and the activity of domestic gas exploration production remains depressed while gas consumption continues its current 1.1 percent annual rate of increase.

[37] They are the demand projections made by the U.S. Department of Energy, Gas Research Institute, Chevron, and Conoco, Inc. For detail see American Gas Association, *The Gas Energy Supply Outlook 1987-2010*, 9, 47.

GRI Projections

The Gas Research Institute (GRI), a research organization of the natural gas pipelines, distributors, and producers, develops an annual baseline projection of United States energy supply and demand for use in guiding GRI's research programs.[38] This projection is developed independently by GRI using public data and commercially available forecasting models.[39] In contrast to the AGA projection, it is not derived from the individual forecasts of GRI-member companies.

The basic economic assumptions used in the GRI baseline projection are: real GNP growth of 2.3 percent on average between 1987 and 2010, an inflation rate projected to be 5 percent on average each year through the same period, and a gradual increase in crude oil prices to $23.25 (in 1987 dollars) per barrel by 1995. After 1995, (as a result of tighter supply worldwide) price would increase more rapidly to $27 per barrel in 2000 and $42.25 per barrel by 2010.

The GRI baseline projection shows that total energy consumption is likely to increase about 1 percent per year over the forecast period, and that the overall energy intensity of the economy will decline 1.2 percent on average annually. The resulting projections of natural gas supply, consumption, and prices of gas and crude oil are summarized in table 1-7. In addition to the baseline projection, another GRI report discusses projections based on eight other alternative scenarios covering a wide range of different economic assumptions.[40] But, since the gas demand projections under alternative scenarios are not in sufficient detail and the gas supply forecasts under alternative scenarios are not yet developed, it is

[38] Gas Research Institute, *1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010* (Chicago: Gas Research Institute, 1988).
[39] Ibid. Three key models used in developing the baseline projection are Energy/Economic Modeling System by Data Resources, Inc., Hydrocarbon Model by GRI, and Industrial Sector Technology Use Model by Energy and Environmental Analysis, Inc.
[40] Gas Research Institute, *Policy Implications of the 1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*.

TABLE 1-7

GRI BASELINE PROJECTION OF GAS SUPPLY, CONSUMPTION, AND PRICES

	1995	2000	2010
SUPPLY (Tcf)			
Contiguous States	15.2	15.3	14.0
Alaska	0.2	0.2	1.4
Imports	1.7	1.9	2.5
Others*	1.3	1.3	1.4
Totals**	18.4	18.7	19.2
CONSUMPTION*			
Residential	4.5	4.5	4.3
Commercial	2.5	2.6	2.9
Industrial	7.3	6.9	6.7
Electric Generation	3.2	3.7	4.2
Transportation	0.6	0.7	0.8
Totals**	18.1	18.4	18.8
PRICE			
Gas#	2.91	3.60	6.14
Oil##	23.25	27.00	42.25

Source: GRI, *1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010* (Chicago: Gas Research Institute, 1988), tables 2, 16.

* Includes coal gas, SNG from petroleum, propane-air, refinery gas, and lease and plant fuel
**Totals may not equal sum of components due to independent rounding
#1987 dollars per thousand cubic feet
##1987 dollars per barrel

impossible to make valid comparisons between alternative scenarios with the baseline projection.

Comparison of Three Projections

A comparison of the base cases (the high-price scenario in the AGA projection) of the three projections shows a high degree of similarity in the underlying assumptions of economic growth, energy intensity, and energy prices. The EIA and GRI projections reflect the likely demand and supply conditions of future gas markets while the AGA projection presents the gas supply responses at various levels of energy prices. Put another way, the EIA and GRI projections represent the amounts of gas demand and supply under prevailing market conditions, while the GRI projection seems to be more conservative than the EIA projection, particularly in the amount of future domestic gas production. The AGA projections, on the other hand, represent a gas supply curve. A higher energy price always leads to a larger gas supply, and the secondary effects that the demand for gas may be depressed due to the reduction of economic activities brought about by higher energy prices are not reflected in the AGA projection. A summary of the economic assumptions and forecast results of the three projections is shown in table 1-8.

Regional Gas Supply and Demand

Most gas supply and demand forecasting models do not contain detailed regional gas consumption and supply information. A GRI report, *The Long-Term Trends in U.S. Gas Supply and Prices*, is the only source available to the authors that has an expanded discussion of regional gas demand and supply projections.[41] The GRI regional projections of gas consumption and supply are summarized in table 1-9.[42] The projections are derived basically through the same method used in the national projection. The major thrusts of the GRI regional projection are that the contiguous states' gas production will shift away from the traditionally important West

[41] Gas Research Institute, *The Long-Term Trends in U.S. Gas Supply and Prices: The 1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*.
[42] The states comprising the different regions are: Pacific 1 (Oregon, Washington), Pacific 2 (California), Mountain 1 (Colorado, Idaho, Montana, Nevada, Utah, Wyoming), Mountain 2 (Arizona, New Mexico), West North Central (Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota), West South Central (Arkansas, Louisiana, Oklahoma, Texas), East North Central (Illinois, Indiana, Michigan, Ohio, Wisconsin), East South Central (Alabama, Kentucky, Mississippi, Tennessee), Middle Atlantic (New Jersey, New York, Pennsylvania), South Atlantic (Delaware, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia), and New England (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont).

TABLE 1-8

A COMPARISON OF THREE PROJECTIONS

	EIA Base Case	AGA High Price Scenario	GRI Baseline Projection
<u>Assumptions</u>			
Annual GNP growth (%)	2.50	N/A	2.30
Crude oil price in 2000 (1987 dollars/barrel)	27	28	27
Annual Rate of Decrease in Energy Intensity (%)	1.30	N/A	1.20
<u>Projections (year 2000)</u>			
Supply (Tcf)	20.90	22.40	18.70
Demand (Tcf)	20.29	N/A	18.40
Wellhead price ($/Mcf)	3.91	3.70	3.60
<u>Projection (year 2010)</u>			
Supply (Tcf)	N/A	23.80	19.20
Demand (Tcf)	N/A	N/A	18.80
Wellhead price ($/Mcf)	N/A	6.37	6.14

Source: Authors' summary of tables 2-1, 2-5, and 2-7.

N/A: Not Available

South Central region, and that most new gas sources (imported and Alaskan gas) will enter the interstate gas transportation system outside this region. The portion of gas supply provided by the West South Central region is expected to drop from 67 percent in 1987 to 58 percent in 2000 and 40 percent in 2010. On the other hand, the gas supply in the Mountain regions will increase from 2.2 Tcf in 1987 to 5.3 Tcf in 2010, and in the three Atlantic regions will increase from 0.6 Tcf in 1987 to 2.7 Tcf in 2010.

TABLE 1-9

CONTIGUOUS STATES' GAS CONSUMPTION AND SUPPLY
(in trillion cubic feet)

	1995			2000			2010		
	Consumption	Supply	Balance*	Consumption	Supply	Balance*	Consumption	Supply	Balance*
REGION									
Pacific 1	0.2	0.2	-0.1	0.3	0.2	-0.1	0.3	0.2	-0-
Pacific 2	2.3	0.6	-1.7	2.5	0.6	-1.9	2.8	0.7	-2.1
Mountain 1	0.6	2.3	1.8	0.7	2.2	1.6	0.7	3.8	3.1
Mountain 2	0.3	1.2	1.0	0.3	1.6	1.3	0.3	1.5	1.2
West North Central	1.2	1.0	-0.2	1.2	0.9	-0.3	1.3	1.2	-0.1
East North Central	3.1	0.4	-2.7	3.0	0.5	-2.6	3.0	0.5	-2.5
West South Central	5.5	11.3	5.8	5.5	10.7	5.4	5.3	7.6	2.3
East South Central	0.9	0.3	-0.5	1.0	0.5	-0.5	1.1	0.9	-0.2
South Atlantic	1.7	0.4	-1.3	1.7	0.8	-0.9	1.9	1.8	-0-
Middle Atlantic	1.9	0.4	-1.6	2.0	0.5	-1.6	2.0	0.8	-1.3
New England	0.4	0.1	-0.4	0.5	0.2	-0.3	0.5	0.2	-0.3
Total*	18.1	18.1	-0-	18.6	18.6	-0-	19.0	19.0	-0-

Source: GRI, The Long-Term Trends in U.S. Gas Supply and Price: The 1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010, tables 26, 27, 28.

*Balances and totals may not equal sum of components due to independent rounding

Based on the regional breakdown of gas supply and consumption, the GRI report indicates that the following four regions seem to have the highest potential for gas supply interruption (in the sense of relying more on gas delivered from outside): Pacific 2 (California), East North Central (Illinois, Indiana, Michigan, Ohio, and Wisconsin), Mid-Atlantic (New Jersey, New York, and Pennsylvania), and New England. According to the GRI projection, California may be the most vulnerable state since its gas imports increase steadily over the projection period.[43] The implications of the increase in gas importation in certain regions of the nation point to the need to closely examine the adequacy of gas transportation capacity serving these particular regions to avoid potential supply shortfall and the possible addition of new gas transportation capacity into these regions. Actually, plans are already underway for a major new 1,600-mile interstate pipeline network designed to bring some 2.5 Bcf of gas per day from Canadian and United States' production areas to California.[44]

A Scenario for Analysis

Based on the various gas supply and demand projections discussed above, a scenario of the future gas market in the United States can be constructed. The purpose of selecting a particular gas demand and supply scenario is to establish a reference framework for the analysis of the supply reliability and cost implications of increasing direct gas purchases by LDCs. For example, if extended surpluses for both gas production and transportation capacity are foreseen, the choice between a spot-market purchase and a long-term gas procurement contract with pipelines might be of little significance to an LDC, since it can be assured of plenty of gas supply at reasonable

[43] According to a report issued by the California Energy Commission's Fuels Planning Committee in early 1989, the overall gas demand in California will continue to grow and curtailments are likely to increase in frequency and severity during periods of peak demand. See "California Report Says Curtailments Will 'Increase in Frequency'," *Inside F.E.R.C.*
[44] "Planned Pipeline System Could Bring 2.5 Bcf/day to California Markets," *Inside F.E.R.C.*, 24 October 1988, 1-2.

costs even if it relies heavily on spot market purchases as its supply sources. On the other hand, if a tight gas market is forecasted, the choice of different gas procurement mechanisms can become critical. The stability and predictability of gas supply and cost associated with long-term contracts with pipelines may be essential to an LDC's ability to serve its customers at reasonable cost and reliability. An overdependence on spot purchases or procurements with wellhead producers directly may turn out to be a less reliable and sometimes a more costly gas procurement strategy over an extended period of time.

The scenario chosen for this study is basically a continuation of current trends in gas demand and supply. One new development is the total deregulation of wellhead gas price by 1993. Even though the full extent of the impact of total deregulation in gas production is not yet clear, this development is likely to enhance the future supply of natural gas. Specifically, no extensive or chronic gas shortages for the nation as a whole are foreseen over the next ten to twenty years. But the so-called "gas bubble" or gas supply surplus is unlikely to continue indefinitely into the future either. Due to the increasing demand for gas in electricity generation and a gradual but slow recovery in gas exploration and production, a balanced and stable gas market will emerge in a few years and probably will remain stable for an extended period of time. The gas supply reliability implication is that the choice of alternative supply options by an LDC does affect the reliability of its gas service to its customers. However, some "margins of error" probably are available to an LDC in experimenting with new gas procurement and transportation options, at least in the initial few years.

Obviously, not everyone shares this more sanguine view about future gas demand and supply conditions. Some gas industry executives such as R. C. Thomas of Tenneco, Inc., and James Gray of Canadian Hunter Exploration Ltd., have expressed great concerns about the ability of United States gas producers to keep pace with growing demand. Imported gas, primarily from Canada, may not be able to fill much of the supply/demand gap.[45] The

[45] See "Promising Demand Projections Dimmed by Anticipated Supply Crunch," 5-6.

executives cite growing environmental concerns, increasing industrial activity in certain regions of the country, and the depressed gas and oil drilling activities in the United States as main reasons for their assessments.

CHAPTER 2

DIRECT GAS PURCHASE: RATIONALES, MECHANISMS, ADVANTAGES, AND LIMITATIONS

In the past, most local distribution companies (LDCs) obtained their gas supplies through long-term contracts with pipeline companies. The pipelines, in turn, obtained the right to take gas from reserves (gas fields) through long-term contracts with gas producers. But with a continuing shift toward relying more on competitive forces than on government regulations in the gas market, procurement and transportation practices have undergone significant changes in the last few years. Most changes are reflected in two areas: a drastic increase in the amount of gas purchased directly by an LDC, and a proliferation of new gas procurement and transportation practices. This chapter details the rationales, the various transaction mechanisms available for purchasing gas directly by an LDC, and the advantages and limitations associated with the use of direct gas purchases by LDCs.[1]

In this study, a broad definition of direct purchase is used. Any gas procurement arrangement entered into between an LDC and an entity other than an interstate pipeline is categorized as a direct gas purchase. Some common forms include purchasing in the spot market, entering a long-term contract directly with wellhead producers, and procuring gas and transportation services through gas marketers and other intermediaries.

The LDCs' growing involvement in direct gas purchase is motivated primarily by three factors: price advantages of spot-market purchases over long-term contracts, easier access to pipeline transportation facilities, and intense interfuel competition and stringent gas purchase requirements at

[1] A previous publication of The National Regulatory Research Institute, *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches*, has a similar discussion about these subjects. That discussion, however, centers around spot purchases and long-term contracts. Other procurement mechanisms are not addressed.

the distribution level.[2] With these three conditions, an LDC has the economic opportunity (price differential), technical feasibility (transportation access), and regulatory incentive to actively secure gas supplies from sources other than its traditional pipeline suppliers.

The increase in the amount of gas directly purchased by LDCs and end-users has been quite dramatic over the past few years. An Energy Information Administration study indicates that the amount of directly purchased gas transported by major pipelines increased six-fold, from 777 billion cubic feet (Bcf) in 1981 to 4,458 Bcf in 1986.[3] For the same group, the amount of pipeline-owned gas transported has decreased from 10,233 Bcf to 5,841 Bcf, a 44 percent drop during the same time period.[4] Consequently, the amount of directly purchased gas as a percentage of pipeline throughput increased from less than 8 percent in 1981 to 44 percent in 1986.

A more recent analysis of the annual sales and throughputs of twenty-four major interstate pipelines shows similar trends.[5] From 1986 to 1988, pipeline gas sales decreased 24.5 percent (6,470 Bcf vs. 4,820 Bcf) while gas transportation grew 65.8 percent (6,619 Bcf vs. 10,975 Bcf). It should be noted that the 1986 to 1988 data are not necessarily directly comparable with those of the previous years since they were derived from different data

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[2] Two additional factors have been cited as contributing to the development of spot markets (a primary form of direct purchase). They are improved computer and electronic networks to facilitate complicated interchange and a "pay-as-you-go" capability for self-financing, both of which expand the participation by small firms. See Anna Fay Williams and Leonard V. Parent, *New Opportunities for Purchasing Natural Gas* (Lilburn, GA: The Fairmont Press, 1988), 8-12.

[3] Energy Information Administration, *Wellhead Purchases by Interstate Natural Gas Pipeline Companies Since the NGPA* (Washington, DC: Energy Information Administration, 1988), table 2. These data are derived from FERC Purchase Gas Adjustment (PGA) filings and FERC Form 2, Annual Report of Major Natural Gas Companies.

[4] Ibid.

[5] See "Pipes' Sales Slide Eases in '88; Carriage, Throughput Both Gain," *Inside F.E.R.C. Special Report*, 24 April 1989. The twenty-four pipelines reported in the *Inside F.E.R.C.* story are roughly the same as the twenty pipelines reported in the EIA study (see footnote 2), except that the information from Arkla Inc. is not included in the EIA data. The 1986-1988 data are derived primarily from Form 10-K submitted to the Securities and Exchange Commission and annual reports to stockholders.

sources and the items included in gas sales and transportation may vary. However, the overall trend toward more direct purchases by LDCs and end-users in the gas market is unmistakable.

Tasks of a Direct Gas Purchase

Traditionally, the quantity and price of gas delivered to the city gate of an LDC are determined through two markets: the field (gas reserve) market, which governs transactions between producers with proven gas reserves to sell and pipelines who seek to obtain the right to take gas from particular reserves, and the wholesale market, which consists of transactions both between pipelines and large industrial customers and between pipelines and LDCs. The LDCs, in turn, resell the gas to residential, commercial, and industrial end-users.[6]

In this three-tier gas industry structure, the pipeline plays the critical role in delivering gas by acting as both gas merchant and gas transporter. It commits long-term purchases to gas producers, works as a wholesaler in pooling demand from LDCs and supply from producers, and finances and builds the required physical facilities to transport gas. By comparison, a direct purchase by an LDC bypasses completely the merchant function of a pipeline even though it may not bypass the physical facilities or transportation functions.

In purchasing from pipeline suppliers, the task facing an LDC is straightforward: to negotiate a "best deal" with the pipelines. Direct gas purchase, on the other hand, involves some additional tasks for an LDC. An LDC or its agent needs to take on many functions previously performed by the pipelines. Primarily, four tasks are involved in consummating a direct gas purchase: finding accessible gas suppliers, evaluating the reliability of suppliers, securing reliable transportation arrangements, and arranging backup services.

The first task of a direct gas purchase is to identify potential gas suppliers that can be accessed through the LDC's current pipeline suppliers

[6] Paul W. MacAvoy and Robert S. Pindyck, "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," *Bell Journal Of Economics* 4 (1973): 460-62.

or the interconnected pipeline systems. In some instances, especially when the amount of gas demand is significant or a potential supplier has a large amount of gas available, an LDC may consider building its own pipeline interconnections.

Once potential suppliers are identified, an LDC needs to evaluate their capability and reliability for delivering the promised amount of gas. Such evaluation includes an assessment of the amount of dedicated gas reserves owned or controlled by a particular gas supplier, the record of the supplier in previous gas deliveries, the interconnection of the supplier with various pipeline systems, and the financial condition of the supplier.

Since it is usually a buyer's responsibility to arrange gas transportation in direct gas purchases, an LDC needs to make arrangements with its current pipeline suppliers or those interconnected with the potential suppliers. At the present, a large percentage of gas transportation service is provided on an interruptible basis even though an LDC may choose to convert a portion of its firm gas purchase to firm transportation service by its traditional pipeline supplier. Thus, the evaluation of the reliability of gas transporters is quite important. Identifying available transportation capacity and reviewing the previous record of transportation service of the transporter are ways to evaluate the reliability of a particular transporter. Currently, there appears to be a lack of reliable information about the extent, duration, and severity of pipeline interruptions. Some suggest that the FERC should devise a mechanism for collecting such information.[7] If the LDC is served by more than one pipeline it needs to compare the conditions and rates of gas transportation services being offered. If the current pipeline supplier is not an open-access transporter or provides transportation on a case-by-case basis only, the LDC may have to bypass the pipeline or build its own interconnection with another pipeline.

Spot gas supplies and transportation services typically are available on a "best effort" basis, and sellers do not have inherent obligations to

[7] "Remarkable Remarks: William F. Hederman, Jr.," *Public Utilities Fortnightly*, 3 August 1989, 7.

serve the buyers. An LDC may need to arrange its own backup gas supplies if the directly purchased gas is not available and cannot be delivered as planned. An LDC's traditional pipeline suppliers may provide such a backup if standby fees are agreed upon in advance. Alternative backup arrangements to LDCs include encouraging customers to maintain fuel-switching capability, contracting backup service with gas marketers, and using gas storage facilities.

Given that most LDCs' previous experience in direct gas purchases is limited to the intrastate market or to smaller-scale purchases, substantial efforts and money may have to be invested before an LDC can acquire sufficient expertise in identifying and evaluating gas suppliers and transporters to take full advantage of such direct purchases. After all, LDCs typically were not involved in direct purchase with wellhead producers through interstate pipeline delivery systems before the mid-1980s.

Rationales of Direct Purchases

Pipeline purchases under long-term contract had been the dominant form of gas procurement by LDCs until the last few years. Many factors have contributed to the increasing use of direct gas purchases by LDCs in obtaining their gas supplies. The more important factors are price advantages of spot purchase in a slack gas market, more readily available access to the interstate pipeline systems, interfuel competition, and state regulatory requirements mandating gas purchases from the lowest-cost suppliers. The following sections detail the rationales for LDCs' growing use of directly purchased gas as a part of its total supply portfolio.

Cost Advantage of Spot Market Purchase

The substantial amount of gas supply surplus in the interstate gas market since early 1980 has depressed the wellhead price of gas. The exact amount of gas supply surplus is difficult to determine. One study indicates the amount of gas surplus in the interstate gas market, as measured by the difference between available gas from dedicated supply sources owned by the pipeline companies and gas sales to LDCs and other customers, has steadily increased from 0.5 Tcf in 1977 to 5 Tcf in 1987.[8]

It can be expected that in a period of substantial supply surplus, the gas price in the spot market that reflects current demand and supply conditions is likely to be lower than the average cost of pipelines' existing supply portfolios, since the long-term contracts in the portfolios generally reflect gas demand and supply expectations of a decade or more ago. Even without gas supply surplus, the spot price of gas can be expected to be lower than that of long-term contracts since the price of a long-term contract generally includes a "premium" that buyers are willing to pay for supply security and price certainty. In a 1988 NRRI study, it was estimated that in a slack gas market the prices of long-term contracts (wellhead prices) were about 9 percent higher than prevailing spot market prices.[9] An examination of seven commodities with both markets for spot purchase and long-term contract shows a similar relationship.[10]

The price differentials between spot-market and long-term contracts for the Texas and Louisiana production area since 1986 are shown in table 2-1. Although the trends indicated here might not necessarily be representative of the country as a whole, the combined Texas and Louisiana production area is an important gas supply region, and its detailed monthly data may be indicative of the typical cost advantages of spot purchases over contract purchases. Out of the thirty-six months where both spot and wellhead prices were available, spot prices exceeded wellhead contract prices in six months (December 1987 to January 1988, and September 1988 to December 1988). The reason that the spot price was higher than the contract price in these two periods was probably the higher gas demand (resulting in a tight gas market) in the heating seasons. Even though there is no guarantee that the price

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8 Cambridge Energy Research Associates, *Natural Gas Trends* (Cambridge, MA: Cambridge Energy Research Associates, 1988), 84.

9 J. Stephen Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches* (Columbus, OH: The National Regulatory Research Institute, 1988), 58-59.

10 Charles River Associates Incorporated, *Natural Gas Procurement: Experience with Spot vs. Contract Pricing in Analogous Commodity Markets* (Boston: Charles River Associates Incorporated, 1986).

TABLE 2-1

MONTHLY SPOT PRICES IN TEXAS AND LOUISIANA
PRODUCTION AREA AND AVERAGE WELLHEAD PRICES
(dollars per thousand cubic feet)

	1986		1987		1988	
Month	Spot	Wellhead	Spot	Wellhead	Spot	Wellhead
January	2.17	2.28	1.49	1.74	1.99	1.97
February	2.13	2.26	1.53	1.73	1.88	1.88
March	2.00	2.16	1.53	1.73	1.63	1.76
April	1.75	2.10	1.49	1.69	1.42	1.64
May	1.55	1.96	1.47	1.65	1.36	1.57
June	1.46	1.85	1.43	1.65	1.39	1.58
July	1.49	1.80	1.41	1.66	1.48	1.59
August	1.49	1.77	1.38	1.63	1.59	1.59
September	1.47	1.78	1.37	1.56	1.71	1.61
October	1.44	1.73	1.37	1.57	1.75	1.62
November	1.42	1.77	1.58	1.64	1.96	1.72
December	1.44	1.76	1.87	1.70	2.11	1.86

Source: Cambridge Energy Research Associates, *Natural Gas Trends* (Cambridge, MA: Cambridge Energy Research Associates, 1988), 20; and Energy Information Administration, *Monthly Energy Review* (Washington, DC: Energy Information Administration, April 1989), 105.

N/A: Not applicable

advantages in the spot market will continue indefinitely, this situation has been quite consistent for the last few years. Many LDCs and end-users are surely tempted to purchase cheaper gas available in the spot market rather than to rely solely on long-term contracts.

It is worth noting that prior to the full implementation of open access to pipeline facilities under FERC Orders 436 and 500, spot purchases by LDCs posed essentially no threat to the LDCs' supply reliability because their pipeline suppliers still had a service obligation for their full historical level of contracted demand. In other words, LDCs were comfortable buying spot gas knowing that, in the event of a supply interruption, the pipelines with whom they had long-term service agreements were ready to meet their requirements. This further enhanced the attractiveness to LDCs of spot gas purchases as a procurement strategy before the full implementation of the FERC open-access transportation policy.

Availability of Transportation Access

The availability of lower-priced spot market gas may not necessarily lead to any significant increase in direct gas purchases by LDCs if they have no access to the gas transportation facilities linking them with alternative gas suppliers. Detailed analyses of the FERC's involvement in fashioning the current pipeline transportation policy are available elsewhere,[11] and the essence of current federal gas transportation policy is embodied primarily in FERC Orders 436 and 500. Through economic incentives (such as a reduction of take-or-pay liabilities) provided by the FERC orders, the pipelines are encouraged to become permanent open-access transporters voluntarily. Alternatively, an interstate pipeline is allowed to provide transportation service on a case-by-case basis on behalf of an LDC or an intrastate pipeline under Section 311 of the Natural Gas Policy Act of 1978 (NGPA).[12]

As of October 1988, nineteen major pipelines had accepted the 436/500 blanket certificate to become open-access transporters, five pipelines were providing transportation access on an interim basis under Section 311 of the

[11] An extensive discussion of major developments in federal gas transportation policy during the 1980s is available in Robert E. Burns et al., *State Gas Transportation Policies: An Evaluation of Approaches* (Columbus, OH: The National Regulatory Research Institute, 1989), 87-155. Also see Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches*, 5-28.

[12] The pipelines are still allowed to provide temporary transportation service in cases of emergencies for other interstate pipelines, LDCs, and end-users under section 7(c) of the Natural Gas Act.

NGPA, and sixteen others were not open-access pipelines.[13] However, the degree of pipeline open access is likely to be underrepresented by the number of open-access pipelines alone. Three other indicators--transmission pipeline mileage (76 percent), annual gas sales (83 percent), and annual throughput (86 percent)--all indicate a much higher degree of open access to pipeline transportation facilities (see table 2-2).

TABLE 2-2

TRANSPORTATION MILEAGE, SALES, AND THROUGHPUT ACCORDING TO PIPELINE STATUS

	Major Pipelines					
	Mileage[1]		Sales[2]		Throughput[2]	
STATUS*	Miles	Percent	Bcf	Percent	Bcf	Percent
Blanket-Certificate Open Access	131,742	76	4,011	83	13,661	86
NGPA-311 Open Access	19,372	11	413	9	1,713	11
Non-Open Access	22,990	13	396	8	421	3
Total	174,104	100	4,820	100	15,795	100

Sources: [1]Energy Information Administration, *Statistics of Interstate Natural Pipeline Companies 1986* (Washington, D.C.: Energy Information Administration, 1987), 251-62. The figures are as of December 31, 1986.
[2]*Inside FERC, Special Report*, 24 April, 1989. The figures are 1988 data.

*As of October 1988.

[13] Cambridge Energy Research Associates, *Natural Gas Trends*, 82-83. Clearly, there are various ways of counting the number of major interstate pipelines. According to the *Statistics of Interstate Natural Gas Pipeline Companies 1987* published by the Energy Information Administration, there are forty-four major interstate pipelines. However, some of them are subsidiaries of holding companies and may be counted as separate in one study and as a part of a holding company in another. This may explain why there seems to be some inconsistency in the total reported number of major pipelines.

It should be noted that even with a blanket certificate of open access, the gas transportation tariffs charged by pipelines remain under FERC jurisdiction for interstate gas delivery. But the use of blanket certificates has provided a simplified and flexible procedure for pipelines to provide transportation service.[14] A blanket certificate covers an unlimited number of transactions. For transportation services not exceeding 120-days duration, the pipelines are authorized to transport on a "self-implementing" basis with limited reporting requirements. For transactions of longer duration, an abbreviated review process is implemented--the "prior notice procedure." The pipelines also may abandon certain services, contracts permitting, on a self-implementing basis without further authorization by the FERC.

State Regulatory Requirements

The incentive of an LDC to purchase gas directly is further enhanced by its desire to maintain market share in the face of fierce competition between gas and other fuels, the threat of customer bypass, and state regulatory requirements of "least-cost" gas purchases. Interfuel competition always has been an important factor affecting the end-users' demand for gas supplied by an LDC. For example, an industrial customer can switch to fuel oil to heat its boilers if there is a gas shortage or if the price of gas becomes too high. Actually, a large percentage of gas-using customers do have some fuel-switching capability. Many electric utilities have dual-fuel capacities for their fossil-fuel-burning generation plants, and more than 50 percent of the industrial plants have fuel-switching capacity.[15] The ability of commercial and residential customers to switch to alternative fuels in the short-run is more restricted than that of utilities and industrial plants, but even here some competition exists between gas and alternate fuels in the long-run.

Most state commissions also have some types of regulatory requirement that an LDC obtain gas at least cost or in a prudent manner, even though the

[14] Williams and Parent, *New Opportunities for Purchasing Natural Gas*, 23-26.
[15] Ibid., 10-11.

exact language and procedures of doing so varies among states, and such requirements at times may be informal.[16] For example, an Indiana statute requires that gas rate increases be granted only if the LDC has made every reasonable effort to acquire long-term gas supplies to offer gas to retail customers at the lowest cost reasonably possible.[17] Least-cost or prudence requirements do not address specifically the issue of direct gas purchase. Nevertheless, the current price differential between spot-market and long-term contracts certainly induces the LDCs to use direct gas purchase as a way of meeting the state requirements of achieving lowest possible gas costs.

Changes in state gas transportation policy provide another incentive for LDCs to find more economic gas suppliers. Just as the FERC has greatly expanded the access to pipeline-owned transportation facilities, many state regulators are in the process of fashioning new state gas transportation policies that may allow end-users to bypass the LDCs completely or to purchase transportation-only service from LDCs.[18] Because of the potential for losing customers to competitors, an LDC needs to secure lower-priced gas to remain competitive with the pipelines, wellhead producers, and other LDCs which potentially can supply gas to end-users within an LDC's service territory. In this regard, an LDC essentially is bypassing the sales service of its pipeline suppliers so that its own customers will not bypass.

Current Gas Procurement and Transportation Practices

Once an LDC decides to purchase directly all or part of its gas supply by itself rather than relying on pipelines, it faces a broad range of alternatives. An obvious choice is to make spot market purchases on a monthly basis. Another alternative is to enter into long-term purchase contracts with wellhead producers directly. The LDCs also can use gas marketers (traders or brokers) to secure gas supplies. As for arranging

[16] See chapter 3 for a more extensive discussion of current state oversights, and Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches*, 48-50.
[17] Ibid., 47.
[18] Burns et al., *State Gas Transportation Policies: An Evaluation of Approaches*, 13-59.

transportation service, an LDC has several alternatives. It can let the gas marketers handle the transportation service, build its own interconnection facilities with other pipelines, or negotiate with its current pipeline supplier for transporting gas.

The following discussion of current gas procurement and transportation practices starts with the analysis of long-term gas purchase contracts. Such contracts have been the dominant form of gas procurement in the past, meaning they can be used as a basis of comparison with other gas procurement and transportation practices that have been used only recently.

Long-Term Contract Purchases

Long-term contracts for gas procurement can exist between a wellhead producer and a pipeline, a pipeline and an LDC, and a producer and an LDC. The focus of this study is the long-term purchase contract between an LDC and a wellhead producer. However, given that direct purchase with wellhead producers was a less prevalent form of gas procurement in the past, most literature on long-term gas contracts centers on the purchase arrangements between a pipeline and a wellhead producer. Since the three types of long-term contracts are of a similar nature and format, any conclusions made about one type are applicable to the other two. No distinction about the three types of long-term contracts is made here.

A long-term gas procurement contract has many unique features.[19] It usually covers a long period of time (up to twenty years in some cases) even though any contract that currently has a duration of more than one year (in some cases, three months) can be characterized as long-term. A long-term contract typically covers the gas production of a particular well or wells in a production area, and is signed after the presence and amount of gas reserves are confirmed but before the actual production of gas and the construction of gas-gathering and transportation facilities. Many long-term contracts have a "committed reserve" provision under which the producer

[19] See John Harold Mulherin, *Vertical Integration and Long Term Contracts in the Natural Gas Industry*, (Ph.D. Dissertation, University of California at Los Angeles, 1984), 17-22; and Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches*, 29-37.

agrees to sell the total production of a particular gas well or a production field to the buyer. In return, the buyer guarantees to take a minimum amount of gas annually (minimum-take provision) and obligates itself to purchase or pay for a certain quantity of gas based on a particular well's deliverability (take-or-pay provision).[20] There are other provisions of price and quantity adjustment which reflect the allocation of future risks associated with a long-term transaction relationship. In essence, a long-term contract commits both buyer and seller to the take and delivery of gas from a particular gas well or production field.

The development of long-term contracts follows closely the structural changes of the gas industry, especially the role of the pipeline companies. Before the 1920s, most gas purchase contracts were of relatively short duration, the amounts of transactions were small, and the distance between production field and consumption market was short. Consequently, the amount of capital investment required for pipeline facilities and gas field production also was rather limited.

With the discovery of large gas and oil fields in the Southwestern United States and the development of high-pressure long-distance underground pipelines, the gas industry and its market greatly expanded. The amount of capital investment required for building large-scale pipeline facilities and developing gas production fields increased drastically. Long-term contracts covering the total production from dedicated gas reserves over fifteen to twenty years to ensure a steady revenue stream for the producers and pipelines became an essential and dominant form of gas purchase. At the same time, the trend toward using long-term contracts was further enhanced by the fact that long-term gas supply assurance also was required in federal regulations before a pipeline could build transportation facilities. Evidence of adequate gas reserve and deliverability had to be demonstrated

[20] Ibid. Besides affording the seller a more stabilized revenue stream, these two provisions also have the technical advantage of ensuring the gas pipelines operate at capacity as much as is possible. It is also argued that the take-or-pay obligation can be viewed as a mechanism for effecting appropriate incentives for contract performances; that is, take provisions can induce buyers to refuse to take gas delivery only when it is efficient to do so. See Scott E. Masten and Keith J. Crocker, "Efficient Adaption in Long-Term Contracts: Take-or-Pay Provisions for Natural Gas," *American Economic Review* 75 (December 1985): 1083-93.

before a pipeline could be certified for interstate commerce by the FERC and before it could obtain the necessary capital in the financial market to construct pipelines.[21]

In addition to these financial and regulatory requirements, various economic explanations for the shift toward the use of long-term contracts and the price and quantity adjustment provisions associated with them have been suggested.[22] The merits and weaknesses of these explanations will not be discussed here. It appears that the reduction of contract hold-up (in the sense that one party may negate the gas purchase transaction after investments involved in the transaction have been made by another party) seems to be the most convincing explanation up to now.[23] The question then becomes what unique historical characteristics of the gas industry contributed to the possibility of contract hold-ups. The examination of the validity of these characteristics in the current gas market may indicate whether it is still necessary or desirable to use long-term contracts as an essential and dominant form of gas procurement.

Characteristics which contribute to the prevalence of long-term contracts include pipeline transportation as the only economically viable mode of large-scale gas transportation,[24] gas production and transportation facilities with few alternative uses in non-gas activities since they are immobile, and restrictions in accessing gas transportation facilities. The

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[21] American Gas Association, *Gas Rate Fundamentals* (Arlington, VA: American Gas Association, 1987), 29-33.

[22] See Mulherin, *Vertical Integration and Long Term Contracts in the Natural Gas Industry*; Masten and Crocker, "Efficient Adaptation in Long-Term Contracts: Take or Pay Provisions for Natural Gas," 1083-93; and R. Glenn Hubbard and Robert J. Weiner, "Natural Gas Contracting in Practice: Evidence from the United States," in *Natural Gas Markets and Contracts*, eds. R. Golombrek, M. Hoel, and J. Vislie (Amsterdam: Elsevier Science Publishers, B.V., 1987).

[23] See Mulherin, *Vertical Integration and Long Term Contracts in the Natural Gas Industry*, 50-66; and Hubbard and Weiner, "Natural Gas Contracting in Practice: Evidence from the United States," 284-307.

[24] It is uneconomical to transport gas through means other than underground pipelines. The heat content of a fixed volume of gas at atmospheric pressure is extremely low compared to other fuels. The potential heat energy in a cubic foot of natural gas is equivalent to only one- to two-tenths of one percent as that contained in a cubic foot of solid or liquid fuel. So gas must be liquified to be transported in special containers at considerable expense if pipelines are not used.

technologies of gas transportation and distribution have not changed significantly during the last thirty years. The one significant change in the last few years which may reduce the importance of long-term contracts is the possibility of open access to pipeline facilities by entities other than pipeline owners.

The wide availability of access to transportation facilities by wellhead producers, LDCs, and end-users has reduced significantly the possibility of contract hold-ups. Though a gas well or a production field remains, in most instances, physically connected to the interstate gas delivery system through only one pipeline, a gas producer can sell gas to many entities other than the connecting pipelines. On the other hand, if a pipeline cannot secure gas from its connecting gas production field, it can access other producers through pipelines owned by others or utilize its unused pipeline capacity to transport gas for others. As a result, alternatives for both the buyer and seller concerning production from a particular gas production field have increased significantly making the threat of a contract hold-up less effective.

In summary, the need for long-term contracts to reduce the transaction costs and opportunistic behavior in gas procurement has been reduced with the structural changes in the gas market. But, given the gas supply stability and price certainty associated with long-term contracts, such contracts are likely to remain an important part of an LDC's supply portfolio whether the procurement contract is made in the form of purchases from a wellhead producer directly or in the traditional form of purchasing from pipeline suppliers.

Spot Market Purchases

The use of spot-market purchases by LDCs is a relatively new phenomenon. A spot-market purchase contract generally is good only for a short period of time (such as a month), and has specific purchase prices and quantities. No price or quantity adjustments are contemplated in most spot purchase contracts. What's more, the commitment binding the seller to supply gas is typically on a "best-efforts" basis, and the buyer itself (rather than the seller) must make arrangements for transportation, storage, and scheduling of gas delivery.

Currently, there are eight broad categories of spot gas being traded in the United States: Texas-Westhaha, East-Houston-Katy, North-Texas Panhandle, South-Corpus Christi, Louisiana-Onshore South, Oklahoma, Alberta, and others. Within these broad categories, there are different prices quoted based on the different delivery points within the interstate pipeline network. For example, there are four delivery points (ANR, NGPL, Northern, and PEPL) in the North-Texas Panhandle category. Overall, there are forty-one delivery points. Two prices are quoted for each delivery point: one for a five-million cubic feet gas package and another for a package of one-million cubic feet or less. A weekly spot gas price survey can be found in *Gas Buyers' Guide* published by Pasha Publications, Inc. of Arlington, Virginia.

A spot market is quite common in the transaction of many commodities. Typically, the existence of a spot market requires the commodities to be readily available from different suppliers with no significant quality difference, and with a relatively large number of buyers and sellers competing actively in the marketplace. Gas is a commodity with generally uniform quality,[25] and potentially large numbers of buyers and sellers abound if open access to pipeline facilities is provided. That gas spot purchases were not widely used in the past is due to the small numbers of potential buyers and sellers resulting from restricted access to gas transportation facilities. With the trend toward open access firmly established, gas spot-market purchase became a viable and important part of the gas procurement strategy for many LDCs and end-users.

The main distinctions between spot purchase and long-term contract purchase are in four areas: contract duration, uniformity of contract clauses, gas supply flexibility or firmness, and price adjustment clauses. The contract duration of spot purchases is typically one month to a year while the duration of long-term contracts can range up to twenty years. Spot purchase contracts are usually quite similar to each other. In

[25] Even though the quality (heat content, water vapor, and so on) of gas produced from different wells may vary somewhat, it typically goes through processing in the gathering system to meet common quality requirements before being delivered into the interstate gas market.

contrast, contract clauses can vary significantly among different long-term contracts.

The degree of firmness in the commitment to supply gas is also quite different between these two types of transactions. Gas procured through spot purchase is supplied mostly by producers on a "best-effort" basis, which essentially means that the seller uses its best effort to deliver to the buyer up to a maximum amount of gas per day. At the same time the buyer uses its best efforts to purchase from the seller a minimum amount of gas per day. Many long-term contracts, on the other hand, have provisions concerning committed reserves under which the wellhead producers guarantee that the total production of a particular gas well will be delivered to the buyer.

As for the price adjustment clauses, spot purchase contracts typically do not include any adjustment clauses since such adjustments are not very useful given that most spot contracts have a duration of only thirty days. On the other hand, price adjustment mechanisms of a long-term contract can be quite elaborate because the buyers and sellers agree in advance on a series of prices over an extended period of time. For example, long-term contract prices may be specified explicitly or linked to alternative fuels, prices offered to other buyers (most-favored nation clause), or the gas price at the distribution level (market-out clause).

Gas Marketers and Other Intermediaries

The third option of direct gas procurement by LDCs is to use gas marketers or other market intermediaries.[26] Gas marketers can work either for the buyers or for the sellers. Here, the discussion is limited to the use of gas marketers who provide service for a gas buyer (an LDC). Since direct gas purchases are a relatively new endeavor for most LDCs, some may not have sufficient expertise and knowledge about gas market conditions and

[26] Other terms such as brokers, traders, or aggregators have been used to describe the gas market intermediaries. Typically, a gas broker only locates buyers and sellers and does not actually take title to gas. A trader, on the other hand, may actually purchase the gas and resell it to his customers. No distinction between a broker and a trader is made here, and a general term "marketer" is used instead.

the arrangement of transportation service. As a result, several forms of market intermediaries who can provide procurement and transportation services or who can assume certain market risks for LDCs have emerged with the increased use of direct purchase.

One study in 1986 indicated that market intermediaries were becoming an increasingly important factor in the direct gas market as the number of market participants increased and as more small firms entered the direct gas market.[27] It was estimated that nearly 30 percent of all direct gas purchases and 44 percent of transactions with below-average purchase volume (6,418 million BTU per day in this instance) were arranged by gas marketers for the first half of 1985.[28]

The current status of the gas marketer industry cannot be known without an extensive survey, and such a survey is not a part of this study. By some estimates, the number of firms involved in gas marketing has steadily increased from fifty-one in 1985 to seventy-two in 1986 and is nearing one hundred in 1988.[29] The amount of gas transaction handled by most gas marketers can range from 150 thousand cubic feet (Mcf) each day to more than 5,000 Mcf each day while some of the largest marketers such as Yankee Resources Inc. and Natural Gas Clearinghouse Ltd. can handle volume, exceeding 100,000 Mcf each day.[30]

The services provided by a gas marketer are primarily locating and qualifying suppliers, aggregating purchases from many buyers, arranging transportation service, providing arrangements for backup supplies or transportation alternatives, handling accounting, managerial, and regulatory matters, and other services. Where the gas marketer actually takes title to the gas to be purchased by an LDC, the marketer also reduces market risks of insufficient transportation, gas production shortfall, or drastic price changes for the LDCs.

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[27] Benjamin Schlesinger and Associates, *Direct Gas Markets and Their Impact on the Gas Utility Supply Planning Process* (Arlington, VA: American Gas Association, 1986), 33-34.
[28] Ibid.
[29] Williams and Parent, *New Opportunities for Purchasing Natural Gas*, 151.
[30] Ibid.

A gas marketer performs many functions previously undertaken by a pipeline with an important distinction being that an independent gas marketer generally owns neither the facilities used in transporting gas nor the gas being transported. Since an independent gas marketer has no ownership interest in any particular gas supply source, it has no conflict of interest in obtaining the best supply sources for an LDC. By contrast, a pipeline has a built-in incentive to sell gas from its own supply portfolio to an LDC or to use its own transportation facilities. However, it should be noted that some marketers are not completely independent and are affiliated with other participants (such as producers, pipelines, and LDCs) of the gas market. In this case, the marketer may have its own biases as the result of its affiliations.

Gas Futures and Options Markets

The use of gas futures and options contracts may become an important mechanism for direct gas purchase even though they are not currently available. A gas futures contract, similar in form to the financial and commodity futures currently available, can be viewed as a right to buy or sell a certain amount of gas at a prespecified price at a future date. In general, a futures market can perform several functions including the management of price and quantity risk, the anticipation of future prices, the provision of additional information for decision making, and the security of additional capital.[31] A gas futures market conceivably can provide similar benefits for the LDCs in gas procurements.

The purchase of an option on gas futures contracts represents the opportunity to exercise a gas futures contract before a predetermined expiration date. In using the options on crude oil futures contracts currently traded at the New York Mercantile Exchange (NYMEX) as a possible format for options on gas futures contracts, the holder of a "call" option can exercise the right to purchase gas while the holder of a "put" option can exercise the right to sell gas at a predetermined exercise price.

[31] Raymond M. Leuthold, Joan C. Junkus, and Jean E. Cordier, *The Theory and Practice of Futures Markets* (Lexington, MA: D.C. Heath and Company, 1989), 33-36.

Establishing such an options market conceivably can provide additional information about the expectations of future demand and supply for gas, which is beneficial to gas supply planning.[32]

However, practical difficulties concerning the FERC's preapproval of gas delivery points and insufficient pipeline capacity to deliver every gas futures contract sold (if required) have cast uncertainty over the prospect of establishing a gas futures market in the near future. Nevertheless, for the past several years, the New York Mercantile Exchange (NYMEX) has attempted to set up a gas futures market using a gas interchange in Katy, Texas. At this writing no gas futures market exists, although interchange services in Louisiana currently serve a similar purpose. The NYMEX is exploring alternative ways of setting up a gas futures market which would not require FERC approval.[33]

Short-Term Advantages and Limitations

The implications of direct purchase on individual LDCs can be characterized in two ways: transitional (short term) and permanent (long term). The short-term effects refer to the advantages and limitations associated with the current market condition of gas supply surplus and the LDC's initial lack of experience in making direct purchases. The long-term effects refer to the advantages and limitations of an LDC assuming certain gas merchant and transportation functions over an extended period of time, including periods of excess demand and supply surplus.

Costs of Gas Supply

Given the relatively abundant supply of gas at the present time, the short-term cost benefits of direct gas purchase are obvious. Through the use of direct purchase, an LDC can obtain lower-cost gas supplies available in the spot market and is afforded an opportunity to structure a gas supply

[32] See James A. Overdahl and H. Lee Matthews, "The Use of NYMEX Options to Forecast Crude Oil Prices," *The Energy Journal* 9 (October 1988): 135-47.
[33] Telephone conversation with Bradford G. Leach, Research Analyst, New York Mercantile Exchange, August 22, 1989.

portfolio consisting mainly of new gas purchase contracts that are more in tune with current gas demand and supply conditions. The cost advantages of direct purchase in the short term can be divided into two categories: savings of spot purchases over long-term purchases with wellhead producers directly, and cost differentials of entering long-term contracts with wellhead producers over purchase from pipeline companies whose existing gas supply portfolio contains many older and higher-cost gas contracts entered into in an earlier period of tighter gas supply.

The data on the cost advantage of spot-market purchases over long-term contract purchases under current market conditions seems clear and will not be repeated here. The comparison of average spot price and wellhead price in the Texas and Louisiana production area, as discussed in the previous section, is a typical example. But the cost advantage of entering new long-term contracts directly with wellhead producers compared with purchases from pipelines needs further elaboration.

In purchasing from a pipeline, the quantity and cost are limited by the quantity and cost of the pipeline's own supply portfolio. A pipeline is unwilling and unable to supply gas to an LDC at an amount more than that available to itself or at a price below its gas acquisition cost, except temporarily and under extraordinary circumstances. At the present time, most pipelines are still bound somewhat by the more expensive long-term contracts of the late 1970s and early 1980s when the future price of gas was projected to increase dramatically. As a result, the opportunity to enter into new long-term contracts with wellhead producers under the current market environment of substantial gas supply surplus offers definite cost savings to an LDC, provided that any increase in transportation costs does not offset the cost savings of building a new supply portfolio through direct gas purchases.

A comparison of the average costs of pipeline gas portfolios and current wellhead gas prices shows a substantial cost savings to an LDC in structuring a new gas supply portfolio. The average costs and total volumes of the aggregate gas supply portfolio of twenty major interstate pipelines are shown in table 2-3. Here, an interstate pipeline is considered major if its wellhead gas purchase equaled or exceeded 40 billion cubic feet (Bcf)

TABLE 2-3

AVERAGE COST OF GAS SUPPLY PORTFOLIO OF
TWENTY MAJOR INTERSTATE PIPELINES: 1984-1987

Type of Gas	1984		1985		1986		1987	
	Volume (Bcf)	Avg. Cost* ($/Mcf)	Volume (Bcf)	Avg. Cost* ($/Mcf)	Volume (Bcf)	Avg. Cost* ($/Mcf)	Volume (Bcf)	Avg. Cost* ($/Mcf)
Old Gas**	4,032	1.58	3,298	1.53	2,634	1.42	2,139	1.34
New Gas**	4,102	4.02	3,569	3.69	2,726	3.08	2,178	2.67
High-Cost Gas**	807	5.96	606	4.68	481	3.34	412	2.67
Non-Wellhead Purchases	1,986	4.35	1,381	4.04	871	4.18	650	4.03
Total Supply Portfolio***	10,927	3.32	8,854	3.01	6,713	2.59	5,379	2.30
Average Wellhead Cost ($/Mcf)****		2.66		2.51		1.94		1.71
Percentage of Wellhead Cost/Avg. Cost of Pipeline Supply Portfolio		80%		83%		75%		74%

Source: Energy Information Administration, Wellhead Purchases by Interstate Natural Gas Pipeline Companies Since the NGPA (Washington, DC: Energy Information Administration, 1988), table 7.

* This refers to the average price of gas (in 1987 dollars) paid by pipelines to gas producers.

** The NGPA divided gas into a large number of sections, each subject to different pricing rules. Generally, there are three broad categories. Old gas is the gas dedicated to the interstate market under Section 104 or subject to roll over contracts under Section 106 of the NGPA. New gas is the gas dedicated to interstate markets after the introduction of the NGPA legislation and gas not covered by other sections of the NGPA. High-cost gas is that covered by Section 107 of the NGPA.

*** Totals may not equal sum of components due to independent rounding.

**** This refers to the nationwide average wellhead price of long-term gas contracts in that particular year. See American Gas Association, Gas Facts 1987 Data, table 9-5.

from 1984 through 1987.[34] The table shows that the average wellhead cost of current long-term contracts is consistently lower than the average cost of the aggregate pipeline supply portfolio during the four-year period. The cost advantages of entering new long-term contracts over purchase from pipelines has actually increased from 20 percent in 1984 to 26 percent in 1987.

Knowledge and Experience in Finding Gas Suppliers

By engaging in direct purchases, an LDC assumes tasks that previously had been undertaken by pipelines, such as identifying potential gas suppliers and evaluating their reliability for supplying gas as promised. Since many LDCs' involvement with direct purchase in interstate gas markets started only during the mid-1980s, an LDC is not likely to have more than six years of experience in direct purchase up to now. In contrast, pipelines' involvement in the interstate gas market may span thirty years. While years of involvement may not be a perfect indicator of knowledge and experience in finding and evaluating gas suppliers, this disparity in terms of years of experience in purchasing from wellhead producers is important.

Spot market purchases are relatively straightforward and an LDC can become an effective participant quickly. Entering new long-term purchase contracts with wellhead producers is more complicated. Literally thousands of potential suppliers and many gas transporters exist. All have diverse sizes, financial conditions, gas field locations, ownership affiliations, and years of experience in the gas industry. Tasks such as finding suppliers, evaluating their reliability, and arranging transportation require an intensive effort in collecting data and analyzing alternatives.

LDCs can use the expertise and knowledge of others by hiring gas marketers or other intermediaries to find and evaluate gas supplies. But,

[34] The pipelines include ANR pipelines, Colorado Interstate Gas, Columbia Gas and Columbia Gulf, Consolidated Gas Supply, El Paso Natural Gas, Florida Gas, K N Energy, Natural Gas Pipeline, Northern Natural Gas, Northwest Pipeline Co., Panhandle Eastern Pipeline, Southern Natural Gas, Tennessee Gas Pipeline, Texas Eastern Transmission, Texas Gas Transmission, Transco, Transwestern Pipeline, Trunkline Gas Company, United Gas Pipeline, and Williams Natural Gas Co.

it still may be up to the LDC to determine which gas marketer to use and to specify particular requirements of gas supplies to fit its overall portfolio. An LDC's unique requirements and preferences may not always be conveyed perfectly to a gas marketer and the gas marketer's interest may not be perfectly aligned with those of the LDC, especially where marketers are affiliated with producers, pipelines, or even other distributors. The reliability of a gas marketer in delivering spot market gas and its difficulties in accessing pipeline facilities also have been cited as actual problems encountered.

It can be expected that in the initial years the knowledge and experience of LDCs engaged in direct gas purchases would not match those of a pipeline procuring gas for many years.[35] Such limitations would not be long-lasting as the LDC became more experienced with direct purchases. Any adverse cost consequences due to an LDC's inexperience are not likely to be major obstacles to the use of direct purchase by LDCs and probably can be offset by the cost advantages associated with other aspects of direct purchases under current market conditions.

Availability of Transportation Capacity

The short-term availability of gas transportation capacity is another limitation to the use of direct purchases by LDCs. Although the trend toward open access is firmly established and a majority of this country's transportation capacity is available to LDCs, a few pipelines still choose not to become open-access transporters. In addition, for those open-access transporters, the total amount of gas that can be transported at any given time is restricted by pipeline capacity and commitments to existing customers. For example, when Columbia Gas Transportation Company implemented its FERC-approved allocation formula among its wholesale customers, there was no transportation capacity left for interruptible customers to make a spot purchase.[36] The interruptible customers also were

[35] It should be noted that the LDCs in the gas production states (Texas and Oklahoma, for example) have engaged in direct purchase from wellhead producers in substantial amounts for many years.
[36] Williams and Parent, *New Opportunities for Purchasing Natural Gas*, 59.

the first to be curtailed in the case of insufficient transportation capacity.

The LDC, however, may be better able to assure gas supply reliability if it purchases firm instead of interruptible transportation service from the pipeline. Firm transportation service, according to section 284.8(3) of the regulations promulgated by the FERC along with its Order 436 "is not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm service."[37] Thus, the LDC may want to purchase spot gas from a variety of suppliers or producers in order to obtain the lowest-cost gas, and purchase firm transportation service from the pipeline to help insure reliability. However, based on a recent FERC ruling, the pipelines can restrict customers' firm transportation volumes at specific gas receipt points as long as they give the customers flexibility to change points.[38]

A gas transporter also can withdraw its transportation service after becoming an open-access transporter. For example, the Northwest Pipeline Corporation, which provides transportation service for self-help gas customers under Section 311 of the NGPA in the Pacific Northwest, withdrew from providing interim transportation service during August 1986 claiming that the FERC-approved transportation tariff did not provide an adequate profit margin.[39] Clearly, unresolved transportation issues, such as the availability of firm transportation to independent marketers of comparable service that pipelines provide for themselves as gas merchant remain,[40] and the speed and timing of their resolution cannot be projected with confidence.

[37] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol, Docket No. RM85-1-000 (Parts A-D), Order No. 436, 50 *Fed. Reg.* 42,493 (October 18, 1985).
[38] See "Pipelines Can Restrict Customers' Firm Transportation Volumes," *Inside F.E.R.C.*, 6 February 1989, 11.
[39] Williams and Parent, *New Opportunities for Purchasing Natural Gas*, 59.
[40] See "Comparable Service Is Key Issue for Marketers in Natural Rate Case," *Inside F.E.R.C.*, 6 February 1989, 1, 5-6.

Long-Term Advantages and Limitations

The question arises of the advantages and limitations of using direct purchase by an LDC over an extended period of time. The long-term effects relate mainly to the inherent strength and weakness of an LDC assuming the gas merchant and gas transportation function and are not derived from the initial or temporary difference of the market positions of an LDC and a pipeline.

Costs of Gas Supplies

Since direct gas purchases (and spot market purchases in particular) are a relatively new phenomenon, no definitive empirical evidence exists concerning the long-term cost effects of purchasing gas directly by LDCs. The relative cost advantages and disadvantages of direct purchases over an extended period of time can be derived only from experiences in other commodity markets that have a longer history of both spot purchases and long-term contract purchases. Not surprisingly, an examination of the pricing behavior of seven commodities (Appalachian coal, bulk ocean shipping, intrastate natural gas, copper, aluminum, nickel, and molybdenum) with both spot markets and long-term contracts shows a consistent pattern of long-term contract prices exceeding spot prices during normal or slack periods with spot prices rising above contract prices during periods of scarcity.[41] This pattern conforms to the usual behavior of an organized market in which a tight market leads to a higher price while a slack market leads to a lower price.

Because gas market demand and supply can reverse their relationship over an extended period, there are only limited (if any) inherent cost advantages in permanently adopting a spot-purchase or a long-term pipeline purchase strategy. For example, a study comparing the long-term cost differences between spot gas supply and pipeline gas supply from a

[41] Charles River Associates Incorporated, *Natural Gas Procurement: Experience with Spot vs. Contract Pricing in Analogous Commodity Markets*.

particular pipeline to the California market from 1986 to 1995 concluded little or no cost difference between these two supply options.[42]

An LDC's decision on whether or not to adopt a spot purchase strategy over an extended period of time depends on its expectation of future demand and supply of natural gas. If an extended period of balanced gas demand and supply is projected, a spot-purchase strategy may be beneficial provided the LDC is willing to accept any increased price and supply risk associated with the strategy. However, if unexpected higher demand occurs, the LDC's strategy will prove costly since it may have to pay higher prices in a tighter spot market or resort to other temporary means to avoid gas curtailment. As a result, the long-term benefits of committing to a spot-purchase strategy rests on how well an LDC's projection of future market conditions fits with those that eventually materialize.

The advantages and limitations of entering long-term contracts directly with wellhead producers as opposed to buying from pipelines depends mostly on an individual LDC's strengths and weaknesses in assuming the many functions of a pipeline. The long-term advantages and limitations (based on the comparison between a typical local distribution company and an average pipeline company in achieving the tasks needed to deliver gas from gas fields to an LDC's city gate) are related less to the format and execution of gas procurement than the amounts of gas procurement as well as the number of suppliers.

As for the availability of transportation capacity for direct purchases in the long term, a pipeline is unlikely to have a definite advantage in obtaining transportation service. While there is no assurance that complete open access eventually can be achieved, it can be expected that regulations on pipeline access (such as how pipelines can quickly add transportation capacity through the operation of an optional expedited certificate) over time will become clearer and possibly more flexible so that transportation access becomes less of a constraint to LDCs' direct purchases in the long term than in the short term.

[42] Charles River Associates Incorporated, *Natural Gas Procurement: Spot vs. El Paso Natural Gas Purchases at the California Boarder, 1987-1995* (Boston: Charles River Associates Incorporated, 1987). Since this is a case study, the results should not be generalized to other regions of the nation.

Market Power in Procurement

Although spot purchase contracts are in a relatively standard format, the provisions of long-term purchase contracts can vary greatly depending on the negotiations between buyers and sellers. The variations in purchase contract clauses reflect the relative bargaining positions and the willingness to take risks on the part of buyers (LDCs and pipelines) and sellers (wellhead producers and, to a lesser extent, pipelines).

There is no indication that a pipeline is a better negotiator than an LDC if both are of the same market position. Due to the sheer size of its gas procurement, however, a pipeline may be in a stronger position than a typical LDC to negotiate gas purchase contracts with producers. More explicitly, a pipeline can commit to purchasing a larger amount of gas from a particular gas production field or sign more contracts with a major gas producer. These can be translated into better price-adjustment or quantity-adjustment clauses such as a lower take-or-pay requirement, market-out clauses, or most-favored-nation clauses for pipelines. Part of the price and quantity adjustment advantages associated with such a pipeline supply portfolio may be passed through to an LDC.

The cost advantages associated with volume purchases by pipelines identified here do not contradict the cost advantages of entering new gas purchase contracts when compared with buying from existing pipeline portfolios as discussed in the previous section. The better bargaining position of a pipeline can be realized if both an LDC and a pipeline are negotiating concurrently under the same market conditions. If they enter into gas purchase agreements at different times, the changes in market demand and supply (such as the presence of a gas bubble) can potentially overwhelm any cost advantages associated with the market power of a pipeline's volume purchase.

Many LDCs are attempting to realize the price and quantity adjustment advantages associated with volume purchases either by using a gas marketer to pool the purchases of many LDCs or by handling the pooling itself. This pooling of gas demand and supply is an important factor affecting the economics of direct gas purchases. In many instances, a large customer's demand may not be satisfied by the production of one gas well, and a gas marketer can commit and combine the productions from various locations and sell it as a single package. In other instances, a small customer may not need the total production from a particular gas well, in which case the marketer may be able to find other buyers interconnected with this particular customer to take the amount of gas made available from a specific well. Such pooling is constrained by two factors: the fees paid to the gas marketers and the capacity and location of interconnected gas transportation facilities. Two LDCs on different pipeline systems may not be able to pool their gas purchases or may be able to do so only with more costly arrangements of gas storage or transportation. As a result, the gas marketers affiliated with producers or pipelines that have access to a large producer pool are likely to be in a more advantageous position in pooling gas demand and supply.

Supply Source Diversification

In addition to the disadvantages of being in a weaker bargaining position in gas procurement compared with a pipeline company, LDCs that purchase gas directly may also be in a less favorable position in terms of supply source diversification. The supply portfolio of a pipeline usually involves a larger amount of gas procurement, a larger number of gas wells, and more suppliers than those associated with a typical LDC purchase. Because of the diversity of supply sources, gas production from any particular well or any one producer usually accounts for a smaller percentage of total supply for a pipeline than does a single gas well or a single producer for an LDC's supply.

It is well recognized that there is a certain degree of uncertainty involved in the production and transportation of gas. A well may produce less than originally estimated, the producer may encounter financial difficulties in continuing production, or a transportation facility may be unavailable as a result of curtailment. All these can cause supply interruptions. But because a pipeline's supply sources typically are more diversified, any interruption of a particular well or producer has less adverse impact on the pipeline's overall ability to provide gas. On the other hand, the production of a particular gas well may be the only supply source directly contracted by an LDC. Then the risk and consequences of supply interruption can be quite severe.[43]

Diversification and risk-spreading also can be applied to the allocation of gas supplies. Since an interstate pipeline generally serves more than one local distribution company, any curtailment or supply interruption can be shared by a larger pool of end-users. As for direct purchase by an LDC, any supply shortfall has to be shouldered by the end-users of the LDC alone.

Pending FERC Initiatives

There currently are two major initiatives underway at the FERC which may affect the relative attractiveness of pipeline and direct purchase to LDCs. They are the gas pipeline rate design initiative and the gas inventory charge. Depending on how these initiatives develop, it is possible that pipeline supply sources may become relatively more attractive or the option of direct gas purchases may become the preferred one. But given that the nature and form of the FERC initiatives are still pending, some caution must be exercised in assessing their likely consequences on the LDC's procurement alternatives.

FERC Rate Design Initiative

On May 30, 1989, the FERC issued a policy statement providing guidance with respect to gas pipeline rate design.[44] The purpose of the policy statement was to provide guidance to administrative law judges and case participants in fashioning rate designs that will allow market forces to play a more significant role in determining the supply, demand, and price of gas. In particular, the FERC was interested in developing a case record concerning the use of annual versus seasonal rates, the design of demand and commodity charges (particularly the division of fixed costs), the use of

[43] Benjamin Schlesinger and Associates, *Direct Gas Markets and Their Impact on the Gas Utility Supply Planning Process*, 57.
[44] Policy Statement Providing Guidance with Respect to the Designing of Rates, FERC Docket No. PL 89-2, 30 May 1989, 54 *Fed. Reg*. 24382, 7 June 1989.

other capacity adjustments (such as capacity brokering or capacity reassignment by firm shippers), the use of discounted transportation and maximum interruptible rates, and forward haul and backhaul transportation rates. The FERC also was to consider designing rates for separately identified cost components.

Specifically, rates must reasonably reflect any material variation in the cost of providing service according to peak and off-peak periods, particularly with regard to seasonal variations. If seasonal rates are called for, then the costs incurred to perform peak season service (such as the cost of storage facilities) should be assigned solely to the peak period.

Concerning demand and commodity charges, most pipelines' costs at present are classified according to the modified fixed variable method, which classifies all fixed production and gathering costs, all variable costs, and return on equity investment in transmission and storage facilities and related income taxes to the commodity component. The remaining fixed costs, including return of investment (the depreciation expense) in transmission plant and storage facilities, are classified with the demand component. The demand component currently consists of two demand charges, D-1 and D-2, and these costs are split evenly. D-1 reflects peak day, while D-2 represents annual usage. The FERC has suggested that the D-2 charges may no longer be warranted and that some phasing-in of a mechanism where the D-1 charge rations peak capacity to those who value it the most may be appropriate.

Concerning capacity adjustments, the FERC notes that implementation of peak and off-peak rates and a change in cost classification may result in costs being shifted to peak users. Capacity releasing, capacity brokering, or capacity reassignment (either short-term or long-term) might help to smooth the transition.

As to discounted transportation rates, the FERC is concerned that rates be designed so that nondiscounted rates cannot subsidize discounted rates, and so that rate discounts can be given on a nondiscriminatory basis without selective discounts. The FERC is particularly concerned about rate discounts to pipeline affiliates. However, developing such a method of rate design might entail the difficult task of forecasting units of transportation service at various discounted and nondiscounted transportation prices.

Regarding interruptible rates, the FERC is concerned that presuming a 100 percent load factor, as in current practice, can yield a maximum interruptible rate that is too high. The FERC suggests that since demand rates can be viewed as a charge to cover the costs for the right to use capacity, the demand charge for interruptible rates should be excluded in part or in whole.

Concerning various types of transportation rates (for example, forward haul and backhaul) the FERC requires that rates reasonably reflect any material variation in costs due to the distance that the gas is transported. It is the backhaul, exchange, or displacement methods of transportation that create interesting problems. Backhaul transportation occurs when a shipper delivers gas to a pipeline downstream of the point where the gas is purchased from the pipeline. There is no backhaul of the gas. Rather, the transaction is an exchange where the pipeline delivers gas in exchange for downstream gas. That actually frees up pipeline capacity between the receipt and delivery points and may result in lower demand charges. Rates should be set to reflect any cost savings.

Finally, the FERC intends that services be unbundled whenever possible. Although bundled rates are not always inappropriate, the FERC is concerned that a pipeline's storage functions, gathering costs, and transportation services be offered separately at rates set to recover only costs that are properly allocated to the service.

The FERC rate design initiative will be implemented on a case-by-case basis with the final orders tailored to the particular pipeline system. As a result, any effect on the pipelines' ability to deliver gas reliably will vary from pipeline to pipeline.

Gas Inventory Charges

As is widely recognized, pipelines typically purchased gas from producers under long-term contracts with take-or-pay clauses. The pipelines then sold the gas to LDCs and direct users under contracts that contained minimum commodity bills. If an LDC bought less than the required minimum, it was required to pay the pipeline a minimum commodity bill equal to the volume of the deficiency times the pipeline's commodity rate. Through these contracts, mutual obligations were created between the producer and the pipeline, and between the pipeline and the LDC. The producer could achieve more financial stability by having a steady flow of income from the pipeline and the pipeline could recover any deficits in sales to the LDC.

However, due to a thriving spot gas market, an economic downturn, and an increased ability of industrial customers to engage in fuel switching, LDCs were buying less than their minimum bill quantities, and pipelines were taking less than their minimum takes under take-or-pay clauses. Pipelines began to incur billions of dollars of take-or-pay obligations. Initially these were passed on to the LDCs; however, in 1984, the FERC issued Order 380 which eliminated the variable costs from pipeline minimum commodity bills.[45] All that a pipeline could charge for were demand-related costs. This destroyed the mutuality of obligations that previously existed in the gas industry. Many analysts have suggested that the FERC could and should have exercised its powers under NGA Section 5 to simultaneously and prospectively reform the pipeline-producer take-or-pay obligations. However, the FERC did not do so until it was ordered by the United States Circuit Court of Appeals for the District of Columbia to address the pipelines' take-or-pay obligations.[46] The FERC addressed these take-or-pay obligations in Order 500 by initiating a one-time cost recovery method which permitted open-access pipelines to bill directly their sales customers for the same percentage of take-or-pay reformation costs that the pipeline itself agreed to absorb.[47]

No mechanism was put in place by FERC Order 500 to deal with any new take-or-pay liabilities that a pipeline would incur after the old take-or-pay liabilities had been dealt with. But Order 500 did call for establishing a mechanism that would compensate pipelines for maintaining gas inventories on behalf of their sales customers. The rate design mechanism

[45] Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Bill Provision, Order No. 380, *FERC Stats. and Regs.* (CCH) para. 30,571 (1984).

[46] Associated Gas Distributors v. FERC, 83 PUR4th 459, 824 F.2d 981 (D.C. Cir. 1987).

[47] For a discussion of gas inventory charges, see Gloria L. Gaylord, "Assigning Responsibility for Long-Term Gas Supply: The Gas Inventory Charge," *Public Utilities Fortnightly*, 17 August 1989, 9-14.

would recover the costs of maintaining committed gas supplies to meet the nominated volume of gas service of firm sales customers, thereby reestablishing a reciprocity of contract obligations for firm sales customers. The pipeline's customers would then be able to consider the charges associated with maintaining gas inventories before making a choice of acquiring gas from the pipeline, from the producer, or from a third-party marketer.[48]

The FERC codified the parameters within which a pipeline may file for a gas inventory charge. The parameters are as follows: (1) the pipeline may not recover take-or-pay or similar charges from suppliers by any other means; (2) the pipeline must allow its sales customers to nominate levels of service freely within their firm sales entitlements or employ a mechanism for the renegotiation of levels of service at regular intervals; (3) the pipeline must announce prior to nominations by the customer a firm price or pricing formula for the service and hold that price or pricing formula firm during the arranged interval; and (4) by nominating a new level of service lower than its current level, a customer has consented to any abandonment of that level of service if sought by the pipeline.[49]

The FERC's May 30 notice of proposed policy statement includes some guidance on what it considers to be a just and reasonable interim gas inventory charge.[50] While the gas inventory charge serves much the same basic function as a minimum billing mechanism, it is different. The gas inventory charge proposed by the FERC contemplates that sales customers will be able periodically to renominate the level of gas inventory service that they are purchasing. Also, the costs of the service will be based on a firm price or pricing formula. Gas inventory charges will be assessed on a monthly basis, based on the service nomination. Minimum bill mechanisms were not so flexible once in place, and the variable commodity charge could

[48] FERC Order 500, III FERC (CCH) para. 30,794 (1987).
[49] 18 C.F.R. sec. 2.105 (1988).
[50] Notice of Proposed Policy Statement, Interim Gas Supply Charges and Interim Gas Inventory Charges, FERC Docket No. PL89-1-000 30 May 1989, 54 *Fed. Reg.* 24400, 7 June 1989. The gas inventory charge is interim because there has not yet a final rule issued implementing it.

vary greatly over time. Also, minimum billing mechanisms tended not to be assessed on a monthly basis, so price signals might not be timely.

The FERC has suggested two methods of calculating an interim gas inventory charge. The first would replace the purchased gas adjustment mechanism with an interim gas supply charge composed of two parts: a gas inventory charge and a gas commodity charge. The gas commodity charge for sales service would be based on the composite competitive market price of gas, and the gas inventory charge would be based on that composite multiplied by a percentage factor. Thus, the gas inventory charge would be a premium over the gas commodity charge to compensate the pipeline for costs related to performing the merchant function not covered by the gas commodity charge. This approach derives a gas inventory charge based on the value of the pipeline holding an inventory of gas supply contracts for the benefit of its sales customers, not on the individual customer's deficiency quantities. It places a value on the pipeline's merchant function of providing and keeping an inventory, which is derived from the approximate value of the inventory of gas supply contracts based on the expected value for which the pipeline could sell the gas in the competitive market.[51]

The second method is the deficiency charge method, which more closely resembles the traditional minimum bill. The pipeline would charge a gas commodity charge based on the current PGA mechanism, plus a gas inventory charge levied only if a firm sales customer's actual purchases fell below a percentage (say 60 percent) of its nominated purchase amounts. The gas inventory charge is designed to compensate the pipeline for the cost of maintaining a ready supply of gas where a customer's actual purchases fall significantly below its nominated purchase amounts. The FERC will allow the pipeline to charge 20 percent of its currently effective weighted average cost of gas (WACOG) as the gas inventory charge.[52]

Some have suggested that the gas inventory charge is anticompetitive because it allows the utility to retain market share unfairly.[53] FERC

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[51] Ibid., 7-16.
[52] Ibid., 16-20.
[53] The Illinois Commerce Commission has made such an argument as reported in Mary Nagelhout, "Gas Storage Charges: The Next Step in Take-or-Pay Cost Allocations," *Public Utilities Fortnightly*, 16 March 1989, 60-64.

Commissioner Charles Stalon has expressed concern that the deficiency-based gas inventory charge is anticompetitive and inferior to the competitively priced gas inventory charge for four reasons: it represents a tying arrangement between the monopoly of gas transportation and the potentially competitive commodity of gas; it tends to make the pipeline's merchant service a base-load service while forcing competitors into providing peaking service; it tends to Balkanize the gas market and create barriers to entry of potential competitors; and it induces inefficient purchases by LDCs, which can be passed along to customers. FERC Commissioner Trabandt, on the other hand, has criticized competitively priced gas inventory charges for failing to provide adequate incentives to lead to further exploration and drilling that will assure future gas supplies.[54]

Others contend that a gas inventory charge cannot be said to be anticompetitive because sales customers are free to choose to nominate whatever volume of gas they please, and hence are free to shop for more reliable sources of gas from other pipelines, from gas marketers, or from the gas producers themselves. Of course, an LDC must face the prospect of being last in line if it nominates less than it needs for its core customers.

The development of the gas inventory charge is essential to create a means by which the value of supply security that is provided through sales service can be reflected accurately in the cost of gas. Other means for collecting this cost also can be developed. The effects of a gas inventory charge on the LDCs' use of alternative procurement mechanisms depend on whether it can reflect the cost of maintaining gas supply by the pipelines while not hindering the operation of competitive forces in the gas market.

[54] "Hesse Sees Long Delay in Interim GICs; Senators Thrash Spot Option," *Inside F.E.R.C.*, 18 September 1989, 3-6.

CHAPTER 3

CURRENT STATE OVERSIGHT OF DIRECT GAS PURCHASES

Changes in gas procurement and transportation practices, especially the increased use of direct purchases by LDCs, have transformed the nature of state gas regulation. In the past when an LDC purchased gas supplies from pipeline companies at a rate set by the FERC, state commissions could rely on the FERC to determine the reasonableness of the rate and the reliability of the supplies. The main concern of state regulators was to monitor the pass-through to end-users of costs incurred by the LDCs. As direct gas purchase becomes more prevalent and gas procurement mechanisms more diversified, the state commissions must take on the additional responsibility of evaluating the economics and reliability of direct purchases, which are not regulated by the FERC.

An Overview

In order to develop current information about state public service commission policies regarding oversight of direct gas purchases by LDCs, a telephone survey was conducted of commission staff in forty-eight states and the District of Columbia during April and May 1989.[1] The questions used in the survey were taken from a previous NRRI study.[2] That earlier survey, conducted during the summer of 1987, included a smaller sample of state commissions (thirty-seven with thirty responding), and excluded states where

[1] Nebraska and Hawaii were excluded from the survey. The Nebraska Commission does not regulate local distribution companies. Manufactured liquified petroleum gas such as propane or butane is used in Hawaii instead of natural gas.

[2] J. Stephen Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches* (Columbus, OH: The National Regulatory Research Institute, 1988) 39-54, 117-48.

the commissions responded that direct gas purchases were unregulated or infeasible.

The 1989 survey covered several topics related to state commission oversight of direct gas purchases. The questions dealt with how state commissions review direct gas purchase contracts between jurisdictional local distribution companies and gas producers. Specific issues included whether a commission's purchased gas adjustment (PGA) procedures had been modified because of the increasing importance of direct gas purchases, whether the LDC must show that its direct purchases were part of a least-cost purchasing strategy, whether direct purchase contracts were subject to a prudence review, whether a commission assessed the riskiness of LDC direct-gas-purchase contracts, and whether the PGA procedure used by a commission contained any incentives for efficient gas purchasing and supply planning.

The survey found that about two-thirds of state utility commissions attempt some oversight of LDC direct gas purchases. This oversight is usually part of ongoing commission reviews of gas purchasing and procurement or cost flow-through and is usually done during a PGA proceeding, a rate case proceeding, or a separate proceeding for contract or gas purchasing review. The commissions differ as to whether they examine the actual contract or merely certain terms of the contracts such as prices. Some commissions restrict their direct-purchase contract review to initial contracts for new gas supplies.

Periodic staff review of contracts is fairly widespread with about two-thirds of the commissions using this practice. Many of the reviews occur during PGA or rate case proceedings. Others occur during separate contract review proceedings. Staff reviews may be institutionalized or staff may reserve the right to conduct random examinations. Review of contracts for the commission by outside auditors is not widespread. Preapproval of direct purchase contracts also is not common.

About half of the commissions use different procedures to handle direct purchase contracts when the producer and the LDC are affiliated. In most cases, the difference consists of closer examination of the contract. Other commissions review or preapprove direct-purchase contracts only when they involve affiliated transactions.

Modification of PGA procedures because of direct purchases has occurred at slightly less than one-third of the commissions and is anticipated to increase to involve slightly less than half of the commissions. Greater emphasis on spot gas purchases has been incorporated. Commissions are also requiring the LDCs to submit more information on their purchases. Some commissions are planning to incorporate incentives in the PGA.

Eighteen commissions have a requirement that the LDC must purchase the lowest-cost gas. However, "least cost" is often modified to mean "best cost" where both cost and reliability are considered.

Direct gas purchases are subject to a prudence review at most commissions. Often, the inquiry is part of a PGA or rate case review. Sometimes prudence is raised with respect to affiliated transactions. At some commissions the issue may not be considered at all unless an intervener raises it.

Nineteen commissions incorporate some kind of risk assessment in their direct purchase review. Determining risk is a part of an overall determination by the commissions as to whether a contract is prudent, or whether purchase of more expensive gas was justified.

Eighteen commissions incorporate incentives into their PGA mechanism. For some, the review process and the possible disallowance of costs is the incentive. For others, the incentives may involve sharing any savings in gas costs between stockholders and ratepayers.

Overall, most commissions appear active in overseeing direct purchase contracts through the use of established procedures such as PGA or rate case review. Procedures such as prudence review, PGA incentives, and risk assessment are less common, although they still are used by more than one-third of the commissions. Therefore, state policies on overseeing direct gas purchases by LDCs are being developed, although for some commissions the direction of the policy development is still uncertain at the present time.

The findings of the 1989 NRRI survey are similar to those of the 1987 NRRI survey. Both surveys found commissions responding to the changing environment through the use of established procedures such as the PGA mechanism. The use of outside auditors and preapproved contracts was uncommon in 1987 and again in 1989. The NRRI found in 1987 that some commissions were planning to revise their PGA procedures, although most were not. Most commissions did not have incentives for efficient purchases incorporated in their PGA. Those commissions that did have incentives used the disallowance of imprudent costs or the splitting of revenues or cost savings between ratepayers and stockholders. The same was true of commissions responding in 1989.

Least-cost purchasing was a fairly widespread requirement, either implicitly or explicitly, in the 1987 survey of commissions. Least cost balanced with reliability was a concern then, although the idea of "best cost" appears to be a new development.

Both surveys found that many commissions conducted prudence reviews, although not necessarily as separate proceedings. Prudence often was raised in PGA or rate proceedings. Risk assessment was somewhat uncommon in 1987. Only about one-third of the commissions reported conducting such an analysis. While only a minority of commissions formally take risk into account, such an assessment is more widespread in 1989.

Review of Direct Gas Purchase Contracts

In the following sections, the details of the 1989 survey results are presented. Given the increasing responsibility of state commissions in monitoring direct gas purchases, the NRRI first sought information on the extent to which commissions were actually overseeing the purchases. The 1989 survey included a series of questions about the direct-gas purchase review procedures (if any) used by a commission. The NRRI asked about the general nature of the process, the occasions for review (PGA, rate case), periodic review by commission staff and outside auditors, preapproval of contracts by the commission, and any differences in commission procedures if the producer and the distributor were affiliated.

Staff members at thirty-three of the forty-nine commissions surveyed told the NRRI that direct gas purchase contracts are reviewed by their agencies. Twenty-three commissions currently review the contracts as part of a purchased gas adjustment proceeding. Most of these commissions conduct PGA proceedings annually. In addition, the Washington Commission plans to start reviewing contracts in PGA proceedings. Twenty commissions review contracts as part of a general rate case. Eleven (including Washington) review direct gas purchase contracts in both PGA and rate case proceedings. Those eleven are Colorado, Connecticut, Delaware, Kentucky, Montana, North

Carolina, Oregon, Tennessee, Washington, West Virginia, and Wyoming. In short, most commissions oversee direct gas contracts, frequently using the PGA procedure and rate cases as forums for that review (see table 3-1).

As might be expected, commissions use a wide variety of practices and procedures. Some (for example, Alabama) review the actual contract, some (for example, Ohio) concentrate on contract pricing provisions, while others (such as Iowa and Virginia) conduct general reviews of LDC purchasing procedures instead of concentrating on specific contracts. Commission review of the contracts may be a process separate from PGA or rate case review. Mississippi and New York, for example, use a separate process of review.

Some commissions review only certain types of contracts. The most important example would be review of a contract with an affiliated producer. West Virginia and New Mexico are two examples.

Some commissions have formal institutionalized review procedures. The LDCs file the contracts and the commission reviews them either in the PGA, rate case, or other proceeding. The Kentucky, New York, and Mississippi commissions are examples of states with formal review procedures in place.

Other commissions may review contracts on an ad hoc basis. There is no institutionalized review procedure, although that does not necessarily mean that the contracts would never be reviewed. Delaware and Arizona are two examples.

(Some examples are described below to illustrate further this technique. The reader is also referred to the appendix of this report for a more detailed commission by commission summary of contract review procedures.)

The Alabama Commission reviews the direct purchase contract itself. The PSC has not found it helpful to review merely the monthly LDC price and quantity data, and so reviews LDC purchasing procedures every month. This review includes information on what the LDC was offered and what it rejected. Contracts are not reviewed in PGA or rate case proceedings.

The Arizona Commission reviews direct purchase contracts on an ad hoc basis in an audit for a rate case or PGA proceeding. There is no specific review policy. The only source of supply in the past for the state was El Paso Natural Gas Company, an interstate pipeline. There has been little direct purchasing activity until recently.

TABLE 3-1

COMMISSION RESPONSES ON OCCASIONS FOR REVIEWING DIRECT GAS PURCHASE CONTRACTS

	Reviewed by Commission	Reviewed in a PGA proceeding	Reviewed in a Rate Case
Alabama	Y*	N*	N
Alaska	Y	Y	N
Arizona	Y	N	N
Arkansas	Y	N	Y
California	Y	Y	N
Colorado	Y	Y	Y
Connecticut	Y	Y	Y
Delaware	Y	Y	Y
District of Columbia	N	N	Y
Florida	N/A*	N/A	N/A
Georgia	N	N	N
Idaho	N/A	N/A	N/A
Illinois	Y	Y	N
Indiana	N	N	N
Iowa	Y	Y	N
Kansas	Y	N	Y
Kentucky	Y	Y	Y
Louisiana	N	N	N
Maine	Y	N	Y
Maryland	Y	Y	N
Massachusetts	N	Y	N
Michigan	Y	Y	N
Minnesota	N	N	Y
Mississippi	Y	N	N
Missouri	Y	Y	N
Montana	Y	Y	Y
Nevada	Y	Y	N
New Hampshire	Y	N	N
New Jersey	N	Y	N
New Mexico	N	N	N
New York	Y	N	Y
North Carolina	Y	Y	Y
North Dakota	N	N	N
Ohio	N	Y	N
Oklahoma	Y	N	Y
Oregon	Y	Y	Y
Pennsylvania	Y	Y	N

TABLE 3-1--Continued

	Reviewed by Commission	Reviewed in a PGA proceeding	Reviewed in a Rate Case
Rhode Island	N	N	N
South Carolina	Y	Y	N
South Dakota	Y	N	Y
Tennessee	Y	Y	Y
Texas	N	N	N
Utah	Y	N	N
Vermont	Y	N	Y
Virginia	N	N	N
Washington	Y	Y	Y
West Virginia	Y	Y	Y
Wisconsin	N	N	N
Wyoming	Y	Y	Y

Source: NRRI telephone survey of state commission staff, April-May 1989.

*Note: Y = Yes; N = No; N/A = Not available or not applicable

The Connecticut Department conducts two types of review. Spot purchases and monthly short-term contracts are reviewed in monthly purchased gas adjustment proceedings while long-term firm contracts are reviewed in rate cases. The Department gives the distributor wide latitude to analyze and take the appropriate least-cost contract. The Department then will review what the LDC has done and conduct a prudence investigation, if warranted.

In Kansas, which has not had any supply problems for many years, contracts are submitted to the Commission and reviewed for price information. Contracts are not reviewed in PGA proceedings and while the expenses associated with contracts are reviewed in rate cases, there is no contract-by-contract review.

The Kentucky Commission requires direct purchase contracts to be filed by LDCs along with the PGA filings. Prices of long-term and spot contracts must be filed as well. Contracts are reviewed in the PGA proceedings and are likely to be reviewed in a rate case.

Some commissions focus their review on initial contracts for new supplies. One example is Maine where this review is a separate process and is not part of a PGA proceeding or rate case. Contracts could be reviewed in a rate case, but no review would occur if no problem had arisen. The Commission has reserved the right to reexamine anything that previously has been approved.

The Mississippi Commission examines new contracts for additional purchases. Contracts are not reviewed in PGA proceedings or in rate cases, and contract review is a separate process with the LDCs submitting the contracts. The agreements are examined, brought to a hearing, and then approved or disapproved.

Other commissions have policies similar to Maine and Mississippi's in that they review new contracts involving new purchases or additional supply. For example, the Oregon Commission reviews direct purchase contracts in a rate case. The Commission, however, conducts this review only when the LDC initially files to recover the costs associated with the agreement. The contract is not reexamined in succeeding rate cases.

As noted above, the New Mexico and West Virginia Commissions are particularly concerned with affiliated transactions. The New Mexico PSC reviews direct purchase contracts only if the transaction involves the LDC and an affiliate. The largest distributor in the state, Gas Company of New Mexico, is a combined producer-pipeline. Contract review is not part of a PGA proceeding or a rate case, but rather is part of a compliance filing that has to be made when the transaction is an affiliated one. The distributor submits the transaction to the Commission within fifteen days after the agreement has been negotiated. The Commission can use ratemaking remedies if it is not satisfied, telling the LDC after the fact that (in the view of the PSC) it has done something wrong.

The West Virginia Commission's policy is similar. New contracts must be filed with the Commission and contracts involving affiliated transactions must be approved in advance. The LDC must file the transaction with the PSC before entering into it. Affiliated transactions are reviewed both in the PGA proceedings and outside of those proceedings. They also may be reviewed in a rate case, or may be approved in advance.

The contract term is a factor in determining whether some commissions undertake review. In North Carolina, a distributor must notify the

Commission if it enters into a contract that lasts more than six months. The staff may raise questions about prudence and the Commission may review the contract if problems are found. In California, an LDC may choose to submit any new contract of more than five years' duration to the Commission for approval.

In Oklahoma, the Commission staff reviews the contracts at the utility offices as part of a six-month work program. Only the major contracts are reviewed because some distributors have as many as two thousand contracts with producers.

The Ohio Commission reviews pricing terms of all purchases. Management performance audits are conducted and contracts are reviewed in these audits once every two years. The staff considers minimum take requirements, take-or-pay, and other topics, but the contracts already have been executed by the time the staff examines them. While the staff may comment on purchasing practices, the Commission cannot void a contract.

The Virginia Commission does not examine specific contracts although it examines aggregate daily and seasonal demands and commodity purchases to determine whether the LDC is being flexible. Purchases, rather than contracts, are reviewed. The LDC must file a demand forecast (daily and seasonal) for each customer class. The Commission examines the source of supply and commodity cost-plan to ensure it is least cost.

Some commissions have decided not to examine direct gas purchase contracts although they have the authority to do so if they choose. The Indiana Commission, for example, has decided not to review contracts because of the burden on its limited staff. The Commission does, however, review LDC gas-cost invoices and other documents in quarterly gas-cost adjustment filings.

Thirty-three commissions responded that direct purchase contracts are reviewed periodically by staff members (see table 3-2). Some staff reviews occur during purchased gas adjustment or rate case proceedings. Other instances occur during separate contract reviews that commissions, such as Mississippi's, have described. At the Connecticut, Mississippi, New Hampshire and New York Commissions, the LDC is required to file each contract and the staff reviews the agreements as they are filed. At some commissions staff reserves the right to review, and examinations may occur

TABLE 3-2

COMMISSION RESPONSES ON PROCEDURES FOR REVIEWING
DIRECT GAS PURCHASE CONTRACTS

	Periodic Staff Review	Reviewed by Outside Auditors	Approved in Advance by Commission
Alabama	Y*	N*	N
Alaska	Y	N	Y
Arizona	N	N	N
Arkansas	Y	N	N
California	Y	N	Y
Colorado	Y	N	N
Connecticut	Y	N	N
Delaware	Y	N	N
District of Columbia	N	N	N
Florida	N/A*	N/A	N/A
Georgia	N	N	N
Idaho	N/A	N/A	N/A
Illinois	N	Y	N
Indiana	N	N	N
Iowa	Y	N	N
Kansas	Y	N	N
Kentucky	Y	N	N
Louisiana	N	N	N
Maine	Y	N	Y
Maryland	Y	N	N
Massachusetts	N	N	N
Michigan	Y	N	N
Minnesota	N	Y	N
Mississippi	Y	N	N
Missouri	Y	N	N
Montana	Y	N	N
Nevada	Y	N	N
New Hampshire	Y	N	N
New Jersey	N	Y	N
New Mexico	Y	N	N
New York	Y	N	N
North Carolina	Y	N	N
North Dakota	N	N	N
Ohio	Y	Y	N
Oklahoma	Y	N	N
Oregon	Y	N	N
Pennsylvania	Y	N	N

TABLE 3-2--Continued

	Periodic Staff Review	Reviewed by Outside Auditors	Approved in Advance by Commission
Rhode Island	N	N	N
South Carolina	Y	N	N
South Dakota	Y	Y	N
Tennessee	Y	N	N
Texas	Y	N	N
Utah	N	N	Y
Vermont	Y	N	Y
Virginia	N	N	N
Washington	Y	N	N
West Virginia	Y	N	Y
Wisconsin	N	N	N
Wyoming	Y	N	Y

Source: NRRI telephone survey of state commission staff, April-May 1989.

*Note: Y = Yes; N = No; N/A = Not applicable or not available

randomly. For example, the Delaware Commission does not have an institutionalized review of direct purchase contracts although the staff reserves the right to review the contracts and some contracts have been reviewed.

The Kansas Commission staff may review contracts when it feels such a review is warranted. There are no planned general reviews. At the New York State Department of Public Service, staff reviews the contracts as they are filed. Any examination after the initial review occurs on a random basis.

In North Carolina, contracts are reviewed by staff, although there is no set time for review. The staff can examine the contracts when it chooses to and may challenge the LDC on prudence in a rate case or purchased gas adjustment proceeding. In South Carolina, the Commission staff generally reviews the direct purchase contracts annually, but may do so anytime.

Review of contracts by outside auditors and prior contract approval by the commission are two other, albeit rare, means of oversight. Only five commissions reported using outside consultants. The Illinois Commission requires that LDC management audits be conducted whenever it feels such action is warranted. The New Jersey Board also requires management audits by outside auditors every five years. In Minnesota, the LDC's annual reports must be audited by outside auditors.

The Ohio Commission requires management audits although no particular guidelines are used. The Commission examines the LDC's overall operating characteristics, such as peak-day requirements, number of customers, participation at the FERC, amount of Ohio gas purchased, spot gas purchased, and transportation for system supply and other customers. These audits can be performed by outside auditors.

The South Dakota Commission uses outside auditors to review direct purchase contracts during rate proceedings, hiring auditors because its own staff is small.

Only seven commissions reported using any advance approval procedure. In Alaska, each direct purchase contract is filed with the Commission. The PUC reviews the agreement for reasonableness, and then either approves it (with or without modifications) or rejects it. The California PUC has approved some contracts in advance, although not recently. The only agreements that have been approved have been service agreements with interstate pipelines. In addition, the LDC may choose to submit any new contract of more than five years' duration to the PUC for its approval.

The Maine PUC also has authority to preapprove contracts involving the state's LDC and its transmission subsidiary. Initial contracts for new supplies must be submitted to the Commission for its approval approximately ninety days before the agreement is to take effect.

The Utah Division of Public Utilities approves in advance contracts involving the smaller LDC in the state. The LDC submits the contract, explains the benefits and discloses the price. The Division of Public Utilities examines the contract to determine whether it is reasonable. The other, larger LDC purchases gas through an affiliated interstate pipeline rather than purchasing directly from producers.

The Vermont Board's staff reviews contracts for direct purchases and makes a recommendation to the Board. The Board could suspend the contract and hold hearings if it felt there were problems with the agreement. The contract still could take effect, as the Board does not have to give its approval officially. If the Board was dissatisfied with the transaction, however, the LDC would proceed at its own risk as the regulators could pursue a rate investigation. Faced with such a prospect, the distributor might choose to answer the Board's objections. In effect (if not officially) then, the Board has approval authority.

In Wyoming, contracts are accepted for filing by the PSC. The Commission examines the agreements to determine if problems exist. If it has any objections, the PSC returns the contract to the LDC; otherwise, the contract is accepted.

The West Virginia Commission, as described above, must preapprove contracts involving affiliated transactions. The LDC has to file the transaction with the PSC before entering into it. The Commission has no deadline and it may conduct an internal review. There may be a hearing if any parties wish to intervene. Besides these commissions that mention advance approval procedures, the New Mexico PSC preapproves affiliated transactions, although it generally does not preapprove direct gas purchase contracts.

With respect to the use of different procedures in the event of producer-LDC affiliation, twenty-four commissions reported such procedures exist (see table 3-3). At thirteen commissions, the difference consisted of a closer examination of the contract. In addition, the New Mexico, Maine, Minnesota, Washington, and West Virginia Commissions must preapprove such transactions.

In Oregon, the affiliated-interest statute is applied to such transactions. The PUC, when examining transfer prices, would take the lower of either the actual cost or the market rates. In Pennsylvania, an additional set of rules involves affiliated interests. The LDC must convince the Commission that it could not purchase the gas more cheaply elsewhere.

The difference in Montana PSC treatment of affiliated transactions centers on the recovery of transaction costs. If the PSC has some flexibility, the costs could be rolled into gas rates on a cost-of-service basis. If the PSC has no flexibility because the affiliate is regulated by the FERC, the PSC must use the rates approved by the FERC.

The South Carolina PSC subjects affiliated transactions to close examination but uses a different pricing arrangement for this type of contract. For example, one LDC has a purchasing subsidiary and if that

TABLE 3-3

COMMISSION RESPONSES ON WHETHER REVIEW PROCEDURES DIFFER IF THE PRODUCER AND THE LDC ARE AFFILIATED

Closer Examination of the Contract	Other Difference(s)
Alabama	Maine
Colorado	Minnesota
Delaware	Montana
Kentucky	New Mexico
Mississippi	Oregon
Missouri	Pennsylvania
New York	South Carolina
North Carolina	Tennessee
Ohio	Texas
Oklahoma	Washington
Vermont	West Virginia
Virginia	
Wyoming	

Source: NRRI telephone survey of state commission staff, April-May 1989.

subsidiary purchases gas from a subsidiary of its suppliers it is not allowed to charge a finder's fee.

The Tennessee PSC uses a different procedure in flowing-back cost savings for one distributor's purchases from affiliated sources. Savings derived from affiliated-producer purchases flow to residential ratepayers. Savings resulting from unaffiliated purchases are used to offset marginal losses incurred by the LDC when it sells gas to industrial interruptible customers.

The Texas Railroad Commission tries to insure that the cost charged to the LDC by an affiliated producer does not exceed the weighted average cost of gas from other producers.

Modification of PGA Procedures

The NRRI found in both the 1987 and 1989 surveys that the PGA was an important mechanism for commission oversight of direct purchases. Thus, it would seem plausible that state regulators would modify the procedure to adapt to the changing gas market. The NRRI asked the staff members whether any purchased-gas-adjustment procedures used by their commissions had been modified because of the increasing importance of direct gas contracts. The staff members also were asked whether they anticipated any changes in the PGA procedures. Respondents at fourteen commissions stated that change had occurred. Change is anticipated by staff members at twenty-two commissions, including some where modifications already have been made (see table 3-4).

The types of changes that commissions are making in their PGA mechanisms range from the broad modification implemented by the California PUC (which divides customers into core and noncore markets) to more limited changes such as placing greater emphasis on spot gas in the PGA. Commissions have made some changes to increase their vigilance over the LDCs in the new environment. One example is the Kentucky Commission's requirement that direct purchase contracts be filed as part of the PGA. Commissions, such as North Carolina and Nevada's, are factoring the cost of nonpipeline-supplied gas into the PGA and rates. A more detailed discussion of specific commission actions follows.

The Arkansas PSC has changed its PGA procedure to emphasize the LDC's choice of supply. The Commission has expanded the scope of its compliance audits. In the past, the PGA mechanism was a mechanical flow-through of the cost of gas. Now, the Commission asks whether the distributor is buying the gas that it should be buying. More change is anticipated, as the process is an ongoing and evolving one with the Commission trying to build up its staff.

In California, the PUC reevaluated its entire approach in light of LDC involvement in the spot market and FERC Order 380. Customers were divided into core and noncore markets and PGA reviews were restricted to the core market, which consists mainly of residential customers. The Commission is still evaluating its policies although no further change is currently planned in those areas. A proposal has been made to exclude LDCs from selling gas in noncore markets. The Commission has not yet made its decision on this proposal.

The Indiana Commission has encouraged the LDCs to purchase the lowest-cost gas possible. The Commission then monitors LDC purchases through gas-cost-adjustment filings. There is, however, no specific written policy.

TABLE 3-4

COMMISSIONS WHERE PGA PROCEDURES HAVE BEEN OR MAY BE MODIFIED BECAUSE OF THE INCREASING USE OF DIRECT GAS PURCHASE CONTRACTS

Change Has Occurred	Change Is Anticipated
Arkansas*	Arizona
California	Arkansas*
Florida	California
Indiana	Colorado
Kentucky	Delaware
Maryland	Florida
Minnesota	Georgia
Missouri	Illinois
Nevada	Kentucky
New Mexico	Minnesota
North Carolina	Mississippi
Rhode Island	Missouri
Virginia	Montana
West Virginia	Nevada
	New Mexico
	New York
	Oregon
	South Carolina
	Tennessee
	Washington
	West Virginia
	Wisconsin

Source: NRRI telephone survey of state commission staff, April-May 1989.

*Note: Some commissions are listed in both columns because respondents indicated that while some changes have been made in their Commissions' PGA procedures, further changes will probably occur.

The Kentucky Commission modified its procedures by requiring direct purchase contracts to be filed as part of the PGA. Spot prices also are required to be set rather than averaged. Further increased review is anticipated.

The Maryland PSC has modified its PGA to place more emphasis on spot gas, reviewing LDC spot purchases monthly. The Minnesota Commission currently is revising its PGA and has been operating for the past three years on the basis of variances to its old rules. It now plans to place into the rules the procedures that it has been following. One such rule is a requirement that the LDC must notify the Commission any time its gas costs change by $.03 per Mcf, or every three months.

The Missouri Commission has revised its PGA procedures in the past to facilitate the timely flow-through of any reduced gas costs that may have resulted from purchases from nontraditional suppliers. The PSC seeks to send timely price signals to end-users.

In Nevada, the PGA base-cost formerly was set on the basis of the pipeline supplier's rates. Now, if the LDC has made any other purchases, the average cost of those purchases would be used. Further change, such as monthly charges, might occur as costs resulting from FERC Order 500's take-or-pay cost sharing are filtered down to the LDCs.

In North Carolina, the Commission uses the pipeline suppliers' current rate for the cost of gas in setting LDC rates. If the LDC bought spot gas, the cost might be lower than what was used to set the rate. This difference would be multiplied by the amount of gas purchased and the amount placed in a deferred account for customers or to offset sales losses.

The Rhode Island Commission recently has required the second largest LDC in the state to supply more information in its PGA filing. The LDC previously did not provide the per-unit cost of gas.

The Virginia Commission undertook a total review of its procedures. As a result, it developed a uniform PGA and required the LDCs to submit forecasts of the daily and seasonal demand of each customer class. The process is evolving and many issues remain undecided.

In West Virginia, some changes in procedures were mandated by the state legislature. The procedure of PSC approval of affiliated transactions, already described, was one change, although the Commission is still working through the affiliated transaction process. Independently produced gas is anticipated to become a larger part of the state's supply.

The Alabama Commission modified its PGA procedures as a result of overall market changes, not just direct purchases. The competitive-fuel-clause portion of the PGA (in which the cost of gas is compared with alternative fuels) was expanded to include gas-on-gas competition.

Other commissions have not yet modified their PGA procedures, but are considering specific changes; Wisconsin is considering a monitoring system. Some commissions, including Georgia and Colorado's, have begun more general reviews of their procedures. Several of these instances are described below.

The Colorado Commission has undertaken a review of its purchased-gas-adjustment methodology. The Commission is considering transportation first and will consider other issues such as uniformity of terms and bypass. The proceeding is expected to be completed by March 31, 1990. The Georgia Commission has begun a proceeding on gas purchasing practices. Changes may result in the Commission's PGA procedures.

The Illinois Commission has not changed its procedures for handling gas purchases, however, the procedures for flow-through of costs are evolving. Change is anticipated with respect to seasonality of costs. The New York Commission has expressed some interest in incorporating incentives into its PGA mechanism in the future.

The Oregon Commission is considering a proposal by its staff to include an incentive mechanism in the PGA. Currently, the PUC sets rates at the beginning of each November based on upcoming costs. A balancing account is established the next year as actual and projected costs are reconciled. The staff's proposal is to allow the LDCs to flow through 80 percent of the costs. Shareholders then would gain or lose the remaining 20 percent. The LDCs oppose this proposal, however, advocating a 100 percent flow-through. The Commission has not yet issued its order.

The Wisconsin Commission is planning to institute a monitoring system as part of its PGA procedure. The Commission is going to request that each LDC, within forty-five days after filing the PGA, file a list of contracts by volume and by cost. A group of LDC representatives and Commission staff is working to establish this system.

The Washington Commission may have to alter its PGA procedure because of a statutory interpretation. The Commission's attorneys have said that deferred accounting, allowing the recovery of past costs in future rates, is illegal under a strict interpretation of the retroactive ratemaking statute. The presumption behind the tariff mechanism was that the LDC purchased gas at pipeline rates. If the LDC was able to purchase gas at a lower price, the savings went into a deferred account. The Commission may have to change its procedure from this mechanism to a procedure based on the weighted average cost of gas.

In South Carolina, some change in the PGA is anticipated because of the reorganization of Transco, the interstate pipeline supplying a large part of the state's gas. The PSC, however, has not yet issued an order.

Requirement of Least-Cost Purchasing

In addition to asking about state commission policies for review of direct purchasing, the NRRI included questions about policies that could be used to influence LDC direct purchase decisions. The first of these was a requirement for least-cost purchasing. Such a requirement could presumably be an important tool that regulators could use, and it might be expected that many commissions would have this type of policy. The NRRI asked the staff members whether their commissions had any requirement for the LDC to show that its direct gas purchases (or lack of them) were an effective part of an overall least-cost gas purchasing policy. Eighteen commissions reported that they have such a requirement (see table 3-5).

TABLE 3-5

COMMISSIONS WITH A REQUIREMENT THAT
DIRECT GAS PURCHASES
BE PART OF A LEAST-COST POLICY

Arkansas	Mississippi
California	Nevada
District of Columbia	New Mexico
	New York
Indiana	Ohio
Iowa	Pennsylvania
Kentucky	Virginia
Maryland	Washington
Michigan	West Virginia
Minnesota	

Source: NRRI telephone survey of state commission staff, April-May 1989.

In Arkansas, state law requires the LDC to buy the most advantageous gas. The Commission has interpreted the statute to mean the "best cost," including reliability and cost.

The combination of reliability with lowest possible cost, or "best cost," was mentioned by several respondents as being part of their commission's policies. In addition to Arkansas, cost and reliability, rather than merely least cost, was explicitly noted by staff members at the Indiana, Iowa, Michigan, Minnesota, Nevada, New York, Ohio, and West Virginia Commissions. The South Carolina Commission's policy also takes other factors into consideration besides least cost. Undoubtedly, the mix of high reliability and lowest possible cost is a part of most, if not all, least-cost policies.

In Indiana, the requirement on the LDC to obtain the lowest cost and most reliable supply is embodied in state law, Indiana Code 812-42-G. Michigan requires the LDC purchase plan to be reasonable and prudent; least cost consistent with reliability. The Minnesota PUC requires LDCs to prove that they are keeping costs to a minimum while maintaining reasonable reliability.

The Nevada Commission is currently considering a proposed rule on gas resource planning. One provision of the rule requires the LDC to implement a combination of supply and demand-side options to minimize the net present value of future revenue requirements, consistent with reliability. The New York Commission's requirement of a least-cost reliable policy is implemented in conjunction with rate cases. Prudence is also a requirement. In Ohio, all LDC purchases must meet the least-cost requirement. The extent to which the distributor does or does not buy spot gas has to make sense in terms of its load profile consistent with reliability. In West Virginia, the LDC must prove that lower-priced supplies were not readily available from other sources. The utility must seek bids and make purchases at the lowest available price among reliable sources.

Another commission with a least-cost purchasing policy is the California PUC. In its annual prudence/PGA reviews of LDCs, the Commission requires each distributor to provide information on where the gas was purchased and the price paid. The LDC also must explain why its decisions were the best that it could have made. Other parties are allowed to intervene. The Commission generally has found that the LDCs are doing a good job.

As in California, the Maryland Commission's least-cost requirement is part of the PGA procedure. In the semiannual PGA review, the individual in charge of the LDC gas supply must affirm that the utility bought the least expensive gas.

The Mississippi Commission conducts a hearing on each direct gas purchase contract after the LDC has submitted it and the staff has reviewed it. The issue of least cost is raised in the hearing.

The Pennsylvania Commission's enabling statute requires least-cost fuel procurement on the part of LDCs. The Commission has annual gas cost reviews during which the actual cost of gas over the previous twelve months is reconciled with what the costs were projected to be. Least-cost direct purchasing is considered part of the review. The Virginia Commission's requirement is that the LDC must show that all costs are least cost. That obligation is not specifically for gas purchases, however.

In New Mexico, the LDCs must demonstrate that they are doing their best in their purchasing. If an affiliated transaction is involved, the LDC must prove to the PSC that it was the best possible arrangement. The LDCs buy from multiple producers. One LDC, for example, purchases gas from 1,200 producers. Thus, the situation facing the Commission is more complicated than in other places. The PSC has no formal least-cost planning methodology, although it does impose certain criteria for the LDC to meet when it requests a continuation of the monthly cost adjustment.

The District of Columbia, Kentucky, and Washington Commissions have not fully implemented least-cost policies, although the policies have been adopted. The District of Columbia Commission is implementing its least-cost policy with the LDCs drawing up least-cost plans for the Commission to approve or disapprove. Productivity improvement working groups (consisting of representatives from the LDC, the PSC, and the Office of People's Counsel) are drawing up the plans.

The Kentucky PSC issued an administrative order requiring the larger LDCs in the state to file a planning strategy that was least-cost. The Commission staff and the LDCs have not yet worked out the filing requirements.

The Washington Commission is developing its least-cost policy. The Commission adopted a rule on least-cost planning and the policy is being developed by a group of advisors to the Commissioners. The LDCs are submitting draft least-cost plans.

Some commissions have not formally adopted least-cost policies for direct gas purchasing. However, the commission may still consider least-cost criteria in its review of direct purchases. A distributor may also pursue least-cost purchasing on its own initiative. The latter is the case in South Dakota where the LDCs are employing least-cost strategies with the Commission's consent but not at its direction.

In Oklahoma, the LDCs perform both the distributor and transmission function. The Commission reviews LDC practices to insure that the utility has obtained the best cost, but there is no statutory requirement. Other factors, such as take-or-pay, are important also. The North Carolina Commission has no specific least-cost policy. However, the Public Staff could challenge any gas costs that seemed out of line.

The New Jersey Board has a least-cost program in place. However, the policy has not operated with respect to direct gas purchases. The Board has not applied least-cost requirements to direct purchases. The New Hampshire Commission has recently implemented least-cost criteria for electric utilities. The policy that may be applied to LDCs at a later time would require the distributor to prove that its purchases were least cost. When new gas supplies begin to come in from Canada, least cost will be more important. The Missouri Commission has no formal written least-cost requirement. However, state law requires LDC rates to be just and reasonable.

In Maine, the issue of least-cost purchasing is raised in gas-cost-adjustment proceedings. The Commission examines LDC spot purchases and tries to determine whether the distributor was trying to purchase at least cost. There is no formal least-cost requirement, but the LDCs provide information to the PUC to prove that they are purchasing at the lowest cost.

The Alaska Commission has no direct least-cost requirement, although gas purchase contracts must be found to be in the public interest when the PUC approves them. In Connecticut, the LDCs have been directed to pursue a least-cost strategy. If the distributor can purchase at least cost and also sell gas to off-peak customers, it would be able to earn extra profits for shareholders.

The Alabama Commission does not have a formal least-cost requirement, although the Commission tries to ensure that the LDC is keeping costs low. The Wyoming Commission also has no formal least-cost rule; however, some LDCs have had to prove that their purchases were the lowest cost, especially when an affiliated transaction was involved. The Commission's policy is to take a case-by-case approach to the issue.

Prudence Review

In addition to a least-cost purchasing requirement, prudence review could constitute another means by which regulators would attempt to influence LDC direct purchases. Regulators may prefer to review what the LDC has already done instead of giving advance approval to future action. As the survey results show, advance approval is not a common practice. The NRRI asked the staff members whether the prices or other terms of direct gas contracts were subject to a prudence or prudence-type review. Thirty-one commissions reportedly conduct some type of review or consider the prudence issue. Sometimes the prudence inquiry is a separate proceeding. At other times, prudence is raised in a rate case or PGA review (see table 3-6).

Some commissions have not yet performed a prudence inquiry, although direct purchase contracts are always subject to such a review. Mississippi, Tennessee, and Wisconsin are three such examples. The Arkansas Commission, at the time of this survey, had just begun one review. Prudence had not been raised, but the possibility existed for its consideration. The Arizona Commission has no specific statement on prudence review, but contracts (conceptually at least) are subject to that review. Contracts are subject to a prudence review in Minnesota, but such review is not done automatically.

The Alaska Commission reviews direct purchase contracts for prudence as part of its preapproval process. The Kansas Commission considers prudence on a case-by-case basis if the need arises. The Maine Commission requires that any contract for the purchase of electricity or gas be prudent. Direct purchase contracts are also subject to a prudence review at the Michigan PSC.

TABLE 3-6

COMMISSIONS THAT CONDUCT
PRUDENCE REVIEWS OF
DIRECT GAS PURCHASE CONTRACTS

Alaska	Mississippi
Arizona	Missouri
Arkansas	Montana
California	New Mexico
Connecticut	Ohio
District of Columbia	Oklahoma
	Oregon
Illinois	Pennsylvania
Indiana	South Carolina
Iowa	Tennessee
Kansas	Utah
Kentucky	Vermont
Maine	Virginia
Maryland	West Virginia
Michigan	Wisconsin
Minnesota	Wyoming

Source: NRRI telephone survey of state commission staff, April-May 1989.

The Wyoming Commission does not use the term "prudence." The Commission examines direct purchase contracts. If problems are found in a contract, the PSC works with the distributor to make adjustments. The Commission in the past has had to remove some purchases from contracts.

The Virginia Commission would initiate a prudence inquiry only if there were problems with a particular contract. The Commission has an informal review process. If questions arose about an agreement, prudence could be considered in a rule-to-show-cause proceeding.

The Vermont Board considers prudence as part of its regular staff review of direct purchase contracts. There are no hearings set aside solely for prudence. The Oklahoma Commission also considers prudence, but it does not approve contracts, only the pass-through of costs. In Utah, there is no formal prudence review. The DPU examines the LDC gas sources to ensure that the distributor has a mix with the lowest average cost. The contracts are examined indirectly for prudence.

Prudence has been raised as an issue at two commissions with respect to affiliated transactions. At the Kentucky Commission, while prudence has been considered in affiliated transactions, prudence inquiries are always a possibility in direct gas contract review. At the New Mexico Commission, prudence inquiry has been restricted to affiliated transactions, but may be expanded in the future to deal with the take-or-pay problem.

The Montana Commission is considering the prudence issue in the context of a general policy review in a case involving Montana-Dakota Utilities which is switching from a single affiliated supplier to purchasing 15 percent of its gas from other suppliers.

The Maryland Commission is not conducting prudence inquiries at present. However, one LDC sought PSC approval for up to fifteen years' worth of purchases from proven reserves. The PSC refused to give its consent for this amount of time and the LDC will have to justify its purchases continuously. The South Carolina Commission recently has conducted three prudence reviews. The PSC staff attempts to compare gas prices paid by the LDCs, especially in spot purchases, to prices paid by others in the region.

Several commissions include prudence inquiries as part of a PGA proceeding or an annual review of LDC purchasing and procurement. The Pennsylvania Commission includes prudence in its annual gas cost review for each LDC. The Iowa Board conducts an annual review of gas procurement during which direct gas purchases are reviewed and prudence is considered. The Illinois Commission also considers prudence in its annual PGA reconciliation procedure. In Missouri, LDC gas purchasing practices and prudence are reviewed annually. In one current case, the PSC staff has questioned whether the distributor purchased the best gas, as opposed to the cheapest gas.

In California, prudence is part of a two-stage annual PGA proceeding. One stage has an offset in which the balance sheets are cleared. The prudence review comprises the second step. In recent reviews, Pacific Gas & Electric was found to be prudent in its purchasing, but in another case, staff has taken exception to some of Southern California Gas's actions. No final decision has been made in the latter case.

The West Virginia Commission also includes a prudence inquiry in its PGA proceeding. The prudence issue was raised in several cases in which distributors bought large amounts of gas from affiliated sources instead of from other available cheaper supplies. Prudence was also raised in some cases with respect to take or pay, but the PSC has not decided the issue.

The Ohio Commission considers prudence in the context of management performance audits which the Commission requires of LDCs every two years. The Commission considers the cost of gas passed through the gas cost recovery procedure. If it feels that the pricing terms are imprudent, the Commission reviews the actions of the LDC.

The Indiana Commission has considered prudence in both gas cost adjustment and rate case proceedings. The gas cost adjustment is usually a direct pass-through of the cost of gas although the Commission could take action if it thought that a purchase had been imprudent. For example, one LDC bought gas from a nonpipeline source that charged more than the pipeline. The Commission did not allow the LDC to recover any amount over that which the pipeline would have charged.

Besides Indiana, the Oregon Commission, the Connecticut Department, and the District of Columbia Commission consider prudence in rate cases. In Oregon, if a purchase by a distributor was thought to be imprudent, the general rate case would be the forum for challenging it at the PUC.

In one case in Connecticut, the supplier was selling to an affiliated LDC, which paid a higher price for gas than it could have paid elsewhere. A clause in the contract between the LDC and the affiliated producer stated that the distributor could tell the producer it would pay a certain amount that it wished to specify for the gas. The DPUC instructed the distributor to exercise that contract option, and told the distributor what the specified amount would be. In the same rate case, the LDC was renegotiating its purchases of synthetic gas from a venture in which it was a partner at a time when other partners were eliminating their volumes of gas. The DPUC investigated and found the LDC had overestimated its marketing projections. The Department disallowed $1.8 million.

In the District of Columbia, LDCs are required to file an annual gas procurement report. The report must include an outline of quantities, purchases, and prices paid for the previous year. The report is reviewed by PSC staff and the Office of People's Counsel. Prudence can be raised by those parties. If any questions arise about some of the LDC purchases, a review could be conducted at the next rate case.

Other commissions do not conduct prudence reviews, but the issue could be considered if a party raised it. This is the case at the Nevada and North Carolina Commissions. At the latter commission, the Public Staff could challenge a cost that it considered to be out of line.

The Alabama Commission does not conduct prudence reviews. However, the LDC could be subject to a review (a show-cause proceeding) if some of its purchases were felt to be imprudent. A prudence review would be conducted at the South Dakota PUC if the prices of gas purchased by the LDC went above the pipeline rates. This is not expected, however.

The New York Commission does not conduct formal structured prudence reviews, but examines LDCs' monthly PGA filings. The prudence issue has been raised in gas cases at the New Jersey Board, but after direct purchase contracts were filed.

The Delaware Commission also does not review for prudence. The courts have told the PSC that it can disallow only for bad faith, abuse of discretion, or waste.

Assessment of Riskiness

Assessing the risk of a distributor's direct purchase contracts is another potential means for regulators to influence direct purchasing. Assessing risk could be especially important for insuring supply reliability as LDCs buy gas from untraditional, nonpipeline sources. Regulators could take the opportunity during the assessment to inform the LDC of any concerns about supply sources that they felt were unreliable. The NRRI asked the staff members whether their commissions assessed the riskiness of a distributor's contracts. The assessment could be in the form of comparing a long-term contract containing a requirement for a minimum volume to be purchased with a short-term contract such as an agreement for spot market gas. Nineteen commissions undertake just such an assessment (see table 3-7).

Commissions consider the issue of risk at various times. Some include the assessment when reviewing direct purchase contracts, some consider risk as part of a general purchasing and procurement review, while some assess risk in the PGA review.

The Maine Commission considers risk in its approval of contracts. The Iowa Board includes a risk assessment in its annual review of gas procurement.

TABLE 3-7

COMMISSIONS THAT ASSESS
THE RISKINESS OF LDC
DIRECT GAS PURCHASE CONTRACTS

Arkansas	Minnesota
California	Mississippi
Colorado	Missouri
District of Columbia	Montana
Illinois	New Hampshire
Iowa	North Carolina
Maine	Ohio
Maryland	Tennessee
Michigan	Texas
	West Virginia

Source: NRRI telephone survey of state commission staff, April-May 1989.

The Colorado PUC staff considers contract risk, but the issue has not yet been raised with the Commission itself. The Minnesota Commission is attempting to make risk assessment less subjective.

The Arkansas Commission considers the riskiness of a contract when determining whether the agreement is good overall. Risk is part of the California PUC's evaluation of why more expensive gas would be purchased by the LDC. The assessment is not only least-cost as more expensive gas could perform an important function.

Risk is also a part of the District of Columbia Commission's determination of whether a contract is prudent; (that is, was it prudent to enter into a particular contract or supply mix? Who are the producers and the pipelines?). The Illinois Commission includes risk assessments in its annual PGA reconciliation.

The Maryland Commission considers risk in its annual evaluation of LDC gas procurement plans. A qualitative measure of the supply portfolio is used. At the Missouri PSC, risk is considered during the annual LDC purchasing and prudence review. The overriding question is how the LDC supply choices affect its obligation to serve. The LDC management must ensure a safe, adequate gas supply.

The New Hampshire Commission has no specific requirements on risk, but the issue has been raised in cost of gas hearings. The main pipeline supplier for the state's LDCs is considering a gas inventory charge that would cause cost increases. The North Carolina Commission considers risk to the extent that it does not want the LDC to purchase spot gas for high-priority customers. The Tennessee PSC evaluates risk particularly in the case of long-term contracts. However, the Commission usually does not take any specific action on risk.

The Texas Railroad Commission does not consider risk in terms of general rates. However, in one case, the LDC sought to abandon some supplies and the Commission expressed concern about the availability of supply.

The Ohio Commission includes a recognition of relative risk in its assessment of gas purchasing, meaning it does not require strictly least-cost purchasing. The requirement, rather, is least cost balanced with reliability. The expectation is that the LDC will balance firmness and the price of gas with relative reliability.

Some commissions have no special risk assessment. In some of these states--such as Virginia, South Dakota, Alaska, and Connecticut--LDCs made long-term purchases in the past and risk assessment was not required. Some commissions want to avoid micromanaging the LDC and thus defer to management's expertise. Other commissions will consider the issue only if it is raised by intervenors to a case.

The Wyoming Commission does not make a rate adjustment unless something appears to be out of line. The PSC relies on the expertise of the LDC management, which has the responsibility of providing adequate service. There is no special risk review.

The Vermont Board has not had a risk assessment up to the present. However, there was the possibility that such an assessment would be conducted in a pending case. The Utah Division of Public Utilities has no formal guidelines (there has not been much spot gas in Utah), but the DPU is aware of the issue. The LDCs in Virginia have entered into long-term contracts only with pipelines. Commission policy on risk is still undecided.

Likewise, risk has not been a large issue in South Dakota. The LDCs have been purchasing supply largely in long-term contracts from pipelines.

Spot gas has not been a large percentage of the mix. The South Carolina PSC expects risk to become a large issue in the future. The LDCs historically have engaged in short-term purchases.

Neither the Nevada nor the Pennsylvania Commissions make specific findings about risk in their assessments of purchases. However, parties intervening in a case may raise the issue for consideration. Risk assessment is inherent in a rule on gas resource planning being considered by the Nevada Commission.

The risk issue also could be raised in a rate case at the New Jersey Board. The Board, however, generally does not include risk assessment in direct purchase review. The Oregon Commission previously has allowed both long- and short-term contracts. It currently has no position on risk assessment. Risk is becoming a factor in Oklahoma. The Commission has not yet addressed the issue, however.

The Kentucky Commission has not evaluated riskiness in any great detail. The staff is aware of the issue in a general sense. The Alaska Commission has not directly assessed riskiness of contracts. All contracts in the state have been long-term. The Connecticut DPUC has not assessed risk as of yet. Contracts have historically been long-term and there have been capacity problems in the Northeast. If excess pipeline capacity develops, the Department would review for risk.

The Alabama Commission has not formally evaluated the riskiness of LDC direct purchase contracts. However, the PSC has had informal discussions with one large LDC, telling the distributor that there should not be too much risk in its supply portfolio.

The Delaware Commission is considering the issue of risk and the question of how to create a portfolio for gas needs. In the view of the staff respondent, the PSC may need to defer to LDC management and not "micromanage" the utility.

PGA Incentives

The fourth type of incentive covered in the survey, is the purchased gas adjustment procedure. Commissions could incorporate incentives in the mechanisms used to recover gas costs. An example would be allowing shareholders to retain a portion of savings resulting from purchasing gas more efficiently or from cheaper sources. A negative incentive would be disallowing (and thus forcing the LDC to absorb) any gas costs that the Commission felt were imprudently incurred or excessive.

The NRRI asked the staff members if the purchased gas adjustment procedures used by their commissions contained any specific features intended to create incentives for efficient gas purchasing and supply planning. Eighteen commissions (including one using an incentive based in rates) use incentive mechanisms of some type (see table 3-8).

TABLE 3-8

COMMISSIONS WHERE THE PGA PROCEDURE INCLUDES INCENTIVES TO PROMOTE EFFICIENT GAS PURCHASING AND SUPPLY PLANNING

Alaska	Michigan
Arkansas	Mississippi
California	Missouri
Connecticut	Montana
District of Columbia	Oklahoma
Illinois	Pennsylvania
Indiana	Virginia
Kentucky	West Virginia
Maine	Wyoming

Source: NRRI telephone survey of state commission staff, April-May 1989.

Staff members at several of the commissions that have used incentive provisions stated that the incentive was mainly negative in nature, such as the possible disallowance of costs after some review procedures. The California Commission's annual PGA/prudence review is one example. If costs are found to be imprudent or if the LDC did not take equally reliable, but cheaper, available gas, those costs could be disallowed to the shareholders. The Illinois Commission's annual PGA reconciliation provides for refunds if the LDC overcollects for its costs and reimbursement at a later date if the LDC undercollects. No sharing mechanism exists, however.

The Indiana Commission has encouraged least-cost purchasing and buying from nonpipeline sources through its orders and engineering reports. The LDCs are monitored through their filings with the Commission.

At the Kentucky Commission, the requirement for fair, just, and reasonable rates is considered to be the incentive. At the Pennsylvania Commission, disallowance of any costs found to be greater than least cost is the incentive. At the Michigan PSC, the incentive is disallowance of costs if the purchase is not found to be reasonable and prudent.

The Mississippi Commission's PGA procedure considers the availability of gas, whether gas could have been purchased at lower cost, and why other supplies were not considered. The procedure itself is thought to be sufficient incentive.

The incentive of sharing revenues (and sometimes losses) is found in the Oklahoma Commission's allowance of a split between stockholders and ratepayers of revenues earned by the LDC when it sells or transports gas off-system. For sales, the split is 90-10. For transportation, the split is 75-25.

In Wyoming, state law provides that if the LDC decreases its costs, not less than 90 percent of the savings may be passed through to the ratepayers. The utility can keep up to 10 percent of the savings as an incentive. In West Virginia, state law requires the LDC to prove that other sources of gas are not available.

The Alaska Commission provides for the establishment of a balancing account. The LDC records the underrecovery or overrecovery of costs. Interest is paid on the account regardless of whether there is underrecovery or overrecovery. If there is underrecovery the interest is set equal to the current prime rate. If there is overrecovery, the account is debited by an amount equal to the overall authorized rate of return for the LDC. The LDC repays any overrecovery with interest set at its rate of return. The LDC should have sufficient incentive to keep the account close to zero.

In Arkansas, certain PGA clauses have incentives. For example, Arkla has a benchmark for the amount and price of spot purchasing. If the benchmarks are exceeded and savings result, they are split with ratepayers receiving 60 percent and stockholders receiving 40 percent.

The Connecticut DPUC includes an incentive in its ratemaking. The Department sets a target for the gross margin that the LDC is likely to obtain for its interruptible customers. If the LDC exceeds the target, firm customers would receive 50 percent of the revenues, which would be flowed-through the PGA. The LDC would retain the other 50 percent.

The District of Columbia Commission, like Connecticut's, has a margin-sharing incentive. Revenues received by the LDC from interruptible, special contract customers are split with residential customers receiving 90 percent and the distributor retaining the other 10 percent.

The Montana Commission does not allow any interest to accrue on the PGA. In addition, as part of the industrial retention rate, the LDC has to absorb 10 percent of the difference between the special rate given to retain the customer on the system and the otherwise applicable rate for the customer.

In Maine, an incentive is achieved indirectly. For interruptible customers, the LDC is allowed to use a separate rate schedule and charge a price as low as five cents above the commodity cost of gas to make interruptible sales. When the LDC sells gas (such as storage gas) at marginal cost during the winter, all of the profit goes to the firm ratepayers. If the LDC sells pipeline supply, there is a 90-10 split with the LDC retaining 10 percent of the revenues. The interruptible programs were approved under their own docket and not as part of the gas cost adjustment. The Commission's intention is to discourage interruptible sales during the winter. Maine also has a special developmental interruptible rate. Under this program, the LDC can sell gas at a discount for five years to a customer that does not have the capacity to switch fuels. Profits obtained from the sales would be used to pay for the customer's installation of dual fuel capability. After the five years are over, the customer would receive gas under a regular interruptible rate schedule.

The Virginia Commission's incentive provisions are related to base rates and gas costs flowing to flexible customers. Those costs are traditionally removed from the PGA and a weighted average cost of gas is used instead. The Commission has prohibited the dedication of cheap supplies to these customers unless the LDC can prove that the incremental cost is the cheapest that would go to these customers from flexible sales. The Commission also has a target revenue mechanism (for nongas revenues) in the allocated cost of service. If the LDC exceeds the target, the difference is split between stockholders and ratepayers. If the LDC does not meet the target it must absorb the loss.

The Idaho Commission currently is considering an incentive proposed by a distributor. The LDC proposal was concerned with any difference between the weighted average cost of gas and the cost of pipeline system supply. If the weighted average cost was higher, the LDC would absorb 5 percent of that difference. If the weighted average cost was lower than the pipeline cost, the shareholders would retain 5 percent of the savings.

Commissions with no special incentives in their PGA procedures include the Missouri PSC. The audit staff of the Commission aggressively reviews the facts during the PGA review. Imprudently and improperly incurred costs are not recovered. An aggressive staff is the Commission's incentive mechanism. The Utah Division of Public Utilities also has no special incentives. The PGA review, it is hoped, provides incentive for the LDCs to be efficient.

The North Dakota Commission has incorporated margin sharing in transportation rates for interruptible customers. The Commission has allowed the LDCs to use flexible pricing to meet competition. Two-thirds of the transportation margins go to the distributor's firm customers. This is not part of the PGA.

Three Commissions--Delaware, Minnesota, and Oregon--are addressing the issue of incentives. In Oregon, the Commission staff has proposed a 20 percent risk or reward for variation from actual, measurable costs.

CHAPTER 4

DIRECT GAS PURCHASES: CONSIDERATIONS OF SUPPLY RELIABILITY

The supply reliability consequences of direct purchase by an LDC can be analyzed in three aspects: as a single gas procurement transaction, as a part of total supply portfolio, and in the context of overall gas market responses in adjusting gas production and transportation capacity. This chapter provides an examination of the supply reliability issue, particularly from the broader spectrum of gas supply planning for an LDC as well as for the nation as a whole. Additionally, the use of direct purchases by an LDC may result in a shift of regulatory forum from the Federal Energy Regulatory Commission to state public service commissions. Such a shift could have implications for gas supply reliability and its oversight.

Direct Purchase as a Single Gas Procurement Transaction

The gas obtained by an LDC through direct purchases, whether a spot market purchase or a long-term contract made directly with a wellhead producer, is generally less reliable than the gas obtained through a long-term purchase contract with a pipeline supplier *if it is viewed as a single gas procurement transaction*. This conclusion is based on the comparison of typical contract provisions of spot purchase contracts with long-term pipeline purchase contracts, the differences in the ability and experience of LDCs and pipelines to consummate a gas procurement contract, and the absence of obligations to serve on the part of sellers in most direct gas purchases.

As discussed in chapter 2, the gas obtained through spot market purchases is delivered mostly on a "best effort" basis, while long-term gas purchase contracts generally include provisions of committed reserve or take-or-pay provisions to firm up the eventual consummation of the gas procurement transactions. Even though there is no empirical evidence to suggest that spot market purchases are unreliable supply sources up to now (given the substantial amount of supply surplus in the current gas market), the reliability of spot gas supplied on a "best effort" basis could suffer in a tight gas market where gas supply is constrained by insufficient production or transportation capacity. In any event, the commitment among sellers to provide gas would appear to be generally stronger under a long-term contract than under a spot purchase contract.

The difference in the duration of the long-term and spot purchase contracts also enhances the supply reliability of a long-term contract in comparison to that of a spot purchase. The instances of lengthening the contract duration of spot purchase to six months or a year is a good indication of certain gas buyers' desire for supply reliability associated with long-term contracts. Once again, the effect of contract duration on supply reliability is more pronounced in a period of tighter gas market conditions than in a slack gas market.

Now we turn to the difference in the experience and knowledge of pipelines and LDCs in consummating a gas procurement contract. For an LDC, the tasks required in a direct purchase contract with a wellhead producer are much more complicated than those involved in entering into a long-term contract with a pipeline. The arrangement of transportation facilities, the scheduling of gas delivery, and the provision of backup service are examples of the tasks that have to be undertaken by an LDC in direct purchases, but which may not be of concern if purchases are made from pipelines.[1] Most LDCs do not have the added capacity or experience to deal with these additional tasks. In that case, an LDC is likely to be in a less favorable position than a pipeline to deal with these complex tasks. Although an LDC can use a gas marketer or other intermediary to perform these required tasks, it still is hard to imagine that gas marketers can consistently outperform a pipeline and help an LDC obtain a more reliable gas supply on a comparable-cost basis. Additionally, since most pipeline supply portfolios are more diversified than the supply sources of gas purchased directly by

[1] See chapter 2 for the tasks involved in direct purchase with wellhead producers.

LDCs, risk spreading in gas supply sources is another reason why direct gas transaction is less reliable when viewed as a single gas procurement.[2]

Furthermore, in purchasing from producers directly or through the spot market, an LDC no longer enjoys the assurance of supply associated with the obligation to serve (as provided by FERC regulations under the Natural Gas Act) on the part of pipelines concerning the part of gas purchased directly. Obviously, the absence of such a change in pipeline service obligation would not enhance the reliability of direct purchases by LDCs. A more extensive discussion of the shift of regulatory forums as a result of direct purchases by LDCs will be provided in a later section.

It is worth noting that the extent and nature of pipelines' obligation to supply LDCs with sales gas may change in the future. According to a proposal submitted to the FERC by the Interstate Natural Gas Association of America (INGAA) in late 1988, pipelines should be afforded the ability to abandon their obligation to serve LDCs with sales gas after due notice and the expiration of current contracts.[3] The INGAA argued that the establishment of the proposed abandonment/conversion procedure will provide pipelines with great certainty concerning their future operational roles and allow them to rely upon their contracts to determine their obligations. The FERC has not made its decision on this proposal, and several parties have expressed strong objections. However, if there are significant changes in the pipeline's obligation to serve, the reliability implications of pipeline purchases relative to direct purchases by LDCs need to be reevaluated closely.

Direct Gas Purchases as a Part of Supply Portfolio

The conclusion that a direct gas purchase is less reliable, *if viewed as a single gas procurement decision*, does not necessarily mean that a gas supply portfolio is less reliable if it contains a certain amount of gas purchased directly. But since a direct gas purchase may be less reliable

[2] See chapter 2 for a more detailed discussion about market power and risk diversification of purchase from a pipeline portfolio.
[3] See "INGAA Offers Mechanism for Pipelines to Adjust Service Obligations," *Inside F.E.R.C.*, 14 November 1988, 1, 5-6.

than a pipeline purchase, it may not be a wise strategy for an LDC to build its gas supply portfolio entirely through direct purchases. In other words, an LDC whose gas supply portfolio is composed solely of gas obtained through direct purchases may be exposing its ratepayers to unnecessary risks of supply interruptions since gas market conditions can change dramatically and quickly.

Specifically, it may be best that an LDC not procure its gas supply totally through spot market purchases over an extended period of time unless it serves no captive customers who lack the ability to switch fuel or obtain gas from alternative sources, or unless it is willing to expose its ratepayers to a higher than usual risk of gas supply interruption. A useful analogy can be provided here. An electric utility generally would not use economy energy as its only source of power supply to serve its captive customers over an extended period of time. A total dependence on economy energy might be feasible in a short period of time if the economy energy is abundantly available. But given that the supply of economy energy can be interrupted at any time, its long-term reliability is not assured. Furthermore, total reliance on spot gas may worry regulators who are concerned about the effects on core customers. For example, as discussed in chapter 3, the North Carolina commission specifically prohibits LDCs to purchase spot gas for high-priority customers.

An LDC may choose to depend entirely on direct purchases from wellhead producers and spot market purchases as its supply sources, but such a supply portfolio is unlikely to be the most economical or reliable unless the LDC is experienced in direct purchases with wellhead producers and has substantial access to pipeline transportation facilities to purchase from a large number of potential gas suppliers. Consequently, one can reasonably conclude that long-term pipeline purchases, direct wellhead purchases, and spot market purchases are likely to coexist in most LDC's supply portfolios for the foreseeable future.

What are the supply reliability implications of direct purchases for a typical LDC if such purchases are used only as a part of the overall gas supply portfolio? No adverse consequences in supply reliability are expected. Most LDCs are likely to serve both captive customers and noncore customers that either have fuel-switching capacity, access to another potential supplier, or a gas requirement that can be met by an interruptible gas supply. These two groups of customers have vastly different objectives in purchasing gas service from the LDC. For captive customers, continuing reliable gas service is probably the most important consideration. For noncore customers such as industrial plants that can switch from gas to oil, the relative cost advantage of gas may be the dominant decision criterion. Thus, the characteristics of the gas supply portfolios to meet the two groups of customers can be quite different.

The availability of spot market gas and direct wellhead purchases can increase the flexibility of an LDC's supply portfolio and may, in a slack gas market, reduce the costs of gas supplies. Since some of an LDC's customers do not need a firm and uninterrupted supply of gas, the "reduced" reliability (for the supply portfolio as a whole) associated with the incorporation of gas procured through spot market and direct wellhead purchases does not necessarily matter to those customers. On the contrary, on a similar-cost basis, the savings associated with obtaining a portion of gas supply through direct purchases can be used to enhance the reliability on the part of a supply portfolio aimed at supplying captive customers. For example, while not necessarily recommending such a policy, an LDC could use the cost savings resulting from obtaining more spot gas that serves primarily the industrial customers to enter into more long-term contracts (or contracts with more stringent supply obligations) to better serve the residential customers. In the end, the service reliability for captive customers (residential customers) can increase while the service reliability experienced by noncore customers (industrial customers) does not decrease as a result of more direct purchases. But, one cannot determine the proper percentage of the amount of gas directly purchased simply by examining the percentages of captive and noncore customers. More complex supply portfolio selection models need to be applied by LDCs to determine the proper mix of directly purchased and pipeline-supplied gas.

Direct Gas Purchases and Aggregate Market Responses

The reliability of an LDC's gas supply portfolio is affected not only by its own procurement strategies but also by the overall gas production in the gas fields and the availability of transportation facilities to deliver the gas. If there are overall gas production or transportation shortfalls, the incidents of supply interruption or high cost of gas resulting from excess demand probably are unavoidable for some LDCs, despite the fact that the LDCs are using the most "reliable" procurement strategies.

The gas shortages that occurred in the 1970s illustrate the importance of overall market responses on the reliability and cost of individual gas procurement decisions. During this period, almost all LDCs used long-term contracts with pipelines to secure gas supply. Direct purchases by LDCs were a negligible part of the overall supply portfolio. The pipelines, in turn, used long-term contracts with wellhead producers exclusively to obtain their own gas supply. Thus, both the contract format and the composition of the gas supply portfolio suggested that a highly reliable supply of gas could be expected. However, due to production shortfalls in the gas field as a result of low wellhead prices imposed by federal regulation, there simply was not a sufficient amount of gas being produced and being made available to the gas market. Severe gas shortages were experienced.

This example shows that the market responses to the increase in direct purchases have significant supply reliability implications even though an individual LDC's procurement decisions have only limited influence on the market supply of gas and transportation capacity. In this regard, the increased use of direct gas purchases has several positive influences over the overall gas supply reliability directly and indirectly.

First of all, the increase in direct purchases can induce more pipelines to choose to become open-access transporters. The data in chapter 2 suggest a close relationship exists between open access to pipeline transportation facilities and the amount of gas directly purchased by LDCs. It is apparent that as more pipelines choose to become open-access transporters, the technical feasibility of direct purchases by LDCs and the potential gas production fields and potential customers of the direct gas market will increase. The increased use of direct purchases by LDCs puts additional pressure on those pipelines that refuse to become open-access transporters to reconsider their previous decisions. As a pipeline's customers have more supply and transportation options (including bypass), a pipeline's refusal to provide transportation service can lead to significant economic loss in the event that some customers choose to bypass the pipeline completely. What's more, the opportunity to increase a pipeline's transportation revenue may not be realized. Therefore, the remaining pipelines have an incentive to become open-access transporters to be more competitive. But the benefits in enhancing gas supply reliability as a result of increasing the extent of open access are probably rather limited at this stage of the development of transportation access because the degree of open access to the transportation facilities is already quite extensive.

A second positive effect comes from the pooling of gas demands and supplies of small customers and producers. Such pooling can encourage development of new gas production fields and the construction of new transportation pipelines. By use of direct purchases and with the prevalence of open access, the gas demand of many small LDCs can be combined, resulting in a larger demand that may allow an *individual* producer to bring into production a larger gas well than could previously be economically justified when that producer shared with other producers the *separate* demands of the LDCs (that is, before pooling). Such an outcome is most likely if the pipelines did not have sufficient coordination among themselves in gas procurement to experience demand that allowed development of larger wells.[4]

Alternatively, certain gas transportation facilities that were not built in the past (because the gas wells that can utilize the transportation facilities had not been developed) can be built. More importantly, the adjustments in gas market production and transportation capacity are accomplished through market forces rather than by government regulation. This means the possibility of creating excess gas demand or excess gas supply is less.

A third positive influence of direct purchase on gas supply reliability is that the price in the gas spot market is more responsive and indicative of future imbalances of gas demand and supply than the price of long-term contracts. As discussed in chapter 1, various measurements such as reserve life and net reserve additions can indicate the future availability of gas. But these measures deal primarily with the physical availability of gas and can hardly predict the market participants' expectations about future gas

[4] This is not to claim that pooling necessarily results in an increase in aggregate national demand for gas; rather, that particular producers may be able to call into production larger wells than would otherwise be the case.

requirement and supply. The best way to gauge future market conditions and current expectations of them is probably the market price itself.

The spot market price, since it is usually good only for a month, reflects the short-term expectation of demand and supply balance in the gas market. The long-term contract price, which is effective for an extended period of time, is the result of long-term demand and supply expectations. Any supply shortfall or excess supply during specific periods may be averaged over an extended period covered by the long-term purchase contract. So the long-term contract prices tend to be more stable than prices in the spot market. A previous study has noted that "in a sense buying and selling on the spot market is the residual activity that serves to clear the market as a whole."[5] Since spot prices are more volatile and indicative of the marginal condition of gas demand and supply, it is a more responsive predictor of gas demand and supply imbalance than the long-term contract price, especially in the short term. This does not mean that the LDCs or the gas industry should pay attention only to spot market prices in assessing future gas demand supply. But with the increased use of spot purchases by LDCs, the short-term supply and demand conditions play an increasingly prominent role in the formulation and execution of an LDC's gas procurement strategies. The spot price is the key to understanding the short-term gas market conditions.

A Shift of Regulatory Forums

Increased use of direct gas purchases by an LDC can also lead to a shift of regulatory forums, with the state public service commissions having the primary responsibility for assuring reliability of service, instead of the FERC. This shift of regulatory authority can be viewed on the other hand as an enhancement of gas supply reliability since it shifts regulatory responsibility for reliable service to the states which are closer to and tend to be more responsive to end-users. On the other hand, the shift of regulatory forums would become a disadvantage where state public service

[5] Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches*, 31.

commissions rely only on contractual remedies to ensure reliable gas supplies, and where state commissions are relatively new at overseeing gas purchases by LDCs to assure that reliability concerns are properly addressed. Moreover, the shift of regulatory forums has diluted, if not eliminated completely, the regulatory obligation to serve on the part of pipelines to LDCs. Such a dilution of service obligation could be detrimental to the gas supply reliability of LDCs in a tighter gas market.

Historically, FERC's regulatory authority has helped assure the reliability of gas supply in interstate commerce, once service has begun. It included issuance of certificates of public convenience and necessity to authorize producers to sell natural gas for resale in interstate commerce. Without such a certificate, no producer may sell natural gas for resale in interstate commerce.[6] The FERC could tie the granting of a certificate to contract provisions assuring supply reliability.

Most of the certificates of public convenience and necessity are issued without an expressed time limit for sales.[7] Once the certificate is issued and gas is delivered into interstate commerce from dedicated reserves, gas service has begun and the service obligation of section 7(e) of the Natural Gas Act (NGA) becomes effective. Although the underlying contract is the primary document setting out the terms under which a producer supplies a pipeline with a reliable source of gas, the service obligation under section 7(e) is separate from the contract obligations and continues even after the sales contract has expired.[8] Where there is no expressed time limit in the certificate once service has begun, the producer is under an obligation to provide continuous service to the purchaser in interstate commerce until the reserves are exhausted or until the FERC permits cessation of service under section 7(b) abandonment authority.[9]

6 15 U.S.C. sec. 717f(c) (1982).

7 The FPC can issue limited-term certificates with a pregranted abandonment when it finds that public convenience or necessity permits cessation of service at a specific time in the future. F.P.C. v. Moss, 424 U.S. 494 (1986).

8 Gulf Oil Corp. v. F.P.C., 563 F.2d 588, 594 (3d Cir. 1977); Sunray Mid-Continent Oil Co. v. F.P.C., 364 U.S. 137 (1960); 15 U.S.C. sec. 717f(e) (1982).

9 Hunt v. F.P.C., 306 F.2d 334, 342 (5th Cir. 1962), reversed on other grounds, F.P.C. v. Hunt, 376 U.S. 515 (1964).

The Natural Gas Policy Act of 1978 (NGPA) exempts certain producers from the modern FERC's jurisdiction under the NGA. Under NGPA section 601, producers are exempt if their gas was not committed or dedicated to interstate commerce as of the day before the enactment of the NGPA (November 8, 1978), or if it was dedicated to interstate commerce, but was determined to qualify as high-cost gas--section 107(c) (1-4)--new gas--section 102(c)--or gas from new onshore production wells--section 103(c). The overall effect of these provisions was to make the reliability of much of the new gas developed under the NGPA subject only to contract provisions as far as reliability was concerned.

Parallel NGA certification requirements existed for interstate pipelines. An interstate pipeline was required to obtain a certificate of public convenience and necessity prior to commencing service to LDCs.[10] To obtain the certificate, the pipeline was required to show adequate gas supply, markets, facilities, and financial resources, and to demonstrate that the project would serve the public need.

Likewise, once service began, an interstate pipeline was subject to a service obligation to its customers (usually LDCs, but sometimes downstream pipelines) that was discrete from the terms of the underlying contract.[11] Thus, pipelines also are subject to the requirement of obtaining authorization before abandoning service to an LDC even though the underlying contract had expired.[12] Thus, the regulatory scheme helped to assure gas supply reliability from the producer to the pipeline and from the pipeline to the LDC. Underlying contracts fell under the jurisdiction of the FERC and an additional and discrete service obligation was placed on the producer and the interstate pipeline by the FPC pursuant to the NGA.

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[10] These producers are not subject to many of the NGA nonprice controls, including certification and abandonment requirements. However, these producers remain subject to certain nonprice controls under the NGPA, including the authority to specify the minimum duration of contracts for purchases and to provide the pipelines with a right of first refusal for the gas that previously had been dedicated to interstate commerce. 15 U.S.C. sec. 717f(c) (1982).

[11] Gulf Oil Corp. v. F.P.C., 531 F.2d 1324 (5th Cir. 1976). In addition, the FPC could compel a pipeline to render service to certain distribution customers even when there is not and never was an underlying contractual obligation. 15 U.S.C. sec. 717a (1982).

[12] 15 U.S.C. sec. 717(f) (1982).

However, the NGPA and recent FERC initiatives (including FERC Orders 436 and 500) have effectively changed how the provisions of the Natural Gas Act operate concerning reliability. The FERC orders encourage interstate gas pipelines to provide transportation rather than sales service. Because the spot market price of gas is low at present, LDCs are encouraged to take advantage of the transportation service option by converting their sales contracts to transportation contracts to buy gas directly from the producer.

In effect, Order 500 encourages pipelines and producers to abandon their previous contracts and to enter into two new implicit contracts: that the producer sell gas directly to the LDC or end-user and that the interstate pipeline provide gas transportation for the first contract in exchange for a transportation service charge and relief from take-or-pay liability for the quantity of gas transported. The FERC does not review the individual contracts between the producer and the LDC or end-users to see if they are just, reasonable, not unduly discriminatory, and assure reliability because the wellhead price of gas sold by the producer largely is deregulated.

Also, FERC Order 451 provides for a multistep good-faith negotiation process, which can result in the deregulation of old gas. The producer can ask for a higher price (set by the FERC as a ceiling) for its old gas and the pipeline can ask for a lower price for newer gas supplies under the same contract, or even other contracts that contain old gas. If the parties cannot agree, the contract is terminated and service is abandoned.[13]

The recently enacted Natural Gas Wellhead Decontrol Act of 1989 (NGWDA) amends the NGPA to eliminate wellhead price and nonprice controls by January 1, 1993.[14] Decontrol is phased-in for all expired, terminated, or post-NGWDA enactment contracts, for all expiring or terminating contracts, for

[13] The Fifth Circuit Court of Appeals recently vacated FERC Order 451. However, the FERC is requesting a rehearing and will appeal to the United States Supreme Court if unsuccessful. See "Special Report: Appeals Court Overturns Order 451, Finds FERC Exceeded its Authority," *Inside F.E.R.C.*, 18 September 1989, 1-2; "Industry, Regulators Scramble to Deal with Court's Order 451 Ruling," *Inside F.E.R.C.*, 25 September 1989, 1, 8-9; "Judge Files Dissent to Order 451 Ruling; FERC to Seek Rehearing," *Inside F.E.R.C.*, 2 October 1989, 1, 8-9.

[14] Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60, 103 Stat. 157 (July 26, 1989).

certain renegotiated contracts, and for all newly spudded, post-NGWDA wells for gas delivered after May 14, 1991. The nonprice controls that are eliminated include the obligation to serve under the NGA. This new act accelerates the shift of the regulatory forum on reliability concerns from the FERC to the state commissions.

In conclusion, state public utility commissions can no longer fully rely on the FERC to ensure that contracts between the LDC and the producer will result in a reliable source of gas. Further, the service obligations that existed between a producer and its pipeline cease to exist when a producer makes a direct sale.[15] It is difficult to ascertain whether such a regulatory shift will lead to a reduction of gas supply reliability to end-users. It rests on the continuing development of federal regulation as well as the progress of state commissions in undertaking the additional responsibility of reviewing direct gas purchase contracts.[16]

Summary

A direct purchase contract itself may not be as reliable as a long-term purchase contract in delivering a specific amount of gas. But the use of direct gas procurement can add flexibility and cost advantages to an LDC's overall supply portfolio. It also can induce a more responsive supply environment for the gas market as a whole. The use of direct purchase, on balance, is likely to enhance the gas supply reliability to an LDC.

There seems to be no evidence up to now to indicate that the reliability of gas supply to an LDC has suffered from the increasing dependence on direct purchases and decreasing dependence on pipeline purchases in the last few years. This is not unexpected given the current gas supply surplus in the marketplace. Furthermore, because the spot purchases only commit the purchaser--an LDC--to a purchase obligation for a short period of time, the consequences of under- or over-purchases are lessened as compared with those under long-term purchase agreements. An LDC

[15] For example, see ANR Pipeline Co. et al., "Order Permitting and Approving Limited-Term Blanket Abandonment and Issuing Limited-Term Blanket Certificates with Pregranted Abandonment," 38 FERC para. 61,046 (January 21, 1987).
[16] 18 C.F.R. sec. 2.105 (1988).

has more flexibility in adjusting the part of its supply portfolio consisting of spot purchases and is willing to follow its projected gas requirement more closely. However, over the long-term, the state regulatory commissions must take a more active approach in overseeing direct purchases by LDCs to assure reliable and economic gas supply to the end-users since the FERC is no longer assuming the primary role of gas purchase oversight and the extent of gas supply surplus may be reduced significantly.

CHAPTER 5

STATE REGULATORY OPTIONS

As stated in chapter 3, the increased use of direct purchases by LDCs has transformed the nature of state gas regulation. A majority of state commissions have used procedures such as purchased gas adjustment (PGA) or rate case review to oversee LDCs' direct purchases. In this chapter, the strengths and weaknesses of such regulatory options as well as options not widely used by state regulators are analyzed. It should be emphasized that this analysis deals with the generic features of these regulatory options. The applicability and relevance of a specific regulatory option to a particular state must be based on its own unique gas demand and supply conditions. The options include the review of direct gas purchases, direct risk assessment, reconciliation of state and federal curtailment policies, clarification of LDCs' obligation to serve to various groups of customers, and the reviewing of the LDCs' contracting procedure to make certain that direct purchase contracts are enforceable.

Reviews of Gas Purchases

One option currently in use by most state public utility commissions is some type of commission review of the direct gas purchases by LDCs. There is a wide variety of practices and procedures in use for reviewing gas purchase. In the following sections, the advantages and potential problems of applying these review procedures are outlined.

Prudence Reviews

Strictly speaking, a prudence review of direct gas purchasing by an LDC is a retrospective, factual inquiry into the LDCs' direct gas purchasing decisions. The prudence review could take place in the context of a PGA proceeding, a general rate case, or as a separate proceeding. There are four well-understood guidelines for a successful prudence inquiry: (1) a rebuttal of the presumption of prudence, (2) a rule of reasonableness under the circumstances, (3) a proscription against hindsight, and (4) a retrospective, factual inquiry.[1]

Unless a particular gas purchase decision is challenged, the LDC's direct-gas-purchasing decisions are considered to be prudent. To rebut the presumption of prudence, more than a mere allegation of an imprudent purchase must be made; typically some substantive evidence must exist to create a serious doubt about the prudence of the purchase decision. In the case of reviewing direct gas purchases, evidence of such a doubt might be a portfolio of gas purchase contracts with a weighted average price that is much higher than that of similar portfolios of other LDCs.[2]

Next, there is a need to develop evidence about whether the decisions that went into the gas supply portfolio were prudent when made. Evidence for prudence or imprudence needs to be retrospective--or backward-looking--because it must deal with the facts and circumstances at the time the decision was made. The factual evidence should cover all the elements that did or could have entered into the decision, including all relevant data, information, decision-making tools (such as computer models), and the circumstances at the time.[3] Evidence concerning gas supply portfolios is likely to include what was known about gas prices, forecasts of future demand, supply, and prices; information about the details of individual contracts; and information about the available decision-making tools available and in use when the decision was made.

In evaluating the evidence, regulators are to apply a standard of reasonableness under the circumstances known at the time. The company is to be judged in light of all conditions and circumstances which were known or which reasonably should have been known at the time the decisions were made.[4]

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1 Robert E. Burns et al., *The Prudent Investment Test in the 1980s* (Columbus, OH: The National Regulatory Research Institute, 1985), 55.

2 Ibid., 55-57.

3 Ibid., 60-61.

4 Ibid., 57-61.

In evaluating gas supply portfolios, it is helpful when state public utility commissions announce the goal sought by the LDC: often the goal is least-cost purchasing. Several state statutes require LDCs to minimize purchase gas costs for reliable supplies. But most gas supplies have degrees of reliability, and often an LDC must trade price for reliability of service. State commissions undertaking a prudence review must gather evidence to determine whether the trade offs made by the LDC were the result of a reasonable decision-making process, given the facts and circumstances known or knowable at the time.

There is a proscription against the use of hindsight in applying the prudence standard. This is a corollary to the reasonableness-under-the-circumstances test just described. In other words, the proscription against hindsight makes it unwise for a commission to supplement the reasonableness test with some form of a final-outcome test, unless that test is used solely to overcome the presumption of prudence.[5]

The proscription against hindsight is especially important when regulators apply the prudence test to an LDC's gas purchase portfolio. For example, if an LDC opts for lower-cost supplies at the expense of reliability, or if an LDC opts for more reliable sources of gas foregoing lower prices, a utility commission ought not hold the LDC responsible for unforeseen and unforeseeable future events which may negatively affect the outcome of the choice. Rather, the proper way for regulators to frame the issue is to ask if the LDC made reasonable decisions about trading reliability against cost in assembling its gas purchase portfolio, given the facts and circumstances known or knowable at the time of the decision.

Least-Cost Purchase Requirement

The objective of a least-cost purchase requirement is to minimize gas supply costs subject to certain reliability conditions. Such a goal obviously is one that regulators, LDCs, and ratepayers all would embrace. However, problems can arise in trying to implement a least-cost purchasing plan, because some situations may arise where buying a higher reliability of

[5] Ibid., 60.

gas service can be achieved only with a more costly gas supply, while a low-cost gas supply might entail a lower level of supply reliability. The trade off between reliability and cost should not be examined merely on a contract-by-contract basis. Such a trade off is best analyzed in the context of the gas supply portfolio as a whole.[6] The key contractual provisions concerning this trade off that a commission would want to consider include price, contract duration, financial security of the producer, deliverability of the gas, market-out or similar provisions, and the existence and enforceability of any liquidated damages or specific performance contract provisions that may be attached for nonperformance.

Contract Preapproval

Presumably, a contract preapproval procedure is meant to prevent abusive and unwarranted transfer payments which can occur when affiliated transactions are not regulated. A major problem for state public service commissions opting for the contract preapproval approach is that it may tend to foreclose the possibility of later prudence reviews of the utility's decision. The doctrine of estoppel, either explicitly or implicitly applied, becomes relevant. A regulatory estoppel would operate if and only if a utility could justifiably rely on a state public utility commission's preapproval of the contract.[7] Also, a preapproval process may tend to coopt the commission staff's decision making because at the time the contract is preapproved, the utility possesses most, if not all, of the relevant information needed to reach a decision. Lacking independent sources of information, a commission could not easily exercise independent judgement.[8]

[6] See chapter 4 on the implication of incorporating gas supply contracts with various degrees of firmness of deliverability in an LDC's supply portfolio.
[7] Russell Profozich et al., *Commission Preapproval of Utility Investments* (Columbus, OH: The National Regulatory Research Institute, 1981), 38.
[8] Ibid., 40.

Gas Purchase Plan Preapproval

The objective of this strategy is to allow regulators, the LDC, and other parties (such as state consumers' counsels and industrial intervenors) to discuss and reach agreement in advance on the gas purchasing goals and strategies of the LDC. The LDC still would have the duty and obligation to implement the strategy, and state regulators still would have an opportunity to review the actual gas purchases made by the LDC to judge their prudence or reasonableness in light of the mutually agreed upon gas supply plan goals. For example, the LDCs can be required to file long-term demand forecasts and gas procurement plans similar to those forecasts and plans filed by electric utilities in many states. Then the commission staff can review them using formal procedures, or discuss them with the LDCs in less formal processes.

The major advantage for the LDC and the regulator is that a mutually agreed upon gas supply plan with explicit goals and strategies gives the regulator a yardstick by which to measure the LDC's performance. It is to the LDC's advantage because the LDC knows how its performance is being measured.

A more important advantage that comes from developing a mutually agreed upon gas supply plan is that the trade off decisions between price and reliability can be made explicit. A gas supply plan allows the regulator and the LDC to agree upon target prices for the gas portfolio, as well as the level or mix of reliability that would be desirable for the contracts in the portfolio.

Incentive Rate Provisions

Another option that state public utility commissions may wish to consider is the incorporation of incentive rate provisions in the LDC's purchased gas adjustment clause. Regulators could use some incentive rate provisions that would encourage an LDC to buy the lowest-cost gas supplies. As described in an earlier chapter, these PGA incentive rate provisions can take a variety of forms. For example, the Wyoming Commission provides that if an LDC decreases its purchased gas costs, not less than 90 percent of the savings may be passed through to the ratepayers. The utility can keep up to 10 percent of the savings as an incentive. Other commissions provide an incentive to buy from least-cost suppliers by disallowing any purchased gas costs that are higher than least cost. But it is a more complex task to design an incentive rate provision giving the LDC an adequate incentive to assure that its supply sources are reliable, particularly when reliability and cost are traded off to a certain extent. Nevertheless, state commission experimentation with such rates, particularly if tests were based on the results of a direct risk assessment, might yield useful results.

Direct Risk Assessment

Direct risk assessment refers to the evaluation of supply reliability associated with gas obtained by LDCs through direct purchases. A direct gas procurement contract has quite different supply reliability implications depending on whether it is viewed as a single gas procurement transaction or as a part of an LDC's gas supply portfolio. From the perspective of assuring reliable gas supply to an LDC's end-use customers, the reliability of an LDC's supply portfolio is the more appropriate perspective.

Direct risk assessment is a relatively new area for state regulation of direct gas purchases since most states do not evaluate the riskiness of an LDC's gas purchases. Among those states that do consider the risk associated with direct purchases, the analysis usually is conducted informally and without explicitly specified guidelines or criteria. It is also likely that in the current environment of relatively abundant gas supply, the risk of gas supply interruptions may not be of great concern to many states; consequently the states are less interested in doing any direct risk assessment. There are various methods for direct risk assessment. In this section, three primary methods of risk assessment--Monte Carlo simulation, Delphi technique in reaching a consensus, and scenario analysis--are analyzed.

The first step in risk assessment is to establish the measurement (index) of risk to be evaluated. In the case of gas supply planning, the frequency of supply interruptions, the duration of curtailments, the amount of unserved energy, and the monetary value of decreased production by industrial and commercial customers and reduced comfort and convenience for residential customers due to gas supply interruptions can be used as possible indices of risk. Once a risk index is chosen, the next step is to identify the linkage between the characteristics of various gas supply sources and the chosen risk index. In many instances, such relationships can be expressed only in probabilistic terms rather than as deterministic relationships. The third step is to extend the likely relationships into the future. Once again, this relationship is most likely represented in probabilistic terms.

Monte Carlo simulation basically is a computer simulation of future demand and supply balances based on the reliability and price characteristics of an LDC's gas supply portfolio and the demand characteristics of its end-use customers.[9] The advantage of such an approach is that a detailed and realistic gas demand and supply model can be constructed to illustrate many possible future scenarios. The major limitations of a Monte Carlo simulation are the extensive data collection efforts required to build the model and the considerable computer processing time required for the actual simulation.

The Delphi technique is the opposite of a Monte Carlo simulation. It relies primarily on the independent judgements of several gas industry experts. The consensus of the experts is the result of the risk assessment. This method is simple and straightforward and can be implemented using relatively limited resources. The Delphi technique is especially useful in evaluating uncertainty and risk over an extended period of time into the future where quantitative information on future conditions are difficult to derive or where extremely large amounts of data are required for a successful simulation. The U.S. Department of Energy recently used the Delphi technique to derive the assessment of the natural gas resource base of the nation in 1988.[10] A review panel consisting of seventeen gas experts was organized and presented with the basic data, the methodology, and the

[9] More discussions about the general procedures and theories of using computers to simulate stochastic processes can be found in Daniel P. Maki and Maynard Thompson, *Mathematical Models and Applications* (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1973), 433-47.

[10] United States Department of Energy, *An Assessment of the Natural Gas Resource Base of the United States* (Washington, DC: U.S. Department of Energy, 1988).

results from a resource analysis prepared by the Department of Energy. The review panel made a judgement of the volumes of natural gas in an agreed-upon resource base determined to be economically recoverable at various wellhead prices. Similar procedures can be applied by state commissions to evaluate the riskiness of a particular LDC's gas supply portfolio.

But such a technique may have some inherent difficulties in its application in state gas regulation where a burden of proof generally needs to be satisfied with expert testimony subject to cross examination. The results of a Delphi technique can rarely be cross examined. There is also the possibility of disagreement on which experts should be used, and whether the findings of the technique should be binding on state regulators.

Scenario analysis is similar to Monte Carlo simulation except that the analysis typically contains only a small number of possible contingencies. Instead of a detailed analysis of all possible situations, a scenario analysis usually chooses only a few scenarios which represent either the most likely situation or the boundary of what could happen in the future (the best- and worst-case scenarios). A scenario analysis is more easily prepared and understood, but may require substantial efforts before several reasonable scenarios can be identified and chosen. As shown in chapter 1, the gas demand and supply projections prepared by both the Energy Information Administration and the American Gas Association used several different scenarios about the future prices of crude oil and natural gas. With the selection of diverse price scenarios depicting possible energy prices, the range of possible gas demand and supply balance can be identified. Such information is obviously more useful than a single projection in evaluating the risk of supply interruptions or drastic price changes.

State and Federal Curtailment Policies

Once an LDC has procured a supply of gas, it still must be concerned with the risk of gas curtailment either by pipeline capacity allocation among transportation customers or through shortages in gas production. The allocation of interstate pipeline capacity is dealt with at the federal level. The current system for allocating pipeline capacity among firm transportation customers, as established in FERC Order 436, is for capacity to be allocated on a first-come, first-served basis.[11] As more end-users and LDCs switch from sales to firm transportation service, the first-come, first-served queue for pipeline capacity becomes longer. At some point, it might be possible for a pipeline's limited capacity to become oversubscribed. In a time of pipeline capacity shortages, customers (be they LDCs or end-users) with earlier contracts for firm transportation service are preferred over those with later contracts. Obviously, those LDCs and end-users with interruptible transportation firm service will lose the right to pipeline capacity first.

The FERC currently is considering having a secondary market in pipeline capacity. In early January 1989, the FERC approved an experiment by the United Gas Pipe Line Company to engage in a three-year experiment in which United would be permitted to broker (resell) firm capacity that it holds on fifteen upstream pipelines and to allow any party that holds firm transportation capacity on its pipeline to broker that transportation capacity.[12] A secondary market where firm transportation capacity could be resold would go a long way toward creating a market-based approach where transmission access was allocated according to the value placed on the capacity by individual customers. Because the three-year experiment is still underway, it cannot yet be judged a success or failure.[13]

Some state commissions with a significant number of intrastate pipelines have specific pipeline capacity allocation procedures. For example, the California Commission's policy provides that in the event of intrastate capacity shortage, core customers receive top priority.[14] The California Commission has also issued an interim decision concerning development of a market-based natural gas pipeline capacity allocation

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[11] FERC Order 436, FERC Stats. & Regs., 31,515-18.
[12] "Outside Firm to Handle Initial Bidding in United Capacity Brokering," *Inside F.E.R.C.*, 16 January 1989, 1-2.
[13] "Pipes Say They've Already Consented to United Brokering Experiment," *Inside F.E.R.C.*, 7 August 1989, 7-8.
[14] Robert E. Burns et al., *State Gas Transportation Policies: An Evaluation of Approaches* (Columbus, OH: The National Regulatory Research Institute, 1989), 31. Also, the case cited in footnote 3, page 51.

program.[15] In that decision, the Commission found that (1) an integrated intrastate-interstate market-based capacity allocation program is desirable, feasible, and could be implemented in the near future; (2) implementation of such a program would provide far more reliable pipeline capacity for a wider range of gas producers, shippers, and end-users; and (3) implementation of a market-based program would stimulate gas-on-gas competition to the benefit of the consumer.[16] Therefore, the Commission required its gas utilities to file proposals for a market-based pipeline allocation system that would integrate the allocation of interstate and intrastate pipeline capacity and that are consistent with nine general principles.[17]

Implementation of curtailment plans in the case of gas supply shortages would occur concurrently at both the federal and state levels. From the LDC's point of view, the curtailment plans of its supplying pipelines are of critical importance since the pipeline's plans determine the quantity of gas available to the LDC. If gas supply shortages were to occur, interstate pipelines would be required by federal law to implement their gas curtailment plans.[18] Traditionally, curtailment plans establish the

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[15] Re Natural Gas Procurement and System Reliability, 99 PUR4th 41 (CalifPUC, 1988).

[16] Ibid., 49.

[17] Ibid., 51. The nine principles are (1) the program should help to meet core customer procurement goals by encouraging gas-on-gas competition; (2) core-elect customers should pay for the secure access to pipeline capacity which core service provides; (3) the program should be consistent with the capacity right which the utilities have on interstate pipelines that serve them, including firm transportation rights under FERC Order 500; (4) firmness of capacity allocated to noncore customers should be independent of whether the customer purchases gas from the utility or another supplier; (5) noncore customers should have the flexibility to coordinate the integrated access to pipeline capacity with storage banking services; (6) the costs of access to firmer pipeline capacity should be borne by those noncore customers who benefit; (7) the value of capacity allocated to noncore customers should be determined by a market-based mechanism, not by a cost-allocation process; (8) the program should encourage the maximum efficient use of transportation capacity over the long term; and (9) the integrated capacity allocation mechanism must be acceptable to both the California Commission and the FERC.

[18] Because the wellhead price of gas is mostly deregulated, and will be totally deregulated by 1992, such a supply shortage would likely be only a temporary dislocation. If demand outstripped supply, prices would rise,

(Footnote continues on next page)

priority of gas delivery when supplies are insufficient to meet sales (as opposed to transportation) gas contract demand. An LDC's entitlement to gas under a curtailment plan is based on the volume of gas used and the end use of the gas during a particular base period.[19] LDCs would be subject to curtailments in their sales service, and perhaps also in their transportation service, from interstate pipelines.[20]

Title IV of the Natural Gas Policy Act of 1978 (NGPA) provides that the Secretary of Energy will from time to time prescribe rules that provide for curtailment of gas deliveries by interstate pipelines. The FERC will implement those rules. Because a pipeline is involved in delivering gas whether or not it is providing transportation or sales service, one possible interpretation of the term "gas deliveries" is that it includes pipeline transportation as well as sales service.

Title IV of the NGPA provides that the curtailment plans of interstate pipelines must give the highest priority of delivery to high-priority users, followed by essential agricultural uses, essential industrial processes, and feedstock uses.[21] A high priority user is any person who uses gas in a residence; uses less than 50 Mcf of gas on a peak day in a commercial establishment; uses gas in a school, hospital, or similar institution; or

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(Footnote continued from previous page)
giving gas producers an incentive to explore and develop new wells. In time, supply and demand would be brought back into balance. See Frederick Moring and M. Lisanne Crowley, "Issues for Gas Utilities in a Time of Deteriorating Wholesale Service," *Public Utilities Fortnightly*, 11 June 1987, 11-17.

[19] Many of the existing curtailment plans use base periods of the early to mid-1970s and are, hence, woefully out of date and of doubtful value for coping with a gas supply shortage in the 1980s or 1990s. See Moring and Crowley, "Issues for Gas Utilities," 15. Many high-priority and essential uses have come into existence and many have ceased to exist since the typical base period in the 1970s. Indeed, unless existing curtailment plans are updated, they are likely to aggravate any short-term market disequilibrium.

[20] As noted by Moring and Crowley and as applied in the 1970s, end-use curtailment policy left intact most pipeline transportation service while gas supply was being rationed. However, it is not clear that such would be the case in the 1980s and 1990s. It is possible, if not likely, that end-use curtailment plans would be applied to all low-priority gas uses, whether the gas is delivered by sales or transportation service. See Moring and Crowley, "Issues for Gas Utilities," 11-17.

[21] 15 U.S.C. sec. 3391-3394 (1982); 18 C.F.R. Part 281 (1986).

uses gas in any other use that the U.S. Secretary of Energy determines would endanger life, health, or maintenance of physical property if curtailed.

An essential agricultural use includes agricultural production, natural fiber production and processing, food processing, food quality maintenance, irrigation, pumping, and crop drying; or as process fuel or feed stock in the production of fertilizer, agricultural chemicals, animal feed, or food, which the U.S. Secretary of Agriculture determines is necessary for full food and fiber production. The Secretary of Agriculture will certify the natural gas requirements of persons for essential agricultural uses to meet full food and fiber production. To the extent that an alternative fuel is economically practicable and reasonably available, essential agricultural uses may be curtailed.

An essential industrial process and feedstock use means any use of gas in an industrial process or as a feedstock which the Secretary of Energy determines to be essential. The Secretary of Energy will certify the natural gas requirements of persons with essential industrial process and feedstock uses. Once again, to the extent that an alternative fuel is economically practicable and reasonably available, essential industrial process and feedstock uses may be curtailed.

An additional wrinkle in federal curtailment policy is caused by section 605 of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA section 605, also known as the "savers-keepers" provision, requires that if the FERC revises the base period of any curtailment plan, the volumes of gas which the LDC demonstrates were previously sold for a priority use and were conserved because of the implementation of the conservation measures are to be treated as still in use for the priority use in the newly revised base period. The provision defines conservation measures as any energy conservation measure implemented after the base-period year in the curtailment plan that was in effect when PURPA was created. In other words, if the base period in the curtailment plan in effect when PURPA was enacted was 1970, any conservation measure implemented after 1970 would fall under the "savers-keepers" provision.

The base periods of curtailment plans have not been revised since PURPA, so the "savers-keepers" provision has not yet been given effect. But it could be used as a wild card favoring those LDCs that have implemented conservation programs for priority uses and can demonstrate that their conservation measures qualify under this provision.[22] The FERC is assigned to determine what conservation provisions qualify for consideration and to develop methods by which volumes of conserved gas are to be quantified.[23]

No provision is made in the federal gas supply curtailment or pipeline allocation policies for priority pricing. Yet such pricing might provide the best indication of the extent to which various customers value their access to reliable sources of gas. Obviously, a customer who has an alternative fuel (whether that customer is a large industrial, commercial, or even a residential customer with the ability to burn fuel oil) will value reliable service less than a customer with no alternative but to use gas. Because most LDCs get a significant portion, if not all, of their gas supplies from interstate pipelines, an LDC will only receive its gas according to the above policies if there is a shortage of interstate pipeline capacity or gas supply.

Although the federal policies on allocating gas pipeline capacity and curtailing gas supply have a pervasive effect because interstate pipelines are usually upstream of LDCs, most (thirty-nine) state public utility commissions have prescribed emergency regulations governing utility service to customers during gas curtailments.[24] Curtailment plans are on file and in effect not only at most of these states commissions[25] but at several of

[22] According to the Conference Report the conserved gas must be the direct result of conservation measures implemented by the LDC. See H. R. Rep. No. 95-1750, 95th Cong., 2d sess., 113 (1978), hereinafter "PURPA Conference Report." Conservation measures implemented by customers on their own apparently do not count.

[23] Of course, developing a method to measure the quantity of gas conserved as a direct result of a conservation program can create its own set of problems. For example, how does one know that the gas would not have been conserved by the end-user without the program? Did the conservation measure have a perverse effect, such as encouraging additional consumption as a response to lower bills?

[24] See National Association of Regulatory Utility Commissioners, *1987 NARUC Annual Report on Utility and Carrier Regulation* (Washington, DC: NARUC, 1988), 512.

[25] The Ohio Public Utilities Commission has curtailment plans of its eight major gas companies on file, but they are all currently suspended. If shortages arise, they will be reactivated. Ibid., 674-75.

the state commissions that have not prescribed regulations concerning gas curtailments.[26] Most of these gas curtailment plans give the highest priority to protecting residential customers. Some also give high priority to "human needs" and small commercial customers.[27] One problem that can arise in state curtailment plans is that during prolonged shortages any mismatch between the federal curtailment policy and the state curtailment policy could result in an LDC receiving less gas than if there was no mismatch.

Furthermore, a 1988 NRRI survey showed that twenty-nine state commissions with gas transportation policies for LDCs provided curtailment services to transportation customers.[28] Twelve of these state commissions stated that their policy cannot have the effect of taking transportation gas and converting it into sales gas for high-priority users.[29] Although these commissions did not convert transportation gas into sales gas, Iowa and Washington curtailed the transportation gas by the same priority scheme as was in effect for sales gas curtailment. In Kentucky, firm sales have the highest priority, followed by firm transportation and interruptible sales. Interruptible transportation has the lowest priority.[30]

Fourteen of the commissions said that their curtailment policy for transportation service could have the effect of taking transportation gas and converting it to sales gas for the use of high-priority customers.[31]

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[26] Ibid. State commissions also report LDCs with gas curtailment plans in Arizona, Arkansas, Colorado, Maine, Massachusetts, South Dakota, Texas, and Washington.
[27] Ibid., 513.
[28] These commissions include those in Alabama, Arizona, California, Connecticut, Delaware, District of Columbia, Illinois, Iowa, Kentucky, Maryland, Massachusetts, Minnesota, Missouri, Montana, Nevada, New Jersey, New York, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Rhode Island, South Dakota, Utah, Virginia, Washington, Wisconsin, and Wyoming. Michigan had such a policy under consideration at the time. See Burns et al., *State Gas Transportation Policies*, 30.
[29] These state commissions are those in Alabama, Arizona, District of Columbia, Illinois, Iowa, Kentucky, Massachusetts, Minnesota, New York, North Carolina, and Washington.
[30] Burns et al., *State Gas Transportation Policies*, 31-32.
[31] These commissions include those in California, Maryland, Missouri, Montana, New Jersey, North Dakota, Ohio, Oregon, Pennsylvania, Rhode Island, Utah, Virginia, and Wisconsin, and Wyoming.

Curtailment then occurs in the order of set priority charges, with transportation customers paying the lowest charges and facing curtailment first. In California, for example, in the event of a supply shortage transportation gas can be diverted to core use, but only if the California Commission decides that core customer curtailment is imminent. The Missouri Commission has a special provision for dealing with gas supply emergencies that allows the LDC to defer delivery of a customer's transportation gas where the unavailability of gas may imperil human life or health. Other commissions have similar provisions to protect high-priority customers.[32]

The topics of pipeline allocation and supply curtailments are addressed at both the federal and state levels. However, because there is some uncertainty over how federal and state policies would actually operate in concert during times of a transportation capacity or gas supply shortage, LDCs might be discouraged somewhat from taking full advantage of current wellhead producer supply opportunities. Even if the LDC could acquire reliable supplies from the producer, there is a question of whether the LDC could actually receive its contracted-for gas during times of shortages.

Clarifying LDCs' Obligation to Serve

State regulators might wish to reexamine the LDCs' obligation to serve. Traditionally, an LDC has an obligation to serve all of the customers within its franchised service area. However, the recent adoption of state gas transportation policies for LDCs transporting gas to their former sales customers raises the issue of whether the LDC has an obligation to provide sales service to these customers should they be unable to buy gas on the spot market, should the producer from whom they made a direct gas purchase default, or should they be unable to arrange for transportation of the gas to the LDC's city gate. It is important for an LDC to have clear guidance from its state regulators as to whether it has an obligation to serve these customers, and if so under what conditions or circumstances. Without such guidance, an LDC will find it difficult, if not impossible, to engage in a

[32] Burns et al., *State Gas Transportation Policies*, 31-32.

least-cost gas procurement program that assures reliability to its current sales customers.

In a 1988 survey, the NRRI found that twenty commissions require LDCs, because of their obligation to serve, to provide transportation customers who were formerly firm or interruptible sales customers with traditional utility sales services if those customers wanted to return to the LDC's system as regular customers.[33] However, eighteen state commissions also allow their LDCs to charge a transportation customer a standby or reservation charge. Such a charge would entitle an end-user to return to the system supply whenever it found it advantageous to do so. These reservation or standby charges are calculated by a variety of methods, but in all cases are cost-based.[34]

Many would contend that those noncore customers that have switched to transportation from sales service have opted out of the regulatory compact and that the LDC no longer has any obligation to serve them unless they pay a standby or reservation charge for the service. To do otherwise places the LDC in the difficult position of needing to have an option to acquire gas for those customers *in case* they return to the system. Not only would this make least-cost purchasing consistent with obtaining reliable gas sources more difficult, but it would unnecessarily compromise the reliability of the customers remaining on the system, namely the core customers who have no other option and the noncore customers who elect to remain on the system.

A public policy which allows noncore customers to return to buy sales gas from the LDC or is "soft" about allowing transportation customers to return without paying a reservation or standby fee invites strategic gaming on the part of the noncore customers. While today there are abundant and relatively low priced gas supplies available, the gas market might become tighter and more expensive, or pipeline capacity might become constrained. Without a clearly stated state policy, when a situation arises where these customers wish to return to the system for cheaper or more reliable sources of gas, a state commission might find it difficult to say "no" due to the

[33] Ibid., 50-51.
[34] Ibid., 51-53.

potential dire economic and political consequences of such an action. Yet, if there is a clearly articulated state commission policy well in advance, noncore customers will know what the rules are and may be less inclined toward strategic gaming.

Concerns about the Enforceability of Contracts

The enforceability of the underlying direct gas purchase contract can affect the reliability of the gas supply.[35] This is the case with direct gas purchase contracts, whether they are short- or long-term, because there is no statutory obligation to serve under a contract between the LDC and the producer. Both parties, the producer and the LDC, are relying solely on contract remedies to ensure that neither defaults. Such a reliance solely on contract remedies to ensure reliability should be a concern to the state public service commission as well as to the LDC. There are two concerns: contract default and bankruptcy. State public service commissions may wish to review the contracting procedures of LDCs to make certain that these concerns are adequately addressed.[36]

Strategies for Avoiding Contract Default

A gas producer may have an incentive to breach a contract if the terms of the contract provided for a price that is well below the current market price of gas, particularly if the contract price does not cover the producer's variable costs nor provides an adequate return on its investment.

[35] The objective of the authors in this section is not to provide a detailed legal treatise but to provide a broad overview of the reliability problems that can be associated with direct gas purchase contracts and to provide some practical strategies for addressing those problems.

[36] Such a review of contracting procedures need not necessarily be in an adversarial setting, particularly since the objective of the commission in such a review would not be a finding of prudence or imprudence. Instead, the commission would be attempting to influence the LDC's contracting procedures prospectively in order to avoid contracting pitfalls that might compromise gas supply reliability. Several nonadversarial administrative procedures which would be available for such a review are described and discussed in Robert E. Burns, *Administrative Procedures for Proactive Regulation* (Columbus, Ohio: The National Regulatory Research Institute, 1988).

When this is the case, the producer has every incentive to find another buyer who is willing to pay the current market price, particularly if it can get a premium over the spot market price. Such a situation is most likely to occur in a tight market. In case of such a breach, because the LDC has a duty to mitigate damages the best the LDC can hope for is to recover the market price of gas, which is likely to be the spot market price. The producer comes out ahead by finding a new contract partner that will pay the market price, and the LDC loses a reliable gas supply source and may have to purchase more expensive gas on the spot market.

There are two approaches that can be used to prevent a breach of contract. One is to create a disincentive for breaching the contract. The most common contractual provision that is used to create such a disincentive is the liquidated damages clause. Such a clause allows the parties to determine in advance the damages in case of a breach. In negotiating the contract, the LDC might argue in favor of a liquidated damages clause that includes damages to cover the projected spot market price of the gas, all incidental transaction costs, and a premium to reflect the value of reliability. If set at such a level, all of the LDC's direct and consequential damages, including transaction costs and the implicit cost of having to rely on a less reliable gas source, could be covered. However, a liquidated damages clause might not be acceptable to the producer.

The second approach is to draft the direct gas purchase contract in such a way as to leave little or no incentive to breach. Here certain lessons can be learned from the experiences of electric utilities with long-term coal contracts.[37] A producer is less likely to breach a contract if the producer is guaranteed its costs, including an adequate return on its investment. One method of achieving this is either to provide the producer with a cost-plus contract or a base-price-plus-escalator contract. In a cost-plus contract, the buyer agrees to pay the producer its variable cost

[37] For more information on long-term coal contracts, see Gary L. Underwood, "Utilities and Long-Term Coal Agreements," *Public Utilities Fortnightly*, 20 July 1989, 32-7; and David M. Weinstein, "Efficiency in Contracting for Coal: How to Reduce Cost and Avoid Litigation," *Public Utilities Fortnightly*, 31 August 1989, 18-21.

plus an agreed-upon profit. However, this type of contract does not provide the producer with an adequate incentive to minimize its costs.

A better approach is a base-price-plus-escalator contract. Historically, escalator provisions in gas contracts were either oil parity clauses or most-favored-nation clauses. Neither type of escalator clause bore any rational relationship to the producers' costs. As such, they resulted in contract prices that bore no relationship to the producers' costs and were grossly "out of sync" with the market. A more rational approach is to fix the initial base price on the current market, taking into consideration the actual production costs, with some premium reflecting what the LDC is willing to pay to have a reliable producer. Then this base price would be adjusted according to an escalator reflecting changing economic conditions of wage rates, supplies and materials, taxes, other production costs, and regulatory changes. The escalator provision might operate using government or industry indices, or by actually auditing the changes of the producer. The use of indices is probably preferable because it gives producers a better incentive to keep their cost down as they try to "beat" the indices.

The one major problem with this approach is that it does not provide the LDC with a market-out if the market significantly slackens after the long-term contract is signed. There is also the possibility that if the market tightens, the producer will still have an incentive to breach the contract and take advantage of the higher market price, assuming that a liquidated-damages clause has not eliminated this incentive. In either instance, the LDC might wish to better assure reliability at the lowest cost by negotiating contract provisions that are tied to the market price.

There are several types of contract provisions that can be tied to market price. The most straightforward (and rarely used) approach is to have a contract provision that ties the price of gas directly to the market price. The market price can be specified as the spot price of gas from particular regions. However, use of this type of contract provision gives the producer no premium over what it could get by selling on the spot market and, hence, no disincentive to sell on the spot market. While a premium could be added to such contract provisions so that the price would be, say, 105 percent of the spot market price of Louisiana gas, it might be more attractive from the LDC's point of view to have a contract provision that provides for periodic, scheduled price adjustments tied to the market price. Such a contract provision could readjust the price for gas to a percentage of the current market price of gas at scheduled periods. This would provide the LDC with a gas supply with greater price stability than if the price followed the day-to-day or month-to-month market price.

It is also conceivable that price ceiling provision in a direct gas purchase contract could have some merit. Such a provision might be tied to the price of number 6 fuel oil. Recall that historically, oil parity contract provisions were used to tie the price of gas to number 6 or number 2 fuel oil. A price ceiling provision would differ by preventing the contract price of gas from going higher than that price. A price ceiling provision could be workable for an LDC if the gas contract were meant to provide gas supplies to industrial or other customers that have fuel switching capabilities.

A final step is to draft the contract in such a way that the means for breaking the contract are well defined. In particular, the parties to the contract should draft contractual provisions that define the situations under which *force majeure* would act to terminate the contract.

Avoiding the Perils of Bankruptcy

Even if the appropriate steps mentioned above are taken, they may be ineffective if the producer goes into bankruptcy. As far as an LDC is concerned, the effect of a producer's bankruptcy is to lessen the reliability of the gas supply. This is because the trustee in bankruptcy, typically appointed by the bankruptcy court, has the authority to repudiate executory contracts[38] if he believes that fulfilling the contract is not in the best interest of the bankrupt producer. If the trustee repudiates an executory contract, the LDC has no legal recourse. A gas purchase contract

[38] An executory contract is one which has not yet been performed or executed, which remains to be carried into operation or effect, is incomplete, or depends on a future performance by either party.

typically would be an executory contract, because the LDC does not pay the producer for gas until it is received.[39]

Even if the LDC acquired some vested right beyond that of a party to an executory contract, producers in many states typically have not acquired full title to the gas until it is taken out of the ground.[40] If this is so, it would be nearly impossible to enforce a legal claim for gas which the producer does not yet own. Thus, if a producer goes into bankruptcy, there is little likelihood the LDC can depend on it to be a reliable source of gas unless the trustee in bankruptcy finds the contract favorable to the producer.

The best way to avoid the difficulties of bankruptcy is to buy from producers that are financially secure. Information about the fiancial conditions of publicly held producers can be obtained from annual reports, Securities and Exchange Commission 10-K reports, and other financial publications. While similar information about privately owned (typically small independent) producers may not be as readily available, an LDC seeking a direct gas purchase contract should seek similar types of verifiable financial information.

[39] An interesting issue would be whether delivery of gas previously paid for but not taken under a take-or-pay provision could be repudiated. Such gas is more likely to be considered an outstanding liability, albeit unsecured.

[40] While the authors do not intend to go into a lengthy legal discourse on theories of oil and gas property, note that in some states oil and gas are subject to capture by adjoining landowners. In other words, landowners over a common pool gain full title to the gas only when they capture it by bringing it to the surface. More common and sensible is the correlative-rights approach. In correlative-rights states, a state agency regulates the production of natural gas under its police powers. In order to avoid wasteful production and inequities, owners of a common pool each are provided with an opportunity to extract their share of the gas. The state agency determines the rightful share. A more difficult question is what happens if a producer fails to take advantage of the opportunity of extracting its rightful share.

CHAPTER 6

CONCLUSIONS

This study has analyzed the supply reliability and cost implications of direct purchases and state regulatory options in enhancing the use of direct purchases by an LDC as a part of its gas procurement strategy. This study concludes that the use of direct gas purchases has certain short-term cost advantages to an LDC as compared to its traditional mode of gas procurement--long-term purchases from pipelines. But most short-term advantages and limitations associated with direct purchases are transitory. It turns out the most important effects of direct purchases are the enhancement of gas supply reliability resulting from more responsive gas production and transportation responses, and the added flexibility of including spot gas purchases in an LDC's supply portfolio.

Apparently, the development of a competitive and responsive gas market cannot be made possible solely by an increase in the use of direct purchases by LDCs. Deregulation of wellhead gas prices and the continuing trend toward open access to pipeline facilities may play a more prominent role. In a sense, the increase in the amount of gas directly purchased by LDCs is the result of wellhead price deregulation and wide availability of access to gas transportation facilities. But there are certainly some feedback effects from the increase of direct purchases on the evolution of a competitive gas market.

An examination of three gas demand and supply projections prepared by the federal government and the gas industry suggests a relatively stable gas market with readily available gas supply to meet increasing demand for the next ten to twenty years. But the amount of gas supply surplus will be reduced gradually and some regional gas supply shortfalls may happen due to the insufficient transportation capacity available to transport large amounts of gas produced outside of these regions.

A projected balanced gas market is likely to strengthen the growing trend of using direct purchase by LDCs. A balanced gas market tends to keep the price in the spot market lower than that obtainable through pipeline contracts. Additionally, the relatively stable gas supply affords end-users ample opportunities to "shop around" among alternative gas supply sources, and keeps the strong interest of state regulators in instituting stringent gas purchase requirements and policies favorable to transportation-only service at the distribution level. With such strong economic and regulatory incentives, the use of direct purchase as a part of an LDC's overall gas supply portfolio is expected to continue.

The primary cost advantages of direct gas purchase by an LDC are the access to low-cost gas supplies in the spot market and the opportunity to build a new supply portfolio consisting mainly of new gas supply contracts, which are more in tune with current gas demand and supply conditions. As for the limitations of direct purchases, a typical LDC's experience and knowledge about such purchases (especially long-term contract purchases) are generally less than those of a typical pipeline. However, the cost advantages and limitations in terms of knowledge and experience are expected to be narrowed or eliminated over time. One possible long-term limitation of direct purchase by an LDC is that its amount of gas purchases are smaller and supplied by fewer gas producers than those of a typical pipeline supply portfolio. Thus, the benefits of volume purchase discounts and diversification of supplies are not available to an LDC for the amount of gas it purchased directly.

The supply reliability consequences of direct gas purchases by an LDC can be analyzed in three aspects: as a single gas procurement transaction, as a part of the total supply portfolio, and in the context of overall gas market responses in adding gas supplies and transportation capacity. A direct purchase, whether a spot market purchase or a long-term contract with a wellhead producer directly, is less reliable than a long-term purchase contract with a pipeline supplier because of the differences in contract provisions governing supply assurance, contract duration, and possible constraints for LDCs in obtaining transportation services, backup service, and scheduling of gas delivery.

If direct purchase is viewed as a part of an LDC's overall supply portfolio, especially when it is aimed primarily at providing gas to noncore customers who have alternative sources of gas or fuel supply, any reliability concerns of directly purchased gas can be offset by the added flexibility and cost advantages of incorporating directly purchased gas into an LDC's supply portfolio. In building a gas supply portfolio, the use of direct gas purchase can become a useful competitive tool for an LDC in maintaining its gas market share.

The reliability of an LDC's gas supply portfolio is affected not only by its own procurement decisions but by the overall gas production in the field and the availability of transportation facilities to deliver it. As the experience of the gas shortage in the 1970s shows, if an overall gas production and transportation capacity shortfall occurs, the instances of supply interruption or high gas cost as a result of gas shortage are probably inevitable regardless of an LDC's supply procurement strategies. So the gas market responses to the increase in the amount of gas purchased directly by LDCs or other structural changes brought about by direct purchases have significant supply reliability implications even though an individual LDC's procurement decision may have little, if any, influence on the market availability of gas production and transportation capacity. In this respect, direct gas purchases can have several positive influences, such as inducing more pipelines to become open-access transporters, providing spot market price signals that are more indicative than long-term contract prices about any future imbalances of gas demand and supply in the market, and pooling gas demands and production of small LDCs and producers which under certain circumstances has the effect of encouraging development of larger gas wells and the addition of new transportation facilities.

This study also contains the findings of a 1989 NRRI survey on state oversight of direct gas purchases. A large majority of states have some oversight of LDC direct gas purchases. Most of the oversight is conducted through the use of established procedures such as purchased gas adjustment (PGA) or rate case review. Other procedures--prudence review, gas purchase incentives, and direct risk assessment of gas supply portfolio which deals specifically with direct purchases--are less common. Three additional oversight options which are being considered by a few states at the present time may also have significant implications in assuring reliable gas supply. They are the reconciliation of state and federal gas curtailment policies, the clarification of LDCs' obligation to serve to various groups of customers, and a closer examination of gas purchase contract enforceability.

There are several areas for future study on the subject of direct gas purchases by LDCs. Identification and analysis of alternative direct purchase mechanisms is one area. Establishment of a gas futures market, the use of competitive bidding to solicit potential gas suppliers and gas transporters, and the use of gas storage as a part of gas supply portfolio are examples of new gas supply procurement practices.

The interactions of federal and state gas transportation regulations is another area of great interest. For example, the federal requirement of nondiscriminatory transportation access might not be completely compatible with the state's gas supply and transportation curtailment policies. A third area for future study is the empirical investigation of the trend and extent of LDCs' experience in purchasing gas directly. Some interesting topics include the characteristics of LDCs that are more inclined to use direct gas purchase and the eventual cost effects on the end-users as a result of increasing use of direct purchase.

APPENDIX

A SUMMARY OF STATE REGULATORY OVERSIGHT ON DIRECT GAS PURCHASES BY LOCAL DISTRIBUTION COMPANIES

Gas Supply Reliability Survey Questionnaire

As one of its Board approved projects for 1989, the National Regulatory Research Institute is studying gas supply reliability. We are interested in what problems, if any, local distributors have encountered in the new, changing environment being encouraged by the FERC and what state commissions could do to help insure an optimal cost-reliability trade-off for LDC gas service.

As part of this project, we are compiling current information on state commission oversight of direct gas purchases by LDCs from producers. Would you mind if we asked some questions about your commission's policies? We would be happy to send you a copy of the final report.

NAME, TITLE, MAILING ADDRESS, TELEPHONE NUMBER OF RESPONDENT:

Contact time: 1st ________ 2nd ________ 3rd ________

QUESTIONS

1. What is the general nature of the process used by your Commission to review direct gas purchase contracts between a local distribution company under your jurisdiction and a gas producer?

    a. Are the contracts reviewed by your Commission? Yes ____ No ____ If not, by any other agency? Yes ____ No ____ Name of agency: ________________________________.

    b. Are the contracts reviewed as a part of a purchased gas adjustment proceeding? Yes ____ No ____ If so, how frequently? ____________________

    c. Are the contracts reviewed as a part of a general rate case? Yes ____ No ____

d. Are the contracts reviewed periodically by Commission staff members?
Yes ____ No ____ When?

____

____

e. Are the contracts reviewed periodically by outside auditors?
Yes ____ No ____ When?

____

____

____

f. Are the contracts approved in advance by your Commission?
Yes ____ No ____ If so, please describe the approval process briefly.

g. Are your Commission's procedures different if the producer is affiliated with the distributor? Yes ____ No ____ If so, how?

2. Have any purchased gas adjustment procedures used by your Commission been modified because of the increasing importance of direct gas contracts? Yes ____ No ____ Do you anticipate any such change? Yes ____ No ____ Please describe briefly.

3. Is there any requirement for a distributor to show that its direct gas purchases or lack thereof are an effective part of an overall least-cost gas purchasing policy? Yes ____ No ____ Please describe briefly.

4. Are prices or other terms of direct gas contracts subject to a prudence or prudence type review? Yes ____ No ____ If so, briefly describe the circumstances and results of a recent review, if any.

5. Does your Commission include in its review any assessment of the riskiness of a distributor's contracts? This might take the form, for example, of a comparison of the riskiness of long-term contracts, perhaps containing a requirement for a minimum volume to be purchased, versus that of shorter term contracts, such as those for spot market gas. Yes ____ No ____

6. Does the purchased gas adjustment procedure used by your Commission contain any specific features intended to create an incentive for efficient gas purchasing and supply planning? Yes ____ No ____ Please describe briefly any feature that creates an incentive or disincentive, in your opinion.

7. Do you have any insights about regulatory review of direct gas purchase contracts that you would like to share with other commissions? A policy or procedure that has worked well, for instance. Yes ____ No ____

8. Could you please provide us with some information about the two largest LDCs in your state?

   Name:

   Volume:

   Principal pipeline suppliers:

   Contact person:

Current Status of Major Oversight Options

This section includes a commission-by-commission summary of the direct gas purchase oversight procedures currently in use at the public service commissions. It is presented as a guide for readers interested in the procedures used by certain commissions and contains additional detail to supplement the discussion in chapter 3. The descriptions contained herein are based on the first series of questions on the survey form. They are drawn from notes taken on the staff members' answers to those questions and also include any additional information that the respondents oftentimes provided.

The following state commission staff members were the respondents for the telephone survey on state commission oversight of direct gas purchases conducted by the NRRI during April and May 1989. The authors would like to thank them for taking the time to answer the questions. They are: Robert Reed, Alabama PSC; Steve Pratt, Alaska PUC; Rick Kauffman, Arizona CC; Gail Jones, Arkansas PSC; Mac McCay, California PUC; Dick Carlson, Colorado PUC; Jeff Honcharik, Connecticut DPUC, Mike Tischer, Delaware PSC; Thomas Redmond, District of Columbia PSC; Wayne Makin, Florida PSC; Jim Cole, Georgia PSC; Dave Schunke, Idaho PUC; Tom Kennedy, Illinois CC; Lucy Downton, Indiana URC; Bill Adams, Iowa SUB; Joe Williams, Kansas CC; Leah Faulkner, Kentucky PSC; Roy Edwards, Louisiana PSC; Dave DiProfio, Maine PUC; Chuck Kruft, Maryland PSC; Barbara Kates-Garnick, Massachusetts DPU; Gary Kitts, Michigan PSC; Stuart Mitchell, Minnesota PUC; Keith Howle, Mississippi PSC; Bo Matisziw, Missouri PSC; Dan Elliott, Montana PSC; Michael Greedy, Nevada PSC; George McCluskey, New Hampshire PUC; Robert Nottingham, New Jersey BPU; Philip Baca, New Mexico PSC; Ronald Streeter, New York State Department of Public Service; Ray Nery, North Carolina UC; Wallace Owen, North Dakota PSC; Marcy Kotting, PUC of Ohio; Jimmy Crosslin, Oklahoma CC; Gerald Lundeen, Oregon PUC; Vernon Chandler, Pennsylvania PUC; Steve Scialabba, Rhode Island PUC; Jim Stites, South Carolina PSC; Dave Jacobson, South Dakota PUC; Hal Novak, Tennessee PSC; Tym Seay, Railroad Commission of Texas; Darrell Hanson, Utah DPU; Kathleen Fleury, Vermont PSB; Cody Walker, Virginia SCC; Ken Elgin, Washington UTC; Byron Harris, West Virginia PSC; Marc Nielsen, PSC of Wisconsin; and Alex Eliopulos, Wyoming PSC.

Alabama:

The Public Service Commission (PSC) reviews the contract itself. Prices and quantities are nominated monthly, but the PSC has not found it helpful to review those data. Thus the Commission also reviews purchasing procedures every month, including what the local distribution company (LDC) turned down and what the LDC was offered, to be sure that each distributor is buying the cheapest, most reliable gas. If the LDC is not buying the cheapest gas, the Commission tries to determine why. Contracts are not reviewed in purchased gas adjustment (PGA) proceedings or rate cases. Staff does review contracts periodically, reviewing purchasing practices each month. The Commission monitors the price that the LDC is paying each producer and checks this against the contract if there appears to be an aberration. Contracts are not reviewed periodically by outside auditors and are not approved in advance by the Commission. While procedures are not technically different if the producer is affiliated with the distributor, contracts in those cases are studied more aggressively.

Alaska:

Each direct purchase contract is filed with the Public Utilities Commission (PUC), which then reviews it for reasonableness. The PUC then approves it with or without modifications or rejects it. Contracts are reviewed in PGA proceedings, about every six years for major gas purchases. The agreements are not reviewed in rate cases. Contracts are examined by PUC staff when a new agreement is executed and filed with the Commission. Contracts are not reviewed by outside auditors, but are approved in advance by the PUC. Procedures do not differ if the producer and the LDC are affiliated. The PUC has not faced this situation.

Arizona:

Contracts are reviewed by the Corporation Commission on an ad hoc basis in the case of an audit for a rate case or an audit requested for a PGA. There is no specific review policy. Contracts are not normally reviewed as part of a purchased gas adjustment proceeding. The only source of supply in the past was El Paso Natural Gas, an interstate pipeline. There has been very little direct purchase activity until recently. Contracts are not reviewed as part of a general rate case, and are not reviewed periodically by staff or outside auditors. Contracts are not approved in advance by the Commission. Procedures do not differ if the producer and distributor are affiliated. The Commission approaches this issue as it arises, and has no set policy.

Arkansas:

The Public Service Commission (PSC) examines some contracts, especially if affiliated interests are involved. No specific findings have been made. The Commission conducts compliance audits of purchased gas adjustments, but there are no PGA proceedings. Contracts are reviewed as part of a general rate case. The agreements are reviewed by Commission staff in the compliance audits every eighteen months, but are not reviewed by outside auditors and are not approved in advance by the PSC. Procedures do not differ if the producer and distributor are affiliated, as almost all LDC contracts are with producers. Distributors are affiliated with producers, and there are few purchases by LDCs from pipelines.

California:

Some contracts are reviewed; all can be depending upon what the Public Utilities Commission (PUC) staff wants to examine. No complaints have been lodged against specific contracts. The PUC sets broad guidelines, such as maximize reliability at the lowest cost, and leaves it to the LDC management to follow these guidelines. The Commission conducts annual prudence reviews. The LDC can submit any new contract of over five years duration for Commission approval if it wishes to do so. Contracts are reviewed annually in PGA proceedings, but are not reviewed in general rate cases. Contracts are reviewed by PUC staff as part of the PGA proceeding. Contracts are not reviewed by outside auditors. Some contracts are approved in advance by the PUC, although not recently. The only agreements approved have been service agreements with interstate pipelines. Procedures do not differ if the producer and distributor are affiliated. The PUC usually is concerned if the interstate pipeline supplier is affiliated with the LDC.

Colorado:

Contracts are reviewed by the Public Utilities Commission (PUC), mainly the contracts involving Public Service Company, the largest LDC. Most gas supply is purchased from pipelines and there is a minimum of direct gas contracts. The PUC has not audited contracts in the past unless they appeared out of line with the spot market. The Commission would not question anything that did not differ greatly from pipeline tariff rates. Contracts are reviewed in PGA proceedings. The PUC verifies the contracts, but not to verify that the contract price was the best price. The Commission has annual hearings and also reviews quarterly reports from the major LDC. The contracts would be examined in rate cases although some companies have not had a case in years because of gas cost adjustment/purchased gas adjustment (GCA-PGA) clauses. Contracts are reviewed periodically by staff, although the PUC does not examine each contract. Contracts are not reviewed by outside auditors and are not approved in advance by the PUC. If the producer and the LDC are affiliated, the Commission would examine the contract more closely.

Connecticut:

There are two forms of contract review: a monthly PGA dealing with spot purchases and monthly short-term contracts, and a rate case in which long-term firm contracts are reviewed. The Department of Public Utility Control (DPUC) gives the LDC a free hand to analyze and take the appropriate least-cost contract. The Department then reviews and has a prudence investigation if it feels that something is wrong. Contracts are reviewed in PGA proceedings. There is a monthly administrative review and there are also quarterly hearings in which the DPUC issues a decision for the previous quarter. Contracts are reviewed by staff. The LDCs file the contracts and staff reviews them as they are submitted. Contracts are not reviewed by outside auditors, and are not approved in advance by the DPUC. Procedures do not differ if the producer and distributor are affiliated.

Delaware:

Some contracts have been reviewed. There is no institutionalized review and not all contracts are reviewed. There is a docket pending on how to deal with gas cost assignment. Contracts could be reviewed in PGA proceedings. Staff reserves the right to review. This issue is being considered in a current case involving Delmarva Power & Light. PGAs are projected. The Public Service Commission (PSC) considers the projected figures and then the costs incurred are reviewed. PGA proceedings are held annually for some LDCs, semiannually for others. Contracts could perhaps be reviewed in a rate case. Contracts are not reviewed by outside auditors, although the PSC does retain consulting firms to assist staff in various matters. Contracts are not approved in advance by the Commission. If the LDC and the producer are affiliated, the PSC examines those transactions more closely.

District of Columbia:

The Public Service Commission (PSC) has not directly reviewed contracts. In a proceeding in 1988, the Office of People's Counsel suggested that the PSC review each contract, but no decision has been made yet. There is an annual procedure in which the LDC files a gas procurement report, outlining quantities, purchases, and prices paid for the past year. Contracts are not reviewed directly in PGA proceedings. In a rate case, however, if a question about costs arises, they would be examined. They might also be examined when the PSC receives the annual gas procurement report. Contracts could be reviewed in a rate case, but not necessarily. They would be if there were some concern on the part of staff about cost or quantity. Other policies have an impact on this also, such as least-cost planning. At some point, the contracts would be examined. Contracts are not reviewed periodically by outside auditors and are not approved in advance by the PSC. Procedures do not differ if the producer and distributor are affiliated. Washington Gas Light has some affiliated production, but it does not use much of it for system supply.

Florida:

There are no contracts to be reviewed yet. Florida Gas Transmission pipeline just filed for open access, one of the last pipelines to do so. Contracts will be reviewed in PGA proceedings. Fuel related costs will not be in the rate base. Fuel costs are separated and any adjustments are then made based on the cost of fuel. Contracts will be reviewed periodically by Public Service Commission (PSC) staff, but it is too soon to tell if outside auditors will review the contracts. The PSC has not decided whether or not to approve the contracts in advance. Procedures to handle situations in which the producer and the LDC are affiliated have not been established yet.

Georgia:

Contracts are not reviewed by the Public Service Commission (PSC), although nothing prohibits the Commission from taking action. Review could be made part of a PGA audit. Contracts are not reviewed in PGA proceedings. There is an automatic adjustment, but the PSC could use a proceeding on the recommendation of the staff. Contracts are not reviewed in rate cases.

Proficiency in the new gas market environment is becoming a large issue raised by industrial customers. This is being examined in a separate docket item: gas purchasing practices. Contracts are not reviewed periodically by PSC staff. Contracts are not reviewed periodically by outside auditors although as part of the gas purchasing practices docket, the PSC has a consultant under contract. The consultant is examining Atlanta Gas' gas purchasing practices. The PSC might allow the consultant to develop criteria that the staff could then use in subsequent cases. Contracts are not approved in advance by the PSC. Commission procedures do not differ if the LDC and the producer are affiliated.

Idaho:

The Public Utilities Commission (PUC) has the authority, but it has not reviewed any contracts. Direct purchase was not an issue until very recently. The two LDCs in Idaho took gas only from Northwest Pipeline until recently. The Commission has not reviewed any contracts. It has initiated a proceeding to review gas purchasing, reasonableness, cost, and reliability. It is yet to be seen if contracts will be reviewed in PGA proceedings. The investigation underway is part of a rate case. The PUC does not know of any LDCs in Idaho that are affiliated with producers.

Illinois:

There is an annual PGA reconciliation during which the Commerce Commission (ICC) considers prudence. Contracts are reviewed but the ICC does not approve them. Contracts are not normally reviewed in rate cases as costs flow through the PGA. Contracts are not reviewed periodically by ICC staff. They are filed with monthly PGAs, but the Commission does not approve or disapprove them. Contracts are reviewed periodically by outside auditors. Management audits of the LDCs are conducted periodically at the discretion of the Commission. Contracts are not approved in advance by the ICC and procedures do not differ if the producer and the LDC are affiliated.

Indiana:

The Utility Regulatory Commission (URC) does not review contracts. It does review LDC gas cost invoices and other documents through quarterly gas cost adjustment filings. Contracts are not reviewed in PGA proceedings, and are not technically reviewed in rate cases. The URC obtains the contracts for information purposes only. Contracts are not reviewed periodically by Commission staff or outside auditors. Contracts are not approved in advance by the URC and procedures do not differ if the LDC and the producer are affiliated.

Iowa:

Contracts are reviewed after the fact as part of the State Utilities Board's (SUB) annual review of gas procurement (ARG). They are filed by the LDC and open for review. Contracts are reviewed prospectively as part of the ARG process. Contracts are not normally reviewed as part of a rate case, but they may be. Contracts are reviewed periodically by staff (in the ARG). Contracts are not reviewed periodically by outside auditors and are not approved in advance by the Board. Procedures do not differ if the LDC and the producer are affiliated.

Kansas:

Contracts are submitted to and reviewed by the Corporation Commission for price information. There have been no supply problems for many years. Contracts are not reviewed in PGA proceedings. PGA cases are monthly. PGAs are infrequently audited to examine what is being included and to determine whether what is included conforms with regulations. There are neither company-specific hearings, nor gas cost-specific proceedings. The expenses associated with contracts are reviewed in rate cases, but no contract-by-contract review. Individual contracts are reviewed by Commission staff when someone makes a case for a review. There are usually no planned general reviews. Contracts are not reviewed periodically by outside auditors and are not approved in advance by the Commission. They are submitted for informational purposes, not for approval. However, they may be disapproved later if shown to be imprudent. Procedures do not differ if the LDC and the producer are affiliated. The Commission does not probe into affiliated transactions.

Kentucky:

The Public Service Commission (PSC) requires contracts to be filed along with the PGA, including prices of long-term and spot contracts. Contracts are available for review and are likely to be reviewed in a rate case. Contracts are reviewed in PGA proceedings, quarterly for large companies. Contracts are reviewed quarterly by staff. Contracts are not reviewed by outside auditors and are not approved in advance by the PSC. If the producer and the LDC are affiliated, oversight is more strenuous and more is required in terms of reasonableness of price.

Louisiana:

Contracts are not reviewed by the Public Service Commission (PSC). When calculating the PGA, the PSC only examines the price that the LDC pays. Most LDCs buy from United Gas Pipeline. Contracts are not reviewed in purchased gas adjustment proceedings. The PSC reviews the Federal Energy Regulatory Commission (FERC) decisions that indicate what can be charged. Contracts are not reviewed as part of a general rate case and are not reviewed periodically by PSC staff. Contracts are not reviewed periodically by outside auditors and are not approved in advance by the Commission. Procedures do not differ if the LDC and the producer are affiliated.

Maine:

Initial contracts for new supplies are reviewed by the Public Utilities Commission (PUC). Every six months there is a cost of gas adjustment. The PUC examines the average cost of gas and reviews supplies to determine if the cost of gas is the lowest possible. There is one LDC (Northern Utilities) with a transmission subsidiary (Granite State). The PUC has no jurisdiction to review contracts between Granite State and producers. It does oversee Granite State and Northern Utilities. Contracts are not reviewed as part of a purchased gas adjustment proceeding. The initial contracts are reviewed separately. Contracts could be reviewed in a rate case but they would probably not be if no problem has arisen. The PUC does reserve the right to examine anything that has been previously approved. Initial contracts are reviewed by PUC staff. If changes are made in the contracts those changes are reviewed in the PGA. Contracts are not reviewed periodically by outside auditors. Initial contracts are approved in advance by the PUC. The LDC must submit the contract approximately ninety days before it is to take effect. Procedures differ if the LDC and the producer are affiliated. The PUC only has the approval authority for contracts between Northern Utilities and Granite State because they are affiliated. If the LDC was affiliated with a producer, there would be the same approval process.

Maryland:

Each month each LDC sends a summary of purchases to the Public Service Commission (PSC). There are semiannual review hearings, and PGA review hearings include spot prices. Contracts are reviewed as a part of a PGA proceeding at least every six months. Contracts are not reviewed as part of a rate case. Contracts are reviewed by staff in the PGA and monthly reviews of spot purchases. Contracts are not reviewed by outside auditors, although the PSC recently had an outside consultant examine the procurement plans of the LDCs. LDCs will have to submit annual procurement plans. This will be a qualitative review. Contracts are not approved in advance by the PSC. Spot purchases are not preapproved. An old order from the early 1980s had specified that contracts had to be reviewed, but the PSC waived this requirement for spot purchases. Procedures do not differ if the producer and the LDC are affiliated; the hearings are not any different.

Massachusetts:

The Department of Public Utilities (DPU) has no procedure. The Department does not review supply plans directly. It does examine gas costs, but there is no direct review of purchases. There is a cost of gas adjustment procedure (CGAC). Starting at the beginning of the period, projections are made for the following twelve months. There are two seasons: November to April and May to October (peak and off-peak). Six-month factors are calculated and these cannot be changed during the six-month period. The LDC tries to recover all of its costs by October. There is an annual reconciliation on November 1. Any overcollection or undercollection is rolled into the following year's rates. In a rate case, the LDC must discuss its supply planning and its efforts to lower costs. The LDC does not submit its contracts. When a company files a rate case, the details of its gas dispatching procedures are examined. The Energy Facilities Siting Council considers procurement and supply-demand projections. In 1981 there was a supply shortage in Massachusetts because of the failure of contracted LNG to arrive from Algeria. The DPU investigated. LDCs are more sensitive to the costs of being caught short on supply reliability. There is more concern about pipeline capacity than inducing LDCs to lower costs. If conditions become better integrated after Canadian gas arrives, the DPU then can encourage supply and transportation diversification by LDCs. Supplies are considered indirectly in PGA proceedings twice a year. The LDCs file plans, but the DPU does not adjudicate them. Contracts could be reviewed in rate cases, although the

Department has not yet done so. Contracts are not reviewed by staff or outside auditors. Contracts are not approved in advance and procedures do not differ if the LDC and the producer are affiliated.

Michigan:

Contracts are reviewed by the Public Service Commission (PSC) in gas cost recovery (GCR) proceedings. State law has abolished the PGA. The PSC has to issue an order before costs can be recovered. The GCR is similar to the PGA of other states. There are annual contested hearings on proposed supply plans. These hearings are part of the GCR and are required by state law. Contracts are not reviewed in a rate case. Contracts are reviewed by staff at the time of the annual supply hearing. Contracts are not reviewed by outside auditors. Contracts are not approved in advance by the Commission, but the LDC supply plan has to be approved. Procedures do not differ if the producer and the LDC are affiliated.

Minnesota:

The Public Utilities Commission (PUC) has not been reviewing contracts. Costs flow through the PGA. The PUC is notified anytime that costs change by 3 cents per Mcf, or at least every three months. Contracts are not reviewed in PGA proceedings in the usual sense. There is an annual filing in which purchasing practices are discussed, but there is no hearing to review contracts. Contracts are reviewed in rate cases. Contracts are not reviewed periodically by staff. LDC annual reports must be audited by outside auditors. Contracts are not approved in advance by the PUC. Procedures differ if the LDC and producer are affiliated. Any contract with an affiliate, not just for gas purchases, has to be approved.

Mississippi:

LDCs submit contracts to the Public Service Commission (PSC). They are examined, brought to a hearing, and then approved or disapproved. The supply situation is a consideration. Contracts are not reviewed in PGA proceedings. Flow-through is allowed. Review of contracts is a separate process. Contracts are not reviewed in a rate case. New contracts for additional purchases are reviewed by staff when presented to the Commission. Contracts are not reviewed by outside auditors and are not approved in advance by the PSC. When the producer and the LDC are affiliated, PSC procedures differ in that there is a closer examination of the contract.

Missouri:

The Public Service Commission (PSC) conducts a review using both internal and external comparative data to assure that a best-cost purchase strategy is implemented. Relative gas costs are compared not only to internal documentation, but also to the purchase data of other LDCs served by the same pipeline. The review also attempts to determine whether the LDC, in its efforts to procure lower-cost gas supplies, has incurred risk or jeopardized the reliability of supply (a consideration related to an LDC's obligation to serve). Contracts are reviewed annually in PGA proceedings. Contracts are not reviewed as part of a rate case. Contracts are reviewed periodically by staff. As part of an annual PGA audit, key changes are reviewed although not every contract is analyzed. Contracts are not reviewed periodically by outside auditors and are not approved in advance by the PSC. Procedures do not differ if the LDC and the producer are affiliated. An in-depth analysis of all available internal and external data is performed on all LDC purchases. However, slightly more emphasis and effort is placed on affiliated transactions.

Montana:

Contracts can be reviewed, but the Public Service Commission (PSC) has no set policy. Montana-Dakota Utilities (MDU) was examined for its source of supply. There are also some vertically integrated utilities and the PSC examines their costs of gas closely. There has been only one major instance of note. MDU is moving from purchasing entirely from an affiliated single supplier and is now taking 15 percent of its gas from elsewhere. The Commission heard testimony on this from the Consumers Counsel. The issue is still pending. The testimony was general, covering issues such as how the PSC should safeguard the lowest-cost supply. Contracts are reviewed in PGA proceedings at least once a year. Contracts can be reviewed in rate cases, although review is usually done in the PGA proceeding. Contracts are reviewed by staff in the PGA. Contracts are not reviewed by outside auditors and are not approved in advance by the PSC. Procedures differ if the LDC and the producer are affiliated. If the PSC has the flexibility, the costs could be rolled in on a cost of service basis to gas rates. If the PSC has no flexibility (i.e., if the affiliate is regulated by the FERC), it must use the rates approved by the FERC.

Nevada:

Contracts are reviewed by the Public Service Commission (PSC) only during the PGA audit, an after-the-fact review, once a year in December. Contracts could be reviewed in a rate case, but it is not a matter of policy to do so. Each rate case has an individual audit program. Contracts are reviewed by PSC staff during the PGA. The PSC also receives monthly reports from LDCs in support of the PGAs and the staff then could review contracts. Contracts are not reviewed by outside auditors although this is not to say that the Commission would not have outside auditors review the contracts. The PSC has made use of outside auditors in the past. Contracts are not approved in advance by the PSC and procedures do not differ if the LDC and the producer are affiliated. The PSC is currently considering a proposed rule for gas resource planning. It would include demand side and supply side just as in electric resource planning.

New Hampshire:

The LDCs file contracts executed with gas suppliers. The contracts are examined but the Public Utilities Commission (PUC) does not tell the LDC what it could have done differently. There is a cost-of-gas adjustment every six months: summer and winter. The PUC tries to determine if the LDC could have reduced costs. Tennessee is the main supplier and it is currently negotiating with its customers over a gas inventory charge. The PUC staff is not involved in the negotiations so there has been little input from the Commission on this issue. Spot purchases make up 90 percent of supply over the summer. Contracts for those purchases have to be filed.

There are two LDCs so the PUC can compare contracts, but the Commission cannot determine what offers were turned down. LDCs cannot obtain spot gas in the winter. Contracts are not reviewed in PGA proceedings or in rate cases. Contracts are reviewed by PUC staff. When the LDC signs a new contract, the agreement must be filed with the PUC within a month of being signed. Contracts are not reviewed by outside auditors and are not approved in advance by the PUC. Procedures do not differ if the LDC and the producer are affiliated. One LDC does own a transmission system. The PUC does not review any contracts involving the parent.

New Jersey:

The contracts are not reviewed. The Board of Public Utilities (BPU) has been checking on reserves through five-year forecasts, but it has not reviewed each and every contract. Once a year there is a levelized purchased gas adjustment. The LDC estimates costs for the following year and prices are set on that basis. Interest is charged for over- or underestimating. This is almost like a rate case. The BPU examines contracts, but not for approval. Contracts are not reviewed as part of a rate case, and are not reviewed by staff. The Board has been discussing staff review, but nothing has been done yet. Contracts are reviewed by outside auditors. Once every five years, there are management audits. Contracts are not approved in advance by the BPU and procedures do not differ if the LDC and the producer are affiliated.

New Mexico:

The Public Service Commission (PSC) reviews contracts only if the purchase involves an LDC and an affiliate. The largest LDC is a combined producer-pipeline, Gas Company of New Mexico, part of Public Service Company of New Mexico (PSCNM). The company has other entities such as gas processing plants. PSCNM is a marketer-broker and sells to the LDC (Gas Company of N.M.). No other contracts are reviewed. The PSC wants the LDC to purchase at lowest cost with best reliability. There is a monthly cost pass-through. Every two years, the LDCs apply for an extension of this pass-through. The PSC does not order the LDCs to buy gas from particular sources. It informs the LDC after the fact if it erred. If the gas costs of the distributor are out of line with others in the region, the PSC investigates. The Commission does not specify the terms of a contract. One LDC has 1,200 contracts with producers. These are long-term, life-of-the-well contracts. Contracts are not reviewed in PGA proceedings or in rate cases. Gas costs are not built into cost-of-service rates. Contract review would be part of the compliance filing when there was an affiliated transaction. Contracts are reviewed by staff only when they are affiliated contracts. The PSC has authority, but it generally does not use it to review other contracts. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. Procedures differ if the LDC and the producer are affiliated. The LDC submits the transaction to the PSC fifteen days after it has been consummated. If the PSC is not satisfied, it can use ratemaking remedies.

New York:

All contracts for LDC purchases are required to be filed with the Public Service Commission (PSC) and are subject to review. Contracts are not required to be approved but staff can raise issues. Contracts are not reviewed as part of a PGA proceeding. LDCs are allowed to file purchased gas adjustments monthly. These are reviewed by staff. Explicit approval is not required but the Commission can challenge the PGA filings. There is no PGA proceeding as such. Contracts are reviewed as part of a general rate case. LDCs must provide information on general purchasing practices. Contracts are reviewed by staff. There is no fixed frequency. They are reviewed when filed, independent of any proceeding. Any subsequent review would be done at random. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. There is no specified different procedure to follow if the LDC and the producer are affiliated, although there is a closer staff review.

North Carolina:

LDCs have to notify the Utilities Commission if they enter into a contract longer than six months. Staff can always raise questions about prudence. The Commission itself can review a contract if the staff finds a problem. Contracts are reviewed in a purchased-gas-adjustment proceeding. PGAs are reviewed in rate cases (see below). Contracts are reviewed in a rate case. Contracts are reviewed by staff. There is no fixed time for the review. Staff can review when it chooses. Staff reviews constantly and can challenge the LDC in a PGA review or in a rate case. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. If the LDC and the producer are affiliated, the contract would be scrutinized more closely.

Base rates are established in a rate case. If gas costs go above or below that level, the difference is placed into a deferred account. Base rates are normally set higher than the market rate. The Commission wants LDCs to offset sales losses by savings in gas costs. Any excess revenue is given back to sales customers, but not to those customers who had negotiated separately for service with the LDC. In a PGA proceeding, fixed costs and gas costs are separated. Gas costs would be recovered through rates, as described above. Fixed costs are FERC regulated and the LDC can file with the state Commission. Fixed costs are allocated to all customers, including transportation customers.

North Dakota:

There is no formalized review. The only review consists of LDC and Public Service Commission (PSC) staff members talking with each other and providing information to Commissioners. One LDC has quarterly updates in which it provides information to the PSC. For the other LDC there is a less formal procedure, consisting of staff conversations after which anything important is passed on to Commissioners. The impact of purchasing is rolled into the PGA. Contracts are subject to review at that time. No review specifically examines the contracts. All contracts are subject to Commission discretionary review but there is no formal process. Contracts are not reviewed in PGA proceedings and probably not in rate cases. Contracts are not reviewed periodically by PSC staff or by outside auditors.

Contracts are not approved in advance by the PSC and procedures do not differ if the LDC and the producer are affiliated.

Ohio:

The Public Utilities Commission (PUC) reviews pricing terms retrospectively. The Commission does not approve contracts, but reviews all purchases. Management performance audits are conducted. No particular guidelines are used in the audits. The PUC examines the overall operating characteristics of the LDC such as peak-day requirements, number of customers, etc. The auditors examine contracts, including minimum-take requirements, take-or-pay, etc. They examine LDC participation at the FERC, the amount of Ohio gas purchased, spot gas purchased, and transportation for system supply and for other customers. The auditors consider these types of topics from year to year. The most important questions are: how does the LDC management address the changing environment and how does the LDC determine its supply mix? The auditors examine what has changed since the last audit and the rationale for any changes. If change was for the worse and was under the control of the LDC, the auditors probe into it. Contracts are reviewed in the management performance audit once every two years. Some reviews are also conducted in a long-term forecast (how the supply portfolio will meet the LDC requirements). The LDC submits this forecast annually. Hearings are held on the forecasts every two years (in different years than the management audit hearings). Contracts are not reviewed as part of a rate case. Staff reviews contracts that are already executed when conducting the management performance audit. Staff can comment on purchasing practices, but the PUC cannot void a contract. The PUC could remove an expense from the gas cost recovery if it thought that the expense was imprudent. Contracts can be reviewed by outside auditors in the management audit. Contracts are not approved in advance by the PUC. When the LDC and the producer are affiliated, the Commission takes that fact into account although it is not a different process. There would be greater scrutiny to ensure that the agreement was the result of arm's-length negotiation. The PUC would examine the pricing terms to be sure that they were neither more nor less favorable than for unaffiliated producers. The Commission would also examine whether affiliated producers were cut back to the same extent as unaffiliated.

Oklahoma:

Contracts are reviewed in the field to protect confidentiality. The Corporation Commission conducts a work program every six months and reviews fuel adjustment and PGA, models, contracts, fuel procurement, reasonableness, and take-or-pay. Notes are taken, but the contracts are not kept on file with the Commission. Contracts are not reviewed in a PGA proceeding. Contracts and costs are reviewed in the work program. Contracts are reviewed as part of a rate case in the normal six-month fuel audit. Contracts are reviewed every six months by staff. The staff does not review every contract, just the major ones. Some LDCs have 1,000-2,000 contracts. Contracts are not reviewed by outside auditors. The Commission does not approve contracts in advance. It does have to approve the pass-through of costs. If the LDC and the producer are affiliated, there is closer examination of the contract.

Oregon:

Contracts are reviewed by the Public Utility Commission (PUC) in general rate cases and gas tracking cases (which are similar to a PGA proceeding). The contracts are examined the first time but are not reexamined in each succeeding rate case. If something looks abusive, adjustments can be made. Contracts are reviewed in PGA proceedings. The PUC is trying to have PGAs once a year. Most contracts are for firm supply and are reviewed in rate cases. Contracts are reviewed by PUC staff when the LDC first files for recovery of gas costs related to them. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. If the LDC and the producer are affiliated, the affiliated interest statute would be applied. The PUC, when examining transfer prices, would take the lower of either the actual cost or what the market rates would be.

Pennsylvania:

The Public Utility Commission (PUC) operates under an enabling statute requiring least-cost fuel procurement. The major utilities file, on a staggered basis, their expected fuel costs for the following twelve months. The PUC trial staff, the Consumer Advocate, and other intervenors examine the expected costs. The Commission also examines the cost of gas actually experienced in the previous twelve months. Any underrecovery of costs is allowed to be balanced in the next period while any overrecovery is required to be refunded. Contracts are reviewed as part of this process, but are not examined in a rate case. The cost of gas is a separate proceeding, as described above. The enabling statute requires, however, that when a rate case is filed the cost of gas be reexamined. Contracts are reviewed by staff in the context of the PGA procedure. Contracts are not examined by outside auditors. The PUC uses its own auditors from the Bureau of Audits. Contracts are not approved in advance by the Commission. Procedures differ if the LDC and the producer are affiliated. There is an additional set of rules involving affiliated interests. The LDC has to convince the PUC that it could not buy gas more cheaply elsewhere. A somewhat closer examination is involved.

Rhode Island:

No contracts have been reviewed. In the last round of PGA hearings in February 1989, the Public Utilities Commission (PUC) questioned Providence Gas about what it did to ensure the best gas purchases. The PUC was not completely satisfied with Providence's answers and ordered an investigation of gas procurement activities. The PUC has not yet done anything beyond ordering the investigation. The Commission has talked with outside consultants about the investigation. The LDCs have been perfunctory with the PGA. They have reported costs, under- and overcollections, etc. The Commission has not conducted much of a review. Contracts are not reviewed by the PUC and are not reviewed in PGA proceedings. Prices are available, but that is all. Contracts are not reviewed in a general rate case nor by staff. This issue will be part of the investigation. The Commission is aware that it has been remiss. Contracts are not reviewed by outside auditors and are not approved in advance by the PUC. Procedures do not differ if the LDC and the producer are affiliated. This situation is not applicable in Rhode Island.

South Carolina:

The Public Service Commission (PSC) has an annual hearing to review LDC purchasing practices. Contracts are reviewed in annual PGA proceedings. Contracts are not reviewed in rate cases, but are reviewed periodically by staff. Generally, staff would review annually but review may be done any time. Contracts are not reviewed by outside auditors and are not approved in advance by the PSC. Procedures differ if the LDC and the producer are affiliated. There is closer examination. The PSC also has a different pricing arrangement for this type of contract. One LDC has a purchasing subsidiary. If that subsidiary purchases gas from a subsidiary of its suppliers, it is not allowed to charge a finder's fee.

South Dakota:

Contracts are reviewed to some degree by the Public Utilities Commission (PUC) with the aid of a consultant. Contracts are not reviewed in PGA proceedings. Contracts are reviewed by PUC staff in rate cases, every two to four years and by outside auditors during rate proceedings. The PUC staff is small. Contracts are not approved in advance by the Commission and procedures do not differ if the LDC and the producer are affiliated.

Tennessee:

Contracts are reviewed when the Public Service Commission (PSC) accounts for cost savings from month-to-month. The LDCs send spot contract and transportation invoices to the Commission and the PSC calculates the savings. The Commission also conducts audits in PGA and rate case proceedings and compliance audits. However, these are done sporadically. Contracts are reviewed by staff in monthly PGA proceedings and in rate cases. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. Procedures differ if the LDC and the producer are affiliated. For one LDC, there is a difference in how cost savings are flowed back. Savings derived from purchasing from an affiliated producer flow to residential ratepayers. Savings resulting from unaffiliated purchases are used to offset marginal losses incurred by the LDC when selling to industrial interruptible customers.

Texas:

The Railroad Commission allows the LDCs to compete. Whatever price the distributors set is passed on. A competitive market is assumed. There is no policy of review. The Public Utilities Commission might examine a contract, however, if the gas was going to an electric power plant. Contracts are not reviewed by the Railroad Commission in PGA proceedings, although they could be. If the Commission conducted a proceeding to examine gas costs, contracts would then be reviewed. However, such reviews are done on an irregular basis. Contracts are not reviewed in rate cases. Railroad Commission staff reviews contracts, but not in a rate-setting context. The LDCs are required to submit in their annual reports information on their sources of gas supply. Certain parts of the contracts are required to be filed, such as how much gas is going to be taken, price, etc. This is part of the filing requirement. This information is reviewed, but staff mainly is checking the accuracy of the arithmetic. Contracts are not reviewed by outside auditors and are not approved in advance by the Railroad Commission. Procedures differ if the LDC and the producer are affiliated. The Railroad Commission tries to ensure that the cost charged to the LDC does not exceed the weighted average cost of gas from other producers.

Utah:

Contracts are reviewed when the LDC first enters into an agreement. There is one large LDC, Mountain Fuel, and one small LDC, Utah Gas. Mountain Fuel used to purchase gas directly, but it then separated its transmission into an interstate pipeline, Questar. It now purchases gas through Questar. Mountain Fuel also owns some production and that gas is transported through Questar for Mountain Fuel. Thus, there are no direct purchases by Mountain Fuel. Utah Gas buys some gas from Northwest Pipeline and other sources. The Division of Public Utilities (DPU) reviews just for pass-through. Utah Gas also has some contractual commitments. The DPU reviews those in pass-through twice annually. Contracts are not reviewed in PGA proceedings or in rate cases. Contracts are not reviewed periodically by staff or by outside auditors. Contracts involving the smaller LDC, Utah Gas, are approved in advance. Utah Gas submits the contract and explains the benefits and what the price will be. The DPU examines the contract to determine if it is reasonable. Procedures do not differ if the producer and the LDC are affiliated.

Vermont:

Contracts are reviewed and approved by the Public Service Board (PSB). Contracts are not reviewed in PGA proceedings. There are no PGA clauses. Contracts can be reviewed in any context. They could be reviewed in a rate case if necessary to establish a price for the cost of gas. Prior to Board members ruling on them, the staff reviews and makes a recommendation. Contracts are not reviewed by outside auditors. There is no place for the Board to sign its approval, but if the PSB had a problem the LDC would proceed with the contract only at its own risk as the Board could pursue a rate investigation. It would be best for the LDC to satisfy the PSB before proceeding. Procedures differ if the LDC and the producer are affiliated as the Board closely scrutinizes affiliated transactions.

Virginia:

The State Corporation Commission (SCC) does not examine specific contracts, but aggregate daily and seasonal demands and commodity purchases to determine if the LDC is being flexible. Purchases, not contracts, are reviewed in two stages. The LDCs are required to file a forecast of the daily and seasonal demand of each customer class. The SCC examines the source of supply and commodity-cost plan to verify that it is least-cost. To determine whether the LDC has made good long-term decisions, the Commission in the PGA review examines recovered costs to compare the costs with what the LDC had demanded. The SCC also considers other issues such as whether firm arrangements are being made for interruptible customers and if so, why. On short-term issues, the Commission asks whether the LDC is buying the lowest-cost gas that it can while satisfying minimum takes. Contracts are not reviewed in a rate case. The SCC has an informal review. If there is a problem, purchases may be examined during a rate case or during a rule-to-show-cause proceeding. It is not considered useful to examine contracts that the LDC has signed unless the Commission could also review contracts that the LDC did not sign. Contracts are not reviewed periodically by Commission staff, although purchases are. Contracts are not reviewed by outside auditors and are not approved in advance by the SCC. Procedures do not differ formally if the LDC and the producer are affiliated, although there possibly would be more careful examination.

Washington:

Contracts are beginning to be reviewed. The Utilities and Transportation Commission (UTC) formerly had quarterly trackers and annual hearings. Contracts will be reviewed in PGA proceedings in the future, probably once a year. There is one interstate pipeline in the state. It accepted a blanket certificate in May 1988. The pipeline allowed its customers to convert from sales to firm transportation. One LDC has converted all but 2 percent of its contract demand to transportation. The Commission is not sure what it will do in the PGA, but it will probably consider this in a tracker. The Pacific Northwest is in good shape. Gas is plentiful. The enhanced oil recovery project could affect this, however. Northwest wants to connect Canadian gas and Rocky Mountain gas to the project. Pacific Gas Transmission wants to bring in gas from Alberta to southern California. This would provide firm transportation to Washington, increasing northern-end capacity. Alberta gas would be available on a firm basis if Pacific Gas does what it wants to do. Contracts are reviewed in a general rate case. In a rate case, staff evaluates general purchasing practices. In the PGA, the UTC does not do very much. "Review" means the staff informing the Commission, but not much more. Contracts will be reviewed periodically by staff. The staff hopes to be able to follow the market and question the LDCs. Contracts are not reviewed periodically by outside auditors, although they might be. Contracts are not approved in advance by the Commission. The UTC will probably never do this, preferring rate case review. Procedures differ if the LDC and the producer are affiliated. The Commission must, by law, approve affiliated transactions.

West Virginia:

New contracts have to be filed with the Public Service Commission (PSC). Contracts are reviewed annually in PGA proceedings. Contracts are reviewed in a rate case, but only if they involve affiliated transactions. Contracts are reviewed periodically by staff in the PGA process if the contract involves an affiliated transaction. Contracts are not reviewed periodically by outside auditors. Contracts involving affiliated transactions are approved in advance by the PSC. The LDC has to file the transaction with the PSC before entering into it. The Commission has no deadline. There may be an internal review only. There may also be a hearing if there are any intervenors. Procedures differ if the LDC and the producer are affiliated. Transactions are reviewed within and outside the PGA, and they may also be reviewed in a rate case. Such transactions also have to be approved by the PSC, as described.

Wisconsin:

The Public Service Commission (PSC) does not review individual contracts. When PGAs are filed, some LDCs submit sales contracts and compute the weighted average cost of gas, but the PSC does not review the contracts. Contracts are not reviewed in a rate case. The PSC is moving toward a review of contracts when trueing-up the PGAC during a rate case audit. The contracts will be reviewed, but they are not now. Contracts are not reviewed periodically by PSC staff. Contracts are not reviewed by outside auditors. The PSC recently completed a test case involving Arthur Andersen. Contracts are not approved in advance by the Commission and procedures do not differ if the LDC and the producer are affiliated

Wyoming:

Contracts are reviewed by the Public Service Commission (PSC) in PGA, and rate case proceedings, and special complaints. Contracts are reviewed in PGA proceedings semiannually. Contracts are reviewed by PSC staff on a filing basis and when fuel-use adjustments are filed. Contracts are not reviewed by outside auditors. Contracts are approved in advance by the PSC, which accepts them for filing. The PSC examines the contract and determines if there is a problem. If there is a problem, the contract is sent back to the LDC. If there are no problems, the contract is accepted. Procedures differ if the LDC and the producer are affiliated. Those contracts are examined more closely. There is not a great deal of difference, however, because the PSC examines all contracts closely.

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