NRRI 88-21

STATE GAS TRANSPORTATION POLICIES: AN EVALUATION OF APPROACHES

Robert E. Burns, Esq.
Senior Research Associate

Daniel J. Duann
Senior Institute Economist

Peter A. Nagler
Graduate Research Associate

THE NATIONAL REGULATORY RESEARCH INSTITUTE
1080 Carmack Road
Columbus, Ohio 43210

January 1989

This report was prepared by The National Regulatory Research Institute (NRRI) with funding provided by the participating member commissions of the National Association of Regulatory Utility Commissioners (NARUC). The views and opinions of the authors do not necessarily state or reflect the views, opinions, or policies of the NRRI, the NARUC, or NARUC member commissions.

EXECUTIVE SUMMARY

The Increasing Importance of Gas Transportation Regulatory Issues

The changes over the last few years in the natural gas market and in the federal regulation of that market have confronted state commissioners with some important new challenges and questions. (For the new commissioner or staff member, an educational background piece on major developments in federal gas transportation policy in the 1980s can be found in appendix A.) Competition is replacing regulation as the driving force in many instances, and the role of pipelines is shifting from that of merchant and transporter of pipeline-owned gas to that of transporter of customer-owned gas. A major shift in throughput from sales gas to transportation gas presents both opportunities and pitfalls for local distribution companies (LDCs) and the state commissions that regulate them. One opportunity is for an LDC and its state commission to establish a state gas transportation policy. Such a policy would allow the LDC's customers access to a pipeline that is providing transportation service. The LDC's customers would then purchase their gas directly from the producer and pay the pipeline and the distributor a separate transportation fee.

Faced with an increasingly competitive environment, many state commissions have developed gas transportation policies that allow end-users to make direct gas purchases from producers with the local distribution company moving the gas from the pipeline to the end-user. The development of gas transportation policy raises a variety of questions and issues, including bypass of a local distributor, discrimination in the allocation of pipeline space in favor of a distributor's marketing affiliate, the shift of revenue requirements among customer classes, and the obligation to continue to provide reliable service to captive customers. The National Regulatory Research Institute (NRRI) has examined state gas transportation policies in 1988, with the objective of providing some guidance on what state commissions are doing and some suggestions as to how they might wish to shape or reexamine their gas transportation policies.

Current State Policies

The NRRI conducted a survey of state commission gas transportation policies during the spring and summer of 1988. Surveys were sent to state commission staff members in forty-nine states and the District of Columbia. Nebraska was excluded because it does not regulate LDCs. Responses were received from forty-four states and the District of Columbia. The data show that the vast majority (thirty-eight of forty-five or 84 percent) of the responding commissions have considered and adopted some type of gas transportation policy.

Most commissions pursuing a transportation policy are doing so case by case. These commissions may want flexibility to meet changing circumstances. However, the need for commission flexibility needs to be balanced with consistency and stability of policy. While flexibility is a worthwhile goal, it is not the only one. A Commission may adopt a case-by-case approval because the new issues can be handled easily within the bounds of the normal, ongoing stream of rate cases. A case-by-case approach might also be used as the first step in a process resulting in a formal policy or order.

The NRRI asked about features of commission policies. Twenty-five commissions have policies regarding firm and interruptible transportation; twenty have provisions concerning maximum and minimum amounts of gas to be transported; eighteen have maximum and minimum transportation charges or mechanisms for setting them; seventeen have mandatory open access, non-discriminatory transportation provisions; fifteen have provisions concerning back-up gas service for transportation customers; eleven have provisions addressing the specific maximum and minimum lengths for transportation contracts; nine provide for the allocation of profits or losses resulting from transportation services; eight have provisions concerning core and non-core markets; and five commissions have addressed storage service.

State commissions have taken action on a variety of transportation issues and concerns. Often, actions have proceeded on a case-by-case basis and incorporated only those provisions necessary to deal with specific situations or problems. There is no unanimity among the commissions on what method to prescribe for calculating transportation service charges. There are four basic approaches.

The <u>simple margin approach</u> allows the inclusion of all fixed costs in the transportation rate, except those allocated to the commodity component of the utility's sales rate for a particular customer. Seven commissions use this method. The <u>full or gross margin approach</u> is similar to simple margin, except that the demand or fixed costs included in the commodity rate for a given class of customers are charged as part of the transportation rate. Twelve commission utilize this method. A <u>cost-of-service approach</u> is used by five commissions, and a <u>value of service approach</u> is used by eight. Thirteen commissions do not prescribe a method.

One surprising finding, given the widespread discussion of the bypass issue, was that few commissions have issued orders or findings to deal with bypass. Bypass means something other than a customer converting from LDC sales service to transportation service. Bypass means that a customer is directly hooking-up to a pipeline to take advantage of the pipeline's transportation service, thereby entirely leaving the LDC system. Commissions are encountering a substantial amount of activity by LDCs, which are establishing marketing affiliates and helping customers to buy spot market gas. Many commissions said that LDC operations have become more complex and costly as a result of the provision of transportation. Several commissions said that this provision has resulted in a shift of revenue requirements among customer classes, and many commissions have also issued orders or statements about the shift of revenue requirements from one class of customers to another. Several commissions also said that the shift of customers to being transportation customers had resulted in increased purchased gas costs. Many commissions require distributors to provide transportation customers--formerly sales customers--with traditional utility service. Transportation customers are held responsible for purchased-gas-adjustment-related demand charge increases. Standby or reservation charges are also allowed in many instances. In short, the states are responding to the new environment.

<u>Economic Considerations and Legal Strategies</u>

Four economic considerations exist by which state commissions can evaluate state gas transportation policies. The original intent of FERC

Order 436, which provided for the unbundling of natural gas service by interstate pipelines, was to promote economic efficiency through the substitution of competitive forces for government regulation. Specifically, the provision of gas transportation service by the pipelines and local distribution companies allows end-users the opportunity to purchase gas directly from gas producers or other unconventional supply sources. Based on this, one economic objective for a state's gas transportation policy is to preserve and enhance competitive forces in the natural gas market so that both conversion of sales service to transportation service and the occurrence of LDC bypass are determined by economic considerations rather than by artificial barriers or incentive.

Besides this efficiency consideration, three additional economic considerations usually are involved in the development of state gas transportation policy. First, a state gas transportation policy ought not to put a disproportionate burden on core customers. Second, a state gas transportation policy ought not to be overly complicated or costly in its implementation. After all, the cost of regulation is eventually reflected in the gas bills of the end-users. A complicated gas transportation policy may be difficult to implement or may prove not to be cost-effective. Third, a state gas transportation policy should guard against the exercise of undue market power or the provision of preferential treatment to end-users or LDCs. The exercise of undue market power or the provision of preferential treatment can distort the operation of a competitive marketplace. The most economical gas supply sources may not be selected while more expensive gas sources are used.

There are also three legal strategies that state commissions may wish to consider when deciding or reconsidering what gas transportation policy to adopt. These strategies are (1) protecting the state's jurisdiction over the local distribution company by avoiding federal preemption, (2) making certain that the local distribution company can meet its obligation to serve its customers, and (3) providing the local distribution company with an opportunity to earn its revenue requirement. State regulators must be concerned with the possibility that the FERC will preempt state commission authority over an LDC either directly or indirectly by encouraging forum shopping. A direct threat might come from allowing an LDC to broker capacity that it has contracted for on its interstate pipeline. In order to resell such capacity, the FERC might require open transportation by the LDC, something a state commission might find not to be in the public interest. Also, such a rule would make the LDC's brokering rates subject to a FERC price cap, even if concurrent state jurisdiction were in effect. Federal encouragement of forum shopping can also be damaging. The FERC has recently approved certificates that result in LDC bypass. While this phenomenon is still unusual, its occurrence is likely to grow as LDCs are forced to bear some of the pipeline's take-or-pay obligations. Customers that can bypass the LDC may choose to do so rather than face rate increases arising from passthrough of take-or-pay obligations.

A local distribution company is typically required to fulfill an obligation to serve its customers on demand. The source of this obligation to serve sometimes is a state statute, sometimes a commission order, or sometimes a clause included in the local distribution company's basic franchise agreement. To meet its obligation to serve, an LDC must be prepared to provide a secure and reliable supply of gas delivered to its city gate and also have sufficient capacity available to meet peak demands (typically in the winter). Before the inception of transportation service, the obligation to serve was generally held to extend to all of the LDC's customers. Since then, however, some contend that the obligation to serve extends only to the LDC's core customers (those who have no alternative to gas sales service from the LDC) and those non-core customers who choose to remain customers of the LDC. It is argued that customers who opt for transportation service would not fairly contribute to the costs of maintaining a secure and reliable gas supply. Therefore, they should not be allowed to enjoy freely the benefits of that supply if their own supply sources become more expensive or unavailable.

Another strategy to apply when developing a gas transportation policy is the legal requirement that a utility--in this case an LDC--be provided an opportunity to earn its revenue requirement. This requirement typically has its origins in statute, commission order, or judicial interpretation. It is usually considered a part of the regulatory compact between a utility and the regulatory body, that provides a utility a reasonable opportunity to earn its revenue requirement in exchange for fulfilling its obligation to serve within its franchised service area.

An Evaluation of Gas Transportation Policies

The phenomenon of customers converting from sales service to transportation service is a natural development of the changing environment in the natural gas market. Such conversion can enhance economic efficiency when end-users achieve some cost saving by replacing high-cost gas supplied by the LDC with low-cost gas provided by the pipelines or producers. However, in other instances, a conversion from sales to transportation service may not be economical even if it is profitable for end-users. This is likely if the transportation rate is not cost-based. As previously noted, there are four approaches to setting transportation rates. The simple margin approach leaves the LDC revenue neutral in terms of the customer's source of gas, but it requires that remaining core customers who stay with the LDC must bear a larger share of the costs than previously. The gross margin approach leaves these core customers insulated from shifts of revenue requirements, but it moves farther away from the objective of having competitive price signals. The value-of-service approach also has the major disadvantage of distorting price signals. Only a marginal cost-of-service based rate would result in proper price signals being given, but it may result in some shifting of revenue requirements. In our view, a complete prohibition of revenue requirement shifting may not be feasible.

Several policy options are available to deal with bypass. State regulators can prohibit LDC bypass, or discourage bypass and place the responsibility of preventing it on the LDC. As an alternative, a state could discourage bypass by allowing a flexible pricing tariff for gas transportation service. The third option is to discourage both bypass and the conversion of sales service to transportation service by authorizing discount or incentive gas rates by LDCs, thereby allowing them to compete with non-LDC gas suppliers. The last option is to adopt a non-interventionist approach toward bypass.

An absolute prohibition of bypass can distort price signals in the gas marketplace. By prohibiting bypass, the state public service commission takes away the LDC's incentive to price transportation services correctly. Thus, the objective of establishing competitive price signals may not be met. However, a policy prohibiting bypass has the advantage of being simple to implement because it eliminates much of the need for state regulation of gas transportation. A laissez faire approach of allowing bypass to occur has the advantage of letting competitive market forces determine the proper level of bypass. Regulatory intervention is kept at a minimum, so the criteria of competitive price signals and administrative feasibility are met. But, potential adverse effects of drastic cost reallocation and exercise of market power by large industrial customers and LDCs are likely to occur. Using the approach of setting a flexible tariff for gas transportation service aims at avoiding the disadvantages of the two extreme approaches outlined above. A flexible transportation tariff can be used to reach a balance between promoting competition and preventing a drastic cost reallocation to core customers, which can result from bypass or conversion from gas sales to transportation. Additional information about likely gas supply sources available to potential bypass customers, the amount of possible bypass, the cost of providing transportation service to individual customers, and related issues needs to be collected. A flexible transportation tariff increases the likelihood of preferential treatment of certain groups of customers by the LDCs. Further, unless demand costs associated with capacity used for transportation service are removed from the LDC's revenue requirement, a flexible tariff either can result in some cost reallocation, or the LDC's inability to achieve its revenue requirement. An incentive gas rate, designed to reduce the economic incentive for bypass, is similar to a flexible transportation tariff. The principal difference is that an incentive gas rate not only eliminates the incentive to bypass, but also an incentive not to convert from sales service to transportation service, even when it may be economical to do so. The identification of real bypassers and those customers who merely use bypass to obtain more favorable prices is a key question in implementing this policy.

No one set of state gas transportation policies meets all the legal and economic considerations. A few observations can be made, however. The keystone of a state gas transportation policy is to determine how transportation rates are to be calculated. All other policy determinations flow from that determination. A cost-based transportation rate has desirable features that should be favorably considered. In particular, a cost-based transportation rate sends the proper price signals to end-users concerning whether it is economic or uneconomic to switch from sales to transportation service. Also, a cost-based rate, particularly one designed to reflect the marginal costs of transportation service to an individual customer, discourages uneconomic bypass of the LDC. Although marginal cost-based rates may cause a reallocation of costs and a shift of revenue requirements, such a shift merely eliminates existing cross-subsidies and gives customers better price signals of their actual costs. Without cost-based rates, the LDC and its customers cannot make rational choices concerning their gas supply and delivery options. Other state gas transportation policy options then may flow from and reflect the proper price signals that result from cost-of-service-based transportation rates.

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd)

LIST OF TABLES

LIST OF TABLES (Cont'd)

FOREWORD

With changes in federal regulation of natural gas markets and pipelines and with new opportunities for local distribution companies (and others) to change their buying and transport practices, state regulatory commissions are increasingly faced with developing a gas transportation policy of their own. Considerations of bypass, discrimination, shifting revenue requirements among customer classes, and capacity allocation are presented.

This report is intended to provide some objective guidance for those commissions wishing to establish or reshape their gas transportation policies by way of identifying what the various state commissions are already doing and by way of offering some appraisals and commentaries.

Douglas N. Jones
Director, NRRI
Columbus, Ohio

ACKNOWLEDGEMENTS

The authors wish to thank especially David Wagman for his fine job editing, and Drs. Kevin Kelly, Stephen Henderson, Douglas Jones, and Suedeen Kelly for their carefully reviewing this report. We appreciate their helpful suggestions and incorporated their suggestions in the report.

The authors also gratefully acknowledge the members of the NARUC Staff Subcommittee on Gas, especially Harold Meyer, for reviewing the commission survey instrument and suggesting numerous helpful changes. The quality of the survey and the report were improved because of their suggestions.

The authors also wish to thank the survey respondents for taking the time to answer this comprehensive survey on state gas transportation policies. In particular, the authors wish to thank Robert E. Reed of the Alabama Public Service Commission; Bill Marshall and Kathi Launius of the Alaska Public Utilities Commission; Dr. David Berry of the Arizona Corporation Commission; Gail M. Jones of the Arkansas Public Service Commission; Brian D. Schumacker of the California Public Utilities Commission; Dick Carlson of the Colorado Public Utilities Commission; Jeffrey P. Honchavik of the Connecticut Department of Public Utility Control; Richard A. Latourette of the Delaware Public Service Commission; John P. Gregg of the District of Columbia Public Service Commission; Wayne R. Makin of the Florida Public Service Commission; Melvin Ishihara of the Hawaii Public Utilities Commission; J.D. Gager of the Idaho Public Utilities Commission; Constance Tripp of the Illinois Commerce Commission; Denny Philpott of the Indiana Utility Regulatory Commission; Jody Stead of the Iowa State Utilities Board; Joe Williams of the Kansas State Corporation Commission; Judy Cooper of the Kentucky Public Service Commission; Roy F. Edwards of the Louisiana Public Service Commission; David M. DiProfio of the Maine Public Utilities Commission; Douglas Kinney of the Maryland Public Service Commission; John B. Howe of the Massachusetts Department of Public Utilities; Gary Kitts of the Michigan Public Service Commission; Stuart Mitchell of the Minnesota Public Utilities Commission; C. Keith Howle of the Mississippi Public Service Commission; Bo Matisziw of the Missouri Public Service Commission; Michael L. Greedy of the Nevada Public Service Commission; Nusha Wyner, Nueva D. Elma, and David McMillan of the New Jersey Board of Public Utilities; Philip L. Baca of the New Mexico Public Service Commission; Ronald Streeter of the New York Department of Public Service; Raymond J. Nery of the North Carolina Utilities Commission; Wallace M. Owen of the North Dakota Public Service Commission; Marcy G. Kotting of the Public Utilities Commission of Ohio; Gerald A. Lundeen of the Oregon Public Utility; John F. Povilaitis of the Pennsylvania Public Utility Commission; Doug Hartley of the Rhode Island Public Utilities Commission; James S. Stites of the South Carolina Public Service Commission; Dave Jacobson of the South Dakota Public Utilities Commission; Tym Seay of the Texas Railroad Commission; Darrell S. Hanson of the Utah Public Service Commission; Cody Walker of the Virginia State Corporation Commission; Ken Elgin of the Washington Utilities and Transportation Commission; Howard M. Cunningham of the West Virginia Public Service Commission; Marc A. Nielsen of the Wisconsin Public Service Commission; and Alex J. Eliopulos of the Wyoming Public Service Commission.

During the production of the study, several persons worked diligently to get this report ready for publication, including Patricia Brower, Joan Marino, and Evelyn Shacklett, and especially Marilyn Reiss. We are very grateful for their fine work.

CHAPTER 1

THE INCREASING IMPORTANCE OF GAS TRANSPORTATION REGULATORY ISSUES

The changes over the last few years in the natural gas market and in the federal regulation of that market have confronted state commissioners with some important new challenges and questions. Competition is replacing regulation as the driving force in many instances, and the role of pipelines is shifting from that of merchant and transporter of pipeline-owned gas to that of transporter of customer-owned gas.

How state commissions are dealing with contract and supply issues posed by direct gas purchases by LDCs from gas producers was discussed in a recent NRRI report.[1] The current study examines a closely related topic. Faced with an increasingly competitive environment, many state commissions have developed gas transportation policies that allow end-users to make gas purchases directly from producers with the local distribution company moving the gas from the pipeline to the end-user.

The development of gas transportation policies raises several questions and issues, including bypass of a local distributor, possible discrimination in the allocation of pipeline space in favor of a distributor's marketing affiliate, the shift of revenue requirements among customer classes, and the obligation to continue to provide reliable service to captive customers. These and other important questions are considered in later chapters of this report.

Before considering the state regulatory issues, it is useful to discuss the federal regulatory and gas market developments that have been the catalyst for recent developments at the state level. These are covered in the next two sections of this chapter, with the final section setting out the content and organization of this report.

---

[1] J. Stephen Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches*, NRRI 87-12 (Columbus, OH: The National Regulatory Research Institute, 1988).

Recent Federal Regulatory Developments: An Occasion for Reexamining State Policies

From the early 1980s to the present there has been a gas surplus due to a variety of factors including falling world oil prices, economic downturn, and the increased conservation spurred by higher energy prices. As it became more difficult for pipelines to sell gas at prices that would recover wellhead costs, fixed by contract, and as pipelines' take-or-pay liability exposure began to increase dramatically because of the lower sales, the Federal Energy Regulatory Commission (FERC) undertook a variety of policy initiatives. These policies were designed to move gas and provide take-or-pay relief for pipelines and to work around limitations imposed by producer-pipeline contracts.

Several of these initiatives, including off-system sales, special marketing programs, blanket certificates, and Orders 436 and 500, are discussed in detail in appendix A. Attention is also given there to the Maryland People's Counsel and Associated Gas Distributors rulings by the D.C. Court of Appeals--decisions that had important effects on the development of federal policy. This appendix is provided as background information for those who are new to federal gas transportation regulation.

Certain key developments at the federal level since 1986 may cause some state commissions to reexamine their gas transportation policies and might also encourage those state commissions that have not yet formulated a gas transportation policy to act. These federal developments concern the issues of bypass, LDC brokering of interstate pipeline capacity, the interplay between the FERC sales conversion and abandonment rules, and the FERC affiliated entities rule concerning gas marketing or brokering. Indeed, it is because of these occurrences that the NRRI has undertaken to examine state gas transportation policies in 1988, with the objective of providing state commissions with some guidance on what other state commissions are doing, and some suggestion as to how state commissions might wish to approach or reexamine their gas transportation policies.

Bypass

The problem of bypass of an LDC is a serious concern for state commissions. Bypass here means more than a customer converting from LDC sales service to LDC transportation service. It means that the customer is directly hooking-up to a nearby pipeline to take advantage of its transportation or sales service, thereby completely bypassing and leaving the LDC system. If bypass occurs, an LDC has a smaller customer base over which to spread its fixed costs. Under one version of the traditional regulatory scheme, the remaining customers may have to pay a larger share of the distributor's demand costs. If the resultant rate increases were large enough, other customers might also bypass and leave the system. It might be possible that all customers would leave the system except for those core residential and small commercial customers that have no other alternative. A report by the Consumer Federation of America warns that LDC bypass could cost these core customers $2 billion. Because of this concern, the NARUC Committee on Gas passed a resolution at its meeting on March 3, 1988 urging the FERC to consider the impact of bypass on the LDC and its remaining customers in its certification process when the decisions to be made would affect the availability and permissibility of bypass. The Committee also urged the FERC to consider the LDC's obligation to serve and to leave the States with sufficient latitude to address bypass problems on an individual basis. The resolution was adopted by the NARUC Executive Committee.[2]

Under the new FERC open access regulatory regimen, it is becoming almost commonplace that interstate pipelines are seeking to bypass an LDC to serve an industrial customer of the LDC directly. The concern of the state commissions and the distributors is that allowing bypass may cause a problem of stranded investment for the LDC. Also, allowing bypass may compound the future take-or-pay problems of the LDC, because there would be fewer customers over which to spread the final take-or-pay burden that may be passed through to the LDC as a result of FERC orders and settlements.

---

[2] "State Regulators Urge FERC to 'Do Your Job' on Take or Pay, Bypass," *Inside F.E.R.C.*, March 7, 1988, pp. 5-6.

The FERC in making its decisions on whether the bypass of an LDC is in the public interest seems to presume that in most cases it is. As stated by FERC Chairman Martha Hesse, "if an LDC is willing to meet the competitive terms of a bypass proposal, the bypass is uneconomic and unacceptable; if it is not willing, the bypass is acceptable."[3]

The bypass issue has become more heated recently because of certain federal court decisions and bills introduced before the Congress. The most controversial federal court decision relating to bypass was issued by the United States District Court for the Western District of Michigan on June 16, 1988. In that decision, the court found that FERC jurisdiction to grant a NGA section 7(c) certificate allowing an interstate pipeline to connect with an industrial customer of an LDC, effectively bypassing the LDC, preempts the authority of the Michigan Public Service Commission to prohibit the bypass.

The case, which involves the FERC, the Michigan Consolidated Gas Company, the National Steel Corporation, Panhandle Eastern Pipeline Company, and the Michigan Public Service Commission, concerned a FERC grant of an NGA section 7(c) temporary certificate to Panhandle Eastern Pipeline to provide gas transportation service to a National Steel Corporation plant that was a customer of the Michigan Consolidated Gas Company, an LDC. The position of the distributor and the state commission was that, while the FERC can issue a certificate for the transportation of gas, a state authorization was needed to connect the pipeline with a customer of the LDC since both were within the same state. There was also the potential for a duplication of facilities and an adverse effect on the remaining customers of the LDC system. Therefore, Michigan Consolidated and the Michigan PSC argued that both state and federal agencies have concurrent jurisdiction over the matter, but that a state commission authorization is necessary for the bypass to occur.

Judge Robert Holmes Bell, who presided, concluded however that such a jurisdictional split would severely undermine the ability of the FERC to discharge its duty to regulate interstate transportation comprehensively and

---

[3] "Hesse Turns Up Heat to Get LDCs to Become Open-Access Transporters," *Inside F.E.R.C.*, May 9, 1988, pp. 1-2.

uniformly. The Michigan Public Service Commission and Michigan Consolidated have appealed to the Sixth U. S. Circuit Court of Appeals, and stated that they will carry the case to the United States Supreme Court if need be.[4]

Legislation was introduced in the 100th Congress to address the LDC bypass issue. Two bills are worth considering here: H.R. 4089 and its companion bill, S. 2313. These would have prohibited the FERC from permitting bypass of an LDC if the state public utility commission disapproved or if the affected LDC agreed to provide transportation for the end-users' gas. The NARUC Executive Committee unanimously adopted a resolution that supports the bills.

The NARUC position is that LDC bypass is a complicated issue of great local concern that should be resolved by the state commissions at the local level. The concern to the state regulators is that allowing a major industrial customer to leave a distributor's system could result in the reallocation of some or all the LDC's fixed costs to the remaining customers. Therefore, any benefit of a bypass should be weighed against the burden that it places on the LDC's core customers.

NARUC argues that clarification of state jurisdiction over LDC transportation and bypass is needed to ensure that the transition to a more competitive marketplace occurs smoothly and equitably. Also, state commissions might be able to provide for alternatives to bypass through the use of innovative rate designs. State regulators are also concerned about how

---

[4] Case citation here. Also, see "Late News," *Inside F.E.R.C.*, June 20, 1988, p. 1; and "Panhandle Bypass Ruling Sends Strong Message; Michcon to Appeal," *Inside F.E.R.C.*, June 27, 1988, pp. 1, 6. Another example of an interstate pipeline seeking to bypass a distributor is described in "Debate on Northern Natural Bypass Application Heating Up in Iowa," *Inside F.E.R.C.*, September 5, 1988, pp. 7-8. Also, Michcon and Panhandle Eastern Pipeline continue to quarrel before the FERC. Panhandle Eastern has sought FERC authorization to provide firm transportation service to National Steel Corporation. Michigan Consolidated has opposed this application, arguing that there are no material cost savings to be realized through the proposed service and that National Steel is merely trying to avoid its share of Michigan Consolidated's take-or-pay obligations. See "Michcon Fights Panhandle Plan to Provide Firm Service to Steelmaker," *Inside F.E.R.C.*, October 17, 1988, pp. 4-5.

bypass would affect the LDC's obligation to serve industrial customers that have left the LDC system.[5]

However, the bypass legislation was opposed by the Process Gas Consumers Group, the Natural Gas Supply Association, the Interstate Natural Gas Association of America, and the FERC. The FERC General Counsel, testifying before the United States Senate Energy and Natural Resources Subcommittee on Energy Regulation and Conservation, made clear that it was the Commission's position that the bills would shield LDCs from competition and could adversely affect the natural gas market. She also claimed that the legislation could undermine the FERC's open-access transportation program.

Capacity Brokering NOPR

The Chairman of the FERC has publicly announced her intention to urge the LDCs to become open-access transporters. Although the FERC has no authority to mandate that LDCs provide open access, the Commission intends to encourage them to do so by conditioning an LDC's authority to resell capacity, which the distributor has purchased from a pipeline on the LDC becoming an open access transporter.[6]

As initially issued, in its Notice of Proposed Rulemaking (NOPR) on capacity brokering on interstate pipelines, the FERC has proposed that any party, including an LDC that holds firm transportation rights on a specific pipeline, would be permitted to assign or "broker" those rights to third parties if two conditions are met. Those conditions are that the party obtain a blanket broker certificate from the FERC and that the pipeline hold both a blanket open-access transportation authorization and a system brokering

---

[5] "NARUC Urges Congress to Enact Legislation Clarifying State Jurisdiction over Natural Gas Bypass," *NARUC Bulletin*, October 10, 1988, pp. 6-7. The bills are also supported by the American Public Gas Association, the Associated Gas Distributors, and the Citizen/Labor Energy Coalition. See "Distributor, Consumer Groups Promoting Market Anti-Bypass Measure," *Inside F.E.R.C.*, April 11, 1988, p. 12.

[6] "Hesse Turns Up Heat to Get LDCs to Become Open-Access Transporters," *Inside F.E.R.C.*, May 9, 1988, pp. 1-2. The term capacity brokering, as used by the FERC, is actually a misnomer. The NOPR actually addresses the issue of reselling capacity, not brokering it.

certificate. Once these two conditions are met, the party, including a complying LDC, would be free to price the brokered capacity at whatever the market will bear, subject to a price cap. The cap would be set by the FERC and referenced to either the pipeline's firm transportation rate or to conditions in the end-use market. Thus, for an LDC to resell its firm capacity rights on an interstate pipeline it must submit itself to FERC jurisdiction for its brokering activities.

While the blanket broker certificate that the FERC would require LDCs to obtain would require them to conduct their brokerage in accordance with any applicable state regulations, the certificate nonetheless constitutes a certificate of public convenience and necessity under the Natural Gas Act (NGA). As a result the LDC would be required to broker capacity on a nondiscriminatory basis to comply with FERC-imposed price caps, to comply with tariff requirements, to file reports with the FERC, and to comply with the FERC general conditions applicable to certificates.

Chairman Hesse has announced her intent to make one of those general conditions a requirement that the LDC provide open access transportation on its distribution system. It is an open legal question as to whether the FERC may so extend its jurisdiction. Also, there are concerns that such an extension of FERC jurisdiction could reduce the reliability of gas service to end-users or, at the very least, increase the cost of pipeline service when capacity is tight.[7] More recent statements by Commissioners suggest that a case-by-case approach will be used and that these conditions may or may not be included.

The FERC Sales Conversion and Abandonment Rules Under Rules 436 and 500

An LDC has the opportunity to convert its sales contract with its pipeline to a transportation contract if the pipeline is an open-access carrier under FERC Order 436. The LDC or its customers could then look to producers to find less expensive sources of gas. The resulting savings would be realized by the LDC's customers.

---

[7] FERC Notice of Proposed Rulemaking, 53 *Fed. Reg.* 15061, et seq. (April 27, 1988).

Such a strategy, however, has some potential pitfalls. If a pipeline accepts an open-access blanket certificate, under FERC Order 436, it must provide transportation service on a nondiscriminatory basis. If an LDC takes advantage of this opportunity and converts from sales service to firm transportation service, the pipeline has been pre-granted the right to abandon sales service to that LDC. The distributor then might not be able to secure the pipeline's capacity when its own contract for firm transportation service expires. This is so because, under Order 436, the pipeline's capacity is allocated on a first-come, first-serve basis and the LDC would be at the end of the line. This concern would not only affect an LDC's willingness to buy gas on the spot market, but it might also affect an LDC's willingness to provide gas transportation services to its own customers.

The FERC has also issued its final rule intended to prevent interstate pipelines from giving preferential treatment to affiliates engaged in marketing or brokering gas.[8] The rule sets out standards of conduct for the pipelines, which require them to implement all tariff provisions in a uniform manner. The rule also prohibits pipelines that have not accepted an open access blanket certificate from offering selective discounts to their marketing affiliates. It also prohibits pipelines from giving their marketing affiliates scheduling or curtailment priorities solely on account of their affiliation with the pipelines. Other similar provisions are in the rules of conduct. However, at least one party, the Interstate Natural Gas Association of America, has raised the issue of what a marketing affiliate is. Although an "affiliate" is defined, nowhere in the order is a "marketing affiliate" defined. As pointed out by INGAA, the Commission's failure to define the term opens the door for any affiliate of an interstate pipeline engaged in the sale of interstate gas to be subject to the order, including LDCs. That would place FERC in the role of possibly regulating entities, such as an LDC and its own marketing affiliates, that are already subject to state regulation, once again threatening possible preemption of state regulation.

---

[8] Re Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, FERC Order No. 497, 43 FERC para. 61,420, 93 PUR4th 493 (June 1, 1988).

Some Background and the Missouri Task Force Survey

The results of a 1986 survey of state public utility commissions on this subject undertaken by the Missouri Public Service Commission are summarized here in this section. The survey questionnaire asked commissions about a variety of facets of their gas transportation programs and serves as a useful base, a benchmark, from which to compare the results of a 1988 NRRI survey of commission gas transportation policies, reported in chapter 2 of this report.

The FERC policies on transportation have had an immediate and significant effect on interstate pipelines, helping to spur the growth and importance of the pipelines' transporter function in lieu of their merchant function. Principally because of FERC Order 436 or regulations implementing Natural Gas Policy Act (NGPA) section 311, twenty-four major interstate pipelines were able to increase their gas throughput by 11.8 percent in 1987 as compared to 1986. During 1987, sales throughput decreased by 19.9 percent, while transportation throughput increased by 43% over 1986 levels. Overall, 64.5 percent of all gas moved by these pipelines in 1987 was under transportation rates, while only 35.5 percent was sold as sales gas.[9]

This major shift in pipeline throughput from sales gas to transportation gas presents both opportunities and pitfalls for local distribution companies (LDCs) and the state commissions that regulate them. One opportunity is for an LDC and its state commission to establish a state gas transportation policy. Such a policy would allow the LDC's customers access to a pipeline that is providing transportation service. The LDC's customers would then purchase their gas directly from the producer and pay the pipeline and the distributor a separate transportation fee.

Most LDCs offer at least some of their customers (typically large industrial customers) gas transportation service. A recent survey by the American Gas Association found that 65 out of the 79 LDCs responding provided transportation service in their 88 service areas. The principal motivation of the distributor was to maintain market share and to avoid potential bypass. Forty LDCs in 53 service areas reported experiencing the threat of customers

---

[9] "Special Report: Sales Only 35.5% of Pipe's Total in '87, But Throughput Up 11.8%," *Inside F.E.R.C.*, April 25, 1988, pp. 1-10.

bypassing them to hook-up directly with an interstate pipeline, usually to take advantage of the pipeline's gas transportation program. According to the AGA survey, 16,024 customers were using gas transportation service by LDCs.[10]

Also, most state commissions have some form of gas transportation policy. A survey conducted by a staff task force from the Missouri Public Service Commission found that, as of March 1986, LDCs and intrastate pipelines that also serve at retail provided transportation service for their customers in at least thirty-five jurisdictions.[11] The survey also showed that twenty-four commissions required their LDCs to publish and adhere to transportation tariffs, while eight commission required the LDC to file its transportation contracts with former retail customers with the commission. Ten commissions required both the tariff and the contract.[12] At the time of the Missouri Commission survey, six commissions had issued opinions and orders establishing generally applicable policies on gas transportation in the form of requirements, guidelines, or informal instructions. Other commissions either provided commission orders adopting specific transportation tariffs in individual LDC proceedings or approved transportation tariffs and contracts without orders or opinions expressing commission policy.[13]

The Missouri survey also found that several commissions had limitations on a customer's eligibility to obtain transportation service. For example, eight commissions required or permitted the LDC to have volumetric restrictions, seven commissions restricted eligibility to industrial customers, and one commission restricted transportation to gas used for boiler fuel. Also, one commission indicated that some of its transportation contracts were limited to incremental loads.[14]

Firm transportation service was offered in twenty-seven states. In twenty-three of those states, interruptible service was offered as well. In

---

[10] "Distributors Use Transportation to Keep Existing Markets, AGA Says," *Inside F.E.R.C.*, August 8, 1988, p. 14.
[11] In the Matter of the Investigation of Developments in the Transportation of Natural Gas and their Relevance to the Regulation of Natural Gas Corporations in Missouri, Case No. GO-85-264 (Mo.PSC 1986), Task Force Report, p. III-2.
[12] Ibid., p. III-4.
[13] Ibid., pp. III-4 - III-5.
[14] Ibid., pp. III-5 - III-6.

eight states, only interruptible transportation service was offered.[15]

Six state commissions responded that they had addressed the issue of whether transportation customers had the right to switch back to the LDC gas supply. This might occur either when customer-owned volumes become unavailable or need to be supplemented. Most of those states indicated that the customers would be allowed to return to the system if they paid some type of reservation or standby charge to maintain back-up supplies. In some states the reservation or standby charge was to be paid on an ongoing basis; in other states, the standby or reservation charge was to be paid (as a penalty) when the customer returned to the system.[16]

Eleven commissions said that they had established policies concerning the curtailment priority of transportation service. Six of these gave the transportation service the same priority as comparable sales service; five commissions gave the transportation service the lowest priority. Two commissions allowed customer-owned gas to be diverted to serve residential customers during supply shortages.[17]

Thirty-one commissions specified the rate design method to be used to develop transportation rates in their states. Fifteen states specified the gross margin method (applicable gas sales rate less the gas commodity cost); eleven states specified the simple margin method (applicable sales rate less both the gas commodity and demand charges); and eight states specified the cost-of-service method. A value-of-service method or some variation of the first three methods was specified by five states. Fifteen state commissions gave the LDCs the option of setting flexible transportation rates within a zone set by the commission.[18]

Twenty-six commissions responded that they had considered the issue of whether the shift from sales to transportation service might increase the cost of gas for the distributor's remaining customers. Eleven of these commissions indicated that they relied on the proper design of the transportation rates to recover sufficient revenues from the transportation customers to provide a net

[15] Ibid., pp. III-6 - III-7.
[16] Ibid., pp. III-7 - III-11.
[17] Ibid., pp. III-11 - III-13.
[18] Ibid., pp. III-14 - III-31.

benefit to all customers. No commission had made any finding that transportation service resulted in any measurable increase or decrease in the average cost of gas paid by the LDC's remaining customers.[19]

Three commissions had established a policy concerning bypass of the LDC by a pipeline or end-users. One commission indicated that it prohibited bypass; another required an end-user bypassing the system to pay an exit fee. The third commission stated that when bypass was possible the LDC was allowed to negotiate a flexible transportation tariff above variable costs, which would permit it to compete. Two commissions responded that although they had not established a formal policy, they would probably oppose bypass. A proposed bypass policy was pending at five commissions.[20]

Organization of this Report

The next chapter presents a summary of the results of a survey conducted in the spring and summer of 1988 of state commissions on gas transportation. Detailed survey responses are found in appendix B. By knowing what other state commissions have done, state regulators can better assess or reassess their own gas transportation policies. In chapter 3, some legal and economic considerations that can be used to analyze the advantages and disadvantages of different policy options are presented. Application of these considerations and discussion of the advantages and disadvantages of various state gas transportation policy options are in chapter 4.

---

[19] Ibid., pp. III-32 - III-37.
[20] Ibid., pp. III-37 - III-39.

CHAPTER 2

CURRENT STATE POLICIES

This chapter contains summary results of a survey on state commission gas transportation policies conducted by the NRRI during the spring and summer of 1988. Surveys were sent to state commission staff members in forty-nine states and the District of Columbia. Nebraska was excluded because its commission does not regulate local distribution companies (LDCs). The detailed responses, received from forty-four states and the District of Columbia, are in appendix B.

The survey questionnaire covered a variety of transportation-related issues. These included whether a commission has a gas transportation policy, what provisions are included, and commission treatment of such issues as bypass, curtailment of service, shift of revenue requirements between customer classes, and standby charges. These and other issues are discussed below.

Which Commissions Have Formulated Policies?

The NRRI asked the staff members if their commissions have considered a gas transportation policy; whether a policy has been adopted or rejected; and whether their commissions are currently considering adopting a gas transportation policy. Table 2-1 displays the responses to the questions.

The data in the two tables show that the vast majority (thirty-eight of forty-five) of the responding commissions have considered and adopted some type of gas transportation policy. This finding is similar to that of the Missouri Commission whose task force found transportation service available in thirty-five jurisdictions. Seven commissions responding to the NRRI survey--Alaska, Colorado, Florida, Hawaii, Louisiana, Maine, and Texas--have not completed consideration of a gas transportation policy. Three of those commissions, Colorado, Florida, and Louisiana, are currently considering the adoption of such a policy, however. In Maine, there is only one LDC and no

TABLE 2-1
COMMISSION ACTIONS ON GAS TRANSPORTATION*

	Has Completed consideration of gas transportation policy	Transportation policy was rejected	Transportation policy was adopted	Currently considering the adoption of a gas transportation policy
Alabama	Y	N	Y	N
Alaska	N	N	N	N
Arizona	Y	N	Y	Y
Arkansas	Y	N	Y	N
California	Y	N	Y	N
Colorado	N	N	N	Y
Connecticut	Y	N	Y	N
Delaware	Y	N	Y	N
District of Columbia	Y	N	Y	N
Florida	N	N	N	Y
Hawaii**	N	N	N	N
Idaho	Y	N	Y	N
Illinois	Y	N	Y	N
Indiana	Y	N	Y	N
Iowa	Y	N	Y	N
Kansas	Y	N	Y	N
Kentucky	Y	N	Y	N
Louisiana	N	N	N	Y
Maine	N	N	N	N
Maryland	Y	N	Y	N
Massachusetts	Y	N	Y	N
Michigan	Y	N	Y	N
Minnesota	Y	N	Y	N
Mississippi	Y	N	Y	N
Missouri	Y	N	Y	N
Montana	Y	N	Y	Y
Nevada	Y	N	Y	N
New Jersey	Y	N	Y	N
New Mexico	Y	N	Y	N
New York	Y	N	Y	Y
North Carolina	Y	-	Y	-
North Dakota	Y	N	Y	N
Ohio	Y	N	Y	Y
Oregon	Y	N	Y	Y
Pennsylvania	Y	N	Y	N
Rhode Island	Y	N	Y	N
South Carolina	Y	N	Y	N
South Dakota	Y	N	Y	N
Texas	N	N	N	N
Utah	Y	N	Y	N
Virginia	Y	N	Y	N
Washington	Y	-	Y	-
West Virginia	Y	N	Y	Y
Wisconsin	Y	N	Y	Y
Wyoming	Y	N	Y	Y
Total	38	0	38	11

Source: NRRI Survey, 1988

* See table 2-2 for a listing of whether each state uses a genuine policy statement, rule, or order, or a case-by-case approach.

** Hawaii faces a situation in which a gas transportation policy is not feasible; All of the gas used there is manufactured liquified petroleum gas, such as propane or butane. There is no natural gas and thus no natural gas transportation policy.

customers or potential bypassers have contacted the Commission or the distributor to request transportation service. In Texas, the Railroad Commission has essentially deregulated gas transportation, subject only to certain anti-discrimination strictures. In short, the reasons for commissions not considering and adopting a gas transportation policy are varied because of individual state circumstances or established commission practice.

Part of the reason for the large number of commissions listed as having adopted a transportation policy is the coding of responses. As table 2-2 shows, most of the commissions classified as having adopted a policy have pursued that policy in the form of case-by-case individual decisions instead of a generic order or rule. However, the sixteen commissions listed in table 2-2 as pursuing transportation policy through a generic order represent a significant increase over the six commissions in the Missouri survey that had issued formal opinions on transportation at that time.

TABLE 2-2

APPROACHES USED BY COMMISSIONS THAT HAVE TAKEN ACTION ON GAS TRANSPORTATION

Approach	Commissions Using that Approach
Case-by-Case; Approval of Individual Tariffs	Alabama, Arizona, Arkansas, Connecticut, Delaware, District of Columbia, Idaho, Illinois, Indiana, Kansas, Michigan, Minnesota, Mississippi, Montana, Nevada, New Jersey, North Dakota, South Carolina, South Dakota, Utah, Washington, Wyoming (N=22; 58% of commissions taking action)
Generic Policy Statement, Rule, or Order	California, Iowa, Kentucky, Maryland, Massachusetts, Missouri, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Virginia, West Virginia, Wisconsin (N=16; 42% of commissions taking action)

Source: NRRI Survey, 1988.

Some conclusions can be drawn from the fact that most of the commissions pursuing transportation policy are doing so in a case-by-case manner. First, the commissions may want to retain as much flexibility as they can. The Illinois respondent, for example, stated:

> The Ill. C.C. has developed its policy on a case by case basis. As the Ill. C.C. accepts or rejects LDC transportation rate filings, it adopts a gas transportation policy. The Ill. C.C. does not plan on a rulemaking or other formal adoption of "a policy" for gas transportation because of the need for flexibility. As new filings by LDCs are adopted, the Ill. C.C.'s policy is modified.

A commission's need for flexibility to meet changing circumstances is certainly an important one. However, from the perspective of LDCs and others such as end-users and brokers seeking to transport gas, the need for commission flexibility should be balanced against consistency and stability of policy. Such consistency is seen in the Kentucky respondent's statement that "[t]he Commission's general policy is that transportation should be available to any end-user when it can be done without detriment to other remaining supply customers."

This is not to suggest that flexibility and consistency are of necessity contradictory. A commission can certainly pursue a consistent policy in a case-by-case manner. A commission might also vary its policies across LDCs while pursuing a consistent, stable policy in its dealings with any single LDC (thus combining both flexibility and stability).

A Commission may also pursue transportation policy in a case-by-case manner because the state is served by only one or two large LDCs. Drafting a generic rule or policy would thus seem unnecessary because the new issues can be handled easily within the normal rate case process. For example, the Utah Commission approved an interruptible gas transportation policy for one distributor, Mountain Fuel Supply Company, which has 99 percent of the market in the state. Transportation has not been considered for Utah Gas Service, the other LDC in Utah.

A case-by-case approach might also be used as the first step in a process resulting in a formal policy or order. The South Dakota Commission approved tariffs for the regulated LDCs in that state. Policy and tariffs will be reviewed when a customer base is established and customer feedback received.

The Wyoming Commission also will consider a generic rule after gaining more experience from case-by-case investigations.

A commission might use a case-by-case approach while encouraging the LDCs under its jurisdiction to pursue transportation. The New Jersey Board has encouraged LDCs to implement transportation tariffs and is considering such tariffs by company. All four New Jersey LDCs have some type of transportation tariff. The Minnesota Commission also encourages LDCs to transport and has approved such plans on a case-by-case basis.

The case-by-case approach might be well suited for commissioners who see their role as one of guiding or making suggestions to LDCs on policy instead of trying to force distributors to pursue new types of options with certain consequences. Case-by-case decision making leaves the initiative with the LDC to decide whether or not to undertake transportation. Regulators, who do not want to second-guess utility managers or who feel that those managers are in a better position to judge what is best for the utility and its customers, might choose to pursue a case-by-case approach.

Table 2-1 also shows the commissions currently considering the adoption of a gas transportation policy. Most (about three-quarters) are not. Eleven state commissions, however, are. They include Arizona, which is dealing with bypass; New York, which is considering transportation of gas for cogeneration; Montana, which is considering gas transportation policies for two of its LDCs and flexible pricing for a third; West Virginia, which is considering adopting a uniform method to apply to gas transportation rates; Wisconsin which has a pending investigation of purchasing and planning practices of LDCs and the operation of the purchased gas account; Ohio and Oregon, which are revising current regulations; and Florida, which is developing a new policy. While most commissions are apparently satisfied with their policies as they are, the answers to this question suggest that there is still a significant amount of policy making occurring.

Major Provisions of Commission Policies

The NRRI survey asked about the types of provisions included in the commission policies. Table 2-3 shows which commissions included the

TABLE 2-3

PROVISIONS IN STATE GAS TRANSPORTATION POLICIES

Provision	Commissions Incorporating That Provision
Mandatory Open Access Nondiscriminatory Transportation	Arizona, California, Connecticut, District of Columbia, Iowa, Kentucky, Maryland, Minnesota, Montana, Nevada, New Mexico, New York, Oregon, Pennsylvania, Utah, Washington, Wisconsin (N=17)
Maximum (Ceiling) and Minimum (Floor) Charges, or a Mechanism for Setting Same	Arizona, California, Kansas, Massachusetts, Minnesota, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Rhode Island, South Dakota, Wisconsin (N=18)
Allocation Between Ratepayers and Stockholders of Profits or Losses Resulting from Transportation Services	California, Connecticut, District of Columbia, New York, North Carolina, North Dakota, Ohio, Oregon, Wisconsin (N=9)
Firm and Interruptible Transportation	Alabama, Arizona, Arkansas, Connecticut, Delaware, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Minnesota, Missouri, New Jersey, New Mexico, New York, Ohio, Oregon, Rhode Island, South Carolina, Utah, Virginia, Washington, Wisconsin (N=25)
Specific Maximum and Minimum Lengths for Transportation Contracts	Arkansas, California, Connecticut, District of Columbia, Minnesota, Montana, New York, South Dakota, Utah, Virginia, Washington (N=11)
Back-up Gas Service for Transportation Customers	Connecticut, Delaware, District of Columbia, Idaho, Iowa, Maryland, Minnesota, Missouri, New Mexico, New York, North Dakota, Ohio, Oregon, Pennsylvania, Wisconsin (N=15)
Preferential Treatment for Gas Produced Within Your State	Indiana, Montana, Pennsylvania (N=3)
Storage Service	Arkansas, New Jersey, New Mexico, Ohio, Pennsylvania (N=5)
Core and Noncore Markets	Arkansas, California, Idaho, Massachusetts, North Dakota, Ohio, Oregon, Wisconsin (N=8)
Maximum and Minimum Amounts of Gas to be Transported	Alabama, Arizona, Arkansas, Connecticut, District of Columbia, Indiana, Kentucky, Maryland, Minnesota, Missouri, Montana, Nevada, New York, North Carolina, Pennsylvania, Rhode Island, South Dakota, Utah, Virginia, Washington (N=20)

Source: NRRI Survey, 1988.

various types of provisions in their policies. Table 2-4 orders the provisions by the numbers of commissions using them.

TABLE 2-4

GAS TRANSPORTATION POLICY PROVISIONS
RANKED BY NUMBERS OF COMMISSIONS USING THEM

Provision	Number of Commissions Incorporating Provision in Their Policies	Percentage of Survey Respondents Incorporating Provision in Their Policies
Firm and Interruptible Transportation	25	56%
Maximum and Minimum Amounts of Gas to be Transported	20	44%
Maximum and Minimum Charges, or a Mechanism for Setting Same	18	40%
Mandatory Open Access Nondiscriminatory Transportation	17	38%
Back-up Gas Service for Transportation Customers	15	33%
Specified Maximum and Minimum Lengths for Transportation Contracts	11	24%
Allocation Between Ratepayers and Stockholders of Profits or Losses Resulting from Transportation Services	9	20%
Core and Noncore Markets	8	18%
Storage Service	5	11%
Preferential Treatment for Gas Produced Within Your State	3	7%

Source: NRRI Survey, 1988.

The tables show that the policy provisions are more or less the same regardless of whether the state approach was a comprehensive policy, an ad hoc case-by-case approach, or a single tariff. Firm and interruptible transportation, and maximum and minimum amounts of gas to be transported are rather basic types of provisions that might be included in various types of policies.

The Alabama, Arizona, Arkansas, Connecticut, Delaware, Illinois, Indiana, Kansas, Minnesota, New Jersey, South Carolina, Utah, and Washington commissions (thirteen of the twenty-five or 52 percent of commissions with such provisions) have approved firm and interruptible transportation while pursuing transportation policy on a case-by-case basis. The Alabama, Arizona, Arkansas, Connecticut, District of Columbia, Indiana, Minnesota, Montana, Nevada, South Dakota, Utah, and Washington commissions (twelve of the twenty or 60 percent of commissions with such provisions) have approved maximum and minimum amounts of gas to be transported while pursuing transportation policy on a case-by-case basis.

Many of these findings are similar to those in Missouri Commission survey, although there are some differences, indicating that state policies have changed. For example, while the NRRI found firm and interruptible transportation incorporated in twenty-five commission policies, the Missouri task force found both types of transportation in twenty-three states, firm only in twenty-seven, and interruptible only in eight. The Missouri survey results listed eight commissions as specifying duration of transportation. The NRRI found that eleven commission had specified lengths of contracts. Missouri found fifteen states that allowed LDCs flexibility to set transportation rates within a zone of reasonableness between a maximum and a minimum. The NRRI found that eighteen commissions had mechanisms in place for setting maximum and minimum charges. Six commissions in the Missouri survey had addressed the issue of using LDC system supply as back-up gas while fifteen commissions in the NRRI survey had done so. Eight commissions in the Missouri survey said that any LDC providing transportation must serve all customers requesting such service. The NRRI found that seventeen commissions had mandatory open access nondiscriminatory transportation as part of their programs. Nine commissions in the Missouri survey had specified minimum volumes to be transported. The NRRI survey found that twenty commissions had specified maximum and minimum amounts to be transported.

All of these differences illustrate the point that in the two years between these two surveys more state commissions have found it necessary to take action on gas transportation. In some instances, only a few additional commissions have needed to use a specific policy provision. In other cases, such as open access, specified volumes, or back-up gas service, a larger increase was found. The large number of commissions specifying open access is one of the more interesting findings of the NRRI survey.

As one moves down the list in table 2-4, one finds provisions, such as open access, back-up service, specified lengths of contracts, and core and noncore markets, which have been adopted by fewer commissions. Generally, these have been adopted more often by commissions using generic policy orders. Transportation policy was approached with a generic policy order or rule by eleven of the eighteen commissions that incorporate maximum and minimum charges in their transportation policies; nine of seventeen commissions that incorporate mandatory open access provisions; nine of fifteen commissions that incorporate back-up gas service for transportation customers; six of the nine commissions that provide for an allocation between ratepayers and stockholders of profits or losses resulting from transportation services; five of eight commissions that provide for core and noncore markets; and by three of the five commissions that include provisions for storage services.

The two exceptions to this trend of provisions less frequently considered being included in generic approaches to policy are specified maximum and minimum lengths for transportation contracts and preferential treatment for gas produced within the state. Only three of the eleven commissions providing for specified maximum and minimum lengths for contracts had issued generic policies or orders. Only one of the three commissions allowing preferential treatment for gas produced within the state had issued a generic rule or order on transportation.

The data in tables 2-3 and 2-4 indicate that a minimalist approach to gas transportation policy would cover the issues of firm and interruptible transportation, maximum and minimum amounts of gas to be transported, and either ceiling and floor charges for the service or a mechanism for setting those charges. More comprehensive policies will also include open access, back-up gas service for transportation customers, specified maximum and minimum lengths for contracts, allocation of profits or losses between ratepayers and stockholders, core and noncore markets, and storage service. Commissions located in gas producing states may also include provisions allowing preferential treatment for gas produced in the state.

Commission Prescribed Methods of Calculating Transportation Charges

The states use different methods of calculating the fixed-cost component in their transportation rates. The NRRI asked the staffs about four major approaches. They are simple margin, full or gross margin, cost of service, and value of service. The simple margin approach can be described as allowing the inclusion of all fixed costs in the transportation rate, except those allocated to the commodity component of the given utility's sales rate for a particular customer. These typically include that demand portion of the commodity price set by the FERC. Thus, determining the transportation rate under the simple margin approach begins with identifying the appropriate sales rate for the customer class and then deducting the entire commodity charge to arrive at a transportation rate. For example, if the appropriate sales rate for a customer were $3.00 per mcf and the entire commodity charge for the customer were $2.75 per mcf, then the transportation rate under the simple margin approach would be $.25 per mcf ($3.00 - $2.75). Seven of the state commissions identified this method as the one used for calculating transportation charges. This method has the advantage of providing captive or core customers with some protection from cost increases that might flow through the PGA clause, because the method makes the LDC neutral concerning whether gas is purchased from them or from the field. However, the method might result in some subsidies, because the simple margin based transportation rate does not reflect the utility's cost of providing the transportation service.

Table 2-5 shows that the full, or gross margin method is used by twelve commissions. These are the commissions in Alabama, Alaska, Arkansas, Delaware, Kansas, Kentucky, Minnesota, New Jersey, North Carolina, Ohio, Oregon, and Washington. This method differs from the simple margin method in that the demand or fixed costs included in the commodity rate for a given class of customers are charged as a part of the transportation rate. In other words, the transportation rate includes the entire demand cost of gas. The

TABLE 2-5

COMMISSION PRESCRIBED METHODS
OF CALCULATING TRANSPORTATION CHARGES

Method	Commissions Prescribing that Method*
Simple Margin	Idaho, Massachusetts, Montana, New York, Pennsylvania, Washington, Wisconsin (N=7)
Full Margin	Alaska, Arkansas, Delaware, Kansas, Minnesota, New Jersey, North Carolina, Ohio, Oregon, Washington (N=10)
Gross Margin	Alabama, Kentucky (N=2)
Cost of Service	Connecticut, Massachusetts, Montana, New Mexico, Virginia (N=5)
Value of Service	Arizona, Connecticut, Delaware, District of Columbia, Kansas, Massachusetts, New Jersey, New York (N=8)
No Prescribed Method	California, Colorado, Indiana, Iowa, Louisiana, Maryland, Michigan, Mississippi, North Dakota, South Dakota, Texas, Utah, Wyoming (N=13)

Source: NRRI Survey, 1988.
* The table is not necessarily completely descriptive. See appendix B for the complete state response.

LDC would recover the demand costs billed by its supplying pipeline. For example, if the appropriate sales rate for the customer were $3.00 per mcf and the commodity charge were $2.75 per mcf, of which $.50 per mcf were a demand charge, then the transportation rate under the full or gross margin approach would be $.75 per mcf ($3.00 - $2.75 + $.50). Transportation rates are set so as to make the same contribution to fixed costs as sales rates. The use of this method completely insulates other customer classes from revenue shifting as a result of the transportation rates. However, this method has the effect of moving farther from a cost-of-service based rate, and therefore can create even larger subsidies.

A value-of-service method is used by eight state commissions. These are the commissions in Arizona, Connecticut, Delaware, the District of Columbia, Kansas, Massachusetts, New Jersey, and New York. This method allows an LDC to charge what the market will bear for its transportation service. For example, under a value-of-service method an LDC might charge only a nominal amount--say $.05 per mcf--for transportation service when there is an abundance of capacity, but might charge much more--say $1.00 per mcf--when LDC capacity is scarce. This method can, but does not necessarily, result in the largest deviation from the cost of providing transportation service. However, it is extremely flexible and allows the LDC to adjust its rates downward to avoid bypass.

A cost-of-service method is used by five state commissions: those in Connecticut, Massachusetts, Montana, New Mexico, and Virginia. Use of a cost-of-service method usually begins with a detailed cost-of-service study of the costs of providing transportation service either to a customer class or an individual customer. The cost-of-service study can use either an embedded or a marginal cost-of-service methodology. The transportation rate is set at the cost of providing transportation service. A cost-of-service method has the advantage of better reflecting the cost of providing transportation service, and is less likely to contain a subsidy. However, use of the rate could possibly result in a shifting of revenue requirements from the noncore to the captive customers.

The Missouri task force found similar results. Gross margin was the most utilized method at the time of that survey also. Fifteen commissions reported using that method, while eleven specified simple margin, eight reported cost of service, and five said value of service. The increase in the use of value of service found by NRRI is a notable difference.

Other Types of Provisions

The NRRI survey included questions about other provisions found in state gas transportation policies. Those questions and the staff responses are discussed in this section.

The NRRI asked if commission gas transportation policies included provisions for interutility (LDC-to-LDC or intrastate-to-LDC) gas transportation. Twenty-seven respondents said that there were no such provisions. Table 2-6 shows that six respondents said that there were. Four respondents gave answers that were indeterminate on this point.

The Alabama Commission's policy is to apply the same rates for interutility transportation as apply for other types of gas transportation.

TABLE 2-6

COMMISSIONS WITH A PROVISION FOR INTERUTILITY GAS TRANSPORTATION IN THEIR POLICIES

Alabama
California
Michigan
Nevada
New York
Wyoming

Source: NRRI Survey, 1988.

In California, interutility transportation is a tariffed service. LDCs in Michigan can provide interutility transportation under state law. The law requires minimal commission oversight. The utilities must file their rates and contracts with the Michigan Commission, but regulatory approval is not required for a transaction. Similar to Alabama, the Nevada respondent said that the usual transportation tariff would apply to this type of transportation. In New York, LDCs providing gas for resale by other distributors also provide transportation for the customer LDC and its end-use customers. The Wyoming Commission considers interutility gas transportation on a case-by-case basis.

The four non-"yes-no" responses included the Illinois Commission. There is no specific Commission policy provision for interutility transportation, but there are "a couple" of contracts for the service. In Iowa, LDCs transporting for other distributors operate under the same rules and conditions as for end-user transportation. The Kansas respondent remarked that "interutility transportation and exchanges have been going on for decades." In Pennsylvania, an LDC can be a customer of another LDC for transportation.

The Ohio Commission has no provision in its policy for interutility transportation. However, the Commission does approve contracts for deliveries of gas from one LDC to another for system supply or for redelivery to an end-user on a downstream LDC's system.

Another question in the survey asked whether commission policy imposed any special restrictions or requirements on the end-use of transported gas.

Examples would include restricting transportation service for a cogenerator or requiring back-up gas service for end-users such as schools or hospitals that provide essential services to their customers.

As seen in table 2-7, only four commissions have this type of restriction. The Wisconsin Commission requires back-up gas or alternate fuel for essential services. The Ohio Commission policy also requires back-up for essential services. Gas use for boiler fuel in Ohio is also limited when a higher priority group is being curtailed, although this restriction might be eliminated in light of the repeal by Congress of the Fuel Use Act. In Utah, interruptible service must require back-up fuel capability. In Washington, gas use for cogeneration is restricted in one service area.

TABLE 2-7

COMMISSIONS* IMPOSING SPECIAL RESTRICTIONS OR REQUIREMENTS ON THE END USE OF TRANSPORTED GAS

Ohio
Utah
Washington
Wisconsin

Source: NRRI Survey, 1988.
* Note: This policy is under consideration in Michigan and Pennsylvania (possibly for cogeneration).

The Delaware Commission policy imposes no special restrictions. However, all hospitals and schools served by one LDC can only elect firm transportation, which includes back-up gas service. Transportation customers of another LDC, including schools and hospitals, must have dual-fuel capability in case of curtailment.

The Massachusetts DPU has not imposed any generic restrictions. Individual LDCs, however, may propose such conditions in rate proceedings. New Jersey Natural's tariff provided that transportation customers had the responsibility of installing standby equipment and maintaining a fuel supply adequate for their operations at all times. The California policy states that as long as a customer is not a core customer, it is allowed to transport gas.

The survey asked whether commission policy limited transportation service to dual-fuel customers only. As seen in table 2-8, six commissions do. The Connecticut Commission imposes such a requirement for interruptible transportation customers unless, as in the case of one LDC, customers (in this instance, asphalt plants) could demonstrate that an alternate supply was not necessary. The District of Columbia Commission imposes a dual-fuel requirement. The Utah Commission policy includes this type of restriction although it is limited to interruptible service requiring back-up fuel capability. North Carolina Commission policy also includes a dual-fuel restriction.

TABLE 2-8

COMMISSIONS* WITH POLICIES LIMITING TRANSPORTATION TO DUAL-FUEL CUSTOMERS ONLY

Connecticut
District of Columbia
Indiana (most rates require this, but no specific commission policy)
North Carolina
South Dakota (some tariffs are restricted)
Utah

Source: NRRI Survey, 1988.
* Note: Michigan has such a policy under consideration.

In Indiana, most transportation rates require dual-fuel capability, but the Commission does not have a specific policy. The South Dakota Commission has restricted some but not all tariffs in this way.

The Arkansas Commission does not limit transportation service to dual-fuel customers only. Customers whose usage is greater than 500 mcf per day qualify automatically for transportation. Customers with usage between 100 mcf per day and 500 mcf per day must demonstrate a less expensive alternative fuel capability or economic distress.

In California, the restriction imposed is minimum usage of 250,000 therms per year. In Delaware, the firm transportation customers of one LDC and the grain-dryer customers of another are not required to have dual-fuel capability. In Kentucky, adjusting transportation rates to meet competition is limited to those customers with alternate fuels.

Minnesota Commission policy is similar to Arkansas. Any customer meeting a minimum size requirement (generally 50 MMBtu/day) qualifies for gas transportation service. As in Kentucky, flexible rates are available to customers with alternate fuel capability or to those who can readily install that capability.

In New Jersey, most utilities require dual-fuel capability for transportation customers. In Pennsylvania, dual-fuel capability may entitle a customer to interruptible transportation service, although the offer of interruptible service is at the LDC's discretion. In Virginia, an end-user without dual-fuel capability may be required to sign an affidavit stating that his service is subject to curtailment.

The Missouri survey also found six commissions requiring alternative fuel capability; however, five of the six were different commissions. Only North Carolina answered "yes" in both surveys. The other five in the Missouri survey were Ohio, Pennsylvania, Florida, Delaware, and New Jersey. This may be an example of a policy that some commissions have tried and later discarded.

The NRRI also asked whether commission policy requires public disclosure of transportation service agreements. Table 2-9 shows that eleven commissions have such a requirement. The Connecticut Commission makes all information on file available to the public. The District of Columbia Commission requires LDCs to file contracts with it. No order protecting contract confidentiality has been sought by any distributors. The Indiana Commission considers transportation tariffs to be public documents. Contract quantities, however, are usually not filed. The Iowa Board requires an LDC to file two copies of each of its transportation contracts within thirty days of the execution of the agreement. The utility may use an identification number instead of identifying the end-user explicitly.

The Kentucky Commission considers all records to be public unless confidentiality is requested. Michigan state law requires all agreements to be filed with the Commission. In Oregon, public tariff rates are used. The Wyoming Commission includes transportation tariffs and contracts as part of

TABLE 2-9

COMMISSIONS* WITH POLICIES REQUIRING
PUBLIC DISCLOSURE OF GAS TRANSPORTATION AGREEMENTS

Connecticut	Michigan
District of Columbia	New Mexico
Illinois	Oregon
Indiana	South Carolina
Iowa	Wyoming
Kentucky	

Source: NRRI Survey, 1988.
* Note: Ohio has this policy currently under evaluation.

the Commission's permanent files available for public review. LDCs may request confidential treatment, however. The Illinois policy is to keep transportation rates on file with the Commission. Volumes transported are available in each LDC's annual report, which is filed with the Commission.

Commissions not requiring public disclosure include Alabama. That Commission has approved a standard transportation contract. Only deviations from the standard are filed with the Commission and thus become public. The Arizona Commission is kept advised of customer and rate changes, although public disclosure is not required. California also uses a standard form, which is public. The parties negotiate the actual terms and conditions, which are not made public. In New York, the service agreement form is filed as part of the tariff. Specific agreements with individual customers, however, are generally not filed with the Commission or made available to the public. The Ohio Commission is currently evaluating the issue of confidentiality. At present, when a utility is responding to competition, rates are confidential.

The NRRI asked whether commission policy provided for curtailment of transportation services to customers. As shown in table 2-10, twenty-nine state commissions, a major increase over the twelve commissions found by the Missouri survey, have a policy that provides for curtailment. The Michigan Public Service Commission is currently considering this issue. The Idaho Public Service Commission does not have a curtailment policy, but there is a tariff provision that allows for curtailment at the discretion of the company. Likewise, the Indiana Commission does not have a specific policy; however, most of the rates are interruptible.

TABLE 2-10

COMMISSIONS* WITH A POLICY THAT PROVIDES FOR CURTAILMENT OF TRANSPORTATION SERVICE TO CUSTOMERS

Alabama	New Jersey
Arizona	New York
California	North Carolina
Connecticut	North Dakota
Delaware	Ohio
District of Columbia	Oregon
Illinois	Pennsylvania
Iowa	Rhode Island
Kentucky	South Dakota
Maryland	Utah
Massachusetts	Virginia
Minnesota	Washington
Missouri	Wisconsin
Montana	Wyoming
Nevada	

Source: NRRI Survey, 1988.
* Note: Michigan has such a policy under consideration.

Twelve of these state commissions state that their policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users. These state commissions are the Alabama Public Service Commission, the Arizona Corporation Commission, the Delaware Public Service Commission, the District of Columbia Public Service Commission, the Illinois Commerce Commission, the Iowa Utility Board, the Kentucky Public Service Commission, the Massachusetts Department of Public Utilities, the Minnesota Public Utilities Commission, the New York Public Service Commission, the North Carolina Public Utility Board, and the Washington Utilities and Transportation Commission.

In the District of Columbia, transportation service is interruptible at the LDC's option. Thus, transportation gas would not be converted into sales gas. The Iowa Utilities Board policy is that, for transportation customers, curtailment or interruption due to capacity limitations occurs according to the priority class, subdivision, or category that the end-user would have been in if it were purchasing gas from the utility. Likewise, in Washington, curtailment is determined by sales schedule priority. In New York, attachment is subject to the capacity available after sales service. Transportation service is generally afforded curtailment levels equal to comparable sales service. There is no provision for the utility taking curtailed customer-owned gas. The Kentucky Commission stated that firm transportation is a higher priority than interruptible sales, and that interruptible sales is a higher priority than interruptible transportation. Firm sales have the highest priority.

The Massachusetts DPU explained that if a firm transportation customer's supply fails, the customer is not entitled to receive system supply unless it has contracted for backup service. If the system supply is constrained but the firm transportation customer's deliveries continue unimpaired (an as-yet hypothetical situation), the transportation customer's deliveries may be cut back on a pro rata basis under emergency regulations. However, the transportation customer would not be deprived of more than its pro rata share.

Fifteen of the commissions with policies providing for the curtailment of transportation service said that their policy can have the effect of taking transportation gas and converting it to sales gas for the use of high priority customers. The California Commission policy provides that in the event of an intrastate capacity shortage, the core customers receive priority. Then the curtailment occurs in order of priority charges, with transportation customers paying the lowest charges being curtailed first. Customers paying residential priority charges, the most expensive priority charge, are curtailed last on a pro rata basis. In the event of a supply shortage, transportation gas can be diverted to core use only if the California Commission decides that core customer curtailment is imminent.

The Maryland Commission does not explicitly address the curtailment of transportation service, but such curtailment falls under the heading of restrictions on availability of transportation service. LDCs are free to propose curtailment restrictions but bear the burden of justifying them. The Missouri Commission policy does not generally have the effect of converting transportation gas to sales gas, but a special provision dealing with system supply emergency has been incorporated into the LDC transportation tariffs. This provision allows the LDC to <u>defer</u> delivery of the customer's gas where the unavailability of gas may imperil human life or health. Otherwise, the general policy is that transportation customers should be considered within the same priority in the event of capacity limitations or constraints as they would be if they were sales customers.

The Montana Commission policy states that curtailment and interruption are reasons for terminating gas transportation on a short-term basis. The retail rates that a transportation customer could shift to are generally interruptible; however, firm general service is also available at a higher price. In New Jersey, one utility's tariff provides that if a customer's take of gas for the month exceeds 130 percent of the gas volume contracted for by that customer, the customer must interrupt the use of transportation gas until the account is balanced. Another utility's tariff provides that, after adequate notice, transportation service can be curtailed as specified in the winter service agreement.

The North Dakota Commission policy can have the effect of converting transportation gas into sales gas if, by contract, customers agree to this. The Ohio Commission curtailment policy is governed by utility-specific curtailment plans. Current guidelines provide for transporters to continue delivering 50 percent of the production during a system curtailment, with the utility making up the converted volumes of gas at a later date. The Oregon Commission policy can convert transportation gas into sales gas for high priority users only during emergency situations. In Rhode Island, the LDC on its own can decide to discontinue service to transportation customers so that the needs of firm customers can be met. In Utah, a transportation customer of one LDC gets a 5 cent discount on the transportation rate if the LDC and the shipper agree that under specific circumstances the distributor will have the right to purchase shipper gas during periods of interruption.

The Virginia Commission rule did not establish policies governing transportation curtailment, but reviews the matter on a case-by-case basis. Curtailment of transportation gas is discouraged when the LDC experiences supply problems as a result of its own contract demand entitlements. However, if the curtailment is the result of distribution system capacity, interruptible transportation is given the same priority as interruptible sales.

The Wisconsin Commission's policy is that, in the event of capacity constraints, transportation services sold at a discount should be curtailed first. In an emergency situation, the LDC should have the right to take transportation gas and must fairly compensate the owner for it. The Wyoming

Commission requires the interruption of transportation service when it interferes with the utilities' distribution responsibilities, especially responsibilities to firm customers. The Pennsylvania Commission's policy also can have the effect of taking transportation gas and converting it to sales gas for high priority users.

The survey included a question on whether there are other important aspects of commission policy not covered in previous questions. The Illinois respondent noted that provisions generally found in transportation rates include: that transported gas is considered the first gas metered for billing purposes; an unaccounted-for gas factor is applied to transport volumes; and transportation customers who wish to purchase LDC system supply gas once again are treated as new customers.

The Maryland Commission tries to encourage smaller LDCs to offer transportation services. The smaller distributors are not presently subject to the Commission's guidelines and policies on transportation service, and thus not required to offer those services.

The Massachusetts DPU policy is in transition. The Department had ordered simple-margin pricing to put firm transportation in place quickly as the regulators would not have the time to review an up-to-date cost-of-service study for each LDC. The Department ordered a cost-based rate when it conducted its first hearing on a firm transportation rate.

Minnesota policy states that rates may not change (flex) to compete with district heating or renewable resources. In Missouri, load balancing should be included in transportation tariffs.

The Pennsylvania Commission has ordered that if a rate provides for a fixed maximum daily quantity, then transported gas should be considered last through the meter. If a customer is sold gas by the LDC under an open-ended rate schedule (one without a fixed maximum daily quantity), however, transported gas may be considered first through the meter. The PUC has also ordered that a utility providing transportation service must reflect in its tariff, at a minimum, a three-month time period within which the transportation customer will balance its deliveries and withdrawals from the utility's system.

Wisconsin Commission policy mandates that LDCs should not divert low cost gas from its system supply in favor of individual end-users. The LDC may obtain and sell on a best-efforts basis a "spot portfolio" of gas. If an LDC does not use this spot portfolio approach, it may market its services only through a subsidiary or outside its service territory.

Interstate pipeline capacity in Connecticut is currently constrained during the winter peak season. Thus, a comprehensive policy offering a menu of services is not possible. The Commission may formally initiate a policy, if necessary to meet end-user need when the capacity problem is solved.

Bypass

The NRRI asked the commissions whether, in formulating their gas transportation policies, or in deciding not to adopt such policies, they had issued a statement or order concerning bypass of a distributor by end-users or intrastate or interstate pipelines. Recall, bypass means more than simply converting from LDC sales service to transportation service. Bypass here means customers leave the LDC system entirely by directly hooking-up with a pipeline usually to take advantage of the pipeline's gas transportation program. As shown in table 2-11, a large number of state commissions have not issued orders or findings about the possibility of bypass. Indeed, only seven state commissions have issued such orders or findings, while three commissions have proceedings pending. This total represents somewhat of an increase over the three commissions that the Missouri task force found had taken action. It is still a small, given the visibility of the issue.

TABLE 2-11

COMMISSIONS* THAT HAVE ISSUED ORDERS OR FINDINGS ABOUT THE POSSIBILITY OF BYPASS

Arkansas
Kansas
Kentucky
Missouri
Montana
Oregon
Virginia

Source: NRRI Survey, 1988

* Note: Orders or findings are pending in Alaska, Arizona, and Pennsylvania

Of the seven commissions that have considered bypass, the Arkansas Commission discourages bypass and places responsibility to prevent it on the LDC. The Kansas Commission has a policy of prohibiting bypass of the LDC. The possibility of bypass is of great concern to the Kentucky Commission. The geographic location of Kentucky makes bypass a possibility because numerous interstate pipelines cross the state. Because of this the Commission has tried to facilitate transportation using LDC facilities. The Kentucky Commission requires a certificate of convenience and necessity before any entity, including an interstate pipeline, is allowed to construct facilities that would physically bypass an LDC.

The Missouri Commission issued a report and order in its Docket GO-85-264 which dealt with some of the unresolved legal issues related to gas transportation. Specifically, the Commission addressed its authority relative to prohibiting bypass. The Montana Commission is handling bypass by considering a proposed flexible pricing tariff for transportation rates. Bypass has not yet been observed in Oregon, but the Commission there has a stated policy in Order 87-402 that it would authorize discounts to compete with bypass on a case-by-case basis if the need arose. The Virginia Commission's position on bypass is that appropriately designed embedded cost-of-service rates should eliminate uneconomic bypass. The Alaska, Arizona, and Pennsylvania Commissions are currently considering the bypass issue.

Several other commissions that have not issued orders or findings about the possibility of bypass have seriously considered the issue. For example, the Connecticut Commission has taken note of the concept of bypass in prior proceedings. This is a direct result of the interstate capacity shortage problems faced in the state. Because any bypass would necessitate expansion of existing capacity on the already constrained interstate pipeline facilities, it would appear to be an uneconomical alternative. The Utah Commission has not needed to address this issue because its one major LDC receives all of its gas through an affiliated pipeline. In Indiana, a statute requires bypassers to file for a certificate of public convenience and necessity.

The Massachusetts Commission is aware of two instances of proposed bypass, that is, direct hookup to the interstate system. Both involved municipal electric companies. In one case the would-be bypasser sought a declaratory order on conditions that should govern bypass and then withdrew its proposal. The Arizona Commission has established that there are many potential opportunities for bypass in the state--one reason for the pending proceeding.

While the New Jersey Board has not issued an order or finding about bypass, it has indicated its opposition to bypass in a litigated case. Also, New Jersey has quantified potential bypass in the decision and order In the Matter of the Petition of South Jersey Gas Company Against Sunolin Chemical and the B.F. Goodrich Company, BPU Docket No. GO8702-82.

The Illinois Commission has also considered bypass, even though it has not issued orders or findings directly on the topic. The Commission has taken the position that uneconomic bypass, that is, bypass to avoid rate subsidies, should be prevented. The Commission has noted that the threat of bypass helps further the development of individual cost-based transportation rates by uncovering subsidies in class-average transportation rates. The availability of individual cost-based transportation tariffs reduces the incentive to bypass. The Commission has indicated its belief that flexibility is needed. Potential bypassers should not be tied to class-average rates. Allowing LDCs to have some flexibility from setting class-average rates would allow transportation rates to be negotiated with potential bypassers which would cover costs and yet prevent bypass. The Commission approved NI-Gas's Rate 17, Contract Service based on this belief. While the Illinois Commission has not quantified the potential for bypass for the entire state, the Commission has considered both the potential loss of the end-user and the cost of bypass in specific instances when bypass has been proposed. Flexible cost-based transportation rates have had the desired effect thus far. There has been only one case of bypass in Illinois.[1]

---

[1] It is worth noting that the Illinois Supreme Court in 1953 determined that the Illinois Commerce commission did not have the authority to prohibit bypass. In the case of Mississippi River Fuel Co. v. Illinois Commerce Commission, it was held that the pipeline was not a public utility under the Commission's jurisdiction because transmission was not offered for public use.

Groups of LDCs and Customers Acting Collectively

The NRRI also asked the state commissions whether any groups of LDCs had acted collectively to buy gas and whether the commissions encouraged or discouraged such a practice. Only two commissions answered that groups of LDCs have acted collectively to purchase gas. The Alabama Commission noted that groups of municipal systems that are not under its jurisdiction have collectively bought gas, but that no jurisdictional LDCs have done so. The Commission neither encourages or discourages such collective buying. Also, the Arkansas Commission has observed that a group of LDCs has acted together. Here too, the Commission neither encourages nor discourages such collective buying.

With only a few exceptions, most state commissions have not observed at any time LDCs acting collectively, and most state commissions have no policy on the subject. One exception is the Iowa Utility Board, which encourages such collective buying, although none has yet occurred. The Board directed the LDCs to meet, to investigate joint purchasing, and to file a report with it. The LDCs' report concluded that joint purchasing was not feasible. The Wyoming Commission has observed that groups of affiliated LDCs have acted collectively to buy gas. The Commission policy is to encourage any method of obtaining energy that lowers utility costs while maintaining continuity of service.

As shown in table 2-12, ten commissions report that groups of customers have acted collectively to purchase gas. In the District of Columbia, the D.C. Hospital Energy Cooperative, a group of seven hospitals, has bought gas. The Illinois Commission reported that the only collective buying that it is aware of consisted of purchases made by the same end-users for different locations. The number of locations range from 2 to 534. In Iowa, groups such as colleges, hospitals, and affiliated entities have collectively bought gas. Groups of customers have acted collectively in Arizona, Kansas, Michigan, New Jersey, New York, Ohio, and Utah. In Michigan, schools in the same district have joined together to buy gas jointly for the whole district. In Ohio, some end-users with multiple delivery points pool their volumes. Also, there are some school consortiums pooling gas. In Utah, a group of state-owned universities is attempting to buy collectively. One Alabama LDC bought gas for transportation to a group of customers, acting as agent for the group, in order to keep the customers on line.

TABLE 2-12

STATES IN WHICH GROUPS OF CUSTOMERS HAVE ACTED COLLECTIVELY TO BUY GAS

Arizona
District of Columbia
Illinois
Iowa
Kansas
Michigan
New Jersey
New York
Ohio
Utah

Source: NRRI Survey, 1988.

The NRRI asked the state commissions that had observed groups of customers buying collectively whether the antitrust implications of such buying had been reviewed. None of the commissions reported making a review. However, some Iowa LDCs have investigated the antitrust implications of their joint purchases. The New York Commission does not review customer agreements with producers. The Ohio Commission policy is that Commission approval of transportation arrangements does not constitute state action for the purpose of applying the state and federal antitrust laws.

LDC Marketing Affiliates

The NRRI asked the commissions whether any of the LDCs in their states had established marketing affiliates, that is, an affiliate or a subsidiary set up to market gas from producers to end-users. As shown in table 2-13, twenty-one commissions report that marketing affiliates have been established in their states. This widespread phenomenon is reported by the Arizona Corporation Commission, the Arkansas Public Service Commission, the Idaho

Public Utilities Commission, the Indiana Utility Regulatory Commission, the Iowa Utility Board, the Kansas Corporation Commission, the Kentucky Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Nevada Public Service Commission, the New Jersey Board of Public Utilities, the North Carolina Utilities Commission, the Ohio Public Utility Commission, the Oregon Public Utility Commission, the Rhode Island Public Service Commission, the South Carolina Public Service Commission, the South Dakota Public Utilities Commission, the Texas Railroad Commission, the Utah Public Service Commission, the Washington Utilities and Transportation Commission and the Wyoming Public Service Commission.

TABLE 2-13

STATES IN WHICH LDCs HAVE ESTABLISHED MARKETING AFFILIATES

Arizona
Arkansas
Idaho
Indiana
Iowa
Kansas
Kentucky
Michigan
Missouri
Nevada
New Jersey
North Carolina
Ohio
Oregon
Rhode Island
South Carolina
South Dakota
Texas
Utah
Washington
Wyoming

Source: NRRI Survey, 1988.

The NRRI then asked the state commissions whether the LDCs or their marketing affiliates are helping customers to purchase gas on the spot market.

As shown in table 2-14, twenty-four commissions said that they had. Perhaps not surprisingly, there is a substantial overlap between the states with LDC marketing affiliates and states in which an LDC or its marketing affiliate has helped customers to buy gas on the spot market. There are some differences, however.

TABLE 2-14

STATES WHERE LDCs OR THEIR MARKETING AFFILIATES HELP CUSTOMERS BUY SPOT GAS

Alabama	New Jersey
Arizona	North Carolina
Arkansas	North Dakota
Idaho	Ohio
Indiana	Oregon
Iowa	Pennsylvania
Kansas	South Carolina
Kentucky	South Dakota
Michigan	Texas
Minnesota	Utah
Missouri	Virginia
Nevada	Wisconsin

Source: NRRI Survey, 1988.

In Alabama, as noted earlier, an LDC (without an affiliate) has acted as an agent for groups of customers interested in buying gas on the spot market. Reportedly, the motivation of the LDC was to keep the customers on line. Also, in Minnesota, North Dakota, Pennsylvania, and Virginia, LDCs without marketing affiliates have been helping their customers to buy spot gas. Even though there have been marketing affiliates set up by LDCs in Rhode Island and Washington, thus far neither the distributors nor the marketing affiliates has helped customers to purchase gas on the spot market. LDCs in New York provided information on pipelines and pipeline sources of gas to customers. Several LDCs in Pennsylvania provide agency agreements on an optional basis to their customers.

As shown in table 2-15, in six states charges have been made that the LDC or its affiliate has discriminated against third party brokers or other large customers. Such charges of discrimination can arise in the context of an LDC or its affiliate being given preferential treatment when allocating pipeline or distribution system capacity available for transportation.

TABLE 2-15

STATES WHERE DISCRIMINATION BY THE LDC
OR ITS MARKETING AFFILIATES HAS BEEN CHARGED

California
Kansas
New Jersey
Ohio
Texas
Wisconsin

Source: NRRI Survey, 1988.

The California Commission staff investigated the discrimination charges and found that the allegations could not be documented. Since then, the Commission has held workshops, and the utilities have made numerous filings concerning the rules of gas transportation. Brokers and large customers in Kansas have charged discrimination against the LDCs or their marketing affiliates. The Kansas Commission has not yet heard these cases. Third party brokers and large customers in New Jersey have made informal allegations to the Board concerning discrimination by LDCs or their marketing affiliates in allocating pipeline capacity. However, no complaints have been filed.

Brokers and large customers in Ohio have charged discrimination. In particular, Columbia Gas of Ohio buys gas on behalf of some transportation customers, as does the East Ohio Gas, River Gas, and National Gas and Oil Companies. Allegations have been made that East Ohio Gas provides transportation service for gas volumes that it would normally sell to customers and not for gas available independently from producers or brokers. The Commission has, so far, permitted this. The customer is generally unharmed, but the producers and brokers believe that the practice makes for unfair competition.

In Texas, there have been allegations that the LDCs and marketing affiliates, when allocating pipeline capacity, are discriminating against third party brokers or large customers who have bought their own gas. The charges of discrimination are currently being investigated.

In Wisconsin also discrimination has been charged. In a generic case, docket 05-GI-102, brokers intervened and raised the issue of the use of excess market power by LDCs. However, the Wisconsin Commission has not yet received any complaints regarding specific instances of discrimination by the LDCs.

Shift of Revenue Requirements

As shown in table 2-16, sixteen commissions have issued a policy statement or order about the possibility of an LDC's transportation rates causing a shift of revenue requirements from one class of customers (mainly noncaptive customers) to another (mainly captive customers).

TABLE 2-16

COMMISSIONS THAT HAVE ISSUED A POLICY STATEMENT OR ORDER ABOUT THE POSSIBILITY OF AN LDC's TRANSPORTATION RATE RESULTING IN A SHIFT OF REVENUE REQUIREMENTS FROM ONE CLASS TO ANOTHER

Alaska	Missouri
California	Ohio
District of Columbia	Pennsylvania
Illinois	South Carolina
Iowa	Virginia
Kentucky	Washington
Maryland	Wisconsin
Massachusetts	Wyoming

Source: NRRI Survey, 1988.

Some of these commissions are considering the issue of shifting revenue requirements. The Alaska Commission order, for example, only discussed the issue. The Kentucky Commission has set the issue for future rate cases in its orders concerning flexible transportation rates. The Commission has not made any presumptions as to where the difference should be recovered. The

Massachusetts DPU, in Order DPU 85-178, solicited comments on the proper method of reallocating costs following customer migration. The Department has not yet taken a final position on this question. The Washington Commission addressed the issue in the Cascade Natural Gas case (Cause No. U-86-100), and there is legislation pending.

Other commissions have already taken action. The California Commission will have annual proceedings to allocate costs based on actual usage. This will insulate all classes of customers from cross-subsidies. The basis of the cost allocation is equal cents per therm on a cold year throughput. Thus, the risk of throughput after the cost allocation is upon the utility. The utility has the authority to discount rates to increase throughput. The District of Columbia Commission reports it has set a value-of-service transportation rate with volumetric limitations to handle this problem.

In Illinois, most transportation rates incorporate a lost and unaccounted-for gas factor in order to prevent the shifting of revenues which would otherwise occur when a customer transports rather than buys system supply. Without such a factor revenues would shift because lost and unaccounted-for gas is accounted for in the PGA clause, which applies only to system gas. The Iowa Board stated in its May 30, 1986 Order Commencing a Rulemaking that LDCs may not transfer any costs of released gas to any other customer. It has stated in its rules that transportation charges and rates shall be based on the cost of providing the service. The Iowa Board may also disallow any costs that the LDC attempts to shift.

The Maryland Commission has provided that its transportation rate should be based on gross margin. The Missouri Commission's policy is based on the view that the LDC should be financially indifferent whether it provides sales or transportation service. The transportation customers are responsible for transportation service-related costs, and the existing cost recovery responsibilities among LDC customer classes is to be maintained.

The Ohio Commission provides that the maximum charge for transportation be based on gross margin. There are currently no official floors, although the Commission does require that all variable costs of service plus a contribution to utility fixed costs be recovered. Although gross margin should prevent profits, the current guidelines do not guarantee rate recovery of losses due to downwardly flexible rates. Allocation between ratepayers and stockholders of such rate recovery occurs in subsequent rate cases.

The Pennsylvania Commission has regulations designed to keep noncaptive customers on the gas system, albeit at a lower rate, rather than to lose their contributions to the company's fixed costs. The LDC has the burden of proving that costs must be shifted to captive customers. The South Carolina Commission handles this issue by setting the margin for transportation service the same as for a regular system sale. The Virginia Commission's initial policy was to require that transportation rates be cost-based and that sales rates should be gradually changed to reflect equalized returns for each customer class. The initial policy resulted in a migration of interruptible sales to interruptible transportation service.

The Wisconsin Commission requires the use of a simple margin approach to address this problem. The Commission has created a presumption that the simple margin approach is cost-based and the parties have the burden of showing otherwise in a rate case. Thus far, no LDCs have attempted to move away from the simple margin approach. The Wyoming Commission uses a case-by-case approach in an attempt to require, where possible, any transportation service that displaces distribution service to benefit all classes of customers and to make the transportation rate cover the revenues of the lost distribution service.

As shown in table 2-17, ten states have already experienced a shifting of revenue requirements among customer classes as a result of the implementation of gas transportation policies by the LDCs. In Indiana, one utility has a below-cost transportation rate which shifts part of the revenue requirement to the other customers through the gas cost adjustment filing. Otherwise, any shift in revenue requirements has been seen in the cost-of-service studies done in rate cases. Several other LDCs have rates that cover less than full costs.

In Kentucky, based on the experience of one case, the Commission permitted a small amount of the revenue requirement to be shifted from the industrial class to the residential class, although not as great a shift as proposed by the company. In New Jersey, the Board has attempted to minimize

TABLE 2-17

STATES IN WHICH SHIFTS OF REVENUE REQUIREMENTS AMONG CLASSES HAVE OCCURRED AS A RESULT OF THE IMPLEMENTATION OF GAS TRANSPORTATION POLICIES BY LDCs

Indiana
Kentucky
New Jersey
New York
South Carolina
Texas
Washington
Virginia
Wisconsin
Wyoming

Source: NRRI Survey, 1988.

the revenue requirements shift. In New York, the Commission responded to a shift in revenue requirements in a specific case by reducing firm transportation rates to reflect a lower cost related to that service. The revenue impact was imputed to firm sales customers. In South Carolina, a shift of revenue requirements has occurred because of the pressures of alternate fuel prices. In Texas, the effects of shifts of revenue requirements are addressed in subsequent rate hearings.

In Wisconsin, the Commission has only approved shifts in revenues established system large commercial, industrial, and interruptible classes. The use of gross margins (netting out the cost of gas) should result in the same distribution margin going to the LDC whether the therm is system gas or transportation gas. If the LDC chooses to lower its transportation rate downward more, the shareholders make up the unrecovered costs.

While the Wyoming Commission has not yet had to address shifting revenue requirements in a rate case, cost shifts occurred when a large industrial customer was lost by an LDC. The Commission has been advised that filings for increased rates based on lost industrial customers will be forthcoming. The Commission has required companies to absorb the lost revenue when they choose to provide transportation service is made available below cost to retain a customer.

Costs and Complexity of Gas Procurement and Operations

The NRRI asked about the effects of transportation service on LDC gas procurement and gas operations, particularly whether the cost and complexity of those operations have increased or decreased because of transportation. Seventeen state commissions, shown in table 2-18, reported that there has been an increase in either the costs or complexity of gas procurement and operations.

TABLE 2-18

COMMISSIONS THAT HAVE EXPERIENCED AN INCREASE IN COSTS AND COMPLEXITY OF GAS PROCUREMENT AND OPERATIONS

California (gas operations)
Illinois
Indiana
Kansas (complexity only)
Kentucky (complexity only)
Massachusetts (complexity only)
Minnesota (complexity only)
Missouri (complexity only)
New Mexico (increased take-or-pay payments)
New York
North Dakota
Ohio (complexity, costs sometimes)
Pennsylvania (complexity only)
South Carolina
Texas (complexity only)
Utah (expected)
Wisconsin

Source: NRRI Survey, 1988.

The impact of transportation service upon LDC gas procurement and system reliability is a topic currently under investigation by the California Commission. However, the Commission has observed that gas transportation significantly increases the complexity of LDC gas operations.

The Illinois Commerce Commission has found that the provision of transportation services has increased the complexity of gas procurement and operations. The LDCs have more decisions to make concerning gas supply sources, pipeline transportation service, and coordination of system operations. In Indiana, the complexity of one distributor's gas procurement activities has increased, because the utility must frequently coordinate with its end-users to assess how much gas each end-user requires from the LDC and how much the end-user is transporting. Consequently, the cost associated with gas operations has also increased. Transportation per se has had little effect on gas operations of New York LDCs. However, the developing spot market has required utilities to devote more attention to their own purchasing practices.

The LDCs in Wisconsin have reallocated and sometimes added staff for transportation service. These changes are reflected in the institution of fixed monthly transportation charges. In addition, the staff from the LDCs and the Commission meet more frequently to discuss transportation service.

The North Dakota Public Utilities Commission believes that the cost and complexity of LDC operations have increased, although it has no measure of the extent. In Utah, the actual impacts are not known. The Utah Commission, however, anticipates that the cost of gas operations will increase because the complexity of the operations will increase.

The Kansas, Kentucky, Massachusetts, Minnesota, Missouri, Pennsylvania, and Texas Commissions have also observed that LDC gas procurement and operations have become more complex. However, Kansas, Kentucky, and Minnesota have no information on costs. As observed by the Missouri Public Service Commission, many LDCs are participating in spot market purchasing for system supply. They have been successful in temporarily reducing their gas costs. However, this has been associated with increased complexity, particularly in the areas of bookkeeping, accounting, billing, and accountability.

Similarly, the Massachusetts Department of Public Utilities has found that LDC procurement activities are becoming more complex due to the fragmenting of the market. Utilities have reported that the increased effort expended on more aggressive procurement, however, results in commodity cost savings which more than offset the increased costs of operations. In a few instances, companies have been willing to pay minimum bill charges for gas not taken in order to take spot gas instead of system supply.

In Ohio, LDCs with substantial amounts of transportation have had to reorder their purchasing in order to maintain throughput and least cost purchasing for system supply. The specific increase or decrease of costs varies company by company, but costs and complexity have increased for most utilities.

In Virginia, transportation has resulted in rate unbundling. This general trend allows LDCs to be better able to quantify the price elasticities of various markets. The enhanced perception of the markets should promote more efficient gas purchasing practices.

Continued Service to Captive Customers

The NRRI asked if commission policy included any provisions to help guarantee continued, reliable service by LDCs to captive customers and what effects, if any, those provisions had. As seen in table 2-19, fourteen commissions have such provisions.

TABLE 2-19

COMMISSIONS* THAT HAVE PROVISIONS IN THEIR GAS TRANSPORTATION POLICIES TO HELP GUARANTEE CONTINUED, RELIABLE LDC SERVICE TO CAPTIVE CUSTOMERS

California
Delaware
Illinois
Iowa
Kentucky
Maryland
Massachusetts
Missouri
Montana
New York
Ohio
Pennsylvania
Washington
Wyoming

Source: NRRI Survey, 1988.
* Note: Such a provision is pending in Michigan.

The California Commission has held hearings on and is investigating the impact of transportation services on LDC procurement and system reliability. Distributors' obligations to serve captive customers remain unchanged in the new industry structure. The Delaware Commission asks LDCs to structure their gas entitlements to continue to provide reliable services to core customers.

The Illinois Commission has had one case in which limited LDC capacity forced the distributor not to transport for end-users so that it could purchase gas for its system supply. The Illinois Public Utilities Act requires the Commission to investigate these types of issues as part of least-cost planning. Thus far, there have been no specific effects attributable to the policy.

The Iowa Code requires utilities to furnish reasonably adequate service and facilities. The Code also requires LDCs to take necessary steps to minimize purchased gas costs while assuring an adequate long-term gas supply.

The Kentucky Commission has stated that continued reliable service to captive customers is the intent of its overall policy. Transportation is encouraged to the extent that captive customers are not unduly harmed.

The Maryland Commission does not require an LDC to provide transportation service if the distributor's capacity is needed to serve firm sales customers. The LDC must prove, however, that it has insufficient capacity to provide the transportation services.

The Massachusetts DPU held hearings in December 1980 and January 1981 on LDC practices. At the time, a regional gas shortage was occurring and the Department ruled that distributors could make interruptible sales or move interruptible volumes only when revenues covered avoidable costs. Margins earned from interruptible service would be credited to firm sales customers instead of being retained by the LDC (as was the former policy). The DPU respondent believes that this policy shift has eliminated any incentives that distributors once had to move interruptible volumes at times when doing so would jeopardize captive customers' supply. There has not been an acute shortage of gas in Massachusetts since the change in policy.

Missouri Commission policy includes a System Supply Emergency provision, which has been incorporated into LDC transportation tariffs. The System Supply Emergency provision allows a distributor to defer delivery of a customer's gas if the unavailability of gas elsewhere would endanger human life or health.

New York policy, similar to Maryland's, provides for mandatory transportation only if the LDC has excess capacity after furnishing reliable service to sales customers. Montana Commission policy mandates that captive, core customers are to have the highest priority service.

The Ohio Commission policy requires back-up gas service for high priority end-users without alternative fuels. In some instances, high priority customers have been required to be firm transporters, with full utility back-up service, or to have adequate supplies of alternative fuel.

Pennsylvania Commission regulations require an LDC to interrupt transportation service if the distributor's capacity constraints place captive customers at risk. Transportation customers must also sell their gas to the LDC in a time of shortage where residential customers are at risk.

Washington state has a statutory requirement for utilities to provide service. The Wyoming Commission policy is to prevent contract or applications for transportation service from jeopardizing reliable service or unfairly raising distribution service rates.

Traditional Service for Transportation Customers

The NRRI also asked whether commissions required the LDCs, because of an obligation to serve, to provide transportation customers, who were formerly firm or interruptible sales customers, with traditional utility services (procurement and transportation) if those customers want to return to the distributors' systems as regular customers. Twenty commissions, as seen in table 2-20, have such a requirement. One other commission would probably impose that requirement.

The Arizona Commission policy is an implied requirement, with nothing stated specifically in transportation tariffs. The Delaware Commission policy states that interruptible transportation customers that request firm service cannot then switch back to interruptible transportation. They must also sign a one-year contract for service.

The Kentucky Commission imposes the requirement to provide service only if the LDC has been collecting a reservation charge. Otherwise, the LDC can charge a "reasonable" re-entry fee. The Montana Commission policy also includes such a requirement to serve, but the loads affected are generally interruptible and low priority.

TABLE 2-20

COMMISSIONS* THAT REQUIRE AN LDC
TO PROVIDE TRANSPORTATION CUSTOMERS,
WHO WERE FORMERLY SALES CUSTOMERS,
WITH TRADITIONAL UTILITY SERVICE

Arizona	Missouri
Arkansas	Montana
Delaware	New Jersey
Idaho	Ohio
Illinois	Oregon
Iowa	South Carolina
Kansas	South Dakota
Kentucky	Wisconsin
Maryland	Wyoming
Minnesota	

Source: NRRI Survey, 1988.
* Note: This matter is under investigation in California and Michigan. Alabama reports it has no policy but would probably require this.

The North Dakota Commission requires LDCs to provide service to returning customers if the company has available gas or can contract for gas to serve a customer. In Pennsylvania, transportation customers declining standby service would receive sales service only if the LDC had capacity available to serve them.

The South Dakota Commission also imposes a requirement on LDCs to serve but only to the extent of firm deliveries contracted for from the pipeline. The Oregon Commission policy applies to firm service of less than 500 therms per day.

Standby and Reservation Charges

The NRRI asked if the commissions allowed the LDCs to charge a transportation customer a standby or reservation charge. Table 2-21 shows that eighteen commissions do, with four others currently considering or investigating the possibility.

TABLE 2-21

COMMISSIONS* THAT ALLOW AN LDC TO CHARGE THE TRANSPORTATION CUSTOMER A STANDBY OR RESERVATION CHARGE FOR RENEWED TRADITIONAL SERVICE

Delaware	New York
Iowa	Ohio
Kentucky	Oregon
Maryland	Pennsylvania
Massachusetts	South Carolina (one company)
Minnesota	South Dakota
Missouri	Virginia
New Jersey (sometimes)	Wisconsin
New Mexico	Wyoming (on a case-by-case basis)

Source: NRRI Survey, 1988.
*Note: Standby or reservation charge policies are under consideration or investigation in Alabama, Arizona, California, and Indiana.

The NRRI results represent a major change from the results found in the Missouri survey. The Missouri questionnaire had asked if charges were accessed against customers for switching from transportation to sales. Only three commissions, New Mexico, Ohio, and West Virginia, said such was the case. This has apparently been an important area of commission concern in the last two years.

In Delaware, firm transportation customers are assessed a standby charge based on the fixed cost of pipeline supply. The Iowa Code requires a distributor to charge a reconnection fee when an end-user receiving only transportation service seeks to return to the system supply. System supply reserve service entitles an end-user to return to the system up to the amount of capacity purchased. The Iowa Code requires all rates and charges for transportation to be based on the cost of providing the service.

In Kentucky, the amount of the standby or reservation charge is a function of demand charges. Re-entry fees would be determined on a case-by-case basis with the Kentucky Commission's approval, taking into account the amount of transportation service and the distributor's pipeline supply commitments. LDCs in Maryland may propose standby or reservation charges in their transportation tariffs. Those charges must be approved by the Maryland Commission.

In Massachusetts, standby or reservation charges are based on the long-run demand cost of the distributor's production facilities, including pipeline demand charges and the level of investment and the annual operating expenses of local supplemental gas sources. In Minnesota, transportation customers have the option of continuing to pay the demand charge for gas sales. In New Mexico, charges are based on the LDC's take-or-pay risk.

The New York Commission policy is to allow a firm customer, if that customer chooses to do so, to pay a reservation charge to reserve the right to return to firm sales service. The charge is equal to the average demand component of the average cost of purchased gas for resale and is billed on every unit of transported gas.

Some distributors in Ohio are charging for standby or back-up service by allocating demand costs and crediting the charges back to the gas cost recovery rates to prevent double recovery. The allocation method varies by utility. In Oregon, standby or reservation charges are included in the full margin rate as pipeline demand charges. In Pennsylvania, standby service rates must be cost-based and reflect the actual cost of providing the service.

The Virginia Commission encourages standby services for transportation customers desiring a gas supply back up although the Commission believes that transportation customers should assume the risk of their decision. Standby charges are generally equivalent to the daily demand charges of the distributor's pipeline supplier.

In Wisconsin, the LDC must continue to charge a system sales customer converting to transportation any demand costs incurred on behalf of that customer until the distributor is able to reduce its gas committments. If the transportation customer then wishes to return to sales service, it would be treated as a new customer.

Transportation and Purchased Gas Costs

The NRRI asked a series of questions on the relationship between transportation service and purchased gas costs. The first question was whether the shift of customers to transportation service had resulted in increased purchased gas costs (demand charge related increases) for customers still on the system. As shown in table 2-22, ten commissions reported that such increases had occurred.

TABLE 2-22

STATES* WHERE THE SHIFT OF CUSTOMERS TO TRANSPORTATION SERVICE HAS RESULTED IN INCREASED PURCHASED GAS COSTS

Indiana
Michigan
New Jersey
New York
Ohio
Pennsylvania
South Carolina
Texas
Utah
Washington

Source: NRRI Survey, 1988
*Note: Iowa has this matter under investigation.

The Michigan Commission reported that demand charges are passed through to sales customers. There have been no changes in rate design. Purchased demand costs have increased for nontransportation customers in some instances in Indiana. In New York, the average cost of gas increased due to constant demand costs being recovered over smaller sales volumes. Increases in the average cost of gas were collected through the purchased gas adjustment.

In Ohio, demand charges remain in the gas cost recovery. When those costs are recovered from transportation customers for back-up or standby service, however, the revenues are credited to the gas cost recovery. The Pennsylvania Commission reviews costs in a purchased gas cost hearing to determine whether the distributor is obtaining the least expensive gas. The South Carolina Commission also allows the increased costs to be collected through the purchased gas adjustments. In Texas, the demand charges are flowed through as a part of the weighted average cost of gas.

The Utah Commission has allowed five cents per decatherm to be added to the transportation service rate. This additional revenue, credited to the gas cost balancing account (Account No. 191), is designed to offset the adverse effects of increased purchased gas costs.

The Washington Commission, responding that costs have increased for other customers, also is dealing with take-or-pay liabilities caused by this cost shifting. Take-or-pay costs may be recovered as part of the commodity gas costs. In New Jersey, some LDCs require that a customer must become a firm or interruptible service customer in order to qualify for transportation service.

The NRRI asked whether firm or interruptible transportation customers are required to pay any costs related to the distributor's gas supply. Twenty commissions, shown in table 2-23, have such a requirement.

TABLE 2-23

COMMISSIONS THAT REQUIRE EITHER FIRM OR INTERRUPTIBLE TRANSPORTATION CUSTOMERS TO PAY COSTS RELATED TO THE LDC'S GAS SUPPLY

Alabama (firm)
Arizona
California
Connecticut
Idaho
Illinois (sometimes)
Indiana
Iowa
Kentucky
Maryland (a standby charge)
Missouri
Nevada
New Jersey
Ohio (only the demand costs)
Oregon (storage and pipeline demand charges)
South Carolina (unaccounted-for-gas)
South Dakota (demand charges)
Utah
Virginia
Wyoming

Source: NRRI Survey, 1988.

The Alabama Commission requires demand charges to be assessed on all firm customers, whether sales or transportation customers. Part of the charge for transportation service in Arizona consists of the interstate pipeline's peak and annual fixed charges to the distributor. In California, certain costs have been identified as transition costs and then allocated across all customer classes. These include take-or-pay costs, uneconomic gas supplies, and system commitments made on behalf of all customers before the Commission implemented its new regulatory structure for gas transportation.

The Connecticut commission's policy is to hold transportation customers responsible for LDC gas supply costs indirectly through retained volumes for unaccounted-for losses on the system. The South Carolina Commission also has transportation customers bear some of the costs of unaccounted for gas. In Idaho, the transportation rate is set at a level high enough to compensate the LDC for gas supply management costs. In Illinois, transportation rates sometimes cover part of the purchased gas adjustment charges. This varies from LDC to LDC. Some of the distributors in Indiana recover their purchased gas demand costs from transportation customers. In Iowa, these costs are recovered from transportation customers when system supply reserve service is provided. The costs are recovered in Kentucky to the extent that demand charges are incurred by the distributor.

The Maryland Commission allows gas supply cost recovery from transportation customers if those customers are furnished with standby service by the LDC. Standby service rates are fully compensatory.

The Missouri Commission mandates that customers must pay any unavoidable pipeline charges incurred by the LDC and allocated to that customer class for sales service to the extent that the pipeline has not modified or eliminated the charges. In New Jersey, South Jersey Gas's firm transportation rates include demand, peaking and storage costs. Storage and pipeline demand charges are also included in firm transportation margins in Oregon. In Ohio, demand costs have been included in transportation rates. In South Dakota, Iowa Public Service Company charges a new transportation customer for the demand charges applicable to that customer's firm sales capacity now displaced by transportation.

The additional charge of five cents per decatherm allowed by the Utah Commission, mentioned above, is also designed to recover some of these supply costs from transportation customers. The Virginia Commission may allow the LDC to charge a transportation customer for a portion of the gas supply costs if it can be shown and quantified that the customer benefits from a specific gas supply cost. The Wyoming Commission requires firm or interruptible transportation customers' rates to cover gas supply expenses incurred as a result of the transportation.

The NRRI asked if transportation customers who had shifted from firm or interruptible sales service are held responsible for PGA-related demand charge increases. Sixteen commissions require this, as shown in table 2-24.

TABLE 2-24

COMMISSIONS THAT HOLD CUSTOMERS WHO SHIFT FROM SALES TO TRANSPORTATION SERVICE RESPONSIBLE FOR PGA-RELATED DEMAND CHARGE INCREASES

Alabama
Arizona
California (through an annual proceeding)
Idaho
Illinois
Indiana
Iowa
Kansas
Maryland
Missouri
North Carolina
Oregon
Virginia
Washington
Wisconsin
Wyoming

Source: NRRI Survey, 1988.

The Alabama Commission policy, as noted above, requires all firm customers to pay demand charges. The California Commission will be considering this issue in annual proceedings to allocate costs based on actual usage. In Illinois, the assessment of demand charges to transportation customers varies by LDC. Charges are handled through the PGA clause. The Indiana Commission allows PGA-related demand charge increases, billed by the pipelines, to be passed on to the appropriate customer classes.

The Iowa Code requires an end-user, who wishes to switch to transportation service without system supply reserve, to pay the LDC a discounted value of any contract remaining in effect at the time that transportation service begins. The discounted value would include directly assignable and identifiable costs and would not be limited to gas costs.

The Kansas Commission allows a transportation customer to be billed directly if such PGA-related increases can be identified with that customer. The Maryland Commission permits LDCs to recommend appropriate rate design changes to handle any such problems. The Commission must review and approve the rate changes.

The Missouri Commission policy, as mentioned above, states that a customer must pay any unavoidable pipeline charges incurred by the LDC and allocated to that customer class for sales service. The North Carolina Commission believes that transportation customers obtain benefits from the LDC contracts and should thus pay their share of the costs. In Oregon, demand charges are passed on through full margin rates.

In Virginia, large sales customers who transport on a short-term basis must contract for demand service from the LDC and incur demand charges regardless of actual consumption. The Washington Commission allows demand charges to be increased for transportation customers.

The Wyoming Commission, as noted above, requires firm or interruptible transportation customers' rates to cover gas supply expenses incurred as a result of transportation. The Wisconsin Commission uses a simple margin approach, which insures that the purchased gas adjustment is the same for sales and transportation customers, because both are assessed similar demand charges.

These findings also represent major departures from the trends found by the Missouri Commission staff. Twenty-six commissions in that survey said that concerns had been raised about shifts to transportation resulting in increases in the weighted average cost of gas to remaining customers. Some of those commissions (11) also responded that they had implemented some mechanisms to counteract this trend. These mechanisms mainly involved the design of transportation rates. However, none of the commissions had made any actual findings that transportation had increased or decreased the cost of gas for other customers.

As tables 2-22, 2-23, and 2-24 above show, commissions have become more aware of potential harm to customers still on the system from other customers shifting to transportation. Many commissions have also tried to do something about it, using a variety of methods.

The NRRI also asked whether the commissions allow the LDCs to charge an exit fee (or similar charge) to firm or interruptible sales customers who become transportation customers. As table 2-25 shows, only two commissions do.

TABLE 2-25

COMMISSIONS THAT REQUIRE AN "EXIT FEE" OR SIMILAR CHARGE FOR SALES CUSTOMERS WHO BECOME TRANSPORTATION CUSTOMERS

California
Iowa

Source: NRRI Survey, 1988.

In California, if a noncore customer chooses to abandon a contract for purchasing gas from a distributor, that customer would be required to make up any allocated costs not captured by the LDC in any new agreement. The Iowa Code, as noted above, requires an end-user switching to transportation service to pay the LDC the discounted value of any contract remaining in effect. While not allowing an exit fee as such, the Wisconsin Commission allows an LDC to charge a customer shifting to transportation from sales service any demand costs incurred on that customer's behalf until the distributor can reduce its nominations of gas. The Missouri survey also found little commission activity in this regard. Only one commission responding in that survey, Colorado, indicated that it allowed a charge to be assessed against sales customers switching to transportation. One other commission, Ohio, said that exit fees were assessed against former sales customers who bypassed the LDC. An exit fee appears to remain an uncommon provision of gas transportation policy.

Conclusion

This somewhat detailed overview of the results of the NRRI survey on state commission gas transportation policies has shown that the state commissions have taken action on a variety of transportation issues. Often, that action has been somewhat piecemeal with commissions proceeding on a case-by-case basis and incorporating only those provisions necessary to deal with specific situations or problems. One surprising finding in both the NRRI and Missouri surveys, given the widespread discussion of the bypass issue, was that few commissions had issued orders or findings to deal with this issue.

The survey also reveals that commissions are encountering a substantial amount of activity by LDCs. Many LDCs are establishing marketing affiliates and helping customers to buy spot gas. Many commissions said that LDC operations have become more complex and costly as a result of the provision of transportation. Several commissions said that the provision of transportation had resulted in the shift of revenue requirements among customer classes.

Many commissions require distributors to provide transportation customers, who were formerly sales customers, with traditional utility service. Transportation customers are required to pay LDC gas supply costs and are held responsible for PGA-related demand charge increases. Many commissions have also issued orders or statements about the shift of revenue requirements from one class of customers to another.

Comparison of the results of the NRRI and Missouri surveys shows that the state commissions are acting in a wider variety of areas now than they were in 1986. More commissions have issued general orders on transportation, have imposed open access requirements, have incorporated back-up service in their policies, are using value-of-service rates, have provided for curtailment of transportation, allow LDCs to assess standby charges, and have become aware of and taken action on the effects of customers' shifts to transportation on the gas costs of remaining customers. In short, the states are responding to the new environment. Policy is emerging and evolving. In the next chapters, these results are discussed in light of various legal and economic considerations. In the final chapter, suggestions are made on what the state commissions could and might want to do to respond further to changes in the gas industry.

CHAPTER 3

ECONOMIC CONSIDERATIONS AND LEGAL STRATEGIES FOR STATE GAS TRANSPORTATION POLICIES

As discussed in previous chapters, the regulation of gas transportation service by local distribution companies is generally under the purview of state public service commissions. As shown in chapter 2, the state commissions have adopted a wide variety of approaches on regulating LDC gas transportation. The purpose of this chapter is to provide regulators with economic considerations and legal strategies they can use to identify and assess the advantages and disadvantages of adopting various LDC gas transportation policies. Several considerations and strategies exist by which such policies can be evaluated. These criteria fall under the broad categories of legal and economic. The next two sections set out four economic criteria and three legal strategies, and in chapter 4, these seven considerations and strategies are applied to evaluate specific gas transportation policy options.

The discussion of four economic considerations and three legal strategies outlines the main considerations in formulating a desirable state gas transportation policy. The economic considerations are proposed primarily to enhance economic efficiency and equity in the natural gas market. Other noneconomic strategies, such as the desirability of avoiding federal preemption, the legal requirements of fulfilling the service obligations of the LDCs, and the revenue requirement of the LDCs, are also discussed. In certain circumstances, the legal strategies may not be compatible with the economic considerations. The state PSCs must reconcile any such conflicts.

It is also clear that the four economic considerations may be in conflict among themselves. For example, the consideration of competitive price signals indicates the desirability of a cost-based gas transportation rate that could result in substantial amounts of bypass if the LDC's cost is relatively high. However, such drastic losses in load potentially could increase the gas rate for remaining customers astronomically. The consideration of equitable cost allocation, in turn, may dictate a higher LDC transportation rate, which may not result in the implementation of competitive price signals. The possible conflict of instituting extensive regulatory oversight to prevent the abuse of market power and the cost-effectiveness and feasibility of implementing gas transportation policy is another example of the likely irreconcilability of the four economic considerations.

Four Economic Considerations

The original intent of FERC Order 436, which provided for the unbundling of natural gas service by interstate pipelines, was to promote economic efficiency through the substitution of competitive forces for government regulation. Specifically, the provision of gas transportation service by the pipelines and local distribution companies allows end-users the opportunity to purchase gas directly from gas producers or other unconventional supply sources, presumably because it is to the customer's advantage.

Based on this, one objective of state gas transportation policy is to preserve and enhance competitive forces in the natural gas market so that both conversion of sales service to transportation service and the occurrence of LDC bypass are determined by economic considerations rather than by artificial barriers or incentives.

Besides this efficiency consideration, three additional objectives usually are involved in the development of a state gas transportation policy. First, a state gas transportation policy must not put a disproportionate cost burden on "core customers" (usually residential and small commercial customers) who have no alternative but to purchase gas from LDCs. Second, a state gas transportation policy should guard against the exercise of undue market power or the provision of preferential treatment to the end-users or LDCs. The exercise of undue market power or the provision of preferential treatment can distort the operation of a competitive market place. The most economical gas supply sources may not be selected while more expensive gas sources are utilized. Third, a state gas transportation policy should not be overly complicated and costly in its implementation. An overly complicated gas transportation policy may be too difficult to implement or may prove not to be cost-effective. In the following subsections, we discuss these four economic objectives associated with a desirable state gas transportation policy.

Competitive Price Signals

The provision of competitively determined price signals for transportation service is the first economic consideration. Two conditions need to be satisfied before a customer would choose to obtain gas from pipelines,[1] producers, or gas brokers as opposed to its LDC. First, the end-user must find cost advantages from purchasing gas directly from non-LDC sources instead of from LDC. Second, the end-user must be able to be physically and economically connected with the alternative gas suppliers. A desirable gas transportation policy should accurately reflect the costs of meeting these two conditions so that no distortions of gas transportation rate or access conditions are introduced into the decision-making process of the end-user. If the gas transportation rate and access policy are so determined, the amount of conversion from sales service to transportation service experienced by LDC is competitively determined and, therefore, desirable based on the economic efficiency consideration.

Two examples are provided here to illustrate the significance of establishing competitive price signals. Suppose the state commission requires the LDC to provide gas transportation service at a rate below the true cost of service. Some uneconomic conversion of sales service to transportation service might occur. Assume a paper mill can purchase gas from pipelines at $2.00 per mcf while the price of gas supplied by the LDC is $2.60 per mcf. The LDC is required by state regulation to provide transportation service at a rate of $0.40 per mcf even though the fully amortized cost is $0.70 per mcf. In this instance, the true cost of direct gas purchase plus transportation is $2.70 per mcf, which is higher than the $2.60 per mcf charged by the LDC. From the perspective of resource allocation, the paper mill should not convert from LDC sales service to transportation service. However, since the price paid by the paper mill for gas and transportation service is less than the LDC's price, the mill has an incentive to purchase directly from non-LDC suppliers. This is a typical example of an uneconomic conversion of gas sales to transportation service.

[1] Alvin Kaufman, *The Bypass of Local Gas Distribution Utilities--How Can You Tell If It Is for Real?* (Columbus, Ohio: The National Regulatory Research Institute, 1986), p. 13.

Another instance is where the state PSC allows the LDC to refuse interconnection with non-affiliated pipelines. Under this circumstance, economic transportation service bypass can be thwarted due to the objection of the LDC. The end-user may achieve significant cost savings even if the interconnection were built at substantial cost. But such cost savings are not realized. The LDC's refusal to interconnect essentially imposes an infinitely high transportation rate to the end-users. In both instances, the price signals for gas transportation service are distorted and the amount of transportation service is not necessarily optimal.

Cost Reallocation

If an end-user with significant load leaves the LDC system, substantial revenue losses result. In most situations the revenue losses can be offset at least partially by collecting gas transportation fees from the end-users if such service is provided. The effects of cost reallocation upon the remaining customers are thus mitigated, if not completely alleviated.

But in some instances, the revenue losses are the result of LDC bypass. Then a substantial reallocation of fixed costs among the remaining customers (usually a small load base) would be required, making a major rate increase likely. Another cost allocation concern is that the LDC might provide preferential transportation rates that could shift revenue requirements from one group of customers to another.

A third cost reallocation concern is the higher purchased gas charge due to regulatory or contractual requirements, such as the requirement that the LDC passthrough its purchased gas costs, including some portion of the pipeline's take-or-pay obligation. The remaining customers may be required to absorb all or part of this increased cost.

Some discussions have suggested that cost reallocation may not be a serious concern.[2] Kaufman argued that average gas costs may decline as a consequence of LDC bypass where less gas is purchased under high cost contracts are reduced, or where a penalty is imposed for purchases that exceed contract volumes. He also stated that the reallocation of costs may be minor,

---

[2] Ibid., p. 10.

provided that end-users leaving the system have not carried a large share of fixed costs, and that any reallocation actually may correct previous subsidies from large users to other customers.

Certainly these are valid arguments in specific circumstances. But cost reallocation generally has significant equity and economic efficiency implications. The first equity consideration is the cost allocation among core and non-core customers. A sudden and significant load reduction might drastically increase the remaining customers' rates who generally are without access to other supply options. For example, a residential customer has neither the expertise nor large enough volumes to consider purchasing gas from non-LDC sources. On the other hand, a large industrial customer can take advantage of lower cost spot gas available from non-LDC sources. A gas transportation policy, particularly one that considers the possibility of LDC bypass, can potentially reallocate cost so that customers without alternatives are charged a higher rate while customers with bypass capability enjoy cost savings. Regulators need to balance the interests between these core and noncore groups of customers.

A second equity consideration is the cost sharing of standby capacity. Presumably, an LDC is obliged to serve all customers upon demand. A customer may choose either to bypass the LDC or convert from LDC sales service to transportation service when low cost gas and transportation alternatives are available, and return to demand LDC sales service when prices rise or the alternatives are no longer available.[3] In this situation, some reserve LDC capacity may be required, and the cost of such reserve shared by all customers. Otherwise, it is unfair to require a customer that stays with the system to pay the reservation costs of those customers who have converted to transportation service.

As for economic efficiency considerations, a sudden and drastic cost reallocation, such as might be caused by an LDC bypass, may trigger the "death-spiral" process, which would result in under-utilization and abandonment of LDC's fixed facilities. Under this scenario, the drastic rate increase resulting from bypass of a few customers with a large load can prompt more customers to look for non-LDC gas supply alternatives making a smaller

[3] Ibid., p. 11.

number of customers responsible for sharing an increasingly larger share of total fixed costs. This process potentially could continue until no customers remain in the LDC system. The efficiency loss associated with the total abandonment of an LDC system can be substantial. Such a loss is unwarranted where the death-spiral process starts from an uneconomic conversion from LDC sales to transportation service associated with extremely low LDC gas transportation rates. It should be noted, however, that a death spiral requires the price elasticity of demand of all customers to be elastic. As long as some core customers remain with inelastic demand, the death-spiral process would eventually stop. The result would not be good--inelastic core customers would bear the entire fixed cost burden. But as long as some customers are captive, it is unlikely that the LDC's business would shrink to nothing--it merely shrinks.[4]

Market Power and Preferential Treatment

This consideration relates to the creation of undue market power due to an LDC's ownership of essential transportation facilities and possible preferential treatment of some parties. An LDC's market power in relation to end-users is derived from two sources: the control of access to essential transportation facilities, and the advantages of experience and buying power in obtaining gas and transportation service. Market power is normal and unavoidable where the number of participants in a market is restricted and where each participant has its own unique cost and information advantages and disadvantages.

One example of such cost and technology advantages is the LDC's superior ability to identify more reliable and economic gas supply sources derived from its experiences in such activities. In other instances, preferential treatment results from government policy. The provision of incentive or discount gas rates to industrial customers to prevent either bypass or the conversion of sales to transportation service is a typical example. In other instances, market power is not created by inherent cost and technology

[4] J. Stephen Henderson et al., *Natural Gas Rate Design and Transportation Policy Under Deregulation and Market Uncertainty* (Columbus, Ohio: The National Regulatory Research Institute, 1986).

advantages, but by ownership and control of certain resources. The exercise of market power associated with such ownership, in combination with preferential treatment to certain participants, may distort the operation of a competitive market.

Since an LDC controls access to its gas transportation facilities, it can institute preferential treatment in several ways. It can set up its own marketing affiliates and may discriminate against non-affiliated end-users in terms of transportation capacity availability. An LDC may curtail transportation service to customers that use transportation service only. As discussed before, an LDC also can provide preferential transportation rates for some customers. As a result of market power and preferential treatment, price signals to end-users are distorted. An industrial customer might forego the economic conversion of sales service to transportation service for fear of transportation service curtailment, while another customer might uneconomically convert from sales to transportation service due to its buying gas from an LDC affiliate and receiving a lower LDC transportation rate. So a state gas transportation policy needs to guard against the exercises of undue market power and the provision of preferential treatment associated with it. But the restraint of such market power should not inhibit the exercise of inherent cost and technology advantages by the LDC or certain end-users. Otherwise, there is no meaningful competition between purchasing from an LDC or obtaining gas from pipelines, producers, or gas brokers.

Cost and Feasibility of Implementation

Some state PSCs may need to expand their staffs to deal with additional regulatory oversights. A large number of concerns also need to be addressed by state regulators, LDCs, and end-users. These include estimating potential bypass in an LDC's service area, calculating gas transportation rates, ordering gas transportation service curtailment, and so on. There are costs incurred by state PSCs in formulating and enforcing such policies. The LDCs also incur certain costs complying with the regulatory requirement of state gas transportation policy. In this report, we do not propose specific methods to calculate the costs associated with the implementation of gas transportation policy. We only emphasize that an overly complicated regulation, even though it may be theoretically attractive, may entail substantial costs in implementation. The benefits of a more complex and comprehensive regulation need to be juxtaposed with its cost. As state regulators gain more experience and knowledge in this area, a more complex and comprehensive gas transportation policy may become cost-effective.

Three Legal Strategies

There are three major legal strategies that state commissions may wish to consider when deciding or reconsidering what gas transportation policy to adopt. These strategies are (1) protecting the state's jurisdiction over the local distribution company by avoiding federal preemption and making forum shopping unattractive, (2) making certain that the local distribution company can meet its obligation to serve its customers, and (3) providing the local distribution company with an opportunity to earn its revenue requirement. Each of these criteria will be discussed briefly in the next three subsections.

Avoiding Federal Preemption and Forum Shopping

When examining various gas transportation policy options, state commissions might look at their effects on possible federal preemption. Even though the regulation of LDCs is clearly within the purview of state public service commissions, there is a threat of federal preemption or forum shopping. State regulators must be concerned with the possibility that the FERC will preempt the state commissions' authority over their LDCs either directly or indirectly. The more direct threat might come from allowing an LDC to resell contracted capacity on an interstate pipeline. If the current FERC capacity brokering NOPR becomes a final rule, state commissions may lose part of their authority over their LDC. While the FERC proposed rule provides that any capacity brokerage must be done in accordance with state regulations, it appears to require that the LDC be an open access transporter. If the proposed rule were to become final, the FERC might require open transportation by the LDC, which a state commission might find to be not in the public interest. Also, such a rule would make the LDC's brokering rates subject to a FERC price cap, even if there were concurrent state jurisdiction.

Federal preemption of state regulatory authority can be indirect by encouraging forum shopping by the customer and still be damaging. In chapter 1, the authors cited the example of LDC bypass where an interstate pipeline applies for and obtains a certificate from the FERC allowing it to provide transportation service to an LDC customer. Either the pipeline or the customer (typically a large industrial customer) pays to lay the pipe for interconnection. About one-half of the state public service commissions require a certificate of necessity before a transmission line or other distribution line may be extended in their states. Other states have the authority to determine service franchise areas and allocate unincorporated (non-municipal) territory among utilities. The rationale behind these regulatory requirements is to prevent an uneconomic duplication of facilities and to protect the customers of the LDC from having to pick up the expense of LDC fixed costs, which are stranded investments solely because of LDC bypass. However, the FERC has recently approved certificates that result in LDC bypass. While this is still unusual, its occurrence is likely to grow as LDCs are forced to bear some of the pipeline's take-or-pay obligations under FERC Order 500. Customers that can bypass the LDC may choose to do so rather than face rate increases due to Order 500.

State gas transportation policy options could either encourage or obviate the possibility of federal preemption or forum shopping. For example, a state gas transportation policy that either sets a customer's transportation prices at the customer's cost of service (as opposed to the customer classes's) or allows the LDC to set flexible transportation rates to meet potential bypass competition would make bypass unlikely.

Obligation to Serve

A local distribution company is typically required to fulfill an obligation to serve its customers on demand. The source of this obligation to serve sometimes is a state statute, sometimes a commission order, or sometimes an obligation spelled out in the local distribution company's basic franchise agreement. Regardless of source, this obligation to serve is universally recognized, although understood differently by different parties. But what does the obligation to serve mean and to whom does this obligation to serve extend?

To meet its obligation to serve, an LDC must be prepared to provide a secure and reliable supply of gas delivered to its city gate and also have sufficient capacity available to meet (typically winter) peak demands. To fulfill this duty, LDCs sign long-term purchase agreements with pipelines, which guarantee that a secure and reliable supply of gas will be available at its city gate.

Before the inception of transportation service, the obligation to serve was generally held to extend to all the LDC's customers. Since then, however, some would contend that the obligation to serve only extends to the LDC's core customers (those who have no other alternative but to buy gas sales service from the LDC) and those non-core customers who choose to remain sales customers of the LDC. This argument is based on the idea that customers who opt for transportation service should be required to contribute to the costs of maintaining a secure and reliable gas supply for others. Therefore, they should not be allowed to reap the benefits of that supply if their own supply sources become more expensive or unavailable.

Determining to whom the obligation to serve extends, however, is a legal question that must be resolved in each state in light of existing statutory language, commission orders, or judicial precedent. A commission, legislature, or court might change the obligation to serve by legislation, commission order or rulemaking, or judicial decree.

A state public service commission needs to take its own state's interpretation of the "obligation to serve" legal doctrine into account when fashioning its gas transportation policy. For example, if the obligation to serve is interpreted only to include core customers and those non-core customers that opt to remain gas service customers of the LDC, then the state public service commission can choose gas transportation policies that do not provide for the likelihood that a non-core, gas transportation customer will return to the system.

If the state public service commission decides, nonetheless, that it is important to provide for the contingency that a transportation customer may return to the system, it may decide that the returning customer should pay a special fee to reconnect to the system. That fee should reflect the costs of having a secure and reliable gas supply, which is fully borne by the other customers while the transportation customer buys its gas elsewhere.

Another possibility is for the state commission to require a transportation customer to pay either a reservation or standby charge while it is a transportation customer for the right to return to the system, or to have an alternative fuel that it can use in case of a supply shortage.

An Opportunity to Earn Its Revenue Requirement

A more difficult strategy to apply when developing a gas transportation policy is the legal requirement that a utility--in this case an LDC--be provided an opportunity to earn its revenue requirement. This requirement is sometimes thought to be the utility's symmetrical benefit that it receives in exchange for its obligation to serve and typically has its origins in statute, commission order, or judicial interpretation. It is usually considered a part of the regulatory compact between utility and regulatory body.[5] The compact provides that a utility is to be given a reasonable opportunity to earn its revenue requirement in exchange for fulfilling its obligation to serve within its franchised service area.

If courts give proper weight to the regulatory compact, the requirement will only apply for that part of the LDC's revenue that would be required to serve its sales customers. If no obligation to serve transportation customers exists, the LDC should not be guaranteed a revenue requirement for that portion of capacity used to serve those customers. The LDC is at risk for the revenues it needs to raise from transportation customers, particularly if the LDC chooses to set its transportation rate below the cost of providing that transportation. But, if the LDC has an obligation to serve its transportation customers, some mechanism must exist to give the LDC an opportunity to earn its revenue requirement associated with those customers.

In all cases, the LDC must have a reasonable opportunity to earn its revenue requirement for the investment and expenditures associated with serving its sales customers. The difficulty, of course, is disentangling the common cost of pipe used by the LDC to deliver sales gas to core customers as well as transportation gas to non-core customers.

---

[5] See Robert E. Burns, "Sorting Out Social Contract, Deregulation, and Competition in the Electric Utility Industry," *Proceedings of the Sixth NARUC Biennial Regulatory Information Conference*, ed. David Wirick (forthcoming) for an explanation of the regulatory contract.

CHAPTER 4

AN EVALUATION OF GAS TRANSPORTATION POLICIES

The purpose of this chapter is to appraise the policy options concerning gas transportation available to state public service commissions. The economic considerations and legal strategies developed in chapter 3 are used to facilitate this commentary. As evidenced in chapter 2, the development of gas transportation policy is in a fluid situation where a variety of gas transportation policy approaches is in use and where no one approach is dominant. The evaluation in this chapter is selective and limited to the more important policy options. In cases where no specific policy options were prescribed in existing state regulation, some new options that may further the evolution of state gas transportation policy are suggested. Some gas transportation policy options are identified as distinct from others, even though they are closely related to one another. For example, if a state adopts the cost-of-service method in determining transportation rates, it is unlikely that it will also require complete insulation of revenue shifting (cost reallocation) from non-core to core customers. Furthermore, the commentary and assessments provided here are not intended to criticize existing state policies. They only reflect the strengths and weaknesses of various policy approaches in terms of the economic considerations and legal strategies proposed earlier in this report.

The chapter is organized around the major issues currently facing state regulators. In each section, the economic considerations and legal strategies described in chapter 3 are applied to the policy options for a major issue. In the first section, the authors address bypass and conversion of sales to transportation service issues. The second section concerns different types of transportation rates. In the third section, the authors consider the issue of shifting revenue requirements; the fourth deals with the issue of increased purchase gas costs for other customers; the fifth concerns standby and reservation charges; the sixth addresses the LDC's obligation to serve captive and transportation customers; and the seventh deals with LDC marketing affiliates and discrimination. A brief summary of some of the authors' conclusions is set out in the final section.

Bypass and Conversion of Sales to Transportation Service Issues

Currently, only seven state commissions have issued orders or findings concerning bypass of a distributor by end-users or by intrastate or interstate pipelines. Three state commissions have proceedings pending. In general, four categories of policy options are available to deal with the bypass issue. State regulators can prohibit bypass of the LDC or discourage it and place the responsibility for preventing it on the LDC. As an alternative, a state could discourage bypass by allowing a flexible pricing tariff for gas transportation service. The third option is to discourage both bypass and the conversion of sales service to transportation service by authorizing discount or incentive gas rates by LDCs to compete with non-LDC gas supply sources. The last option is to adopt a non-interventionist approach toward bypass.

The phenomenon of customers converting from sales service to transportation service is a natural development of the changing environment in the natural gas market. Such conversion is possible when end-users achieve some cost savings by shifting from purchasing from an LDC to directly contracting with non-LDC suppliers.[1] In some instances, conversion from sales service to transportation service can enhance economic efficiency as high-cost gas supplied by LDCs is replaced by low-cost gas provided by pipelines or producers. In other instances, a conversion from sales to transportation service may not be economical even if it is profitable for the end-users to do so. This is likely if the transportation rate is not cost-based.

Bypass of the LDC by an end-user is different. When bypass occurs, an LDC customer does not convert from sales to transportation service to obtain less expensive gas from non-LDC sources. Rather, the customer bypasses the

[1] A detailed discussion of the advantages and disadvantages of providing contract carriage which allows certain customers to purchase their gas from non-LDC sources is provided in Leonard A. Helman, "Contract Carrier Methodologies," *Proceedings of the Fourth NARUC Biennial Regulatory Information Conference*, ed. Raymond Lawton (Columbus, Ohio: The National Regulatory Research Institute, 1984), pp. 905-914.

entire LDC system and takes neither sales nor transportation service from it. The customer directly connects with a pipeline and obtains its transportation service (and possibly also its sales service) from that source. Bypass should be allowed to occur only when it is economical. Bypass is only economical when the pipeline's cost of providing transportation service to the customer is less than it is for the LDC, assuming that the end-user would be obtaining the gas from the same source in either case. Except where a large industrial customer is located near a pipeline, in which case the large industrial customer is already a natural candidate to become a direct sales customer of the pipeline, the LDC's cost of providing transportation service should be less than the pipeline's. After all, the LDC is already connected to the end-user. If, however, the rate for gas transportation service by the LDC is made artificially high, an LDC may succeed in discouraging economical conversion from sales service to transportation service, while at the same time encouraging uneconomical bypass. This would be the case because the end-user seeking less expensive gas would have no alternative than to leave the LDC system to obtain gas at a lower combined cost than that charged by the LDC. Nevertheless, the actual cost of providing gas and transportation might be higher with the pipeline than with the LDC. The point here is simply that uneconomical bypass can occur if transportation services are not priced correctly. To prevent uneconomic bypass, an LDC should charge a transportation rate that reflects the fair cost of providing transportation service to a customer. If rates for transportation services are set properly, uneconomic bypass of the LDC should be rare.

An absolute prohibition of bypass can distort price signals in the gas market place. By prohibiting bypass, the state public service commission takes away the LDC's incentive to price transportation services correctly. Thus, the criterion of establishing competitive price signals may not be met. Even so, a policy prohibiting bypass has the advantage of being simple to implement by eliminating much of the need for state regulation of gas transportation. The state PSCs do not need to deal with the issues of cost reallocation, preferential treatment, and implementing complex new regulations. Because there is no bypass, no competitive pressure exists to force the LDC to set its rates for transportation service close to its costs. The LDC can set its rates so that cost reallocation is not necessary. If bypass is prohibited, no need exists to give transportation customers preferential treatment.

Bypass cannot be eliminated completely through state regulation. First, the FERC is claiming that it can issue certificates that let pipelines transport gas to LDC customers in spite of any state prohibition against bypass. Thus far, the FERC has been upheld in the courts, although a test case is on appeal. A state prohibition against bypass, when combined with LDC transportation rates set above the cost of a nearby pipeline that is providing transportation service, invites the customer to seek economic relief by forum shopping. The resulting federal certificate is viewed as an indirect form of federal preemption by some observers. Second, the LDC is not only competing with other providers of natural gas, but also with other fuels such as oil. Such interfuel competition can invalidate a regulatory policy prohibiting bypass, particularly if the rate for transportation service is set too high. Under a high transportation tariff, end-users simply could switch to their alternative fuel.

At the opposite extreme, a laissez faire approach allows all bypass to occur. This has the advantage of allowing competitive market forces to determine the proper level of bypass with the regulatory intervention kept at a minimum. This means the considerations of competitive price signals and administrative feasibility are likely to be met. On the down side, however, drastic cost reallocation and exercise of market power by large industrial customers and LDCs may occur. Customers with substantial flexibility and fuel-use options can achieve cost savings while the share of fixed cost shouldered by core customers grows as a result.

Use of a flexible tariff for gas transportation service can help avoid the disadvantages of these two extreme approaches. A flexible transportation tariff is intended to reach a balance between promoting competition and preventing a drastic cost reallocation to core customers as a result of bypass or conversion from gas sales to transportation. By making bypass less likely, the possibility of forum shopping by the customer is lessened. Additional information about the likely gas supply sources for potential bypass customers, the amount of possible bypass, the cost of providing transportation service to the individual customer, and related issues all need to be collected. A flexible transportation tariff also increases the likelihood of preferential treatment of certain groups of customers by LDCs. Further, unless demand costs associated with capacity used for transportation service are removed from the LDC's revenue requirement, a flexible tariff can either result in some cost reallocation, or the LDC's inability to achieve its revenue requirement.

The provisions of incentive gas rates to reduce the economic inducement for bypass is similar to offering a flexible transportation tariff. The principal difference is that such a rate provides not only an incentive not to bypass, but also an incentive not to convert from sales service to transportation service, even when it would be economical to do so. The identification of real bypassers and those who only use bypass to obtain more favorable prices is the key question in implementing this policy. Some argue that use of an incentive gas rate is a superior approach to the use of a flexible transportation tariff. In their view, subsidies should be available whether the end-user buys its gas from the LDC or buys its own gas and has the LDC transport it.[2] However, as previously mentioned, the use of incentive gas rate provisions can lead to uneconomic choices. Here too, there would be problems either with a reallocation of costs among customer classes or with the LDC not being given an opportunity to earn its revenue requirement.

Types of Transportation Charges

As discussed in chapter 2, the states use four major approaches in calculating the fixed-cost component for gas in their transportation rates. They are simple margin, full or gross margin, cost of service, and value of service.

The simple margin approach includes all fixed costs in the transportation rate except those allocated to the commodity component of a particular customer's gas price. The advantages of such an approach are twofold. First, it is a relatively simple and straightforward approach as the commodity price of gas is readily available. It also reduces the effects of

[2] David R. Cain, James C. Case, and Thomas E. Kennedy, "Distribution Transportation Tariffs for Customer-Owned Gas," *Proceedings of the Fourth NARUC Biennial Regulatory Information Conference*, ed. Raymond Lawton (Columbus, Ohio: The National Regulatory Research Institute, 1984), pp. 893-904.

cost reallocation. Under this approach, the LDC is revenue neutral in terms of the source of a customer's gas, assuming that there is no purchased gas cost increase as a result of the conversion from sales service to transportation service. However, the remaining core customers are taking on a larger share of cost than previously. Also, the utility will likely have a reasonable opportunity to earn its revenue requirement. The issue of preferential treatment is minimal. The disadvantages of this approach are that the transportation rate usually does not reflect the true cost of providing such service. The economic consideration of competitive price signals is compromised and uneconomical conversions from sales to transportation service or foregoing of economic conversion from sales to transportation service is likely. Also, because the transportation rates are not cost based, the possibility for uneconomic bypass of the LDC exists. Such bypass might occur as an end-user tries to obtain a higher cost gas supply to save on its total gas cost. That would be possible if it could get low cost transportation service that more than offsets the higher gas costs. Bypass, whether it is economical or uneconomical, brings with it the shift of jurisdiction from the state commissions to the FERC.

The gross margin approach differs from the simple margin method in that demand costs included in the gas commodity price are included as a part of transportation rates. As a result, the remaining sales customers are completely insulated from any revenue losses resulting from the transportation customers' conversion from sales to transportation service. The LDC has an opportunity to earn its revenue requirement, and there is no need to address the cost reallocation issue at all. This policy is a little more complicated than the simple margin approach since the LDC needs to calculate the portion of demand costs associated with the amount of gas previously contracted by the bypassing customers. But a more serious concern is that this approach has the effect of moving farther from the economic consideration of competitive price signals. The potential for economic conversion from sales to transportation service might sometimes be completely thwarted. Also, as the option of making an economic conversion from sales service to transportation service becomes less available, the likelihood of LDC bypass and the possibility of forum shopping increases.

The cost of service approach sets the transportation rate based on the LDC's embedded or marginal cost of providing the service. A transportation rate determined by a marginal cost-of-service method has the advantage of allowing a true competitive environment to determine the degree of bypass. The disadvantage is potentially significant cost reallocation from noncore to core customers, particularly if the LDC is to be given an opportunity to earn its revenue requirement. Such cost reallocation may be unfair to the core customers and it is also inefficient, particularly if the LDC is facing the complete or partial erosion of its gas sale market share associated with the "death spiral" phenomenon. However, if the capacity associated with providing transportation service to the LDC's transportation customers is excluded from the LDC's rate base and revenue requirement (as was suggested as an option in chapter 3) any cost reallocation might be less onerous to the remaining sales customers. A marginal cost-of-service approach discourages uneconomic LDC bypass and the resulting erosion of state jurisdiction, particularly if transportation rates are set to reflect the costs of serving individual customers.

The value-of-service approach allows an LDC to charge what the market will bear for its transportation service. This is quite flexible and can be used by an LDC to avoid completely system bypass by charging potential bypass customers an extremely low transportation rate. However, since the transportation rate may be lower than the cost of providing such service, other customers may be required to pick up the revenue shortfall if the LDC is to earn its revenue requirement. This cost reallocation problem can be serious. The problem can be mitigated, however, if the capacity costs of serving these transportation customers are removed from rate base and from the LDC's revenue requirement, and if the financial risk of that portion of cost recovery is placed on the LDC's shareholders. A value-based tariff has the major disadvantage of distorting price signals, resulting in uneconomic conversions from sales to transportation service. It also has the disadvantage of permitting an LDC to exhibit preferential behavior toward customers with other potential sources of transportation service.

Shift of Revenue Requirements

The policy concerning the shift of revenue requirements is closely related to the possibility of bypass, the potential for a conversion from sales to transportation service, and the type of transportation charges selected. Recall that we are discussing a shift in revenue requirements among customer classes, primarily from the non-core (industrial) classes to the core (residential and small commercial) classes. Most state commissions have adopted, at the present time, a conservative approach toward the shift of revenue requirements. That is, no drastic shift of revenue requirements is allowed unless specific conditions warrant such a shift. In the states where such shifts are allowed, the amounts are limited, closely monitored, and determined on a case-by-case basis.[3] The principal rationale of this conservative approach is to protect the interest of core customers.

The range of policy options concerning the shift of revenue requirements is best viewed as a continuum. On one end is the policy of allowing no bypass and setting transportation rates by the full-margin method. Under this approach, no shift of revenue requirement would occur and no need exists to prescribe a policy. On the other end is the policy of no intervention where end-users can have complete freedom of LDC bypass and where the transportation rate is determined by the market. Under such a policy, a significant shift of revenue requirement is likely. No state commission has adopted such a hands-off approach to the shift of revenue requirement.

Most states fall in between these two extremes, taking measures to limit the amount of cost reallocation. For example, the Ohio Commission prescribes a policy that sets maximum transportation rates by gross margin and minimum rates by the variable cost of transportation service (marginal cost) plus a portion of fixed costs.

In our view, a complete prohibition of revenue requirement shifting may not be feasible and can significantly reduce the intended effect of providing gas transportation service--the unbundling of gas service and the pricing of such services through competitive forces. The amount of economic conversion from sales service to transportation service is inhibited since potential transportation customers may not derive any economic benefits from purchasing gas directly. The policy objective of obtaining more economic gas supply is compromised by the concern for protecting core customers. But as we discussed before, a total prohibition of bypass to prevent revenue requirement shifting is difficult to achieve with the availability of other competing fuels. In

[3] See chapter 2, supra.

the end, a customer of the LDC may be completely lost with the remaining customers still required to share the revenue losses they initially wanted to avoid.

A total disregard of the shift of revenue requirement is probably not acceptable under the existing regulatory environment. Regulators would be hard pressed to justify a result of transferring cost from a few industrial customers to a large number of residential customers. Even without such a political considerations, a drastic cost allocation is also unfair, at least in the short term. Cost reallocation also has the potential of inducing a "death spiral" where the LDC's fixed investment becomes "useless". Accordingly, the approach adopted by the Ohio Commission may be a necessary compromise in light of the four economic considerations discussed in this report.

Another alternative might be to abandon the legal requirement that a utility be allowed a reasonable opportunity to earn its revenue requirement for that portion of the LDC's capacity that serves the LDC's transportation customers. That would mean the LDC would be responsible for correctly pricing its transportation charges, with profits or losses realized below the line. Core customers would be responsible for the demand cost that they incur in their revenue requirements. While such an approach would likely mitigate the effects of shifting revenue requirements, some still might shift if the LDC had subsidized costs between service classes. If such an approach were taken, there also should be a concomitant rejection of the utility's obligation to serve its transportation customers. If transportation customers are treated as operating essentially in a deregulated market, there should also be no obligation to serve those customers in circumstances of a capacity shortage or a failure of third-party gas supplies.

Increased Purchased Gas Costs for Other Customers

As a customer chooses to bypass the LDC or to convert from sales to transportation service, demand-related charges for gas purchased are recovered over a smaller sales volume. These costs include, but are not limited to, take-or-pay costs, interstate pipeline peak and annual fixed charges, and gas supply management costs. As a result, the customers still on the LDC system may experience increased purchased gas costs.

Another source of increased purchased gas costs is associated with the cost of unaccounted-for gas or transportation loss. There are also some potentially significant long-term costs such as an LDC's reduced ability to negotiate for gas supply, which can be caused by small, low-load factor, and weather-sensitive customers replacing large, high-load factor customers. Another long-term cost is the increased complexity of communication and decision-making processes of the LDC.[4] In certain states, any increase in the cost of gas is collected from sales customers only. Other states allow the recovery of all or a portion of the demand-related costs from transportation rates. Of course, collecting the increased purchased gas costs is consistent with and necessary for the utility to have an opportunity to achieve its revenue requirement.

In terms of providing competitive price signals, increased purchased gas costs, in principle, are best shared by those customers responsible for such increases. Rates for transportation customers should include them. Such a pricing approach is also desirable in terms of the economic consideration of cost reallocation. The remaining customers need to share additional cost burdens as a result of conversion from sales to transportation service. However, two considerations may prevent the complete recovery of these increased purchased gas costs. First, it is difficult to identify and quantify all cost increases as a result of a conversion from sales to transportation service. For example, what is the cost effect of a reduction in an LDC's ability to negotiate from strength with its pipeline as a result of reduced LDC load? Second, a transportation rate reflecting increased costs may induce some customers to switch fuel or bypass the LDC system completely. In either event, the portion of the revenue contributed by transportation rates is lost. If the end user bypasses the LDC system, the commission's jurisdiction over that customer would be lost.

---

[4] See Sean Casey, "Natural Gas Transportation in California: Evolution and Status," *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, ed. Robert E. Burns (Columbus, Ohio: The National Regulatory Research Institute, 1986), pp. 439-447.

Standby and Reservation Charges

The policy on standby and reservation charges can be divided into two parts. The first deals with whether the LDC can refuse to let a transportation customer who has already left the LDC system return. The second deals with the costs assessed by the LDC on a transportation customer (such as a re-entry fee and reservation charge) if it is allowed to exercise the option of returning to the LDC system in the future.

The legal strategy of a utility fulfilling its obligation to serve might also be met by providing transportation customers with the option of paying a standby or reservation fee for the right to return to the LDC system. If a transportation customer rejects the option, that action could be interpreted as a release of the utility's obligation to serve that customer should its gas supply become unavailable or too expensive. Another alternative is allowing a transportation customer who has refused to pay a standby or reservation fee to buy LDC system gas only after payment of a re-entry fee reflecting the LDC's cost of making available that system supply.

The policy of maintaining standby service for transportation customers at a cost-based rate is attractive on economic grounds. First, it provides a competitive price signal for transportation customers in deciding whether to take the risk of providing its back-up gas supplies. Second, it does not create an additional cost burden on the remaining customers for maintaining standby capacity. No additional cost reallocation problems are created. As for the determination of standby and reservation charges, most states use cost-based rates even though there are variations in terms of the specific cost items being considered. The contribution made by a transportation customer for standby and reservation service can help give the LDC an opportunity to earn its revenue requirement.

Obligation to Serve Captive and Transportation Customers

All state commissions provide that the LDC has an obligation to serve its core customers. It is less clear from the survey whether their LDC is still subject to the same obligation to serve its transportation customers. While state commissions that have addressed the issue indicated that a transportation customer may return to the LDC system as a sales customer if it pays a reservation or standby charge, it is less certain whether a customer that refuses to pay such a charge must be served on demand. If the customer is treated as a new customer, it must pay the appropriate reconnect charges. Yet, reconnect charges may not entirely reflect the cost of adequately maintaining system supply. A more fully cost-based reentry fee would reflect those costs.

The LDC's obligation to serve its transportation customers is also reflected in the states' curtailment policies. In about half of the states with a curtailment policy, a transportation customer is given the same curtailment priority as a sales customer. In the other states, the transportation customer is given a lower priority. A few states provide that under certain emergency circumstances, gas owned by transportation customers can be converted to sales gas to serve core customers.

The economic criterion on preferential treatment suggests that sales gas customers and transportation customers should be treated alike during curtailments. Otherwise, some economic conversion of sales service to transportation service might be foregone due to the threat of potential curtailment.

The legal strategies suggest that the obligation to serve transportation customers should only be enforced if revenues generated by transportation customers are counted toward the LDC's revenue requirement and are part of the regulatory compact. Otherwise, the LDC should not be treated as having an obligation to serve its transportation customers. However, even if the obligation to serve does not extend to transportation customers, the LDC cannot deny those customers service because it possesses essential facilities. According to current interpretations of section 2 of the Sherman Act, access cannot be denied to essential facilities unless providing access would jeopardize the utility's ability to serve its own customers.

LDC Marketing Affiliates and Discrimination

A local distribution company can set up a marketing affiliate to help its customers buy gas on the spot market and to provide information on pipelines and pipeline sources of gas. Charges have arisen in several states that the LDC or its marketing affiliate has discriminated against third party brokers or large customers. Such discrimination may take the form of an LDC or its affiliate being given preferential treatment in pipeline or distribution capacity allocation.

Currently, the issue of discrimination by an LDC is not viewed by the states as prevalent or as a serious threat to the gas transportation market, and state PSCs have not instituted formal regulations concerning the establishment of market affiliates and possible discrimination. Only in a few instances are specific policy guidelines available. However, the anticompetitive practices related to the marketing affiliates of interstate pipelines has attracted the attention of the FERC. Indeed, the FERC has issued a final rule intended to prevent interstate pipelines from giving preferential treatment to their own marketing or brokering affiliates.[5]

Based on the economic and legal considerations we identified, no strong reason exists to prohibit the establishment of LDC marketing affiliates. Such affiliates, with their experience and information advantages, can provide valuable service to customers who are considering either converting from sales to transportation service or bypassing the LDC. The LDC also can use a marketing affiliate as a separate gas supplier (a buyer as well as a seller) to compete with pipelines, producers, and gas brokers. The existence of additional competitive pressure may help customers to obtain more economical gas supplies.

One key issue concerns the cross-subsidy between the LDC and marketing affiliates. It may not be fair to LDC customers to pay for the costs of operating the marketing affiliates. Customers who are using the service of the marketing affiliates should pay for those services.

But, the establishment of marketing affiliates enhances the possibility of exercising undue market power and discrimination. For example, an LDC might give its marketing affiliate preferential treatment when it comes to allocating the LDC's distribution system capacity. It is also possible that the LDC would give its affiliate information about its customers that is not generally available to third-party marketers and brokers. The state PSCs may have to develop policy guidelines to prevent such abuses.

[5] See Re Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, FERC Order No. 497, 93 PUR4th 493, 43 FERC para. 61,420 (1988).

Some Conclusions

Although no one set of state gas transportation policies satisfies all of the economic considerations and legal strategies, a few observations can be made. The keystone of a state gas transportation policy is to determine how gas transportation rates are to be calculated. All other policy determinations flow from this determination.

The authors suggest that a cost-based transportation rate has desirable features that should be favorably considered. In particular, a marginal cost-based transportation rate sends proper price signals to end-users concerning whether it is economic or uneconomic to switch from sales to transportation service. Also, a cost-based rate, particularly one designed to reflect the costs of transportation service to an individual customer, discourages uneconomic bypass of the LDC. Although cost-based rates may cause a reallocation of costs and a shift of revenue requirements, such a shift may merely eliminate any existing cross-subsidies and give customers a truer price signal of what their actual costs are. Without cost-based rates, the LDC and its customers cannot make rational choices concerning their gas supply and delivery options. Other state gas transportation policy options can then be derived from the proper price signals that result from cost-of-service based transportation rates.

APPENDIX A

MAJOR DEVELOPMENTS IN FEDERAL GAS TRANSPORTATION POLICY DURING THE 1980s

This appendix is intended to provide the reader with a more detailed description of the gas transportation policies pursued by the FERC during the 1980s. The subjects discussed here include off-system sales, special marketing programs, blanket certificates, the Maryland People's Counsel decisions, Order No. 436, the Associated Gas Distributors decision, and Order No. 500. This treatment should give interested readers a better idea of the types of policies and options that the FERC considered and the rationale behind those policies.

Off-System Sales

The FERC issued its Statement of Policy on off-system sales on April 25, 1983.[1] The statement defined an off-system sale as "a sale of natural gas that is excess to the pipeline's current demand, that is of a short-term, interruptible nature, and that is made to a customer outside or away from the pipeline's traditional or historic market area."[2] The Commission listed four objectives for the program: enable pipelines with excess gas to sell to pipelines (interstate, Hinshaw, or intrastate) or local distribution companies that had a shortage of gas; allow pipelines with excess gas to sell to

---

[1] Off-System Sales, Docket No. PL83-2-000: Statement of Policy, 23 FERC para. 61,140 (1983). This statement represented the third phase of Commission involvement with off-system sales. In late 1980, the FERC allowed such sales for pipelines and distributors, experiencing shortages, to buy from pipelines that had surplus gas. In 1981, pipeline surpluses were becoming more widespread and take-or-pay liabilities were increasing. Off-system sales were used to alleviate take-or-pay liabilities while allowing pipelines to continue contracting for long-term fuel reserves. See Statement of Policy, pp. 61,305-61,306.

[2] Ibid., p. 61,305.

pipelines, LDCs, or end-users who might otherwise have to pursue more expensive sources of supply; alleviate take-or-pay burdens; and avoid overburdening the seller's traditional customers and transferring problems of the interstate market to the intrastate market in the course of accomplishing the first three goals.

Transactions involving two interstate pipelines were to be priced at the higher of the seller's system average load factor rate (based upon the rates in effect at the time) or its average NGPA Section 102 gas acquisition cost. The seller was allowed to negotiate a higher rate in a transaction if the buyer was not another interstate pipeline.

The selling pipeline was required to prove that it had sufficient surplus gas so that making the sale would not harm service to its current customers. The seller also had to demonstrate that it had at least potential take-or-pay liability. This take-or-pay requirement was based on the Commission's view that on-system customers faced the possibility of harm when contracted reserves were sold elsewhere. The sale might also increase their average cost of gas. Thus, a requirement of potential seller take-or-pay exposure, which could be avoided because of the off-system sale, would serve to offset some of the potential harm to on-system customers resulting from the sale.[3]

The Commission did not impose end-use restrictions on off-system sale gas and sales were authorized for one year. The FERC did require the seller to identify the buyer except in cases where the buyer was another interstate pipeline.

The Commission was concerned that off-system sales could result in loss of markets by established suppliers whose customers purchased gas in off-system sales from other suppliers. Loss of sales by intrastate pipelines to interstate pipelines was a particular concern. An interstate pipeline might be able to offer a lower price because it could recover its fixed costs elsewhere while the price offered by the intrastate pipeline would include both fixed and variable costs. The Commission stated that in those instances the interstate pipeline's rate for the sale might have to be increased to include a portion of its fixed costs.

---

[3] Ibid., p. 61,307.

In a subsequent order issued July 30, 1984, the FERC revised its off-system sales policy to include a net economic benefit test as the standard for assessing the sales' impact on on-system customers.[4] The sales were to be beneficial in terms of first, take-or-pay obligations, allowing the pipeline to make up outstanding payments and avoid additional payments; second, cost contribution and discrimination, by providing for rates that were not unduly discriminatory against on-system customers and were paying pipeline fixed and variable costs; and third, long-term supply, by using up the short-term excess deliverability so that the pipeline could plan future supplies more efficiently and economically. The Commission also found off-system sales to be consistent with the special marketing programs (discussed below) even though the transportation rates of the latter programs were required to make a greater contribution to fixed costs.[5]

In the Statement of Policy, the FERC recognized that off-system sales, while yielding some potentially beneficial effects, had not been as successful up to that point as the pipelines had predicted. Thus, they were not the ultimate solution to the problems facing the gas industry at the time. The Commission stated that "off-system sales do have a role to play in the current circumstances of the natural gas markets, although that role may be more limited than some would hope."[6] Other options were also pursued, including blanket certificates and special marketing programs.

Blanket Certificates

In 1981, the FERC issued two Notices of Proposed Rulemaking (NOPR) concerning blanket certificates. In the first NOPR, published in March 1981, the Commission proposed a program under which some transactions would be authorized automatically under a blanket certificate, and other transactions would be authorized under a certificate after the completion of a notice and protest procedure. A third set of business deals, while also authorized under

[4] Natural Gas Pipeline Company of America, Docket Nos. CP81-302-007, -008, -009, -010, -011, -012, -013, -014; Order on Rehearing of Order Authorizing Off-System Sales, 28 FERC para. 61,174 (1984).

[5] Ibid., pp. 61,326-61,329.

[6] Statement of Policy, 23 FERC, p. 61,306.

a blanket certificate, would be allowed only after a specific case determination by the Commission.[7]

The Commission elaborated further on these distinctions in the NOPR. The first category included routine pipeline activities that had relatively minor financial impact on ratepayers or routine activities so well known as established practice that little examination would be needed to determine whether they were compatible with the public convenience and necessity. The second category included activities which, while relatively routine, might still be of concern to various parties. The Commission thus wanted to provide an opportunity for review and possible adjudication. The third category included activities with major potential impact on ratepayers or nonroutine activities with such important considerations that the Commission felt that closer scrutiny and deliberation by the FERC would be warranted.[8]

The proposed rule would have allowed an interstate pipeline to obtain a blanket certificate and proceed with the first category of activities without making a formal application to the Commission for each action. These projects and/or transactions would be automatically authorized. They included the construction and operation of minor facilities, defined as any jurisdictional facility except for the pipeline's main line, an extension of the main line, or a facility which would alter the main line's capacity. The cost of a particular project was not to exceed $3,500,000 and the Commission also proposed a cap of $36,000,000 (or 3% of the pipeline's net plant, whichever was less) on the dollar amount of projects that could be automatically authorized in a single year.

Automatic authorization of gas transportation for certain end-users was also available under the blanket certificate. At the time of the NOPR, the FERC had various transportation programs in place under three different orders. Order No. 2 authorized interstate pipelines to transport gas sold by a producer to commercial, process, and feedstock users. Order No. 27 authorized pipelines to transport gas to schools, hospitals, and essential agricultural users. Order No. 30 authorized the transportation of gas for the purpose of displacing fuel oil.

---

[7] Interstate Pipeline Blanket Certificates for Routine Transactions; Proposed Rulemaking, Docket No. RM81-19, 46 *Fed. Reg*. 16,903 (March 16, 1981).
[8] Ibid., p. 16,904.

These programs generally required separate certification for each transaction. The Commission proposed automatic authorization for transactions of up to five years' duration. Transactions lasting longer than five years would have to be approved through the notice and protest procedure.

The FERC also proposed to modify its then current blanket certificate program. Under Order No. 60 the Commission allowed an interstate pipeline to transport gas on behalf of any other interstate pipeline or for an intrastate pipeline or local distribution company under Section 311 of the NGPA. Transactions were limited to two years or less duration. In the NOPR, the FERC proposed allowing transactions to last longer than two years (after approval through the notice and protest procedure) provided that no additional capacity would be required and that the gas would ultimately become part of a pipeline's or distributor's system supply.

Other types of operations covered in the NOPR included sales taps, changes in delivery points, storage service, storage volumes, underground storage testing, abandonment, changes in rate schedule, and changes in customer name. The Commission proposed to authorize automatically sales taps for the purpose of delivering relatively small volumes of gas to right-of-way grantors. The volumes to be delivered could not exceed 200 MMBtu per day in order to qualify for automatic authorization. Construction of taps to serve existing customers other than right-of-way grantors would be authorized under the notice and protest procedure.

The Commission proposed to authorize a certificate holder, subject to notice and protest, to add new delivery points or reassign volumes between delivery points. The volumes delivered to the customer were not to exceed previously authorized amounts. Authorization would not be granted if the certificate holder's tariff prohibited the change or if the pipeline had insufficient capacity to make the deliveries without harming service to other customers.

Regarding storage, the FERC proposed to authorize automatically storage service if the service to be provided was within the pipeline's certified storage capacity, the service would be provided for two years or less, and the rate for the service was included in a current rate schedule. Service to be provided for longer than two years would be authorized through the notice and protest procedure. Increases in the volumes to be stored would also be authorized through the notice and protest procedure provided that the certificate authorized the operation of the storage facility, the additional volumes would not exceed the facility's capacity, and additional facilities would not have to be constructed. Certificate holders were also automatically authorized to test and develop new underground storage fields provided that the pipeline spent no more than $1,000,000 on such activities in any one year.

The Commission proposed automatic authorization of abandonment of facilities and service if the seller had been authorized to abandon a sale or the transaction had stopped had been removed from the Commission's abandonment jurisdiction by Section 601(a)(1) of the NGPA. Previously, the Commission had to agree to such abandonment on a case-by-case basis. Sales taps and lateral lines could also be abandoned, but under the notice and protest procedure. All customers served through the tap or lateral line would have to agree to the abandonment.

The Commission also proposed to authorize certificate holders to shift an existing customer's purchases from one rate schedule to another automatically. The changes would have to be consistent with effective tariffs and not change volumetric limitations or deliveries for the customer.

Amendments to certificates to account for customer name changes would also be automatically authorized if the name change resulted from corporate reorganization or acquisition. Name changes for other reasons would have to be authorized through the notice and protest procedure.

In June 1982, FERC Order No. 234, which resulted from the NOPR just described, was published in the Federal Register.[9] Some changes in the rule were made. The Commission restricted eligibility to receive a blanket certificate to interstate pipelines that had been issued a certificate (other than a limited jurisdiction certificate) under Section 7 of the Natural Gas Act and had had rates accepted by the FERC. The Commission also included a thirty-day reconciliation period in the notice and protest procedure. During this period, a blanket certificate holder would attempt to resolve any minor differences, such as those caused by misunderstanding or lack of information, with a party filing a protest and thus try to avoid a case-specific determination of the issue by the FERC.

[9] Interstate Pipeline Certificates for Routine Transactions, Docket No. RM81-19-000, Order No. 234, 47 *Fed. Reg.* 24,254 (June 4, 1982).

The Commission also increased the per-project cost limitation from $3.5 million to $4.2 million. The lower limit had been taken from a 1979 order and the FERC thought it was necessary to raise the limit to reflect 1982 costs. The Commission also provided a procedure whereby a certificate holder could apply to the Director of the Office of Pipeline and Producer Regulation for a waiver of the per-project cost limitation. The annual expenditure limitation of the NOPR was also dropped. The FERC felt that that additional limitation was unnecessary given the other requirements of the program.

Regarding sales taps, Order No. 234 included a clarification of the definition of "right-of-way grantor" to specify that the term meant not only a person who grants right-of-way to the certificate holder but also a successor to the grantor's interest. This change was intended to expand the number of customers who could be served by a tap authorized by a blanket certificate.

The Commission also increased the amount that could be spent on testing and developing storage facilities from $1,000,000 per year to $2,700,000. The lower figure had been taken from an earlier order issued in 1964. The Commission agreed to increase the limitation to reflect higher costs.

Regarding changes in rate schedule, the Commission added a clarification that both the certificate holder and the customer would have to agree to any such change in order for it to occur. The regulation was meant to apply only to changes requested by the customer.

In August 1982, the FERC issued Order No. 234-A.[10] Among other things, the order required certificate holders to submit additional data on the impact of a proposed project or service on the certificate holder's current service. The data to be submitted included the impact of the proposed project on the pipeline's peak day and annual deliveries. A description of the end-use of the gas was also to be submitted. These data were also to be submitted for the recipient of storage service if that recipient was also an interstate pipeline. The Commission felt that this additional information would help the FERC staff and any intervenors to assess a project's impact more completely.

The Commission also clarified the regulation regarding the establishment of new delivery points for existing customers. The regulation had authorized

[10] Interstate Pipeline Certificates for Routine Transactions; Docket Nos. RM81-19-000 through RM81-19-009; Order No. 234-A, 47 *Fed. Reg.* 38,871 (September 3, 1982).

the establishment of new points and the clarification specifically authorized the construction and operation of the necessary facilities.

The FERC included an additional requirement for certificate holders seeking to abandon service or facilities. While not requiring a pipeline to notify all indirect customers served (direct customers had to consent in writing to the proposal), the Commission did require the certificate holder to notify the state public service commissions with jurisdiction over the retail sales to the indirect customers. The Commission felt that this requirement would adequately protest the interests of those customers, as the state commissions would be given the opportunity to intervene and protest the abandonment.

In the second NOPR, mentioned above, that the FERC issued in 1981,[11] the Commission made a variety of proposals to expand the scope of the blanket certificate program. One of the major proposals in this NOPR was to allow an interstate pipeline holding a blanket certificate to make off-system sales to another interstate pipeline. The buyer would then include the gas in its system supply. The Commission imposed various requirements and restrictions on the transactions. These included a one-year limit on a transaction and maximum deliveries of 100,000 MMBtu in any single day. Sales were also subject to the notice and protest procedure. If any party or the FERC staff protested, the sale would not be authorized under the blanket certificate.

Sales were to be priced according to a rate schedule that the Commission considered appropriate. The schedule would include a commodity charge that would enable the pipeline seller to recover its average purchased gas costs and transportation charges to recover the costs of delivery. Revenues received in excess of costs incurred were to be flowed back to the seller's customers.

The proposal also included a prohibition on the sale of gas, acquired by the certificate holder for the specific purpose of making an off-system sale, under the blanket certificate program. The Commission feared that otherwise a series of pipelines would sell the same gas repeatedly under the blanket certificate and create "undesirable rate consequences" for their customers.[12]

---

[11] Sales and Transportation by Interstate Pipelines and Distributors; Docket No. RM81-29, 46 *Fed. Reg.* 24,585 (May 1, 1981).
[12] Ibid., p. 24,588.

The Commission also proposed to eliminate or simplify volumetric and end-use restrictions on the gas transported to end-users under the blanket certificate. These restrictions applied to gas sold directly by a producer to the end-user and were an attempt by the FERC to prevent excessive diversion of gas from the interstate market. Pipelines had been allowed to transport gas, under Orders 533 and 2 (issued by the Commission in the mid and late 1970s before the passage of the NGPA) for end-users needing fuel for high-priority uses, such as process and feedstock requirements. End-users could not increase their requirements and were expected to try to convert to other fuels. After passage of the NGPA, the Commission had instituted, in Order No. 27, a direct sale program for schools, hospitals, and essential agricultural users. That program did not include the restrictions found in the earlier programs.

In the blanket certificate NOPR, the FERC proposed automatic authorization for transportation of gas to the end-users served under the previous programs if the transportation was for a period of five years or less. Transportation for longer than five years would be subject to the notice and protest procedure.

The proposal to eliminate or simplify end-use and volumetric limitations would allow new process and feedstock customers to be served in the same manner as new agricultural users were served under Order No. 27. The Commission retained the requirement that direct sale gas be used in qualified end-uses, which was defined to include the Order No. 2 and Order No. 27 uses.

Regarding volumetric limitations, the Commission reasoned that any new loads served by direct-sale gas would be outside of an interstate pipeline's curtailment plan. The end-user would have to be aware that future service from system supplies would not be assured. As the new loads would not adversely affect other pipeline customers, the volumetric restrictions of the other programs would not be necessary.

The FERC also proposed to allow unlimited successive two-year extensions of self-implementing transportation arrangements. NGPA Section 311(a)(1-2) allows the Commission to authorize interstate pipelines to transport gas on behalf of intrastate pipelines or local distributors and intrastate pipelines to transport gas for interstate pipelines and any local distribution company served by an interstate pipeline. The Commission had limited those transactions to two years or less with the option for a single two-year extension. While proposing to allow unlimited extensions, the Commission retained a requirement for extension requests to be filed at least ninety days before the end of the current authorization so that the FERC could review the request if it so desired.

The Commission also proposed to modify its Section 311 regulations to allow intrastate pipelines to transport direct-sale gas for an interstate pipeline. Such service, while incidental to an interstate pipeline's transportation of such gas, required Commission authorization. The FERC proposal was to allow an intrastate pipeline to transport direct-sale gas on behalf of the interstate pipeline without prior approval. The intrastate pipeline could collect a fair charge for this service from the end-user or from the interstate pipeline.

The Commission NOPR also included a proposal for local distribution companies. The FERC would have allowed any LDC, which was served by an interstate pipeline and which held a blanket certificate, to transport gas on behalf of an interstate pipeline or another LDC served by interstate pipelines without becoming subject to federal regulation. This modification was intended to grant to LDCs a benefit enjoyed by Hinshaw pipelines[13] (being able to undertake some transactions in interstate commerce without being subject to FERC regulation).

On July 20, 1983, the FERC issued two orders in the two blanket certificate dockets discussed above. FERC Order No. 319 was derived from the second NOPR just discussed.[14] In this order, the Commission retained the elimination of volumetric limitations on gas that could be transported for high priority customers (as proposed in the NOPR). As with previous FERC programs (Order No. 27), transportation service under the blanket certificate

[13] A Hinshaw pipeline, named after the amendment to the NGA creating the exemption to the Act, is a pipeline transporting or selling gas for resale in interstate commerce. The exemption from federal regulation applies if the gas was received within or at the boundary of a state, if the gas was consumed within that state, and if the pipeline was subject to regulation by a state commission. See Charles F. Phillips, *The Regulation of Public Utilities: Theory and Practice* (Arlington, Virginia: Public Utilities Reports, Inc., 1984), p. 584, n. 34.

[14] Sales and Transportation by Interstate Pipelines and Distributors; Expansion of Categories of Activities Authorized under Blanket Certificate; Docket No. RM81-29-000; Order No. 319, 48 *Fed. Reg.* 34,875 (August 1, 1983).

would not be limited to a pipeline's current customers. Gas owned by an end-user not served at that time by the pipeline could also be transported. High-priority users included schools, hospitals or similar institutions, essential agricultural uses (as defined by the Secretary of Agriculture under the NGPA), process or feedstock users, customers using gas for plant protection, and large commercial establishments (using 50 Mcf or more on a peak day). The FERC also retained the authority to designate other end-uses as eligible for transportation under the blanket certificate.

The Commission expanded the number of sellers eligible to have their gas transported under a blanket certificate on behalf of high-priority customers. In the proposed rule, gas could be transported if it had been purchased from a producer or if it was owned and developed by the end-user. In Order No. 319 the FERC decided to include gas purchased by the end-user from an intrastate pipeline or the local supplies of a local distributor as well. The Commission reasoned that this inclusion would not divert gas from the interstate market and might encourage exploration and development of domestic gas supplies.

The Commission retained the proposal that transportation for high-priority end-users lasting five years or less be automatically authorized. Longer arrangements would be subject to notice and protest procedures. The final rule, however, did include a modification concerning automatic authorization for transportation of gas reserves owned and developed by the end-user. Such transportation could last up to ten years or the life of the reserves, whichever was less, and still be eligible for the automatic authorization.

The FERC also decided to allow transportation of gas under a blanket certificate on behalf of other pipelines or local distribution companies where the gas would be used by the pipeline or LDC for its system supply. The transaction would be subject to the notice and protest procedure.

Order No. 319 included a multifaceted treatment of revenues received by a pipeline for the transportation of gas. In the first NOPR, the Commission had proposed that a pipeline choose one of two options. The first was to include representative revenues or volumes in test period based rates and then keep all revenues received if the revenues or volumes of service fell within the projected levels. Alternatively, the pipeline could choose to exclude transportation volumes and revenues from the test period based rates and flow through to sales customers (via Account No. 191) all revenues over one cent per MMBtu or in excess of proven expenses. In Order No. 319, the Commission retained these two options stressing (because ambiguous language in the NOPR had led to some misunderstanding) that revenue crediting to Account No. 191 was required only when the pipeline had not chosen the first option of including representative revenue and volume levels in its rate case. If revenues exceeded the representative levels, the pipeline could keep them.

The Commission felt that the rule would provide incentives for pipelines to transport gas more readily. However, because underrecovery of costs was also a distinct possibility, the FERC also felt that an additional incentive might be needed for pipelines to provide transportation service for industrial customers. The Commission wanted an incentive that, unlike the representative levels mechanism, had no risk of underrecovery of costs and also provided an opportunity for a pipeline to increase its revenues.[15]

The Commission's incentive was to allow pipelines to charge end-users an Additional Incentive Charge (AIC) of up to 5 cents per MMBtu. The AIC approach would, according to the Commission, share the economic benefits received by the end-user who would be receiving cheaper gas with other on-system customers. The AIC was to be used along with the revenue crediting mechanism. Pipelines not using the representative revenue-volume levels option could choose to use the AIC by filing a tariff for end-user transportation under Section 4 of the NGA.

The Commission stated that end-users were not required to pay the AIC. The pipeline certificate holder could collect the charge only if the end-user agreed to pay it. The Commission assumed that end-users would not agree to pay the transportation charge unless the total gas cost was less than other energy supplies available to the customer. The AIC was approved as an experiment and was to last eighteen months.

[15] Ibid., pp. 34,880-34,881. The Commission's rationale was that volumes moved in individual transactions for end-users were generally smaller than those moved for interstate or intrastate pipelines or LDCs. Pipelines may have also been unfamiliar with most end-users as those customers were generally served by LDCs and thus less than enthusiastic about modifying their operations to meet the needs of those customers. In the view of the FERC, "Thus end-users would appear to have been confronted with greater institutional and informational barriers in negotiating with pipelines for transportation than have been faced by larger and more established shippers," and pipelines would need more of an incentive to serve those customers.

The Commission, in Order No. 319, retained the Phase II Notice's provision of off-system sales, subject to the notice and protest procedure. The one-year limit on such transactions was also retained, however; the volumetric limitation (100,000 MMBtu per day) was dropped. The Commission stated that "the basic premise of the off-system sales program is that there is a surplus of natural gas. The imposition of a volumetric limitation is inconsistent with this premise."[16]

Another modification to the off-system sales proposal incorporated in the final rule was the addition of a requirement that the selling pipeline have at least potential take-or-pay liability. The Commission felt that this requirement would insure that on-system customers would receive some benefit from the sales. This change was meant to respond to some commenters' concerns that off-system sales would harm on-system customers by selling off contracted reserves and also by potentially increasing the on-system customers' average cost of gas.

Regarding pricing of the off-system sales, the Commission decided to modify slightly the requirement in the NOPR that the price should recover the average purchased gas costs (plus cover transportation costs as well as include a commodity charge). In Order No. 319, the FERC stated that the price should be the higher of this system average load factor rate or the approximate replacement cost of the gas sold in the off-system transaction. The system average load factor rate would be based on the rates in effect at the time that the sale was proposed. The gas acquisition cost would be the average NGPA section 102 gas acquisition cost based on the pipeline's most recent purchased gas adjustment filing at the time that the sale was proposed.

The Commission decided to treat revenues derived from off-system sales in the same manner as transportation revenues under the blanket certificate. The pipeline could credit revenues received over one cent per MMBtu to Account 191 or estimate representative volumes and revenues in its rates and then return all revenues received over those levels.

The Commission retained the NOPR prohibition of reselling off-system gas acquired by a pipeline solely to make its own off-system sale. Order No. 319 also included a clarification of language concerning occasions when the

[16] Ibid., p. 34,884.

transactions may be interrupted. The proposed rule had stated that off-system sales would be interrupted when gas was needed to serve the pipeline's other customers. The FERC, in Order No. 319, made clear that "other" meant on-system customers.

With respect to its NGPA Section 311 regulations, the FERC adopted its proposal to permit unlimited, successive two-year extensions of self-implementing transportation, subject to Commission review. An intrastate pipeline wishing to charge a new rate during the extension period would have to obtain FERC approval. The FERC also adopted its proposal to allow intrastate pipelines to transport direct-sale gas on behalf of an interstate pipeline without prior Commission approval. The proposal would also apply in cases in which the gas was sold by the intrastate pipeline.

The Commission retained its proposal to allow any local distribution company which was served by an interstate pipeline and which held a blanket certificate, to transport gas on behalf of an interstate pipeline or a local distribution company served by an interstate pipeline without becoming subject to the Commission's jurisdiction. This exemption had already been applied to Hinshaw pipelines.

The second order issued by the FERC on July 20, 1983 pertained to both of the blanket certificate rulemakings. In Order No. 234-B, the FERC expanded the blanket certificate program to authorize transportation for more types of end-users.[17] Order No. 319 authorized transportation for high-priority end-users such as schools, hospitals, process, feedstock, and agricultural customers. Order No. 234-B allowed transportation of direct sale gas under blanket certificates for industrial and boiler fuel users.

This last program was to be a two-year experiment, running through June 30, 1985. Transportation arrangements lasting 120 days or less would be self-implementing. Arrangements lasting longer than 120 days would have to be approved through the notice and protest procedure.

[17] Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors; Docket Nos. RM81-19-000; RM81-29-000; Order No. 234-B, 48 *Fed. Reg.* 34,872 (August 1, 1983).

End-users would be able under the rule to contract for gas directly from producers, intrastate pipelines, and LDCs. When a transaction involved a first sale of gas, NGPA ceiling prices were to apply.

A few months later, on November 3, 1983, the FERC issued Order No. 319-A, granting in part and denying in part rehearing of Order Nos. 234-B and 319.[18] The Commission dismissed as unsubstantiated complaints that the blanket certificate program would lead to substantial loss of load by some LDCs to other LDCs operating in the same area or to interstate pipelines located close to large customers. The FERC also was not convinced by some commenters who claimed that the program would harm residential and commercial customers. In response, the Commission stated that if the program resulted in direct sales to customers who would have otherwise left the LDC's system, those customers would continue to shoulder some of the transporting pipeline's fixed costs. This result would be beneficial to the pipeline's other customers. Direct sales would also help to keep wellhead prices responsive to the prices of other fuels. Blanket certificates would also create incentives for pipelines to employ gas purchasing practices to keep their prices for delivered gas competitive as customers would be able to shop around for alternative supplies. All of these developments should, the Commission felt, benefit all customers, including residential and commercial.

The Commission clarified the regulations concerning sellers eligible to have their gas shipped under the blanket certificate program. Eligibility was extended to any seller in a first sale except interstate pipelines selling their own production. The FERC had inadvertently excluded independent marketers and resellers from the regulation and the change was intended to include them.

The FERC also clarified its regulations concerning transportation of end-user owned gas. In Order No. 319-A, the Commission stated that end-user owned gas may be transported up to 120 days under automatic authorization but under the notice and protest procedure for longer periods. The terms concerning gas purchased from third parties and transported under Order No. 234-B were to

---

[18] Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors; Docket Nos. RM81-19-000 and RM81-29-000; Order No. 319-A, 48 *Fed. Reg.* 51,436 (November 9, 1983).

apply. The FERC also stated, however, that proven reserves, purchased by an end-user, would not qualify for the blanket certificate program.[19]

The Commission revised its regulations to state explicitly that pipelines needed to file a generally applicable transportation tariff schedule even if they had previously filed special transportation rate schedules with the FERC. The Commissioners believed that requiring a general tariff would facilitate use of the blanket certificate program because gas shippers would be able to shop around and compare pipeline tariffs and find a transporter whose rates would best meet their needs.

On March 22, 1985, the FERC issued a Notice of Proposed Rulemaking concerned with blanket certificates.[20] In this Notice, the Commission proposed a six-month extension of the Order No. 234-B direct sale program for low-priority end-users, including industrial and boiler-fuel users. The program would run until December 31, 1985. The Commission stated that "although the past two years' experience with the Order No. 234-B program has fulfilled the Commission's expectations for its success in moving gas expeditiously to end-users, the Commission desires the benefit of further study..."[21]

The Commission also proposed a modification of its Order No. 234-B regulation to allow end-users, whose gas was being transported by a pipeline, to file for an extension of transportation authorization on behalf of the pipeline. Under the Order No. 234-B regulations then in effect, the pipeline had to file a request with the FERC subject to approval via the notice and protest procedure for transportation arrangements lasting longer than 120 days. The arrangement could lapse at the end of that time if the pipeline failed to reapply and the customer's service would be interrupted. The Commission's proposal was designed to help end-users avoid this possible disruption.

[19] Ibid., p. 51,441. The Commission wanted to ensure that while an end-user may not have begun the development of a gas reserve, that customers still needed to complete significant development of the reserve, "so that the end-user's efforts to reduce its gas costs involved some element of risk."
[20] Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors; Docket Nos. RM81-19-000 and RM81-29-000, 50 *Fed. Reg.* 12,326 (March 28, 1985).
[21] Ibid., p. 12,327 (reference deleted in quotation).

By the time this NOPR was issued in March 1985, the FERC was in the midst of the rulemaking that would result in Order No. 436. In addition, the rulings in the Maryland People's Counsel cases were issued soon afterwards.

On June 17, 1985, the FERC issued a final rule regarding blanket certificates. The Commission decided to adopt the proposals in the March 22, 1985 NOPR with some modifications. End-users would be authorized to file for an extension of transportation authorization on behalf of the pipeline transporting their gas. The Commission added a requirement for the end-user to notify the pipeline in writing that it was taking such action. In light of the decision in Maryland People's Counsel v. FERC II, which vacated the blanket certificate orders, the Commission decided on an extension of the blanket certificate Order No. 234-B program until October 31, 1985 or the effective date of a final rule in the Order No. 436 docket, instead of the proposed December 31, 1985 deadline.[22]

Special Marketing Programs

Special Marketing Programs (SMP) represent a third type of transportation policy pursued by the FERC in the early and mid-1980s in response to the gas market conditions at that time. In a special marketing program, gas committed by a producer to a pipeline would be released from that contract by the pipeline and made available to other customers, such as distributors, end-users, or other pipelines. The price would be negotiated by the producer and the buyer and it could not exceed NGPA ceiling prices. The customers of the pipeline involved in the original contract with the producer could also purchase the gas as part of their firm supply entitlements. The pipeline releasing the gas would provide transportation to the new buyer, although transportation under SMPs was to be secondary to the pipeline's regular transportation commitments.[23]

[22] Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors; Docket Nos. RM81-19-000 and RM81-29-000, 50 *Fed. Reg.* 25,701 (June 21, 1985). The FERC applied for a stay of the Court's order to allow for this extension. As discussed below, the stay was granted.

[23] See U.S., Federal Energy Regulatory Commission, *1984 Annual Report*, FERC-0116 (Washington, D.C.: U.S. Government Printing Office, 1985), p. 7.

On November 10, 1983, the FERC approved several special marketing programs. One of these programs involved Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company.[24] Because that program was the target of the Maryland People's Counsel litigation, it serves as the focus of the following discussion.

Earlier in 1983, Columbia Gas had invoked force majeure provisions in its contracts with all of the producers and suppliers of its gas because of supply surpluses and declining markets. Columbia sought to reduce its required purchases below the levels mandated by the take-or-pay and minimum daily purchase provisions of the contracts.

Columbia then reached an agreement with Exxon, its largest supplier, to relieve that producer of its obligation to supply gas to the extent that Columbia was unable to take the gas. Under the terms of the agreement, Exxon could sell gas released from its contract with Columbia directly to industrial customers on Columbia's system who had the capability to switch to No. 6 fuel oil. The released gas could also be sold for the purposes of reopening a closed plant or preventing an imminent plant closing. Other customers would be eligible to purchase the released gas after Columbia's industrial customers had exercised their right of first refusal.

Columbia was to be credited against its take-or-pay obligation to Exxon for gas sold by that producer under the agreement. While the original contract between Exxon and Columbia covered both NGPA Section 102(c) and 103 gas, the credit to the pipeline was to be \$2.70 per Mcf of released gas sold prior to November 1, 1983 and \$2.97 per Mcf sold after that date until November 1, 1984, regardless of the price category of the gas.

Columbia Gas and Columbia Gulf requested FERC approval of the transportation of the gas for Exxon, including 161,700 Mcf per day of gas which was dedicated to interstate commerce before November 8, 1978 and 16,000 Mcf of gas which was not. Transportation rates were to be at the average Columbia systemwide storage and transmission costs, excluding gas that was unaccounted for or set aside for company use. Revenues received in excess of

[24] Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company, Docket No. CP83-452-000; Findings and Order after Statutory Hearing Granting Interventions and Issuing Certificate of Public Convenience and Necessity, 25 FERC para. 61,220 (November 10, 1983).

one cent per decatherm each for Columbia Gas and Columbia Gulf would be credited to customers through Account No. 191.

The Commission approved the plan with some modifications. The original plan had not included high-cost gas, such as NGPA Section 107 gas, in the fuel to be released from a contract and then sold elsewhere. The FERC decided that such gas should be included as customers would benefit from Columbia's lessened take-or-pay obligations (producers were required to excuse Columbia's take-or-pay obligations for gas released, sold and transported) to its suppliers who provided the high-cost gas. Gas was to be released into the program beginning with the highest priced gas. All of Columbia's suppliers would thus be allowed to participate, not just those providing cheaper fuel.

Another modification dealt with eligible purchasers of gas under the SMP. The Commission decided that local distribution companies should be allowed to participate in addition to end-users.

The weighted average cost of the gas released under the program was to be, prior to its release, equal to or greater than Columbia Gas's weighted average cost of gas. Gas sold and transported in the program was to be moved in the same proportions of NGPA pricing categories under which the gas was released, regardless of the actual price paid by the buyer. Producers were to charge the buyer the lesser of the rates specified in the contract or the applicable NGPA ceiling price.

As for eligible uses of the gas to be sold in the program, the Commission ordered that sales would be restricted to new loads not served up to that point by gas or to requirements which were or would otherwise have been served by alternative fuels, direct sales by producers, gas purchased in industrial sales programs, or other similar programs, gas sold by pipelines at special discount rates, or in off-system sales, or propane or synthetic gas. It is important to note, in light of the subsequent litigation, that captive customers were not eligible to participate in the program.

The Commission, in approving the plan, stated that it was exploring innovative and experimental plans to deal with the market conditions existing at that time (gas surplus and declining markets). Accordingly, "this Commission believes that the approach to the existing problem contemplated herein is totally consistent with the mandate given to other independent

Federal regulatory agencies to test remedies of an experimental, limited-term nature to protect the public interest."[25]

On January 16, 1984, the FERC issued an order clarifying and reaffirming the order of November 10, 1983, just described.[26] The Commission discussed the benefits that it felt the program would have. The recipients of the gas would benefit from receiving fuel priced competitively with other fuels and other sources of gas because their own operations could be run more economically. Customers not eligible to participate would still benefit from fixed-cost recovery that would result from the SMP. Producers participating in the SMP would benefit from increased sales and revenues. The Commission noted that all classes of customers and the entire industry could potentially benefit, stating, in addition, that "in any event, no class of customer will be any worse off as a result of the program."[27]

The Commission discussed the charge, made by the Maryland People's Counsel and the Process Gas Consumers Group, that the program by excluding the core, captive markets of a pipeline, limited gas versus gas competition, discriminated against the captive customers, and conflicted with pro-competitive laws such as the Natural Gas Act and the antitrust laws. The Commission stated that its intent, in approving the program, was to intensify any existing price competition among producers, expecting that such competition would force down prices. However, the Commission noted that it was also concerned about contracting gas markets. Shifts by core customers from one pipeline to another could have increased the share of pipeline fixed-costs borne by those core customers left behind without an alternative supplier while at the same time worsening the take-or-pay obligations of the pipeline from which the core customers had shifted.

The Commissioners stated that they were not disregarding the competition issues. However, the Commissioners felt that it was at that time too soon to assess the impact of the SMP, and they noted that the program did increase competition for certain loads.

---

[25] Ibid., p. 61,563.
[26] Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company, Docket No. CP83-452-001, et al.; Order Clarifying Prior Orders and Denying Rehearing. 26 FERC para. 61,031 (January 16, 1984).
[27] Ibid., p. 61,081.

The Commission decided to allow the special marketing programs to compete with interruptible service provided by pipelines and distributors. Further steps, such as including core markets, might be taken at a later date. The Commission asserted that while allowing competition between SMPs and interruptible service would be beneficial,

> we are not yet prepared to say that competition for the firm markets would achieve a net benefit. The pipelines have made long-term supply commitments, have designed their operations, and have major investments in pipeline capacity and other facilities, e.g., above ground and underground storage and synthetic gas, in order to serve these markets. Under competition, there would be winners and losers and the pipelines that lost firm markets would be forced to attempt to recover their costs from other captive markets that were unable to take advantage of competition. The shifting of these costs could constitute undue discrimination. On the other hand, failure to recover these costs could place the pipeline in financial jeopardy which could affect the reliability of service to those customers and consumers dependent upon the pipeline. We have not spoken our last word on this subject.[28]

The Commission noted that it was at the same time issuing a Notice of Inquiry on special marketing programs. It also asserted that all of Columbia's customers would benefit from the program by reductions in their shares of the pipeline's fixed costs made possible by the SMP. If any undesirable or unforeseen impacts on customers were to result, the FERC still had the power to modify the program.

In addition to responding to the assertions of discrimination and anti-competitiveness, the FERC also imposed the requirement that gas could not be released in the program unless its maximum lawful price (excluding any NGPA section 110 adjustments) was higher than the maximum lawful price set by NGPA section 109.

In the Notice of Inquiry,[29] mentioned above, the Commission asked whether it should increase the opportunities for gas against gas competition beyond the modification it made in the Columbia program and two other programs

[28] Ibid., p. 61,087.

[29] Inquiry on Impact of Special Marketing Programs on Natural Gas Companies and Consumers; Docket No. RM84-7-000, 49 *Fed. Reg.* 3,193 (January 26, 1984).

(SMP v. interruptible service). The FERC also stated that it was concerned about the discrimination of the SMPs against pipeline customers who were not eligible to receive gas under the programs. It would approve only those SMPs with a net benefit to the direct and indirect customers of the pipeline who were not eligible to receive gas, even though some discrimination may have resulted.

The Commission requested comments on a variety of questions and issues, including whether companies with special marketing programs should be allowed to compete for the core customers of other pipelines or local distribution companies. The FERC also asked whether residential, commercial and other firm customers should be able to participate in the programs.

The Commission asked about some of the conditions that it had imposed on the special marketing programs. It requested comments on whether requirements other than that the weighted average cost of the gas released in an SMP be equal to or greater than the weighted average cost of the pipeline's system supply might protect better the pipeline's core customers. In addition, the FERC asked whether it should omit or relax the requirement that the participating producers give the pipeline take-or-pay credit for the gas released and then moved in the program.

After reviewing the comments received in response to the Notice of Inquiry and from a public conference, the FERC issued an omnibus order on September 26, 1984 that extended and modified the special marketing programs in effect at that time.[30] The Commission stated that experience with the programs up to that point showed that customers were benefiting, pipelines were receiving significant take-or-pay relief, and producers willing to charge market clearing prices were selling gas that they might not have otherwise sold. The Commissioners did not want the experiment to end and so they extended the programs for one year until October 31, 1985.

In response to the arguments that the programs were discriminatory, the FERC decided to expand the program in a limited fashion to include firm

[30] Tenneco Oil Company, Houston Oil & Minerals Corporation, Tenneco Exploration, Ltd., Tenneco Exploration II, Ltd., Tinco, Ltd., and Tenneco West, Inc., Docket Nos. CI83-269-000 through CI83-269-023, et al., Order Amending Certificates of Public Convenience and Necessity, Extending Limited-Term Abandonments, and Establishing Procedures, 28 FERC para. 61,383 (September 26, 1984).

service customers. Firm customers of a pipeline releasing gas in an SMP could nominate up to ten percent of their firm supply entitlement to be purchased under the special marketing program. The Commission stated that it was providing these firm customers with the option of purchasing gas either for their own system supply or on behalf of an end-user. Thus, "all firm customers of the releasing pipelines have an opportunity to benefit from lower gas prices whether or not they serve industrial loads."[31]

The Commission decided to expand the eligibility requirement that a market must be capable of being served by an alternative fuel in order to be served under a special marketing program. The capability to use the other fuel would not have to be installed at the time in order for the market to qualify for service under the new requirement.

The Commission deleted its requirement that the weighted average cost of SMP gas had to be equal to or greater than the weighted average cost of the releasing pipeline's system supply. The Commission stated that this condition had been intended to protect the pipeline's captive customers from higher prices resulting from the pipeline releasing cheap gas into the SMP. The Commissioners reasoned that this requirement was no longer necessary as captive customers were now eligible for SMP benefits. In addition, the stipulation that gas released into a special marketing program must have a price higher than that mandated by NGPA section 109 was retained.

The FERC also retained the general requirement that a pipeline transporting gas in a special marketing program charge a fully allocated cost of service based rate. The pipeline, however, could show that some costs were not incurred in providing the service or it could charge a lower rate and absorb some of the costs.

Another general requirement retained in this order was that the pipeline releasing gas into the SMP must be granted take-or-pay relief for volumes of gas released and sold in the program. The Commission, however, dropped the requirement that gas transported for a distributor or an end-user served by an LDC satisfied that distributor's or end-user's minimum commodity obligation. This stipulation had applied to variable costs which the FERC had deleted from minimum bills in Order No. 380.

[31] Ibid., p. 61,686.

On December 21, 1984, the FERC issued a follow-up order clarifying some points and making some modifications in the program.[32] The Commission deleted a requirement that the price charged by a producer for gas sold in a special marketing program had to be no higher than the rates specified in the contract from which the gas was released or the applicable NGPA maximum lawful prices (whichever of these two options was less). The Commissioners felt that market forces would keep prices down and the contract price portion of the requirement was, as a result, not necessary. The applicable NGPA maximum lawful price was retained as the ceiling.

The Commission declined to take a suggestion offered by the Maryland People's Counsel to require nondiscriminatory access to transportation. The Commission was not sure that it had such authority and thought that such a requirement might be counterproductive with less gas being moved as a result. However, the Commission did agree with another suggestion to require pipelines releasing and transporting SMP gas to provide firm transportation of any gas purchased under a special marketing program by their firm customers.

The Commission also discussed its requirement of a fully allocated cost of service based rate for transportation. Such a rate should recover fully the cost of providing service. If no cost of service study had been done, the Commission stated that it would also accept the nongas component of the pipeline's commodity rate for gas that was part of a contract demand or the 100 percent load-factor firm sales rate, excluding the cost of gas, for other transportation.

The FERC, in responding to a pipeline's comments, stated that a pipeline could keep revenues earned from transporting SMP gas to a firm customer as part of the entitlement to SMP gas (ten percent of contract demand) that a firm customer was allowed to receive. The Commission reasoned that SMP gas purchased by a firm service customer displaced sales that the pipeline would have otherwise made. These SMP volumes of gas would have already been included in the calculations of sales rates. Thus, the pipeline was entitled to the revenues.

[32] Tenneco Oil Company, Houston Oil & Minerals Corporation, Tenneco Exploration, Ltd., Tenneco Exploration II, Ltd., Tinco, Ltd., and Tenneco West, Inc., Docket Nos. CI83-269-000 and CI83-269-024 through CI83-269-034, et al., 29 FERC para. 61,334 (December 21, 1984).

The assumption of displaced sales could not hold for SMP gas sold to other customers eligible to receive that gas, however. Those sales were to be for new loads or for customers who would have used alternate fuels, propane or synthetic gas, or been served under special or interruptible service programs. In those instances, transportation revenue crediting through Account No. 191 was required.

The Commission returned to the minimum bill issue in this order. In response to some comments, the FERC decided to allow special marketing program gas volumes sold to a local distributor (up to ten percent of the LDC firm contract entitlement from the pipeline) to be applied to the fixed cost portion of the distributor's minimum bill obligation to the pipeline. Other volumes sold to a distributor under the program would be marginal or interruptible service and thus would not apply against the minimum bill.

On February 26, 1985, the FERC issued an order denying the Maryland People's Counsel's request for a stay of the September 26, 1984 order.[33] The People's Counsel argued that the special marketing programs were anti-competitive because they eased any pressure that pipelines (and indirectly producers) would have otherwise felt to reduce prices to retain customers with alternative fuel capabilities. According to the People's Counsel, the special marketing programs restricted gas-on-gas competition, relieving pipelines of an incentive to reduce purchased gas costs. Customers were harmed by the program, especially captive customers.

The Commission responded that the People's Counsel had ignored the important role of price elasticity in all end-use markets and the significance of the Commission's decision to include ten percent of firm customers' entitlements in the special marketing programs. This change in the program allowed all end-users to benefit. The FERC also stated that the average cost of pipeline purchased gas had declined in the first nine months of 1984. Thus, special marketing programs did not shift high-cost gas to ineligible customers but rather had helped this decline in costs to occur. Producers participating in the special marketing programs had, from May 1983 through

[33] Tenneco Oil Company, Houston Oil & Minerals Corporation, Tenneco Exploration, Ltd., Tenneco Exploration II, Ltd., Tinco, Ltd., and Tenneco West, Inc., Docket Nos. CI83-269-000 and CI83-269-024 through CI83-269-034, et al., 30 FERC para. 61,202 (February 26, 1985).

October 1984, revised the price of 134 Bcf of gas to market clearing levels.[34]

The Commission also asserted that the special marketing programs could not be viewed in isolation. The other programs, such as blanket certificates, undertaken by the FERC encouraged competition. The Commissioners concluded that if they "granted the requested stay, the benefits of these programs [SMPs] would be lost, perhaps permanently, with resulting harm to consumers and to the industry."[35]

The Maryland People's Counsel Decisions

As noted in the above discussion, the Maryland People's Counsel (MPC) intervened at various times during the implementation of the special marketing program policy. The People's Counsel's main argument was that this policy was anticompetitive and harmful to the captive customers of the pipelines. The FERC disagreed with these assertions and proceeded with the policy, arguing that in any event the policy was an experiment and might be altered after more experience was gained.

The MPC took its case to the U.S. Court of Appeals for the District of Columbia. The result was three rulings in the spring and summer of 1985 that had a major impact on FERC gas transportation policy and enabled the Commission to pursue other, more sweeping, initiatives.

The first two decisions were handed down in May 1985. In Maryland People's Counsel v. F.E.R.C. I, the Court ruled on the validity of the Columbia Gas special marketing program.[36] The Court stated that it was not ruling on the Commission's authority to approve special marketing programs, but rather on the Commission's power to exclude captive customers or core markets from the program. In addition, "no one questions that it would have been within the Commission's power to strike restrictions on eligible purchasers from Columbia's proposal."[37]

[34] Ibid., p. 61,411.
[35] Ibid., p. 61,412.
[36] Maryland People's Counsel v. Federal Energy Regulatory Commission, 761 F.2d 768 (D.C. Cir. 1985).
[37] Ibid., p. 774.

The opinion included a discussion of several Commission reasons for deciding not to strike the restriction on captive customers. The first such reason was that ineligible customers would still benefit from a reduction in their share of the pipeline's fixed costs. If the program increased the amount of gas transported, the costs could be spread over a larger number of volumes, reducing the amount that each customer would have to bear. The Court labeled this argument as the "cost spreading rationale".

The "cost spreading rationale" was found to be unpersuasive. The MPC and the Court asked why such savings to captive customers would still not occur even if those customers were allowed to participate. "Additional SMP sales would presumably still occur, and fixed costs would still be spread to the benefit of captive customers."[38]

The MPC argued that savings to captive customers from cost spreading would be dwarfed by the savings not realized because of the restrictions incorporated into the program. As structured, the special marketing program would enable the pipeline to sell any over-priced gas, perhaps purchased imprudently, to the captive customers while charging market rates to fuel switchable customers. Pipelines would be shielded from the effects of any unwise gas purchasing practices. Thus, the SMP facilitated exploitation of the customers, whom the Natural Gas Act was designed to protect.

The FERC had rejected these arguments. However, the Court stated that the Commission needed to consider this factor further if it was to protect the consumer from excessive rates. In the view of the Court, competition may be an effective way to protect the consumer "...but the Commission has not explained why competition restricted in the fashion it has approved would do so merely because of its effect upon costs shared by those to whom the competition itself is denied."[39]

The second major Commission argument was labeled "enhancement of pipeline competition". The argument was that competition between pipelines for each other's core markets would not necessarily be in the public interest.

[38] Ibid., p. 775. The Court stated that avoidance of take-or-pay obligations also was not a satisfactory justification for the same reason. These obligations could be avoided with or without the exclusion of captive customers.

[39] Ibid., p. 777.

Pipelines had made commitments for gas and investments in equipment to serve core markets. A pipeline that lost such a market would have to recover its costs from its other core markets. This cost shifting would be unduly discriminatory, but failure to recover the costs might jeopardize the pipeline financially and lower the quality and reliability of service to the other customers.

The Court also found this rationale unpersuasive. According to the judges, it was not necessary to exclude core markets entirely from the program in order to avoid the competition for those markets that the Commission feared. A pipeline could have been allowed to transport gas released from its system supply to its own captive customers only. The FERC might have been justified in limiting competition between pipelines, but there was no justification offered for limiting competition between producers within a pipeline's service area.[40]

The third major Commission argument, labeled the "other dockets rationale", was that the points raised by the MPC would be considered in other dockets and subsequent proceedings dealing with the Columbia program. The Court noted, however, that the Commission's lawyers could not find another docket in which the People's Counsel's arguments were being addressed. The Commission's "Fabian approach" was unacceptable: "While there may well be circumstances where a particular objection is more properly deferred to a later proceeding, ...that is assuredly not the case where the objection goes to the heart of the public interest determination immediately to be made."[41]

The Court also noted the Commission's view that Columbia's gas purchasing practices should be considered in a NGA section 5 proceeding, then pending. However, gas purchasing was not at the heart of the MPC arguments and a section 5 proceeding was not a sufficient substitute for considering an application for a section 7 certificate.

---

[40] Ibid., p. 778. The Commission also argued that nothing in the program stopped Exxon or other producers from charging Columbia less for the gas that they had contracted to sell the pipeline. The Court observed that "While all that is true, it is ridiculous to assume that Exxon or any other business will lower prices simply because there is nothing that stops it from doing so. The point is that the program approved by the Commission does not permit the stimulus of competition, which alone would cause Exxon to engage in such self-sacrificing behavior."
[41] Ibid. p. 778.

The fourth and final major Commission argument discussed in the opinion was labeled the "experiment rationale". The Commission had undertaken an experiment in the special marketing programs, and it was not possible at the time to assess its full impact. An experiment was unpredictable. Core markets were not included, but the program was a major departure from existing regulatory policy. The experiment must be limited for now.

The Court stated, however, that there were reasonable experiments and arbitrary experiments just as there were reasonable programs and arbitrary programs. The law required the Commission to state why it felt that more good than harm would result from its actions. It had not done so. The MPC had argued that the Commission's departure from existing regulation was counterproductive and would harm the customers, vulnerable to pipeline monopoly power, that the NGA was intended to protect. "It is no response to say that for the moment the experiment is 'carefully circumscribed' to help those who do not need the Commission's protection while hurting those who do."[42]

The Court found the original Columbia SMP order to be invalid. However, that order had already expired by the time the opinion was issued and successor orders had been promulgated. As those orders were also being challenged, the Court ordered the Commission to show why the newer orders should not be vacated and remanded to the FERC for reconsideration.

In Maryland People's Counsel v. FERC II, issued the same day as the previous decision just discussed, the Court ruled on the validity of the blanket certificate orders.[43] The arguments made by MPC against blanket certificates were the same as those made against the special marketing programs. Pipelines will keep their rates reasonable only because of the threat of losing large industrial end-users who have the capability to switch fuels. Under the law, a pipeline could not lower its rates to those customers without lowering its rates to all customers.

The blanket certificate program as structured, however, allowed a pipeline to transport reasonably priced gas from producers to the fuel switchable end-users, keeping those customers on the pipeline's system. The

---

[42] Ibid., p. 779.

[43] Maryland People's Counsel v. Federal Energy Regulatory Commission, 761 F.2d 780 (D.C. Cir. 1985).

same service was not provided to the captive customers. The program removed any competitive check on pipeline rates and allowed the pipeline to collect monopoly rents from the captive customers. The Commission should have conditioned blanket certificates on nondiscriminatory access for captive and noncaptive customers. In that way, the captive customers would not be exploited.[44]

The Court agreed that the People's Counsel had raised serious questions about the blanket certificate program; questions that the FERC had "brushed aside without warrant..."[45] The Commission's avoidance of the antitrust implications of the program was "puzzling."[46]

The Commission argued that charges of anticompetitive effects of the blanket certificates were premature. Any price discrimination would have resulted from abuse of the authority granted by the certificate. Abuses could be handled in ratemaking or in antitrust suits. The Court, however, disagreed.

The Commission also put forth three arguments as to why it was unconvinced by the MPC objections. The first was the cost spreading rationale, described above, that the program would keep the fuel-switchable customers on the system. Those customers would continue to pay a share of the pipeline's fixed costs to the benefit of all customers. The Court dismissed this argument in the same manner as it had in the first case, stating that the FERC had not explained why those benefits would not be available if captive customers were included in the program.

The second FERC argument was that direct sales between producers and end-users through the blanket certificates would keep wellhead prices responsive to the reductions in prices of other fuels. Price competition from those other fuels would be felt at the wellhead. The Court found no reason in this argument for allowing pipelines with excess capacity to favor only certain customers, and stated that "...if, in the absence of a license to discriminate, pipelines refuse to transport direct-sale gas to anyone, the result will presumably be still greater surpluses of gas at the wellhead--the

[44] Ibid., pp. 784-785.
[45] Ibid., p. 786.
[46] Ibid.

clearest possible signal to producers that their long-term contract prices are too high."[47]

The third Commission argument was that the blanket certificate program was designed to encourage pipelines to purchase gas so as to keep their delivered prices competitive. This incentive would result from end-users purchasing gas from other sources besides pipelines or distributors. The Court failed to see what incentive would be created when pipelines could satisfy the fuel-switchable customers through transportation of direct-sale gas and special marketing programs.

The Court vacated the blanket certificate orders to the extent that transportation of direct-sale gas was provided for fuel-switchable, non high-priority end-users but not for local distributors and captive customers. The judges instructed, "on remand, FERC should fully consider and reasonably analyze the competitive concerns advanced here by MPC."[48]

On June 28, 1985, the D.C. Court granted a stay of its decision in Maryland People's Counsel v. FERC II. The Commission had applied for the stay to allow for the extension of the blanket certificate program until October 31, 1985 or the effective date of a final rule in the Docket No. RM85-1-000 (Order No. 436). The Court noted that the MPC did not oppose the stay ". . .provided that it is secured against use as a wedge for an even longer period of tolerance for discriminatory transportation programs."[49] While the Court approved the stay until the deadlines requested by the FERC, it also stated that no further requests would be granted.

The opinion in Maryland People's Counsel v. FERC III was issued on August 6, 1985.[50] In the first Maryland People's Counsel case, the Court ruled that the Columbia SMP order was invalid and as that order had expired, directed the FERC to state why the successor orders should not be vacated. In this third case, the judges ruled on those successor special marketing program orders which had allowed limited participation by firm customers in the programs.

[47] Ibid., p. 788.
[48] Ibid., p. 789.
[49] Maryland People's Counsel v. Federal Energy Regulatory Commission, 768 F.2d 1354 (D.C. Cir. 1985).
[50] Maryland People's Counsel v. Federal Energy Regulatory Commission, 768 F.2d 450 (D.C. Cir. 1985).

The Court stated that the FERC had still failed to respond to the arguments raised by the MPC. The benefits of the SMPs listed by the Commission in the September 26, 1984 order extending the program, including take-or-pay relief, spreading of fixed costs and encouragement of exploration and development, were rejected by the Court in the first two MPC cases.

Allowing firm customers to nominate up to ten percent of their contractual entitlement to be purchased in an SMP still permitted substantial discrimination. The Court asked whether the FERC had a reasonable explanation for allowing continued discrimination. The FERC orders provided no answers and the Court was not willing to accept the Commission's arguments that more restructuring of the gas market beyond that in the SMP order could result in adverse cost shifting and that including captive customers may have led to less SMP gas being moved.

In concluding, the judges stated that ". . .we are pursuaded that the new SMP orders are of a piece with the old. They may be marginally less discriminatory than their predecessors, but they continue to entail identical lapses of logic and evidence." However, because the orders were to expire on October 31, 1985, the court concluded that it would be better to allow the orders "to die a natural death." Vacating the orders might, in the short term, have done more harm than good. However, "if the Commission wishes to retain discriminatory SMPs in some form after October 31, we trust that it will do so only if it can demonstrate that the petitioners' concerns are unfounded or are outweighed by other relevant considerations."[51]

Thus, it was clear after the three Maryland People's Counsel v. FERC rulings that the Commission was going to have to proceed on a somewhat different course as it grappled with the problems of the gas market. Blatantly discriminatory programs would be unacceptable to the courts unless a reasonable justification was offered. As shown in the next section, the FERC was well on the way to establishing its new course by the time the MPC decisions were issued.

[51] Ibid., p. 455.

FERC Order 436

The process resulting in Order No. 436 began at least several months before the MPC cases were decided. The FERC issued two Notices of Inquiry (NOI); the first on December 24, 1984 and the second on January 18, 1985. In the first NOI,[52] the Commission stated that its aim was to "elicit constructive and thoughtful discussion about how regulation of interstate transportation of gas under the Natural Gas Act should be structured to ensure that the natural gas market becomes a viable and competitive market in which consumers are provided adequate supplies of gas at the lowest reasonable cost."[53] The Commission sought new and innovative proposals for a regulatory framework and reviews of the programs that it had in place.

Regarding the reviews of its programs, the Commission sought comments on the eligibility criteria, rate treatment for transportation, policies toward core markets, and mandated carriage of gas for nonowner shippers. For blanket certificate eligibility, the Commission asked, among other questions, whether the eligibility of all end-users should be extended beyond the June 30, 1985 deadline, perhaps being made permanent, whether the Additional Incentive Charge (AIC) of the Order No. 319 blanket certificate program was useful and should be retained, whether reporting requirements were burdensome, and whether imported natural gas should be included in the program. For special marketing programs, the FERC asked if the programs should be modified, eliminated, or made permanent.

On rate treatment, the Commission inquired on whether an unbundled transportation charge should be used, instead of a fully allocated cost approach, and how an unbundled rate would be structured. The Commission also asked if pipelines had enough incentive, such as the AIC, to transport gas voluntarily for others.

On core markets, the Commission sought answers to the question of what the effects would be of making core market sales subject to competition by alternate sellers; whether there was a level or a kind of firm sales that made up a market needing protection so that those customers would have to be denied

[52] Interstate Transportation of Gas for Others; Docket No. RM85-1-000, 50 *Fed. Reg.* 114 (January 2, 1985).
[53] Ibid., p. 116.

access to competitive sources of gas; and what the rationale should be for extending core market restrictions in anything other than a temporary experimental program. On mandated carriage, the Commission asked if there were circumstances under which an interstate pipeline had a legal obligation to carry a nonowner shipper's gas; whether a refusal to transport gas might be considered prima facie reasonable or unreasonable (in relation to the antitrust laws); and whether the Commission might have authority under the NGA to compel transportation in certain circumstances.

The second NOI contained questions relating to rate making and the risk and financial implications of partial wellhead decontrol.[54] On ratemaking, the FERC noted three factors of increasing importance. First, policies should result in prices communicating clear market signals to buyers and sellers. Second, pricing should include incentives to minimize costs so that services can be provided at the lowest cost consistent with reliability. Third, customers should be given flexibility in choosing among services and among providers of services.

The Commission then raised a series of questions under various aspects of ratemaking. On the cost basis for rates, the Commission asked questions such as whether the practice of basing rates on rolled-in costs should be continued; whether spot market prices were a reasonable estimate of the current cost of gas; whether FERC policies encouraged pipelines to enter into long-term contracts with inflexible pricing terms; and how could pipelines be encouraged to maximize capacity use and minimize operating costs if no fixed costs were included in commodity charges.

On rate flexibility, the Commission stated that it did not want its policies to restrict the ability of jurisdictional companies and customers to respond to competitors who were not regulated. The Commissioners asked whether the FERC should continue to set fixed rates for pipelines or set a range (with ceiling and floor or just ceiling) of rates that pipelines could charge; and whether problems of undue discrimination would arise if rate flexibility were allowed.

[54] Natural Gas Pipeline Ratemaking, Risk, and Financial Implications after Partial Wellhead Decontrol; Docket No. RM85-1-000, (Phases II & III), 50 *Fed. Reg*. 3,801 (January 28, 1985).

The Commission also asked about one part versus multipart rates. The Commission noted that the two part demand and commodity rate might not have encouraged pipelines to minimize their costs and operate efficiently because demand charges recover large amounts of revenue regardless of sales made. The Commission asked whether a customer should pay a charge to reserve the right to receive service; what the appropriate function of a demand charge should be; when single part volumetric rates would be preferable to multipart rates; and under what terms and conditions service should be available to a customer if it was not reserved.

The fourth rate issue discussed by the FERC was rate design consistency among pipelines. The Commission noted that it decided most rate matters on a company specific case-by-case basis and asked whether that approach resulted in economic distortions or unfair competitive advantages or disadvantages.

Regarding risk and financial implications, the Commission first raised the issue of the regulatory importance of risk, asking generally whether its policies biased pipeline and consumer decisions in inappropriate ways. The Commissioners also wanted to know whether the allocation of risk, between investors and ratepayers resulting from their policies had helped or hindered the cause of competition at the wellhead and the burnertip. The Commission asked more specifically if gas pipelines had the proper incentives to operate efficiently and if not whether a misallocation of risk was to blame; whether shifting risks to customers reduced pipeline incentives to minimize costs; what an appropriate allocation of risk should be among industry segments; and whether business risk should be unbundled if rates and services were and how this would be done.

The second risk related issue concerned specific regulatory policies affecting risk sharing. The Commission asked whether it should continue to allow pipelines to change their rates as throughput changes and how the cost of unused capacity should be allocated between customers and the pipeline; whether pipelines should be permitted to impose minimum bills that recover fixed costs; how costs for gas not taken should be distributed between pipeline and customer; and what other types of rate mechanisms could be used to result in more efficient risk sharing between investors and customers or among customer classes.

The final risk related issue was the financial implications of alternative risk sharing policies. The Commissioners noted that in the NOI they were asking if the FERC should attempt to influence directly how risk was shared between investors and customers and thus they needed to consider the financial implications of such actions. They asked what types of consequences, other than an increase in the cost of capital, would result from shifting more risk to investors; if regulation should occasionally permit a rate of return greater than the cost of capital if all risks were to be shifted to investors; and whether changing how risk was shared by investors and customers would affect the evolution of the industry's structure.

On May 30, 1985, the FERC issued a Notice of Proposed Rulemaking.[55] This was approximately three weeks after the first two Maryland People's Counsel decisions had been handed down and the Commissioners mentioned that "we have also begun to receive the guidance of reviewing courts on appeal of some of the initiatives set in motion by the Commission over the last year and a half in anticipation of partial wellhead decontrol."[56]

The Commission stated that its intent was to "make such adjustments in our regulation of interstate transportation of natural gas as are required to ensure that the natural gas markets are viably and sufficiently competitive so that consumers are provided natural gas at the lowest reasonable rates consistent with reliable long-term service." The Commission sought to identify and change "those aspects of our current regulations that may now appear to hinder the development of competition in those areas where competition will better protect the public interest than will traditional public utility regulatory rules."[57]

The Commission noted that the commenters responding to the Notice of Inquiry generally felt that transportation programs should be available and should be made permanent. The commenters also thought that pipeline services could be unbundled and that in the longer term, open access to nondiscriminatory transportation at appropriate rates (to the extent that pipeline capacity was available) could be implemented.

The proposed rule included four parts covering transportation; take-or-pay, optional, expedited certificates, and block billing. Regarding

[55] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket No. RM85-1-000 (Parts A-D), 50 *Fed. Reg*. 24,130 (June 7, 1985).
[56] Ibid., p. 24,130. (Citation deleted).
[57] Ibid., p. 24,131.

transportation, the proposal would have required any pipeline seeking blanket or expedited certification for transportation service to provide that service on a nondiscriminatory basis. Transportation would be offered separately from sales and would be separately tariffed. The curtailment priorities and procedures, which a pipeline used for transportation customers, would have to be the same as the priorities and procedures used for sales customers.

A customer contracting for firm service would receive such service as long as there was available capacity. Interruptible transportation service would also be available.

In order to allow sales customers to participate more fully in the program, the proposed rule provided for contract demand reduction. Firm gas sales customers of pipelines that had agreed to transport gas for other customers would be entitled to reduce their contract demand for gas by up to 25 percent in any one year. The pipeline could allow the customer to reduce its demand by greater than 25 percent. If the pipeline agreed, the customer could reduce its contract demand up to 100 percent. The customer was required to give thirty days' notice to the pipeline.

On rates, the FERC stated that transportation rates would recover only costs attributable to transportation. Customers not using transportation service would not have costs shifted to them if the pipeline did not recover all of its transportation-related costs.

Volumetric rates would be used, and costs would be fully allocated. The rates would be intended to recover costs assigned to a particular rate period. Customers' volumetric rates would be differentiated according to mileage or zone depending on where the gas was to be delivered. Peak rates would be designed to ration pipeline capacity. Off-peak rates would be intended to increase throughput.

Maximum and minimum rates were proposed. The maximum rate in off-peak periods would be the incremental cost of providing service. In peak periods, the maximum would be based on the fully allocated costs of the service less any fixed costs recovered in the off-peak service maximum rate. The minimum rate was the short-run average variable costs of providing the service. Pipelines would be allowed to charge any rate between the maximum and the minimum.

The Commission stated that is would allow some selective discounting if a pipeline decided to charge a lower rate to some but not all customers, noting that the "fact that a different price is paid is not in itself either undue discrimination or 'an unreasonable difference' in rates."[58] Discounting would be unduly discriminatory if a discount enjoyed by one customer was paid for by other customers not offered the discount.

Optional, expedited certificates would be available to pipelines willing to accept the risk of a venture, such as new or expanded services and construction of the facilities needed for those services. Blanket certificates would be available through this process. Rates charged would have to comply with the rate conditions described above for transportation. Firm or interruptible service could be offered, but service would have to be offered on the basis of nondiscriminatory access. The certificate holder would be given authority, at the request of the party whose gas was being transported, to shift receipt and delivery points of the gas without prior notice and approval of the FERC. Because pipelines would be expected to assume more risk of a competitive environment, competing certificates to serve markets would be granted.

The Commission stated that pipeline accountability was an essential part of the proposed rule. If a pipeline accepted a certificate and assumed the risk of a venture, it was assumed that the venture was prudent. Pipelines would not be allowed to shift costs among customers in future rate cases.

The FERC would employ four principles to ensure that costs would not be shifted improperly. First, rates would be volumetric so that a pipeline would be at risk if it did not sell or transport amounts close to the representative volume levels upon which rates were based. Second, rates would include only properly allocated costs so that cross-subsidization could not occur. Third, representative volumes could not be reduced in future rate cases. Fourth, pipelines would not be able to recover past losses in future rate cases.

Pipelines accepting the optional certificates would be allowed pregranted abandonment. Service could be ended when the contract with the customer expired, if the customer had alternate suppliers available. If no alternative was available to the customer and the customer was willing to continue paying for the service, the pipeline could be ordered by the FERC to continue to provide the service if the customer petitioned the FERC for such an order.

[58] Ibid., p. 24,137.

The take-or-pay provisions of the proposed rule would apply to pipelines offering nondiscriminatory access to transportation. Pipelines' payments to end their minimum payment or purchase obligations under contracts for first sales of gas would be assumed to be prudent (a "safe harbor" presumption of prudence) for purposes of satisfying the NGA. The presumption of prudence would be subject to rebuttal with any interested party having to prove that the pipeline was not acting prudently.

The fourth major part of the proposed rule was a billing mechanism. The Commission would require pipelines to separate gas purchase costs into three parts. Block 1 would include "old gas" as defined by the NGPA sections 104, 106(a) and 109. Block 2 would include "new gas", and the costs of imported gas. Block 3 would include demand and commodity costs not included in the first two blocks.

A customer would be entitled to purchase block 1 gas on the basis of its past purchases from the pipeline. The percentage entitlement would be figured by dividing the amount of each customer's firm gas purchases from the pipeline in calendar years 1982, 1983, and 1984 by the pipeline's total firm sales for those years. The pipeline would be required to notify its customers each year of the estimated contract quantity of block 1 gas that would be available.

Pipelines would bill their customers using a gas and nongas rate structure. The gas rates would include units of block 1 gas and units of block 2 gas multiplied by the weighted average cost of the gas. The nongas rate would include the other pipeline costs.

The Commission also proposed to offer pipelines the presumption of justness and reasonableness for sales of block 2 gas. In order to qualify for this treatment, a pipeline would have to offer firm transportation on a nondiscriminatory basis and allow firm sales customers to reduce their contract demands by 100 percent over a four year period.

On October 9, 1985, the FERC issued two documents. Order No. 436 and a request for additional comments on block billing. Regarding block billing, the Commission made some changes in the proposal in addition to requesting more comments.[59] Block 3 was dropped from the proposal. In its place, the

[59] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket No. RM85-1-000 (Part D), 50 *Fed. Reg.* 42,372 (October 18, 1985).

FERC added to the list of costs included in both the block 1 rate and the block 2 rate, the unit nongas cost component of the pipeline's commodity charge.[60] Nongas costs would continue to receive "as-billed" treatment by including in block 1 the costs of purchases from other pipelines at their own block 1 rate and by including in block 2 the unit nongas component of the commodity charge for purchases from other pipelines.

Other changes to the block billing proposal included a change in the base period used for determining entitlement to block 1 gas from the 1982-1984 period of the original proposal to December 1, 1978 to December 31, 1984. The FERC also decided to include a customer's interruptible (in addition to firm) gas purchases in the factor used to determine entitlements to block 1 gas. The Commission also clarified that the presumption of justness and reasonableness for block 2 costs, offered to a pipeline for providing nondiscriminatory access and allowing its firm sales customers to reduce their contract demands by 100 percent, was subject to rebuttal and was to apply only to rates reasonably related to the acquisition cost of the gas. The FERC, it should be noted, has yet to implement the block billing proposal.

In Order No. 436, the Commission implemented with some modifications, two of the three remaining parts of the proposed rule: transportation and optional expedited certificates.[61] On the take-or-pay proposal, the Commission noted that most commenters had opposed its "safe harbor" presumption of prudence for one-time payments to end payment or purchase obligations of contracts. The Commissioners thus were "persuaded that an attempt to impose a regulatory solution at this time may actually aggravate the situation rather than improve it."[62]

In place of the NOPR proposal, the Commission decided to reaffirm its April 1985 policy statement on take-or-pay.[63] In that policy, the FERC had decided that first sellers of gas would not violate the NGPA requirement that they not receive prices for gas in excess of the NGPA maximum lawful prices

---

[60] Ibid., p. 42,394.

[61] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket No. RM85-1-000 (Parts A-D); Order No. 436, 50 *Fed. Reg.* 42,408 (October 18, 1985).

[62] Ibid., p. 42,462.

[63] Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations; Docket No. PL85-1-000, 50 *Fed. Reg.* 16,076 (April 24, 1985).

when they received payments made by pipelines to amend or waive take-or-pay or other minimum payment obligations. The pipelines making such payments could file to recover them in an NGA section 4 rate case. The Commission would consider on a case-by-case basis each pipeline's methods for recovering the costs of the payments and how the costs would be allocated among its customers. Customers would be allowed to question the prudence of the payments, the allocation plan, and any other appropriate issues. The Commission also pledged to authorize any abandonments or amend any certificates expeditiously for producers as needed to implement the policy.[64]

In Order No. 436, the Commission clarified some points of the take-or-pay policy. It said that expeditious consideration of producer abandonment would be appropriate when take-or-pay buyout, as envisioned by the policy, had been carried out or in cases in which the producer faces substantially reduced takes of its gas without payment. Gas purchasers would be given the opportunity to object to any abandonment. Abandonment applications designed to help move shut-in or untaken gas would also be expedited.

The transportation provisions of Order No. 436 included nondiscriminatory access to the self-implementing transportation services offered by a pipeline under section 7 of the NGA (blanket certificates) or section 311 of the NGPA. Service would be provided on a first-come first-served basis. Interstate and intrastate pipelines might offer firm or interruptible service, but that service had to be offered without undue discrimination or preference.

Rates were to be volumetric and downwardly flexible between a maximum and a minimum. The rates were to be based on projected volumes to be transported. The number of units could be changed only in a subsequent NGA section 4 rate filing. Rates were to be differentiated according to the time that the service was provided (peak or off-peak period) and the distance covered. Rate schedules were to include maximum and minimum rates. A maximum rate was to be designed to recover only those costs properly allocated to the service. Minimum rates would be based on the average variable costs properly allocated to the service.

[64] Ibid., p. 16,080.

Pipelines would be allowed to charge reservation fees for firm service. Pipelines would also be allowed to offer discount rates below the maximum rate. Such discounting, however, would be at a pipeline's risk of not recovering its costs. The pipeline would not be allowed to recover the costs in a future rate case. Intrastate pipelines were exempted from these rate conditions for self-implementing transportation.

The Commission retained the contract demand (CD) reduction provisions of the proposed rule, but added a CD conversion option. If a pipeline provided self-implementing transportation under the rule, it would be required to allow its firm sales customers to convert their firm sales service to firm transportation service. The customer would be allowed to convert up to 25 percent of its firm sales entitlement to transportation in any twelve month period, although a pipeline could allow a greater percentage to be converted. Any units of firm transportation purchased were to be credited to the customer's minimum commodity bill obligations to the pipeline.

The pipeline could also impose a reservation charge on customers exercising this conversion option. Any reservation charge for firm service was not to recover any fixed or variable costs in excess of those that would have been recovered through ratemaking to determine the demand charge in a pipeline's sales rate.

The CD reduction provision, as noted above, allowed firm sales customers of a pipeline providing self-implementing transportation to reduce their firm sales entitlement up to 25 percent in any given year. The pipeline could allow the customer to reduce its entitlement by a greater amount. The Commission extended the advance notice that a customer would have to give the pipeline before reducing its CD. The proposed rule required 30 days' advance notice while the final rule required 150 days. The FERC also included a provision in Order No. 436 that required a pipeline, when a customer exercised the reduction option, to reduce the minimum commodity bill that required the customer to pay the fixed cost component of a certain percentage of the customer's firm sales entitlement.

Customers could exercise both options at the same time, reducing some entitlement to firm sales service and converting some additional sales service to transportation. However, the combination in any given year would not be allowed to exceed 25 percent of the customer's total entitlements, unless the pipeline agreed to allow a greater percentage.

If a customer used either the CD reduction or conversion option, that person or entity was assumed to have consented to abandonment of sales service. The pipeline would be allowed to file for abandonment which would be considered to be in the public interest.

Order No. 436 also provided for grandfathering existing transportation arrangements that had been authorized under NGPA section 311 and the blanket certificate program. This was to allow suitable transition to the new program. Section 311 arrangements were to continue until the expiration of their original term or October 31, 1987, whichever was earlier. Blanket certificate transportation for high-priority users was to continue until the certificate expired. Blanket certificate transportation for low-priority users could continue, but would have to be nondiscriminatory.

The Commission made two other points regarding transportation. First, the rule did not apply a blanket, nondiscriminatory access condition to individual NGA section 7 transportation and sales certificates. Those would be reviewed on a case-by-case basis to determine consistency with the objectives of Order No. 436. Second, as noted earlier, intrastate pipelines were exempt from the rate conditions of the self-implementing transportation program. They were also exempt from the CD reduction and conversion requirements and they were not required to offer firm service under the program.

Regarding the optional, expedited certificates to be granted under NGA section 7, the FERC retained the main elements of the proposed rule. The Commission did make a slight change in the wording of the nondiscriminatory access requirement from the proposed rule. The NOPR had explicitly stated that any certificate holder providing transportation service under an optional certificate had to offer nondiscriminatory access. In Order No. 436, an applicant for an optional certificate who sought to provide transportation service had to state that he/she/it had filed for and would accept a blanket transportation certificate under the transportation provisions of the order and would comply with the various requirements of those provisions, one of which was nondiscriminatory access.

As before, certificates would be for new service and for the construction (or acquisition) and operation of necessary facilities. Certificates would be nonexclusive and the pipeline would be expected to assume the full risk of the venture. As before, the certificate holder would have the authority to switch delivery and receipt points for gas at the request of the customer whose gas was being transported. Sales taps could also be constructed under the certificate as long as the right-of-way grantor consumed the gas and no more than 200 MMBtu of gas per day was to be delivered.

Rates for services were to be one part and were to recover costs allocated to the services. Demand charges, minimum bills, minimum take provisions, or other revenue guarantors could not be included. The rates were to be based on projected units of service. These units could be increased in a subsequent rate filing but not decreased. Any differences in costs due to differences in the time when the service was provided (peak or off-peak periods) or the distance covered in providing the service were to be reflected in the rates.

The rate schedules were to state maximum and minimum rates. The pipeline could not charge a rate greater than the maximum or less than the minimum. A maximum rate was to be designed to recover on a unit basis only the costs allocated to the service while a minimum rate was to be based on the average variable costs properly allocated to the service. A pipeline could not file a new rate to recover costs not recovered under previous rates. A pipeline could not shift costs previously allocated to one service to another service unless the Commission approved.

Conditional pregranted abandonment authority was another major part of the optional certificates, as in the proposed rule. Service would be abandoned when the contract(s) covering the service expired, if the pipeline requested this authority in its application. The pipeline had to give the customer 45 days advance notice if it intended to abandon any part of the service. The customer had the right to file a protest with the FERC. The Commission could order the pipeline to continue to provide the service if the customer could not, after reasonably trying, find an alternative supplier of the service, and the customer was willing to pay the rate on file for the service.

The FERC issued several follow-up orders to Order No. 436. None of these incorporated fundamental changes in the framework of the original order and they are briefly summarized.

Order No. 436-A was issued on December 12, 1985.[65] One of the changes made in the Order No. 436 framework by the FERC in this order was that pipelines transporting under the rule would be required to keep a log of all transportation requests. The information to be recorded included the date of that transportation request, the name of the person requesting the service, and the volume of gas to be transported. This log would be available for public inspection and would help interested parties determine whether the pipeline was operating in an nondiscriminatory manner.

The Commission also added a requirement for an intrastate pipeline participating in the program to file a one-time statement with the FERC describing how it would engage in the transportation arrangements. Operating conditions, such as the pipeline's quality standards and the financial viability of the shipper, would have to be described. The pipeline would have to file the statement within thirty days of the commencement of the service. Amendments to the statement, because of changes in the pipeline's operating conditions, would have to be filed within 30 days of the commencement of the changes.

The major modifications to Order No. 436, found in Order No. 436-A, dealt with the CD reduction/conversion option.[66] The Commission extended from December 15, 1985 to February 15, 1986 the deadline for interstate pipelines to provide self-help transportation for local distributors under NGPA section 311 without starting the CD reduction/conversion process. The Commissioners thought that it would be better for the industry to extend the Order No. 436 transition period through the bulk of the 1985-86 winter heating season to avoid unduly disrupting transportation arrangements.

The Commission also decided to require firm sales customers, wishing to use the CD reduction option the first year that it was available, to give the pipeline written notice of its intention within forty-five days after the pipeline became part of the transportation program. The reduction would then take effect 150 days later. In subsequent years, the customer would have to give notice 150 days before the reduction would take effect. The Commission

[65] Regulation of Natural Gas Pipelines after Partial Wellhead Deregulation; Docket No. RM85-1-000; Order No. 436-A, 50 *Fed. Reg.* 52,217 (December 23, 1985).

[66] Ibid., pp. 52,273-52,274.

intention was to make notice deadlines and effective dates for customers wishing to exercise this option more certain. Order No. 436 had only included a requirement of notice of 150 days before the reduction would take effect.

A major change in the CD reduction/conversion option made in Order No. 436-A involved the schedule of the conversion or reduction. Order No. 436 had specified a four year, 25 percent per year, change in a customer's firm sales entitlement. A customer could either convert or reduce that entitlement up to 25 percent in any one year, unless the pipeline allowed a greater amount.

Order No. 436-A mandated a 5 year phase-in with potentially varying amounts of conversion or reduction each year. The five year period would begin when the pipeline began or continued a transportation arrangement under NGPA section 311 or accepted a new blanket certificate. Reductions or conversions would be cumulative so that a customer not taking the full amount of allowed reduction or conversion in one year could in subsequent years reduce or convert the full cumulative amount eligible to be reduced or converted in that and all previous years.

In the first year, a customer could reduce or convert up to 15 percent of its firm sales entitlement. In the second year, the customer could reduce or convert an additional 15 percent or a cumulative amount up to 30 percent. In the third year, the customer could reduce or convert an additional 20 percent, or a cumulative amount up to 50 percent of firm sales entitlement. In the fourth year, the customer could reduce or convert an additional 25 percent, or a cumulative amount up to 75 percent of the entitlement. In the fifth year, and thereafter, the customer could reduce or convert an additional 25 percent or a cumulative amount up to 100 percent. The pipeline could allow its firm sales customers to reduce or convert by amounts greater than these.

The FERC issued Order No. 436-B on February 14, 1986.[67] The Commissioners again postponed the deadline, from February 15, 1986 to June 30, 1986, for pipelines to transport gas without having to offer firm customers the CD reduction/conversion options. They stated that orders 436 and 436-A were major changes in the regulation of transportation and the transition to

[67] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket No. RM85-1-000; RM85-1-148; RM85-1-150 and RM85-1-152 (Part A), 51 *Fed. Reg.* 6,398 (February 24, 1986).

the new regulatory environment would take time to achieve. Postponement of the deadline would allow pipelines and their customers to work together to determine their participation in the program and apply for needed authorizations.[68]

Orders 436-C, D, and E were issued on March 28, 1986. In Order No. 436-C, the FERC denied rehearing of Order No. 436-A.[69] Some of the requests for rehearing were concerned with the contract demand conversion/reduction option. The petitioners claimed that while the Commission was gradually phasing in this option, the cumulative nature of the CD reduction or conversion undercut that phase-in. A customer could reduce its demand by up to 75 percent or 100 percent in the fourth or fifth year of the process, presenting a pipeline with a large reduction in demand. The petitioners suggested that the reduction or conversion should not be cumulative beyond the first year in which the right to reduce or convert would exist.

The Commissioners disagreed, believing that most customers would not wait until the fourth or fifth years of the reduction/conversion process and then reduce or convert 75-100 percent all at once. The Commissioners also noted that only firm sales customers with service agreements with the pipeline begun before the pipeline joined the Order No. 436 program were eligible for the CD conversion/reduction.

In addition, the cumulative scale was to last only for the transitional period. After that five year period, a customer could reduce or convert up to 100 percent of contract demand in any single subsequent year. Thus, the Commissioners felt that nothing would be gained by preventing a customer from exercising the right to convert or reduce cumulatively during the transition period since the right to convert or reduce up to 100 percent would be available thereafter.[70]

In Order No. 436-D, the Commission denied rehearing of Order No. 436-A on the question of whether to reinstate the February 15, 1986 date for contract

---

[68] Ibid., p. 6,399.
[69] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Order Denying Rehearing; Docket Nos. RM85-1-144, 145, and 147 through 152; Order No. 436-C, 51 *Fed. Reg.* 11,566 (April 4, 1986).
[70] Ibid., p. 11,567.

demand reductions and conversions to begin.[71] The Commissioners defended the extension of the trigger date for CD reduction/conversion until June 30, 1986, stating that the public interest would not have been served by trying to make major changes in transportation arrangements during the winter heating season. The extensions were "a small price to pay for the resulting continued stability in the gas markets and transportation."[72]

Order No. 436-E dealt with a petition by the state of Louisiana.[73] The state's representative claimed that the "first-come, first-served" requirement of Order No. 436 would hinder service to local communities because intrastate pipeline capacity would be taken by interstate shippers. The Commissioners replied that they did not intend to regulate intrastate transportation and that the open access and fair allocation of capacity requirements of Order No. 436 applied only when an intrastate pipeline was involved in interstate service. In addition, intrastate pipelines were not required to provide firm transportation. The Commission denied Louisiana's petition. However, the Commissioners recognized that a situation such as Louisiana's representatives described could occur and they allowed the state to file a subsequent petition if such an instance of impaired local service arose.

---

[71] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Order Denying Rehearing; Docket Nos. RM85-1-160 and RM85-1-161; Order No. 436-D, 51 *Fed. Reg.* 11,569 (April 4, 1986).

[72] Ibid. The Commission also dismissed a petition for rehearing from the Maryland People's Counsel. The MPC had argued that a Commission order allowing Texas Gas to provide interruptible transportation service to fifty-two end-users under Section 7(c) of the NGA had rendered Order 436 meaningless. MPC claimed that this was so because the Texas Gas order gave pipelines a choice as to whether or not to follow Order 436 when offering blanket or self-implementing transportation. The Commissioners disagreed, stating that Order 436 was voluntary and that pipelines still had the option to offer transportation under section 7 of the NGA. The FERC would not consider undue discrimination more acceptable under section 7 certificates than under Order 436. In addition, Texas Gas had said that it would not refuse access to other customers and no allegations of discrimination had been made by Texas Gas' customers.

[73] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Order Denying Reconsideration; Docket No. RM85-1-000; Order No. 436-E, 51 *Fed. Reg.* 11,566 (April 4, 1986).

AGD v. FERC

The court challenge to Order No. 436 was initiated by the Associated Gas Distributors (AGD). The case of Associated Gas Distributors v. F.E.R.C. was decided by a three judge panel of the U.S. Court of Appeals for the District of Columbia Circuit on June 23, 1987. While upholding most parts of Order No. 436, the judges decided to remand the order back to the FERC to deal with certain issues that they felt needed further consideration.[74]

The judges first discussed the open access requirements of Order No. 436. They noted arguments made by some pipelines and other parties that these requirements went beyond the Commission's authority to impose and said that the arguments relied on the assertion that open access was equivalent to common carriage.

Examining the NGA, the judges found that the legislative history "provides strong support only for the point that Congress declined itself to impose common carrier status on the pipelines. . . . It affords weak--almost invisible--support for the idea that the Commission could under no circumstances whatsoever impose obligations encompassing the core of a common carriage duty." "Modest support" was provided for the view that Congress did not want the Commission to impose common carriage at will.[75]

The Court noted that the NGA, particularly sections 4 and 5, was concerned with undue discrimination. For the judges, the issue was that while Congress gave the Commission the power and duty to eradicate undue discrimination, it was alleged that the Commission's attempted exercise of that power in Order No. 436 was invalid because Congress had not conferred common carrier status on the pipelines and had not authorized the Commission to do so. This argument was to control regardless of the soundness of Order No. 436 as a response to the facts presented to the Commission. But the Court felt that this reasoning "turns statutory construction upside down, letting the failure to grant a general power prevail over the affirmative grant of a specific one."[76]

---

[74] Associated Gas Distributors v. Federal Energy Regulatory Commission, 824 F.2d 981 (D.C. Cir. 1987).
[75] Ibid., p. 997.
[76] Ibid., p. 998.

The Court also referred back to its decision in Maryland People's Counsel v. FERC II. That decision had vacated the blanket certificate program because of the failure to provide service to captive customers.

> Our holding in MPC II obviously did not require the Commission to make the findings that it has. It surely carried the implication, however, that if it did make supportable findings of undue discrimination in pipeline use of the old blanket certificates, it would have the authority to employ suitable remedies. And it carried the further implication that among them might be a requirement that any pipeline offering blanket certificate transportation agree to serve "LDCs and captive consumers on non-discriminatory terms."[77]

The MPC II decision "came about as close to endorsing the Commission's approach as Article III permits."[78]

Turning to the NGPA, the Court discussed the argument that section 602 of that law prohibited the open access conditions of Order No. 436. Section 602(b) stated that no person would be made subject to regulation as a common carrier under federal or state law because that person was providing transportation under section 311(a) of the NGPA and some other provisions of the law. Section 311 allowed interstate pipelines to transport gas on behalf of LDCs and intrastate pipelines. It also allowed intrastate pipelines to transport on behalf of interstate pipelines or LDCs.

The judges believed that section 602(b) was an effort by Congress to alleviate pipelines' concerns that the states would regulate them as common carriers if they transported gas under section 311. The imposition by the FERC of a duty not to discriminate was entirely different and was meant to accomplish the purposes of Congress set out in the law. The judges doubted that the Congress intended section 602 to prevent the FERC from conditioning section 311 transportation on nondiscriminatory access.

The Court examined claims that the "first-come, first-served" allocation of pipeline capacity was arbitrary and capricious. It noted that the FERC had provided no guidance in Order No. 436 on how to implement this procedure. A potential regulatory gap was alleged by some parties to have been created.

---

77 Ibid., p. 1000.

78 Ibid.

Pipelines could persist in discrimination. Even if willing to comply, a pipeline would not be entirely certain as to what to do. Shippers would not know what to do to secure priority status or choose between bundled and unbundled service.

The Commission had decided to deal with these issues on a case-by-case basis as each pipeline became part of the Order No. 436 structure, filed tariffs, and described operating conditions. The judges said that the Commission could not postpone the necessary decisions endlessly. However, because the FERC had not been more specific on what it would do in implementing the doctrine, the Court decided that the issue was not ripe for review.[79]

The judges then examined the Order No. 436 rate conditions. They dismissed an argument that the Commission had not made specific findings that rates charged by individual pipelines were unlawful before imposing the new conditions. The Court's answer was that the FERC did not have to make individual findings if it was issuing a generic rule.

The Court also dismissed arguments that selective discounting was discriminatory, that the rates favored unbundled transportation service over the transportation component of a bundled sales package, and that uniform discounting requiring a pipeline to promulgate in advance criteria under which it would provide discounts, instead of selective discounting, should have been required. The Court found that the mere existence of a rate disparity did not constitute undue discrimination and the judges generally deferred to the Commission's judgment and ability to experiment in dealing with these questions.

The judges also found that the Order No. 436 selective discounting did not violate the MPC II decision. The Commission had suggested in some supporting statements that discounting to meet competition from alternative fuels or other pipelines was not in and of itself discriminatory.

The Court noted that the Commission, by allowing captive customers access to the spot market, had dealt with its objections to the earlier transportation program, expressed in MPC II. The judges said that "to read MPC II as a rule that price differentials based on demand conditions are

[79] Ibid., pp. 1005-1007.

always unduly discriminatory would render the decision a defiant and unreasoned exception to the general pattern. The judicial acceptance of such price differentials is longstanding."[80] The Commission, however, would not be free to allow every price distinction based on differing demand elasticities. It could defer dealing with those issues to another time.

The Court next examined the contract demand adjustment provisions of Order No. 436. The judges referred to a previous decision by the D.C. Circuit Court, Panhandle Eastern Pipeline Co. v. FERC.[81] In that case, the Court had ruled on the Commission's use of its NGA section 7 power to condition certificates of public convenience and necessity. Panhandle had sought approval of transportation service that it wanted to provide for an industrial end-user. The FERC had approved the certificate but had required that revenues resulting from the service were to be flowed through to Panhandle's wholesale gas customers. The Court decided that the FERC had illegally used its section 7 power to change previously approved rates and thus circumvent NGA section 5. Section 5 allows the Commission to modify rates that it finds to be unjust or unreasonable only after a hearing in which the FERC has the burden of proof.

The CD adjustment provisions of Order No. 436 presented a similar issue, in the Court's view. The Commission argued that it had used section 7(b) authorizing it to permit natural gas companies to abandon service. The Court stated, however, that section 7(b) only dealt with the pipeline's obligation to provide service and did not support the Commission's decision to free pipeline customers from their contracts. Section 5 would allow such Commission action.

The Court was also not persuaded by the Commission's argument that applications for blanket certificates were voluntary and that there was, thus, no need to refer to any congressional grant of power. All section 7 applications are voluntary and this argument would have, in the court's view, uprooted the Panhandle doctrine.

Because the voluntariness argument and the invocation of NGA section 7(b) were inadequate and the Commission did not rely on any other statutory

---

80 Ibid., p. 1011.

81 Panhandle Eastern Pipeline Co. v. Federal Energy Regulatory Commission, 613 F.2d 1120 (D.C. Cir. 1979); Cert. denied 449 U.S. 889 (1980).

provisions, the court found the CD modifications to be without a basis in law to the extent that blanket certificate transportation under the NGA was conditioned on customer release from contract obligations. The Commission could, however, legally attach the CD conditions to transportation under NGPA section 311.[82]

In considering CD conversion, the judges noted that unilateral abrogation of a contract was "extreme" even if it was partial abrogation such as CD conversion.[83] However, the Court found the CD conversion rationale persuasive, noting that the contracts reflected the pipelines' monopoly power. CD conversion denied the pipelines some of the benefits of the contracts, but only because the contracts were remnants of monopoly power. The conversion option sought to correct the consequences of that monopoly power and thus conformed to the intent of the NGPA. Thus, the Court concluded that the FERC was correct in providing the CD conversion option to customers of pipelines transporting gas under NGPA section 311.

Regarding CD reduction, however, the Court agreed with the petitioners who claimed that the FERC had not developed an adequate rationale for that option. The Court noted that in the proposed rule, CD reduction had been offered but not CD conversion. When the Commission later offered CD conversion, the analysis of CD reduction became, in the Court's view, obsolete. If CD conversion was available, the justification of CD reduction as also necessary to provide customers access to spot market gas "fails."[84]

The FERC argued that CD reduction would be needed to help guarantee LDC access to gas competitively priced at the wellhead. The judges stated, however, that there was no indication in the record that competitive wellhead prices varied significantly by region. Any such variations, however, would still not create a problem of such magnitude that a 100 percent CD reduction would be required.

The Court also did not believe that the CD reduction option was supported by the Commission's argument that the level of service that a firm sales customer contracted for no longer corresponded to what the customer needed. This argument seemed "highly relevant to CD reduction", but "it hardly

[82] AGD v. FERC, pp. 1014-1015.
[83] Ibid., p. 1016.
[84] Ibid., p. 1018.

supports the broad remedy adopted."[85] The Commission itself had observed that most firm sales customers needed their full contract demand on peak days. The argument that the FERC made thus referred to a limited part of the industry and it was not certain why an industry-wide solution was required.

Some LDCs had claimed that the CD reduction option would force them to bear a greater share of the pipelines' capital costs as other, noncaptive, customers exercised that option. The Commission had answered that customers would probably seek little net CD reduction and that there would be little net change in aggregate recovery of costs.

The Court felt that this response was an insufficient answer to captive customers who might lose in the competition. The judges said that the FERC had not confronted the problem or developed any reasons to expect aggregate gains for customers.

The judges then considered the topic of producer-pipeline contracts and the take-or-pay issue. They identified the problem as the combination of high contract prices far in excess of the current market prices, with take-or-pay clauses requiring the pipeline to purchase the gas or make payments for it anyway. The issue for the Court was whether the Commission's lack of direct action on the contracts in Order No. 436 was permissible, especially due to the possibility that the order would help customers avoid the threat of the contracts by allowing them to obtain gas at current wellhead prices and thus possibly make the pipelines bear the burdens themselves.

The Court observed that virtually all parties (other than producers) attacked the Commission's refusal to take action on the producer-pipeline contracts. Their argument was that Order No. 436 denied pipelines leverage over producers. That leverage was the threat not to transport a producer's new gas when the producer refused to negotiate a pipeline's liabilities under old contracts. The argument also said that many pipeline customers would use open access and CD conversion to avoid dependence on their pipeline suppliers. A spiral would result with more LDCs leaving pipeline systems because of increasing gas cost burdens caused by the previous step of pipeline customers taking advantage of open access and CD conversion. Only distributors, who would incur substantial costs in developing secure, nonpipeline supply

[85] Ibid., p. 1019.

sources, would remain as pipeline sales customers. The customers of those LDCs left stranded on the pipeline system would bear the burdens of the expensive gas, defeating the purposes of Order No. 436 and the consumer protection purposes of the NGA.

The parties also maintained that the Commission's inaction would distort the structure of the gas market. This would result because FERC policy would have resulted in an artificial advantage for unbundled transportation service. The pipelines' merchant role would wither away despite the fact that bundled service, sales, and transportation, was more efficient.[86]

The FERC had responded to the pipelines' claim of loss of a bargaining chip in negotiations with producers by saying that open access and CD modifications were not intended to affect contract renegotiations. The judges responded that the Commission's intentions were not the problem. The dispute concerned the likely consequences of its policies and the Commission had not responded to this point.

The Commission also stated that Order No. 436 was a voluntary program. The Court responded, however, that refusing to participate could lead to bankruptcy for a pipeline. If a pipeline could not offer transportation for fuel-switchable customers, load loss might result.

The Court also noted that the Commission's argument blurred the distinction between all pipelines and individual pipelines. Order No. 436 gave pipelines the option of blanket certificate transportation. However, if one pipeline chose to participate in the program, all competing pipelines would face competitive pressure to be as flexible and thus participate.

The Commission also argued that CD conversion/reduction might not injure the pipelines. The Court, however, stated that customers' conversion to transportation would impair the pipelines' ability to deal with their (pipelines) overpriced gas. In addition, the judges asserted that Order No. 436 would cause CD reduction only in instances when the reduction injures the pipeline. A pipeline would voluntarily release a distributor if it had an equally profitable use for its capacity, in the view of the Court.

The FERC claimed that Order No. 436, in allowing producers expedited abandonment when a take-or-pay settlement has been reached or when a producer

[86] Ibid., p. 1023.

experiences major reductions in takes of its gas, would help pipelines. In the latter instance of a producer seeking abandonment because of reduced takes, abandonment would allow the pipeline to use contract defenses against the producer if it tried to resell the gas. The judges, however, said that it was unclear if that option would be very useful for pipelines. The difference between contract price and market price was the problem for the pipelines and abandonment did not solve this problem.

The Commission also stated that Order No. 436 did not bar gas shippers, such as LDCs or end-users, from negotiating conditions in their contracts to buy gas directly from producers that would require the producers to grant take-or-pay relief to the pipeline transporting the gas for the shippers. The Court found this possibility to be unlikely, saying that there would be no reason for a shipper to sacrifice anything of value to itself just to gain some benefits for the pipeline.

The FERC also had held out the possibility that pipelines could obtain relief from take-or-pay burdens under Order No. 436 by the Commission's shifting costs downstream to customers. The Court, however, found some problems with this possibility, saying that economic constraints would make passthrough of costs to customers impossible. If large amounts of take-or-pay costs were allocated to pipeline gas charges, customers would then use their contract demand conversion option, thus abolishing pipeline merchant functions. Only customers who would be unable to secure their own gas supplies cheaply enough would be left on the system to incur the take-or-pay costs.

The Court considered the Commission's reasons for not taking action on contracts. The FERC had decided not to use its powers under section 5 of the NGA to set aside contracts because it said that that remedy would not solve the entire problem and would thus be inequitable. However, the Commission had also stated that most of the problem contracts were pre-1982 pacts and involved offshore gas regulated under NGPA section 102. The Court instructed the FERC on remand to make clear to what extent contracts for gas under its jurisdiction were problem contracts. The Court also instructed the Commission to reassess its decision not to act under section 5 because its reasoning for not doing so was not clear enough for the judges to evaluate.

The Commission had refused to condition producer access to transportation on cooperation in solving take-or-pay problems because the Commissioners felt that it would be unduly discriminatory for a pipeline to refuse transportation to a producer just because the producer and pipeline could not agree on how to resolve the problem. The judges, however, did not agree that violation of the anti-discrimination ideals of Order No. 436 was sufficient reason to avoid dealing with the problem. Interpreting the section 5 prohibition of undue discrimination to prohibit conditioned producer access was not persuasive to the Court, especially in light of the fact that the Commission had identified the problem contracts as a major cause of the ills that Order No. 436 was trying to cure.

The Court said that the Commission had not made a sufficient case against conditioning producer access. More explanation would be required.

The judges concluded that the Commission's decision not to take action on the producer-pipeline contracts was based on questionable legal and factual premises. The policy concerns of Order No. 436, however, were forceful. The Court decided to remand to the FERC to reassess its decision not to act, stating "we do not require that FERC reach any particular conclusion; we merely mandate that it reach its conclusion by reasoned decisionmaking."[87]

The judges next considered the part of Order No. 436 on optional expedited certificates, noting the concerns of LDCs and state commissions with respect to the risk of waste through duplication of facilities and the bypass of distributors.[88] Regarding wasteful, for duplication of facilities, the Court noted that Congress sought to prevent uneconomic waste through the certification procedure. However, Congress had not adopted a policy against firms using their own money on projects that might ultimately prove unjustified in terms of return on investment.

The judges stated that the challenge for the FERC was to protect ratepayers from the risks of wasted investment being shifted onto them while allowing customers to benefit from now available investment and competition that had been obstructed under the old system of certification. Optional

[87] Ibid., p. 1030.
[88] Ibid., pp. 1034-1036.

expedited certificates were meant to achieve the intentions Congress had specified and not thwart them. The Court believed that expedited certification would occur only when the risk of wasteful investment was not great and that the FERC had given pipelines incentives to make correct decisions.

With respect to bypass, the FERC argued that there was little in the record to suggest that industrial customers wanted to bypass LDCs. What those customers wanted was gas at competitive prices. If distributors, either as merchants or transporters, provided such gas, the customers would have no incentive to bypass the LDC.

The FERC also argued that state agencies had a variety of powers to control the risk of bypass. The Commission asserted that the risk from bypass derived from distributors, under pressure from state commissions, using industrial rates to subsidize residential rates. Pipelines could try to attract those industrial customers off of the LDC system with more attractive rates, skimming the cream off of a distributor's system. The FERC argued that state agencies could avoid this cream skimming by adopting more cost-based rates.

State agencies would also have jurisdiction over a would-be bypasser's pipeline. If that pipeline intends to sell gas at the retail level, it must obtain a certificate of convenience and necessity from the state. In the Court's view, this power undermined any arguments that the states were unable to do anything about bypass.

The FERC also argued that state commissions could protect captive customers, if bypass occurred, by changing rate designs so that LDC shareholders instead of ratepayers would face the consequences of the distributor's inability to deal with competition. Most cases might involve LDC loss of customers because of imprudent judgments or rate designs. In those cases, the Court felt that the state commissions' authority to do as the FERC suggested was indisputable.

Overall, with respect to bypass, the Court found the arguments made by the FERC to be persuasive. The judges also dismissed an argument by state commissions that the FERC had not adequately explained its shift from an old policy against allowing bypass. The judges felt that the Commission had justified its policy sufficiently.

The Court then examined several miscellaneous arguments. One of these dealt with the grandfathering provisions of Order No. 436.[89] The Court was particularly concerned about grandfathering that would allow transactions, which the FERC now considered unlawful, to continue into the 1990s.

> Perhaps these are rare enough, or involve so little volume, that the grandfathering will only trivially encourage pipeline resistance to the concept of nondiscrimination. Or perhaps the equities of the participants are stronger than appear. We cannot, however, "discern the path" by which the Commission has reconciled such grandfathering to its acknowledged mandate to stamp out discrimination.[90]

The Commission had grandfathered the transactions, offering such reasons as a smooth transition to the new arrangements, the reliance customers placed on the transportation, and the need to avoid undue infringement on authorized transactions. In the Court's view, however, these reasons "do not seem to us to meet the modest standard implicit in the concept of reasoned decisionmaking."[91]

The Court was also not satisfied with the Commission's differing treatment of NGPA section 311 transactions and NGA section 7 transactions. In grandfathering the NGPA section 311 transactions, the Commission had imposed a two-year limit on extensions, noting that its original 1979 regulations had said that such certificates were always subject to prospective change. Section 7 certificates, however, were allowed to continue for longer time periods, five to ten years. The judges were, as noted above, not satisfied with the Commission's decision to grandfather some transactions into the 1990s. The difference in treatment between section 7 and section 311 transactions "deepens our mystification."[92]

Thus, while it upheld the substance of Order No. 436 and the Commission's procedures used to adopt the order, the Court found some defects in the CD adjustment, take-or-pay, and grandfathering provisions. Noting that the various parts of the order were all interdependent, the judges decided to

[89] Ibid., pp 1040-1042.
[90] Ibid., p. 1041.
[91] Ibid.
[92] Ibid., p. 1042.

vacate Order No. 436 and remand it to the FERC for further action consistent with the opinion.

On July 2, 1987, nine days after the Court issued its decision, the FERC stayed the CD modification regulations until it took further action to comply with the AGD decision. The Commission stated (in a footnote) that it did not expect to seek a rehearing of the Court's decision.[93]

FERC Order 500

The FERC issued a rule responding to the Court's AGD decision on August 7, 1987. Order No. 500 was intended to be an interim response while the Commission examined more thoroughly the aspects of Order No. 436 which concerned the Court.[94]

In this order, the FERC reissued the regulations of Order No. 436. Some modifications were made, however. The Commission decided not to repromulgate the CD reduction option. While believing that the objectives of CD reduction were still valid, the Commissioners did not think that the record developed in the Order No. 436 docket contained sufficient information about the amount of cost-shifting to captive customers that CD reduction might generate. Thus, the FERC could not balance the potential gains with the potential adverse impacts of the regulations. The Commissioners did encourage pipelines and their customers to negotiate voluntary CD reductions. They also held out the possibility that reductions could be ordered in specific cases if warranted.

The Commission also decided to retain the CD conversion option, saying that this option "is the only effective means by which a pipeline's firm sales customers may have a realistic opportunity for immediate access to competitively-priced gas supplies available from alternative suppliers."[95] The five-year phase-in schedule was retained.

[93] Natural Gas Pipelines after Partial Wellhead Decontrol; Order Staying Effectiveness; Docket No. RM85-1-000, 52 *Fed. Reg.* 27,798 (July 24, 1987). See also "Statement by FERC Chairman Martha O. Hesse on Order 436 Court Decision," *NARUC Bulletin*, No. 27-1987, July 6, 1987, pp. 11-18.
[94] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket No. RM87-34-000; Order No. 500, 52 *Fed. Reg.* 30,334 (August 14, 1987).
[95] Ibid., p. 30,348.

On the grandfathering regulations, the FERC decided to repromulgate the provisions of Order No. 436. The Commissioners explained that all of the transactions so authorized were for terms of five years or less. Thus, all transportation under this authorization would end by 1990. In addition, information available to the Commission indicated that the volumes transported were relatively small (estimated 44,000 mcf/day during 6/87 to 6/88 up to 52,000 mcf/day during 6/90 to 10/90), and the impact of the transactions was declining.

The Commission also felt that grandfathering did not create incentives to avoid the nondiscriminatory provisions of Order No. 436. Most (14 of 17) pipelines involved in grandfathered transactions were also participating in Order No. 436 and the grandfathered transactions of the pipelines not participating involved small amounts of gas.

The Commissioners also noted that many of the grandfathered transactions involved high-priority transportation of self-help gas. This had been encouraged by the Commission to deal with the interstate supply shortages of the late 1970s and early 1980s. Thus, on balance, the Commission felt it best to allow the grandfathered section 7 transactions to run the course of the term of their certificates.[96]

With respect to take-or-pay, the Commissioners noted that the causes of the pipelines' problems were complex. No one part of the industry was responsible for the problems and thus all parts of the industry should have to bear some of the burdens.

In Order No. 436, the FERC had decided that it would be discriminatory for a pipeline to refuse to transport a producer's gas because the producer and the pipeline could not agree on take-or-pay relief in another contract. The Commissioners decided in Order No. 500, however, to allow a pipeline to refuse to transport a producer's gas unless the producer agreed in a signed affidavit to offer to credit the gas it wanted transported against the pipeline's take-or-pay liability to the producer. This policy shift was meant to respond to the Court's concern in the AGD decision that the FERC was taking away a pipeline's bargaining chip in negotiations over take-or-pay problems with producers.

[96] Ibid., pp. 30,349-30,350.

For each unit of gas that a pipeline transported for a producer, the pipeline would obtain credit as if those volumes had been purchased under pre-June 23, 1987 take-or-pay contracts. The pipeline would have to treat the credited volumes as if it had purchased them in the same contract year that it transported the gas for the producer or any previous calendar year (back to January 1, 1986) in which the pipeline was an open-access carrier. The cut-off date of June 23, 1987 was the date of the AGD decision and a date by which the Commission believed that pipelines should no longer be agreeing to any more contracts with problem take-or-pay provisions.

The Commission decided that two categories of gas would not be eligible for credits. In other words, pipelines would not receive credits for transporting these volumes. They included first, gas which the pipeline previously had purchased under a contract that had since expired. Thus, the fuel was not presently committed to the pipeline under any contract. The second category included gas released from a contract that had a market-out clause allowing the pipeline to end the agreement at its discretion.

The Commission believed that the crediting mechanism would be very beneficial to the pipelines, helping them to avoid aggravation of take-or-pay problems if they provided transportation under Order No. 500. Sales lost by a pipeline because it was transporting the gas of a producer to whom it had a take-or-pay liability could be offset by the credits received under Order No. 500. The credits could be applied against high cost contracts helping the pipeline to avoid even more liability than if it had made a sale. In the case of a sale, however, volumes sold would have been taken from both high and low cost contracts. In addition, pipelines would obtain credits under Order No. 500 even if their sales were not displaced by transportation so that take-or-pay liability would be reduced below what the pipeline would have owed even if it was not offering transportation.

The Commissioners also hoped that the two exceptions to crediting provided by the rule, gas not presently contracted for by the pipeline but previously taken under a now expired contract and gas released from a contract with a market-out clause, would encourage producers to agree to buy out existing uneconomic take-or-pay arrangements and to include market-out clauses in existing contracts. Producers taking such actions could then have gas formerly subject to the contracts transported without having to provide credits.[97]

The pipeline would be allowed to choose to which contract it would apply the credits it received if it had more than one eligible contract with a producer. Crediting would not be required by a producer if the pipeline had no contracts with that producer for the purchase of gas which on June 23, 1987 was owned by that producer. Once the producer had submitted an affidavit to the pipeline offering credits for transportation, the pipeline would have to transport on a nondiscriminatory basis regardless of any subsequent disagreements over how the crediting would be done.

If a pipeline and producer had negotiated an agreement to release gas with some type of crediting toward the pipeline's take-or-pay liability (other than market-out clauses allowing the pipeline to terminate the contract), the producer would still have to offer credits under Order No. 500 in order for its gas to be transported unless the pipeline waived its right to the Order No. 500 credits. If the pipeline decided to take the credits under the order instead of the release agreement, it would have to release the producer from any other obligation to provide credits under the release agreement or other contract provisions. The pipeline could also not then claim that its annual deliverability of gas under the contract, which had been supplanted by the release agreement, had been reduced by the volumes credited under Order No. 500 against another contract (thus recovering double credits).

The pipeline must have also allocated its Order 500 credits to a contract other than the one containing the release agreement and because of the release there might be insufficient gas subject to that released contract for the pipeline to receive gas for which it had made prepayments. In those cases, the Commissioners decided that the producer must repay the prepayments or deliver gas from another source, such as the contract that the pipeline credited.

The Commission also noted that in some cases several pipelines were needed to transport gas to a particular location. If one of those pipelines

[97] Ibid., p. 30,339.

had been a party to the contract from which the gas was released, only that pipeline would receive credits under Order No. 500. No other pipeline would receive credits.

In other cases of multiple pipelines providing transportation, all of the pipelines would receive credits against their take-or-pay liabilities. The pipelines could allocate the credits among themselves. The total number of credits allocated would be equal to the volumes transported. The pipelines could not receive any credits until they agreed on an allocation. Failure to agree, however, would not make the gas ineligible for transportation.

Producers were also required to provide credits for existing transportation in addition to new transportation. If a pipeline was transporting gas owned by a producer on June 23, 1987, that gas would not qualify for transportation as of the first day of the second month after the effective date of the rule unless the producer had offered the pipeline credits.

In addition to the crediting mechanism, the FERC also adopted passthrough procedures for pipelines to recover take-or-pay buyout or buydown costs. The first procedure would allow pipelines to passthrough prudently incurred take-or-pay buyout and buydown costs in their sales commodity rates.

The second mechanism would be available to pipelines that agreed to transport under Order No. 500 and to absorb an equitable share of their take-or-pay costs. Under this procedure, if the pipeline agreed to absorb 25 to 50 percent of the take-or-pay buyout and buydown costs, the FERC would allow the pipeline to recover an equal amount through a fixed charge. Any amounts then remaining, up to 50 percent of the total buyout and buydown costs, could be recovered through a commodity surcharge or a volumetric surcharge on the pipeline's total throughput.

Volumetric surcharges would be based on the volumes on which the pipeline's most recent FERC-approved rates were based. The fixed charges would be based on a customer's cumulative deficiencies in purchases in the years during which the take-or-pay liabilities of the pipelines were incurred in relation to that customer's purchases during a representative period when the pipeline incurred no take-or-pay liability.

In calculating the fixed charge, the pipeline first would have to select a representative base period. This period would have to represent a typical level of purchases by the pipeline's firm customers at a time before the take-or-pay problems grew. The pipeline would then determine the level of firm purchases by each customer under contracts and rates for firm service during that base year. For each following year, the deficiency in firm sales for each customer would be calculated. The fixed charge would then be based on each customer's cumulative firm sales deficiency compared to total firm sales deficiencies.

The pipeline was free to select a reasonable amortization period for buyout and buydown costs recovered through the fixed charge or volumetric surcharge. Downstream pipelines would flow through approved take-or-pay fixed charges based on the purchase deficiencies of their customers. Volumetric surcharges would be flowed through to those customers on a volumetric basis.

The Commissioners intended that firm sales customers would be liable for both the fixed and volumetric surcharges based on their historical and current service. Interruptible sales and transportation customers would be liable for volumetric charges only based on the volumes of gas sold or transported to them.

The FERC also adopted some principles designed to avoid the recurrence of take-or-pay problems in the future. These principles established FERC policy, but did not establish requirements for the pipelines. First, pipelines transporting under Order No. 500 would be allowed to include in their tariffs a charge for standing ready to supply gas to sales customers. This standby charge would be unrelated to facilities. Second, pipelines could not recover take-or-pay or other similar charges in any way other than the standby charge. Third, pipelines would have to allow sales customers to nominate different levels of service within their firm sales entitlements or use some other mechanism to allow regular renegotiation of service levels. Fourth, prior to a customer deciding on a service level, the pipeline would have to announce a price or pricing formula for that service and not change that price or formula during the interval for which the customer's selection of service was to last. Fifth, a customer choosing a lower level of service would be agreeing to any abandonment of service sought by the pipeline to reconcile the difference between the approved current level of service and the new nominated level.

Order No. 500 went into effect on September 15, 1987. The D.C. Court of Appeals denied rehearing of the AGD decision and issued its mandate effective immediately, allowing Order No. 500 to take effect.[98]

The FERC has issued several follow-on orders to Order No. 500. In Order No. 500-B, issued October 16, 1987, the Commission granted a request to postpone until January 1, 1988 the date by which producers would have to offer credits to pipelines in order to continue ongoing transportation arrangements. The Commission also extended the stay of the contract demand conversion regulation until January 1, 1988. Both of these extensions were granted to give the industry more time to arrange transactions under Order No. 500.[99]

The Commissioners also discussed some of the comments that had been received on the rule and made some clarifications. One point raised by several parties was that a lease may be owned by more than one working interest. Transportation could be prevented for a majority of the owners if a minority, owning a small portion of the volumes to be transported, did not want to offer the take-or-pay credits. The Commission decided that offers of credits would have to be received only from the owners accounting for 85 percent of the gas to be transported. While all of the gas would still have to be carried, the pipeline would receive no credit at that time for the 15 percent (or less) owned by interests unwilling to give credits. This was referred to as the "85 percent of volumes rule."[100] The Commissioners emphasized that a single working interest could not be broken up to avoid crediting if the interests were not separate on June 23, 1987.

The FERC also decided that it was not necessary to state that the offer of credits had to be an irrevocable offer. The intent had been that the offer, if accepted, would be a binding contract.

The Commission issued, also on October 16, 1987, an order explaining the

[98] See "Hesse of FERC Pleased with Court Issuance of Mandate Allowing Order 500 Interim to Take Effect," *NARUC Bulletin*, No. 87-39, September 28, 1987, p. 12.
[99] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket Nos. RM87-34-001 through -052; Order No. 500-B, 52 *Fed. Reg.* 39,630 (October 23, 1987).
[100] Ibid., p. 39,631.

crediting provisions of Order No. 500.[101] Among the points made by the Commission in this order was that for purposes of determining the credits, the volume of gas transported would be the total volume received by the pipeline for transport and not the volume actually delivered which may be less because of shrinkage and usage. The Commission also said that if gas had not been owned by any producer on June 23, 1987, the pipeline transporting the gas would receive credits from the producer who owned the fuel at the time that it was transported.

Another point was that in cases of transportation by multiple pipelines, none of the pipelines would receive any credits if the gas was formerly purchased under a terminated contract or a contract containing a market-out clause and the old contract or market-out clause covered the transportation of the gas. The Commission wanted to preserve incentives for producers to buy out uneconomic take-or-pay contracts and to include market-out provisions in contracts.

The FERC issued Order No. 500-C on December 23, 1987.[102] In this order, the Commissioners dealt with several different applications of the provisions of Order No. 500. One of these was casinghead gas, which is gas produced in conjunction with petroleum.

Producers requested that the FERC forbid pipelines from applying their take-or-pay credits against contracts for the purchase of this type of gas. The producers argued that take-or-pay clauses are included in contracts in cases in which the failure of the buyer to take the gas could have major harmful impact on the producer. Such was the case with casinghead gas. If pipelines did not take this gas, it would have to be flared or the associated oil production might be stopped, or the well would be damaged. The Commission agreed with the producers' request, deciding that pipelines should not apply credits, generated before April 1, 1988, against contracts for the purchase of casinghead gas until the FERC had studied the issue further.

[101] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket No. RM87-34-000; Order Explaining Crediting Provisions of Order No. 500, 41 FERC para. 61,025 (October 16, 1987).
[102] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket No. RM87-34-000 through RM87-34-054; Order No. 500-C, 52 *Fed. Reg.* 48,986 (December 29, 1987).

Other parties expressed concern that crediting under Order No. 500 would reduce exploration for and development of new gas supplies. Producers would have less incentive to undertake development of new supplies if transportation of that new gas resulted in credits being applied against pipeline obligations to the producers for the purchase of existing gas.

The Commission agreed with those arguments and decided that transportation of certain new gas would not generate credits and that interstate pipelines could not apply their take-or-pay credits against contracts to take this new gas. The new gas would be from wells drilled after June 23, 1987 which were 2.5 miles or more from the nearest Order No. 500 marker well (any well from which gas was produced commercially after January 1, 1970 and before June 23, 1987), or which were at least 1,000 feet deeper than the nearest marker well within 2.5 miles, or which were drilled into a reservoir from which gas was not produced in commercial quantities before June 23, 1987.

Some parties claimed that a producer might have to provide double credits under Order No. 500 to both an intrastate pipeline and an interstate pipeline. This could happen if the intrastate carrier released the gas from a contract between it and the producer (receiving credits from the producer as part of that agreement) and then the intrastate pipeline and an interstate pipeline carried the gas (with the producer required to provide Order No. 500 credits to the interstate pipeline).

In response to these concerns, the FERC adopted a temporary exemption from crediting for gas released by an intrastate pipeline from its system supply under a release agreement in which the intrastate pipeline would receive credits for transporting the gas. The producer would not have to provide credits for the interstate pipeline's part of the transaction. This exemption was to apply to transportation carried out before April 1, 1988.

The FERC also dealt again with the problem of multiple interest owners. In some cases, offers of credits would have to be obtained from thousands of interest owners involved in providing a pipeline's system supply. In addition, marketers may lump many working interests together into a package.

In order to provide administrative relief for a pipeline, the Commissioners decided to allow the shipper of the gas or any other willing party to act as a guarantor for other interest owners even if owners of less than 85 percent of the gas to be transported had agreed to offer credits. The guarantor would be required to compensate the pipeline for any take-or-pay payments that the carrier had made for gas which the guarantor has agreed to cover and which the pipeline carried without obtaining credits. The pipeline would have to carry the gas once it had offers of credits or guarantees covering 85 percent of the fuel in question. The Commissioners stressed that the party in question decided himself or herself to act as guarantor.

In Order No. 500-D, issued on March 8, 1988, the Commission removed the deadlines for crediting exemptions that had been imposed in Order No. 500-C. The Commissioners stated that it was not feasible for a final rule to be issued by April 1, 1988, the deadline for the modifications, and so they removed that deadline from the casinghead gas, gas released from intrastate pipeline system supply, and other (processing plant) crediting exemptions.[103]

In Order No. 500-E, issued on May 6, 1988, the Commissioners denied rehearing of Orders 500-C and 500-D. Various parties had argued that the amendments adopted in those orders had reduced the take-or-pay relief intended by Order No. 500. The Commissioners did not think that modifications were needed. However, they did say that the issues raised would be considered in the development of the final rule.[104]

---

[103] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Order Modifying Dates; Docket No. RM87-34-000 through RM87-34-053; Order No. 500-D, 53 *Fed. Reg*. 8,439 (March 15, 1988).

[104] Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol; Docket Nos. RM87-34-055 and RM87-34-056; Order No. 500-E, 53 *Fed. Reg*. 16,859 (May 12, 1988).

APPENDIX B

QUESTIONS AND RESPONSES FROM SURVEY OF STATE COMMISSIONS

In order to compile current information on state commission gas transportation policies, the NRRI surveyed the commissions during the spring and early summer of 1988. Survey questionnaires were sent to forty-nine states and the District of Columbia. Nebraska was excluded as it does not regulate local distribution companies. Responses were received from forty-five commissions. No response was received from five commissions.

This appendix contains the survey questions and the answers of the state commission staffs. The responses are arranged alphabetically by state for each question. Apart from some minor editing, particularly in the cases of questions with multiple parts where responses are summarized, each response reported here is quoted directly from the survey form.

THE NATIONAL REGULATORY RESEARCH INSTITUTE

Survey on
State Commission Gas Transportation Policies
for Local Distribution Companies

March 1988

As one of its Board approved projects for 1987-88, The National Regulatory Research Institute has undertaken a study of state commission natural gas transportation policies. **Specifically, this study concerns the gas transportation policies that many state commissions have developed to allow customers to purchase their gas directly from the producer or through a broker, with the local distribution company providing transportation services from the pipeline to the customer**. This survey is an important part of the study, designed to develop current information about various commission provisions and policies, as well as about commission views on transportation-related issues, such as bypass of a local distribution company and reliability of long-term gas supplies.

We would like the survey to be completed by the commission staff person who is most knowledgeable about your commission gas transportation policies. Please provide copies of any commission opinions, orders, statements, or other documents that might be useful in understanding commission policies and viewpoints. Please return your answers by April 29, 1988 to:

Mr. Robert E. Burns
Senior Research Associate
The National Regulatory Research Institute
1080 Carmack Road
Columbus, OH 43210-1002

If you have any questions, please call Mr. Burns at (614) 292-9307 or (614) 292-9404.

Name of person completing this survey:

Title:

Phone Number:

Our questions make references to "a policy" or "the Commission's policy." Recall that this survey concerns state gas transportation policies for local distribution companies. We realize that a commission may have adopted different policies for different LDCs. If this is the case at your Commission, please try to incorporate as much of that variety, particularly the major differences among policies, as possible in your responses.

I. First, we would like some information on your Commission's gas transportation policy for LDCs: whether the Commission has adopted, has rejected, or is currently considering adopting a policy and the types of provisions included. Please check "yes" or "no." If "yes" is checked, please provide a brief explanation.

   1. Has your Commission considered a natural gas transportation policy? Yes____ No____. If so, was a gas transportation policy rejected? Yes____ No____. Please explain.

      Was a gas transportation policy adopted? Yes____ No____. Please explain.

      Is your Commission currently considering the adoption of a natural gas transportation policy? Yes____ No____. Please explain.

Alabama: The Commission has considered and has adopted a gas transportation policy. Two LDCs, Alabama Gas Corporation and Mobile Gas Service Corporation, have applied for and have had transportation rates approved. AGC has both firm and interruptible rates; MGSC has only interruptible. The policy was adopted by approving those tariff filings. The Commission is currently not considering the adoption of a gas transportation policy.

Alaska: The Commission has not considered and is not currently considering adoption of a gas transportation policy.

Arizona: The Commission has approved transportation tariffs for the two largest LDCs. The Commission is now considering bypass policy which involves transportation.

Arkansas: Although the Commission did not formulate a generic transportation policy to be applied to all LDCs, transportation programs have been established for two Arkansas LDCs.

California: The California PUC has established a transportation program. Transportation was considered an integral part of the comprehensive restructuring of gas within California.

Colorado: The Colorado PUC has not established a gas transportation policy, but intends to do so in the near future.

Connecticut: Connecticut has not, as yet, considered a comprehensive transportation policy applicable to all LDCs under a uniform policy. However, the three primary LDCs operating in Connecticut all have interruptible transportation tariffs available for customer utilization.

Delaware: The Commission does not have a generic policy. There are two LDCs under our jurisdiction. One LDC (LDC No. 1) has both firm and interruptible transportation service. The other LDC (LDC No. 2) has only interruptible transportation service. There is a difference between the interruptible transportation service of the two LDCs. To date, no gas has actually been transported by LDCs in Delaware.

District of Columbia: In the context of the single request for a LDC transportation tariff.

Idaho: Gas transportation was considered in 1981 for one company and 1984 for the other company. Gas transportation was adopted as a tariff schedule to meet the needs of specific customers.

Illinois: The Illinois Commerce Commission has developed its policy on a case-by-case basis. As the Commission accepts or rejects LDC transportation rate filings, it adopts a gas transportation policy. The Commission does not plan on a rulemaking or other formal adoption of "a policy" for gas transportation because of the need for flexibility. As new filings by LDCs are adopted, the Commission's policy is modified.

Indiana: The Commission did not issue a specific policy order but has pursued transportation by a Commission letter (1/9/85) urging use of low-cost supplies, including direct purchase and transportation, and by approval of LDC transportation tariffs for end users. The present case-by-case approach has produced the desired results.

Iowa: A rulemaking was initiated and the Board solicited comments from different parties. Present rules were established as a result of that rulemaking.

Kansas: Gas transportation matters have been handled on a case-by-case basis.

Kentucky: The Commission undertook an administrative case to investigate the entire scope of the natural gas industry as a result of Order 436. The Orders in Administrative Case No. 297 of the Kentucky Public Service Commission are the result. The Commission's general policy is that transportation should be available to any end-user when it can be done without detriment to other remaining customers.

Louisiana: There is a docketed case awaiting decision that may indicate the position the Commission may take on this issue.

Maine: The Maine Commission does not have a gas transportation policy as of yet. There is only one natural gas utility in Maine, Northern Utilities, Inc., which is at the very end of the Tennessee Transmission Line (which actually ends in Plaistow, New Hampshire). Northern Utilities is the only utility in Maine that has an approved franchise to serve natural gas. There have been no gas customers or potential bypass end-users that have contacted Northern or the Commission to request the need for gas transportation services or a Commission gas transportation policy. With the situation at hand, it is doubtful that any large volume gas customer in Maine would find securing its own gas supply and paying the LDC and transmission companies to get the gas to them to be economical at this time.

Maryland: See Commission Order No. 67583 in Case No. 7962.

Massachusetts: Yes, we have considered and implemented a transportation policy. On August 7, 1987, the Department issued an order in DPU 85-178, a proceeding initiated by a group of industrial gas customers in Massachusetts seeking the ability to transport gas. The order imposed a requirement that all Massachusetts LDCs offer firm and interruptible transportation.

Michigan: The Michigan Commission is considering these matters in individual contested case proceedings for each affected industry.

Minnesota: No formal gas transportation "policy." The Commission has encouraged and approved gas transportation for individual utility companies.

Mississippi: There is no set gas transportation policy. Everything is done on an ad hoc, company-by-company basis.

Missouri: A generic transportation docket was established under Case No. GO-85-264. A Stipulation and Agreement was entered into by the participating parties and approved by the Commission in Case No. GO-85-264. See the Report and Order dated 9/18/86.

Montana: The Commission regulates three large gas utilities: Montana Dakota Utilities (MDU), Montana Power Company (MPC), and Great Falls Gas (GFG). The PSC has approved two vintages (and methodologies) of gas transportation rates for MDU. GFG has an application pending and MPC is in the midst of a gas transportation docket. The Commission is currently considering adoption of a natural gas transportation policy for GFG and MPC for the first time, and for flexible pricing for MDU.

Nevada: See Southwestern Gas' ST-1 Tariff. Transportation is only available in southern Nevada. The northern Nevada system is separate, and no transportation is available there.

New Jersey: This Board has encouraged local utilities to implement transportation tariffs. Rather than issuing a statewide transportation policy, the Board considered each utility's transportation tariffs on an individual basis. All four state gas utilities have some form of transportation tariffs in place.

New Mexico: The New Mexico PSC currently has its First Revised General Order No. 44 in effect. This Order requires all gas utilities under NMPSC jurisdiction to provide transportation on request.

New York: In March 1985, the Commission issued an order requiring the filing of transportation tariffs by all LDCs and stating guidelines for those tariffs. The Commission is currently considering the need for and adoption of guidelines for negotiated contracts for the transportation of gas to be used in cogeneration facilities.

North Carolina: A policy was adopted. No further explanation was provided.

North Dakota: We have no general policy but we have approved tariffs for the three regulated natural gas companies that allow transportation.

Ohio: Ohio has had gas transportation rules since 1973, which were revised in 1977, 1983, and 1985. We are currently working on another revision. The gas transportation policy initially dealt with the movement of Ohio production, but now it deals with all types of transportation.

Oregon: An interim policy has been in effect since 1986. The transportation policy is under consideration currently in OPUC Docket UG-23.

Pennsylvania: The PUC has adopted a transportation policy providing service under a contract between jurisdictional class A & B utilities and customers. Transportation service shall be provided under terms, conditions and rates that minimize the shifting of costs to retail customers and provide the natural gas utility with an opportunity to recover the fixed costs incurred to serve the customer. Class A utilities are those with revenues of $2,500,000 or more. Class B utilities are those with revenues between $1,000,000 and $2,500,000. A natural gas transportation policy was adopted by PUC at its public meeting held October 16, 1986. This replaces the previous "gross margin" transportation program adopted January 13, 1984.

Rhode Island: A gas transportation policy was adopted on an experimental basis in Docket No. 1877, Order No. 12401.

South Carolina: Transportation rates are approved on a company-by-company basis.

South Dakota: Because of the unique utility circumstances, a number of tariffs were approved for the regulated LDCs in South Dakota. When a customer base is established and customer feedback is received, policy and tariffing will be reviewed in light of actual experience.

Texas: The Commission is investigating the transportation practices of one major jurisdictional gas utility pursuant to several complaints of discriminatory practices.

Utah: An interruptible gas transportation policy has been approved for Mountain Fuel Supply Company (MFS), the major LDC in Utah, which has 99 percent of the market. Gas transportation has not been considered for Utah Gas Service or the other LDC which supplies approximately 1 percent of Utah gas sales. See In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates, Report and Order, Docket No. 86-057-07 (April 27, 1988).

Virginia: The Virginia Commission conducted a rulemaking proceeding in June 1986 and subsequently issued its Opinion and Order on September 9, 1986 to adopt policy regarding natural gas industrial rates and transportation policies. In the gas transportation policy that was adopted, the Commission (1) found that transportation is in the public interest, (2) provided for voluntary transportation, and (3) established policies to encourage transportation and to govern transportation rate design and related services.

Washington: Equivalent sales margin.

West Virginia: On March 11, 1987, the Commission promulgated final rules on natural gas transportation, which became effective May 10, 1987. (See General Order No. 240.) In addition, the Commission has issued its General Order No. 240-G which initiates a generic proceeding for the purpose of considering the adoption of a uniform methodology applicable to gas transportation rates. As of this writing, that proceeding is still pending.

Wisconsin: The Wisconsin PSC conducted a generic rate case (Docket OS-GI-102) during the first half of 1987. An outcome of this docket has been an "Enunciation of Principles" that lists ten principles referenced in individual rate cases since they were issued. A generic investigation of purchasing, planning, and practices of LDCs and the operation of the PGAC is pending.

Wyoming: The answers are all based upon "policy" developed by the Wyoming Commission on a "case-by-case" basis. No generally applicable policy decision or rule has been issued by our Commission. The Commission has authorized gas transportation by LDCs to permit them to retain the new revenue flow that would have been lost through the loss of the involved large industrial customers. The Commission assisted our Legislature in the preparation of a gas carriage law. Some transportation accomplished by special contracts. Commission "policy developed on a case-by-case basis. No filing has been made to date pursuant to the new gas carriage law. The Commission will determine if a policy set forth in rule form is necessary and what the rules shall contain when experience is developed under the case-by-case investigations and rulings.

TABLE B-1

GAS TRANSPORTATION POLICY PROVISIONS BY STATE

State	Mandatory Open Access Nondiscriminatory Transportation	Maximum (ceiling) and Minimum (floor) Charges for Transportation Service, or a Mechanism for Setting Same	Allocation between Ratepayers and Stockholders of Profits or Losses Resulting from Transportation Services
Alabama	N	N	N
Alaska	N/A	N/A	N/A
Arizona	Y	Y	N
Arkansas	N	N	N
California	Y	Y	Y
Colorado	N/A	N/A	N/A
Connecticut	Y	-	Y
Delaware	-	-	N
District of Columbia	Y	N	Y
Florida	N/A	N/A	N/A
Hawaii	-	-	-
Idaho	N	N	N
Illinois	-	N	N
Indiana	N/A	N/A	-
Iowa	Y	N	N
Kansas	-	Y	-
Kentucky	Y	N	N
Louisiana	N/A	N/A	N/A
Maine	N/A	N/A	N/A
Maryland	Y	N	N
Massachusetts	N	Y	N
Michigan	N/A	N/A	N/A
Minnesota	Y	Y	N
Mississippi	-	-	-
Missouri	N	Y	N
Montana	Y	N	N
Nevada	Y	Y	N
New Jersey	N	Y	N
New Mexico	Y	Y	N
New York	Y	Y	Y
North Carolina	N	Y	Y
North Dakota	N	Y	Y
Ohio	N	Y	Y
Oregon	Y	Y	Y
Pennsylvania	Y	Y	N
Rhode Island	N	Y	-
South Carolina	N	-	N
South Dakota	N	Y	N
Texas	N/A	N/A	N/A
Utah	Y	N	N
Virginia	N	N	N
Washington	Y	-	N
West Virginia	-	-	-
Wisconsin	Y	Y	Y
Wyoming	-	N	N

Source: NRRI Survey, 1988
N/A = Not applicable

TABLE B-1

GAS TRANSPORTATION POLICY PROVISIONS BY STATE (CONT.'D)

	Firm and Interruptible Transportation Service	Specific Maximum and Minimum Lengths for Transportation Contracts	Back-up Gas Service for Transportation Customers
Alabama	Y	N	N
Alaska	N/A	N/A	N/A
Arizona	Y	N	N
Arkansas	Y	Y	N
California	N	Y	N
Colorado	N/A	N/A	N/A
Connecticut	Y	Y	Y
Delaware	Y	N	Y
District of Columbia	N	Y	Y
Florida	-	-	-
Hawaii	-	-	-
Idaho	N	N	Y
Illinois	Y	-	-
Indiana	Y	N/A	N/A
Iowa	Y	N	Y
Kansas	Y	N	-
Kentucky	Y	N	N
Louisiana	N/A	N/A	N/A
Maine	N/A	N/A	N/A
Maryland	Y	N	Y
Massachusetts	Y	N	N
Michigan	N/A	N/A	N/A
Minnesota	Y	Y	Y
Mississippi	-	-	-
Missouri	Y	N	Y
Montana	N	Y&N	N
Nevada	N	N	N
New Jersey	Y	N	N
New Mexico	Y	N	Y
New York	Y	Y	Y
North Carolina	N	N	N
North Dakota	N	N	Y
Ohio	Y	N	Y
Oregon	Y	N	Y
Pennsylvania	N	N	Y
Rhode Island	Y	N	N
South Carolina	Y	N	N
South Dakota	N	Y	-
Texas	N/A	N/A	N/A
Utah	Y	Y	N
Virginia	Y	Y	N
Washington	Y	Y	N
West Virginia	-	-	-
Wisconsin	Y	N	Y
Wyoming	N	N	N

Source: NRRI Survey, 1988
N/A = Not applicable

TABLE B-1

GAS TRANSPORTATION POLICY PROVISIONS BY STATE (CONT.'D)

	Preferential Treatment for Gas Produced Within your State	Storage Service	Core and Noncore Markets	Maximum and Minimum Amounts of Gas to be Transported
Alabama	N	N	N	Y
Alaska	N/A	N/A	N/A	N/A
Arizona	N	N	N	Y
Arkansas	N	Y	Y	Y
California	N	N	Y	N
Colorado	N/A	N/A	N/A	N/A
Connecticut	N	N	N	Y
Delaware	N/A	N	N	-
District of Columbia	N	N	N	Y
Florida	-	-	-	-
Hawaii	-	-	-	-
Idaho	N	N	Y	N
Illinois	-	N	N	N
Indiana	Y	N/A	N/A	Y
Iowa	N	N	N	N
Kansas	-	-	-	-
Kentucky	N	N	N	Y
Louisiana	N/A	N/A	N/A	N/A
Maine	N/A	N/A	N/A	N/A
Maryland	N	N	N	Y
Massachusetts	N/A	N	Y	N
Michigan	N/A	N/A	N/A	N/A
Minnesota	N/A	N	N	Y
Mississippi	-	-	-	-
Missouri	N	N	N	Y
Montana	Y	N	N	Y
Nevada	N	N	N	Y
New Jersey	N	Y	N	-
New Mexico	N	Y	N	N
New York	N	N	N	Y
North Carolina	N	N	N	Y
North Dakota	N	N	Y	N
Ohio	N	Y	Y	N
Oregon	N	N	Y	N
Pennsylvania	Y	Y	N	Y
Rhode Island	N/A	N	N	Y
South Carolina	N/A	N	N	N
South Dakota	N	-	N	Y
Texas	N/A	N/A	N/A	N/A
Utah	N	N	N	Y
Virginia	N	N	N	Y
Washington	N	N	N/A	Y
West Virginia	-	-	-	-
Wisconsin	N/A	N	Y	N
Wyoming	N	N	N	N

Source: NRRI Survey, 1988
N/A = Not applicable

2. If your Commission has a natural gas transportation policy in place, please specify whether it includes the following types of provisions by checking "yes" or "no" below each. If you check "yes", please also include a brief description of the provision.

   a. Mandatory open-access, nondiscriminatory transportation. Yes____ No____.

   b. Maximum (ceiling) and minimum (floor) charges for transportation service, or a mechanism for setting same. Yes____ No____.

   c. Allocation between ratepayers and stockholders of profits or losses resulting from transportation service. Yes____ No____.

   d. Firm and interruptible transportation service. Yes____ No____.

   e. Specified maximum and minimum lengths for transportation contracts. Yes____ No____.

   f. Back-up gas service for transportation customers. Yes____ No____.

   g. Preferential treatment for gas produced within your state. Yes____ No____.

   h. Storage service. Yes____ No____.

   i. Core and noncore markets. Yes____ No____.

   j. Maximum and minimum amounts of gas to be transported. Yes____ No____.

Alabama: The policy (tariffs) has ceiling and flow charges. For Alabama Gas, the ceiling is the filed tariff and the floor, under a competition fuels clause, is 5 cents/Mcf plus tax. For MGSC, the minimum bill is $2,400. Firm and interruptible services, as mentioned in No. 1 above, are available. Back-up service is not required but is allowed. Most customers have part of their supply in either firm transportation or firm sales. AGC requires a minimum amount of 100 Mcf per day to be transported.

Alaska: Not applicable.

Arizona: The policy has mandatory open-access, nondiscriminatory transportation, with tariffs available to customers who meet criteria (size and availability of competing supplier). There are maximum (ceiling) and minimum (floor) charges for transportation services. The maximum is the otherwise applicable margin. The minimum is short-run marginal cost. Whether there will be an allocation between ratepayers and stockholders of profits or losses resulting from transportation is determined in rate cases. There is a minimum average daily quantity of gas to be transported.

Arkansas: No elaboration on the above answers.

California: The California PUC's gas transportation policy includes provisions for mandatory open-access, nondiscriminatory transportation subject to certain provisions concerning capacity curtailment. Also, there is a therm use restriction. Access to transportation is restricted to those using at least 250,000 therms per year. There is a ceiling that is the fully allocated embedded cost of the transmission system, and the plan is variable cost, chiefly fuel in some cases. There is an allocation between ratepayers and stockholders of profits or losses resulting from the transportation service. The utility is at risk for recovering revenues from transportation. There is a zone within which the utility retains or loses the full amount of the costs allocated to transmission service during a two-year transition period. There is no firm and interruptible transportation service. However, there is a priority charge system being considered where customers bid for priority. The only firm transmission is for the residential and small commercial classes under traditional bundled rates. The minimum term of transportation contracts is thirty days. There is no back-up service for transportation customers, although the Commission is considering a separate charge for this service. There is no preferential treatment for transportation for gas produced within the state. Storage service is considered separately. The Commission is currently considering the availability and terms of service for the separate storage service. There are provisions concerning core and noncore markets. The core market's annual use is under 250,000 therms. Customers using more may elect service from the utility's core gas portfolio. Although there is no maximum or minimum amounts of gas to be transported, take-or-pay clauses are considered.

Connecticut: As previously responded, there is no formal gas transportation policy, however, applicable answers will be provided. Under Connecticut statutes, a filed and Commission-preapproved tariff is available to any and all customers who meet tariff eligibility criteria. One LDC has a winter and summer minimum transportation rate only. There is no maximum, thereby allowing the LDC to maximize revenues as market conditions dictate. LDCs have a built-in credit for firm customers revenue requirements established during rate proceedings. The credit is the net margin "target" established for transportation or interruptible sales services. To the extent that the LDCs exceed this "target" level, all excess margins are split 50/50 between the company and firm ratepayers. The three primary LDCs have interruptible tariffs. One LDC currently has filed for an approval of a firm transportation tariff. There are specified maximum and minimum lengths for transportation contracts per tariff terms and conditions. There is back-up gas service for transportation customers, per tariff terms and conditions. Primarily, back-up service is available depending on supply adequacy and/or serviceability. No gas is produced in Connecticut. Maximum and minimum amounts of gas to be transported are set per tariff terms and conditions or as mutually agreed.

Delaware: LDC No. 1 will provide transportation service for all customers except residential customers. LDC No. 2 will provide transportation service only for non-firm customers. LDC No. 2 has a maximum and minimum charge for transportation service. The minimum charge is 5 cents per Mcf.

The maximum charge is the non-gas portion of the tail block rate for firm commercial and industrial services. LDC No. 1 has set rates instead of a maximum and minimum charge. LDC No. 1 has both firm and interruptible transportation service. LDC No. 2 has only interruptible transportation service. Concerning back-up gas service for transportation customers, only LDC No. 1 has firm transportation customers. There is no storage service, except for balancing between the daily gas consumption of the transportation customer and those gas volumes received at the LDC city-gate for the customer that day. The customer shall execute an agreement of service with the Company that specifies the maximum daily volume of gas to be transported. No minimum is specified.

District of Columbia: There are volumetric limitations to the mandatory open-access, nondiscriminatory transportation provisions. There is only interruptible transportation service.

Idaho: There are provisions for back-up gas service for transportation customers and provisions for core and non-core markets.

Illinois: Concerning mandatory open-access, nondiscriminatory transportation provisions, the major LDCs have implemented transportation tariffs voluntarily. The most recent filings do not contain volumetric or customer-type restrictions. Currently, eleven utilities provide transportation while five small utilities do not. There are firm and interruptible transportation service provisions. However, most transportation is on a "best efforts" (or interruptible) basis. The specified maximum and minimum lengths for transportation contracts varies by LDC. Back-up gas service rights for transportation customers vary by company. Most LDCs provide some banking of gas, which is a form of storage service. The Illinois Commerce Commission recently approved a specific storage rate for transportation customers of Northern Illinois Gas, Standard Rider 26: Experimental Storage Service. Most minimum volume requirements have been eliminated from transportation tariffs and there are no maximum limits. Remaining limits are:

CIP	500 Mcf per day
Illinois Gas	1,000 therms per day
South Beloit	50,000 therms per day

Indiana: Concerning the allocation between ratepayers and stockholders of profits or losses resulting from transportation service, the rates are provided at the expense of the utility in one case and at the expense of the remaining customers and the utility in another case (see the response to question 4). Yes, there are provisions for firm and interruptible service. The preferential treatment for gas produced within the state is set by statute. The first case under this statute is currently being heard. Volumetric qualifications are in almost all the tariffs.

Iowa: Mandatory open-access, nondiscriminatory transportation provisions are subject to capacity limitations. Transportation rates and charges are to be based on the cost of providing service like all other rates and charges. LDCs are required to make available both firm and interruptible transportation. LDCs are required to provide back-up gas service for transportation customers, if the customer wants it and pays for it. There is no gas produced within the state of Iowa. The Board specifically left the matter of storage service to the LDCs in its Order Adopting Rules, due to variation among the companies. LDCs, tariffs, and practices are subject to Board review, however. There are no maximum or minimum amounts of gas to be transported. Gas transportation is to be available on a mandatory basis.

Kansas: There is a maximum and minimum charge for transportation service. The maximum price has always been full margin. The minimum has been incremental cost. Both firm and interruptible transportation service have been approved.

Kentucky: There are provisions for mandatory open-access, nondiscriminatory transportation. Tariffs are required at the large distribution companies. It is optional for small companies to maintain tariffs until a request for service is received. Then they must provide transportation. The specified maximum and minimum lengths for transportation contracts are at the company's discretion. Back-up gas service for transportation customers is provided only if arrangements have been made with the LDCs. There is no preferential treatment for gas produced within the state in the transportation policy itself. A company may establish minimum amounts of gas to be transported in tariffs.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: See page 12 of Commission Order No. 67583 concerning mandatory open access, nondiscriminatory transportation provisions. See pages 17-20 of the same order concerning the lack of a maximum or minimum charge for transportation service. See page 11 concerning firm and interruptible transportation service. See page 14 concerning back-up service for transportation customers. And, see page 12 of the order concerning minimum volume restrictions on the amount of gas to be transported.

Massachusetts: For interruptible transportation, the floor price is the short-run variable cost, such as compression and line losses; there is no ceiling price, as the delivered price of a customer's alternate fuel is considered to operate as a *de facto* ceiling. For firm transportation on an interim basis, companies have been ordered to calculate rates based on the "simple margin" method. Back-up service is not required; it must be contracted for separately. The distinction between core and noncore customers has been drawn, but it does not operate as pervasively as in other jurisdictions, such as California. Concerning maximum and minimum amounts of gas to be transported, one company, Commonwealth Gas, has an adjudicated cost-based firm transportation rate; terms and conditions specify a minimum monthly volume and a maximum daily transportation quantity (MDTQ).

Michigan: Not applicable.

Minnesota: Concurring maximum and minimum charges for transportation service, rates are generally flexible and operate within a range. Under state law, flex rates must have a minimum, which recovers the incremental cost of service, and no maximum. The minimum period for transportation contracts is one year. The maximum length may vary. Back-up gas service is available for transportation customers if they choose to pay a sales demand charge. The minimum amount of gas to be transported is 50 MMB/day. There is no maximum amount, except as negotiated between utility and customer.

Mississippi: We have a flexible rate tariff with a cap. It is not really a transportation rate, but a transportation customer rate.

Missouri: Concerning mandatory open-access, nondiscriminatory transportation, mutually acceptable guidelines were devised for voluntary transportation in GO-85-264. The maximum charge for transportation service is (1) any unavoidable pipeline charges incurred by the LDC and allocated to the transportation customer that have not been extinguished by the pipeline, plus (2) the LDC's full margin component based on LDC's most recent rate case. The minimum charge for transportation service is the charges specified in (1) and that portion of (2) that is equivalent to the LDC's customer charge and its variable cost of providing distribution services. Firm and interruptible transportation service are both available to the extent they are offered on a sales basis, and to the extent capacity limitations on an LDC's system justify the offering of different qualities of service. Concerning specified maximum and minimum lengths for transportation contracts, the duration of arrangements are to be individually negotiated. They should be of sufficient length to permit the LDC to reasonably factor the arrangement into its gas procurement plans. To reserve back-up service, the customer should be required to pay a reservation charge equal to a reasonably allocated share of the LDC's cost of maintaining the gas supplies necessary to provide the service, provided that such costs are not already included in the transportation rates. Missouri is essentially a non-producing state. An LDC may establish reasonable minimum volume eligibility requirements based on a consideration of the transportation and administrative costs associated with providing transportation service.

Montana: There are provisions for mandatory open-access, nondiscriminatory transportation. However, in the case of MDU and because of the vintage of policies, certain industrial customers in an ongoing MDU gas transportation docket contend the existing tariffs are discriminatory. MDU's most recent filing features both minimum and maximum prices for transportation service, if such is not currently tariffed. There is no policy on the allocation between ratepayers and stockholders of profits or losses resulting from transportation service, but this will be a PSC consideration. There is only interruptible service for MDU. For one vintage of MDU tariffs, there are specified maximum and minimum lengths for transportation contracts. There are none for the other vintages. There is provision for storage service with respect to the three LDCs only. One of the MDU's transportation tariffs has a minimum amount of gas to be transported: Rate 81 for General Service Customers has a 2,500 cubic foot per hour minimum.

Nevada: Concerning mandatory open-access, nondiscriminatory transportation, see the availability clause in ST-1 tariff. Concerning the allocation between ratepayers and stockholders of profits or losses resulting from transportation service, Account 191 customers receive a credit. The minimum rate for transportation could be at a zero margin. The ST-1 tariff provides only for interruptible transportation service. Back-up gas service for transportation customers could be included in individual contracts. No gas is produced in Nevada. The minimum amounts of gas to be transported are defined in the availability and applicability clauses of the ST-1 tariff as well as in contracts.

New Jersey: One utility has an explicit provision in its tariff on maximum and minimum transportation charges. Profits are shared 95% to firm customers and 5% to stockholders for New Jersey Natural Gas Company, Elizabeth Gas Company, and South Jersey Company. All of the profits for Public Service Electric and Gas Company go to firm customers. Two utilities have both firm and interruptible transportation tariffs. The other two offer only interruptible transportation. One utility requires a specific contract length. The other three are covered by contracts that are negotiable. Two utilities offer back-up service for transportation customers. There is no local gas in New Jersey. One utility has a core market concept. Whether there are maximum and minimum amounts of gas to be transported depends on the contract provision.

New Mexico: Mandatory and nondiscriminatory transportation is required to the extent that capacity is available and the quality of the gas to be transported meets the utility's specifications. The maximum charge for transportation service is the fully allocated cost-of-service. The minimum charge is variable costs. Allocation between ratepayers and stockholders of profits or losses resulting from transportation service will be determined during a rate case. Stand-by service may be provided at the option of the utility. Customers are not required to purchase stand-by service from the utility. Storage service may be provided at the option of the utility.

New York: There is mandatory open-access, nondiscriminatory transportation, pursuant to tariffs, provided capacity is available. For interruptible transportation service, the floor charge is ten cents, the ceiling is firm rates. Concerning the allocation between ratepayers and stockholders of profits or losses resulting from transportation service, there is imputation and/or credit to firm customers with a small percentage (10-20 percent) to stockholders as incentive to maximize revenues. There are only set minimum amounts of gas to be transported.

North Carolina: No further explanation.

North Dakota: Maximum ceiling is the rate that would otherwise apply to this service. Minimum is the cost of gas plus an arbitrary mark-up. We have allowed tariffs only with an allocation of profits.

Ohio: There is no provision for mandatory open-access, nondiscriminatory transportation, although almost all utilities in the state do transport. All large companies and some small ones with very little industrial loads do. The maximum charge for transportation service is the General Service Rate, exclusive of gas costs (that is, gross margin). There are currently no floors officially, although for individual companies the commission requires a floor covering all variable costs of service plus a contribution to utility fixed costs. Although gross margin should prevent profits, the current guidelines do not guarantee rate recovery of losses due to downwardly flexible rates. Allocation of recovery between ratepayers and stockholders occurs in a rate case. All companies providing transportation are to provide both firm and interruptible transportation services. Back-up gas service is required for high priority end users without ample alternative fuels. Service requires allocation of costs incurred by the utility (demand costs). The provision of back-up is equal to firm service. The level of back-up has been varied for some customers. Storage service is permitted if the utility chooses to offer it. A distinction between core and noncore markets is not in the current guidelines, but specific cases have required high priority customers to be firm transporters (that is, with full utility back-up) or have adequate alternative fuel.

Oregon: No further explanation.

Pennsylvania: Transportation service shall be provided without discrimination as to type and location of customer. The maximum charges for transportation service shall be the weighted average retail rate for the service less costs relating to supply. The maximum rate for gas produced in Pennsylvania shall be based on a cost-of-service study. No minimum rates are required. LDCs are to offer firm service unless capacity constraints require interruption of the service. The minimum length for transportation service is twelve months or less if both the LDC and the customer agree to same. There is no maximum length of service contract. The Commission does not require mandatory or optional back-up service for transportation customers. A customer may request back-up service based on contracted levels if the transportation company decides to provide such service. The maximum rate for gas produced outside the state is simple margin. The maximum rate for gas produced in Pennsylvania is cost-of-service. A provision for storage service is required only of LDCs that possess storage capability. Each utility can propose a minimum amount of gas to be transported in the tariff; however, customer groups can be created to meet the minimum by combining usage.

Rhode Island: Firm transportation is available for at least 2,000 Mcf monthly and daily meter readings; firm, off-peak is the same as above but may be discontinued by company. Interruptible service has no volume requirement and may be discontinued. There is no gas produced in Rhode Island. A minimum of 2,000 Mcf/month of gas is to be transported for firm and firm, off-peak customers.

South Carolina: The transportation rates approved for individual companies are all maximum rates. There is no gas production in South Carolina.

South Dakota: What is described in table X-2 and below is not a policy requirement. Instead, an apt description would be a tariff requirement. There are some minimums on lengths for transportation contracts. Back-up gas service is available for transportation customers of one company. Storage service is available for one company.

Texas: Not applicable.

Utah: Yes, there is mandatory open-access, nondiscriminatory transportation for interruptible service. At present, we have fixed transportation rates which will not be altered until there is a general rate case. Only interruptible transportation service is offered. There is a minimum requirement to get a 5 cent reduction in the transportation rate by making the gas available for firm customers during the peak period. There is a minimum requirement of 200 Dth per day of gas to be transported.

Virginia: Virginia chose not to mandate transportation. However, it actively encourages transportation informally and cites certain punitive measures for companies that do not offer a transportation service. The Virginia Commission rejected flexible transportation rates because it felt that such rates may result in discriminatory ratemaking. (See page 18 of the Opinion and Order in Case No. PUE360024.) Although the Virginia Commission did not distinguish between firm and interruptible transportation in its rulemaking, such rates have been approved on a case-by-case basis. Firm rates typically have a demand component. Virginia found that a standby service should be offered at compensatory rates. Limitations on the availability of transportation have been established on a case-by-case basis. No minimum level has been established generically. Rates may vary depending on usage levels (declining block rates).

Washington: The specified minimum length for transportation contracts is a function of the minimum length for the appropriate sales schedule. Whether or not there is back-up gas service for transportation customers is not specifically defined in the tariffs. But, since the rate is a function of sales margin, standby service is generally available.

Wisconsin: Transportation service is available to all except "essential services" (schools, hospitals, etc.). Essential services must have either alternate fuel capability or a back-up contract with the LDC to transport. The maximum charge for transportation service is revenue requirement (gross-margin) based. The floor charge is set by the utility. Any losses from "flexing" of the transportation rate are to be borne by shareholders and not ratepayers. There is no prohibition against either firm or interruptible transportation service. The use of a gross margin approach creates classes that parallel system supply classes. Therefore, both firm and interruptible transportation are available. Back-up gas service for transportation customers is optional, but is required for essential services. It establishes a priority for return to system supply. Concerning core and noncore markets, any group can transport. However, we are maintaining a one meter-equals-one-customer rule. Therefore, pooling by residential customers is unlikely. Also, at this time the Wisconsin PSC has not formally regulated nominations of MDQ and ACQ to cover the core market.

Wyoming: See the Wyoming Gas Carriage Law - Sec. 15-1-103(a) (xxxiii) (c), Sec. 15-1-103(b).

TABLE B-2

COMMISSION PRESCRIBED METHODS
OF CALCULATING TRANSPORTATION CHARGES

State	None	Simple Margin	Full Margin	Cost of Service	Value of Service	Some Other Method
Alabama						Gross Margin
Alaska			Preferred			
Arizona					X	
Arkansas			X			
California	X					
Colorado	X					
Connecticut				X	X	
Delaware			X		X	
District of Columbia					X	
Florida						
Hawaii						
Idaho		X				
Illinois						
Indiana	X					
Iowa	X					
Kansas			X		X	
Kentucky						Gross Margin
Louisiana	X					
Maryland	X					
Massachusetts		X		X	X	
Michigan	X					
Minnesota			X			
Mississippi	X					
Missouri						X
Montana		X		X		
Nevada			X?			
New Jersey			X		X	
New Mexico				X		
New York		X			X	
North Carolina			X			
North Dakota	X					
Ohio			X			
Oregon			X			
Pennsylvania		X				
Rhode Island						
South Carolina						
South Dakota	X					
Texas	X					
Utah	X					
Virginia				X		
Washington		X	X			
West Virginia						
Wisconsin		X				
Wyoming	X					

Source: NRRI Survey, 1988

3. Is there a Commission prescribed method or methods for calculating transportation charges? Yes____ No____. If so, please check the method that you use.

do you use simple margin? ____
full margin? ____
cost of service? ____
value of service? ____
some other method? ____

Please describe or document.

Alabama: Gross margin.

Alaska: No. Full margin is the preferred method.

Arizona: Maximum rate is otherwise applicable rate minus average cost of gas, adjusted for losses and demand charges paid to interstate pipeline. The minimum rate is short-run marginal cost.

Arkansas: Yes. Full margin.

California: No, although the maximum rate is the fully allocated embedded cost of the transmission system, including return on equity. The transportation customer and the utility may negotiate a different rate. The utility is at risk for allocated revenues.

Connecticut: Primarily cost of service during the determination, however, the Commission has evaluated value of service and marketability of service in establishing appropriate charges.

Delaware: Full margin is used for LDC No. 1. Value of service is used for LDC No. 2, whose minimum charge is the incremental cost and whose maximum charge is the full margin.

District of Columbia: See Washington Gas Light Company Interruptible Service Rate Schedule No. 3 and the Opinion and Order No. 8910, In the Matter of the Application of Columbia Natural Gas...for Authority to Provide a New Service for Delivery of Customer-Owned Gas on an Interruptible Basis.

Idaho: Yes, simple margin.

Illinois: Calculation of charges depends on the company. Most LDCs use some type of margin approach (with part or all of the PGA charges credited back). One company has a fixed rate per Mcf.

Indiana: Various tariffs use some of all of these approaches. See the response to question 4.

Iowa: LDCs are either equivalent sales service non-gas margins or transportation rates based on separate cost-of-service studies. The Board has approved both methods. In addition, many LDCs have higher customer service charges for transportation than for sales service due to the decreased costs associated with providing transportation service.

Kansas: Case-by-case determination.

Kentucky: In most cases, the rate is set as the "gross margin," that is, the sales service rate the transportation customer would normally be served under, less the commodity cost of purchased gas. This results in a transportation rate that is roughly the LDC's margin plus pipeline demand charges.

Louisiana: No.

Maine: No.

Maryland: No. See pages 17 through 20 of Commission Order No. 67583. The transportation charges imposed by the state's four major LDCs are currently under investigation.

Massachusetts: The methods are as follows: for interruptible, value of service; for firm (those companies operating on an interim basis), simple margin; for firm (those companies that have adjudicatory rate proceedings after August 7, 1987), cost-of-service.

Michigan: No.

Minnesota: As noted before, transportation rates are flexible. For rate case purposes, transportation is assumed to occur at a rate equal to the gross margin for similar sales. In some cases, the margin is reduced to remove peak sharing costs not applicable to transportation customers.

Mississippi: See the response to question 2.

Missouri: The parties to the generic transportation case agreed to establish rates using general guidelines (see Report and Order in GO-85-264 dated 9/18/86, page 13, paragraph D).

Montana: For MDU's transportation services, the Company proposed, and the PSC approved, the following:

Year Approved	Tariff	Method
1983	97	Embedded Cost-of-Service
1985	81,82	Full Margin

Also, MDU has proposed flexible pricing in ongoing Docket 87.12.77.

Nevada: See ST-1 tariff. Minimum and maximum rates are set in a general rate case. The last general rate case was settled by stipulation, therefore, the method for calculating the transportation charges is not known.

New Jersey: There is no prescribed method, rather it is set on an individual case basis.

New Mexico: Cost-of-service for maximum cost.

New York: Firm rates are generally based upon simple margins. In some cases the Commission has reduced rates based upon evidence developed in rate cases for cost-of-service or competitive considerations. Interruptible rates are generally set, within limits, at the discretion of the utility, presumably based on value consideration.

North Carolina: Full margin.

North Dakota: No.

Ohio: Full margin is specified in the guidelines (see the response to question 2b) under competitive situations (gas-on-gas, gas-on-oil, primarily). There are negotiated rates, often for total burner-tip price. The utility is at risk for nonrecovery of fixed costs. (See the response to question 2c.)

Oregon: See Northwest Natural Gas Company Tariff Schedule 57.

Pennsylvania: The maximum charge allowed is the weighted average retail rate for that type of retail service less all costs relating to natural gas supply including demand, commodity, and storage costs. Pennsylvania-produced gas should be transported by LDCs at a rate no higher than a cost-of-service rate.

Rhode Island: See Order 12401.

South Carolina: The approved rate less the cost of gas plus an unaccounted-for factor.

South Dakota: No. However, in general, the non-gas portion of the retail rate, which might be described as full margin recovery, is the transportation rate.

Texas: Section 5.02(b) of the Gas Utility Regulatory Act states: "Rates charged or offered to be charged by a gas utility for pipeline-to-pipeline transactions and to transportation, industrial, and other similar large, volume contract customers, but excluding direct sales-for-resale to gas distribution utilities at city gates, are considered to be just and reasonable and otherwise to comply with this section, and shall be approved by the regulatory authority, if: (1) neither the gas utility nor the customer had an unfair advantage during negotiations; (2) the rates are substantially the same as rates between the gas utility and two or more of those customers under the same or similar conditions of service; or (3) competition does or did exist with another gas utility, another supplier of natural gas, or with a supplier of an alternative form of energy."

Utah: The rate for MFS was determined by subtracting the gas cost from the total for the corresponding sales rate and adding 54. However, this is not a generic prescribed method.

Virginia: Virginia required that embedded cost-of-service studies be filed by each LDC. These studies would then be used as the basis for establishing cost-based transportation rates.

Washington: We consider simple margin and full margin to be the same.

Wisconsin: Simple margin.

Wyoming: Basically cost-of-service, but value of service, marginal cost and other relevant evidence considered on a case-by-case basis. (Contract rates set by the marketplace are allowed if basic costs are covered.)

4. Are the transportation charges designed to recover all of the costs of providing the service to each customer group or are they designed to provide discounts for certain groups of customers? Please describe any such discounts. Who bears the burden for the under-recovery of revenues, if any, caused by providing these discounts?

Alabama: Designed to recover all the costs by class.

Alaska: Not applicable.

Arizona: Each customer may negotiate a rate lower than the maximum. The maximum varies by customer class. "Under-recovery" will be addressed in rate cases.

Arkansas: Not applicable.

California: The maximum rate is the fully allocated embedded cost of the transmission system, including return on equity. The transportation customer and the utility may negotiate a different rate. The utility is at risk for allocated revenues.

Connecticut: Yes, recovery of all costs.

Delaware: LDC No. 1 recovers all the cost of providing the service. LDC No. 2 recovers at least the incremental cost. LDC No. 2 stockholders bear the burden for under-recovery of revenues.

District of Columbia: Rates are designed to keep alternative fuel users from leaving the system.

Idaho: The revenue allocation attempts to balance the burden of under-recovery between core and noncore markets by the use of block rates and rate design procedures.

Illinois: Only NI-Gas' Rate 17, Contract Service, permits discounting of transport rates to prevent bypass. Other customers share in any underrecovery of revenues from discounts given under this rate.

Indiana: Indiana has transportation rates that are margin-based off of the parent rate. These parent rates may or may not be exactly cost-based. We also have transportation rates that are cost-based as determined by a cost-of-service study. A couple of LDCs have discounted rates, one of which is a variable rate and the other of which is a fixed rate. The rates are provided at the expense of the utility in one case and at the expense of the remaining customers and the utility in the other case.

Iowa: LDCs may "flex" their transportation rates just as they may "flex" sales rates. See our rules.

Kansas: On a case-by-case basis, some discounts exist. Disposition of underrecovered revenues will be considered in future rate cases.

Kentucky: Transportation charges are designed to recover all costs. For customers with alternate fuel capability, some LDCs have the ability to flex the transportation rate to meet such competition. The Commission has said that the underrecovery would be considered in the subsequent rate case.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: The Commission has not authorized discounted transportation rates for any customer group, but it has not prohibited LDCs from offering flexibly priced interruptible service to meet competition from alternate fuels.

Massachusetts: Charges are designed to recover costs in full. A company may offer discounts to retain customers, but the Commission has warned companies they may be required to impute any foregone revenues in future rate proceedings.

Michigan: Utilities are currently providing transportation under a provision of state law which allows them to set initial rates without Commission approval. Under this system, some utilities are providing discounts and others are not. The PSC has not made any decision on these discounts.

Minnesota: Although there is nominal freedom to flex upward, competition generally dictates that any flexing be downward. Individual customers may receive discounts depending on the cost of alternate fuels. The utility company bears the burden of under-recovery.

Mississippi: Not applicable.

Missouri: Application of the maximum rate contemplates full recovery from the transporting customer. Application of the minimum rate contemplates partial recovery. Any downward movement from the maximum rate is absorbed by the LDC and its stockholders; other customers, therefore, remain financially neutral because of transportation.

Montana: The margin and embedded approaches are intended to recover fixed costs but not take-or-pay.

Nevada: The Company absorbs under-recovery.

New Jersey: Transportation charges are designed to recover all the costs of providing the service to each customer group. Some utilities can flex the rate.

New Mexico: Charges may range from just above the variable cost-of-service to fully allocated cost-of-service. The actual rate is negotiated between each customer and the utility. The responsibility for under-recovery is determined during a rate case.

New York: In limited cases, utilities have been allowed to defer revenue loss associated with transportation rates that are less than the full sales service margin. The Commission in the future may allow recovery of the deferred revenue loss from general ratepayers.

North Carolina: Yes. Negotiated rates to meet market competition. The loss is offset by spot gas savings. If that is not sufficient to offset losses, the stockholders pick up the losses.

North Dakota: Depending on alternate fuel prices, any under-recovery is absorbed by the company.

Ohio: The goal is to have the cost-of-service recovered, but where the utility may lose the load entirely due to competition, the Commission permits downwardly flexible rates; recovery of any deficiency of fixed costs is conditioned on review of the utility actions conducted in a rate case. (See the responses to questions 2c and 3.)

Oregon: Service for interruptible customers who can switch to No. 6 oil is discounted to the extent necessary to keep them on gas.

Pennsylvania: There are no discounts provided for any group of customers. Transportation charges are to recover, to the maximum extent possible, the fixed costs associated with the service, but the LDC may charge any rate below the maximum established above. Shortfalls are subject to review in the next base rate case review.

Rhode Island: Not applicable.

South Carolina: No.

South Dakota: Designed to recover costs of providing service plus margin.

Texas: Not applicable.

Utah: It is designed to recover all the costs.

Virginia: The Virginia Commission does not provide for discounted transportation rates.

Washington: Not applicable.

Wisconsin: At rate-setting time, rates are set by the gross (simple) margin approach to recover all costs. The LDC may flex downward from these rates, but any underrecovery of revenues is borne by the shareholder.

Wyoming: Transportation charges must not place a burden on other ratepayers.

5. Is there a provision for interutility (LDC-to-LDC or intrastate-to-LDC) gas transportation? Yes____ No____. If so, please describe briefly.

Alabama: Yes, same rates would apply.

Alaska: No.

Arizona: No.

Arkansas: No.

California: Yes. This is a tariffed service.

Connecticut: No.

Delaware: No.

District of Columbia: No.

Idaho: No.

Illinois: Although there are no specific provisions for interutility transportation, there are a couple of individual contracts for this service.

Indiana: No.

Iowa: Currently, LDCs that transport for other LDCs do so under the same rules, terms, and conditions as for end-user transportation.

Kansas: Interutility transportation and exchanges have been going on for decades.

Kentucky: No.

Louisiana: No.

Maine: Not applicable.

Maryland: No.

Massachusetts: No.

Michigan: Yes. Utilities have and continue to provide interutility transportation under a provision of state law that provide for little PSC oversight. These utilities are only required to file their rates and contracts, but these do not need Commission approval.

Minnesota: No.

Mississippi: Not applicable.

Missouri: No. The agreement only dealt with LDCs and their downstream customers.

Montana: No. All MDU transportation rates are interruptible.

Nevada: Yes. The same as any other ST-1 customer.

New Jersey: No.

New Mexico: No.

New York: Yes. LDCs which provide gas for resale by other LDCs also provide transportation service both for the customer LDC and the end-use customers of the LDC.

North Carolina: No.

North Dakota: No.

Ohio: No. Not formally in the Guidelines, but the Ohio Revised Code permits it and the Commission approves contracts for deliveries from one LDC to another for system supply or for redelivery to an end-user on the downstream LDC's system.

Oregon: No.

Pennsylvania: An LDC can be a "customer" of another LDC's transportation service.

Rhode Island: No.

South Carolina: No.

South Dakota: No.

Texas: Not applicable.

Utah: No. It is physically not possible.

Virginia: No.

Washington: Not applicable.

Wisconsin: No.

Wyoming: Yes. A case-by-case determination.

6. Does the policy impose any special restrictions or requirements on the end-use of the gas? Yes____ No____. For example, is transportation service for a cogenerator restricted or is back-up gas service required for end-users who provide essential services to their customers (like hospitals and schools). Please describe any such special restrictions or requirements.

Alabama: No.

Alaska: Not applicable.

Arizona: No.

Arkansas: No.

California: No. As long as a customer is not a core customer, the customer may transport gas.

Connecticut: No.

Delaware: No. LDC No. 1 firm customers can only elect firm transportation. They cannot elect interruptible transportation. All hospitals and schools served by LDC No. 1 are firm customers and can only elect firm transportation which includes back-up gas service. LDC No. 2 transportation customers must have dual-fuel capability. Therefore, if a hospital or school elects interruptible transportation, it must have dual-fuel capability in case of curtailment.

District of Columbia: No.

Idaho: No.

Illinois: No.

Indiana: No.

Iowa: No.

Kansas: No.

Kentucky: No.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No.

Massachusetts: No. (Note: While the DPU has not imposed any generic restrictions, individual companies may propose such restrictions through their terms and conditions on a litigated rate proceeding.)

Michigan: No. The Commission is currently considering the issue.

Minnesota: No.

Mississippi: Not applicable.

Missouri: No.

Montana: No.

Nevada: No.

New Jersey: No. New Jersey Natural's tariff provides that the customer shall have full responsibility to have standby equipment installed and maintained in good operating condition and maintain fuel supply adequate for its operation at all times.

New Mexico: No.

New York: No.

North Carolina: No.

North Dakota: No.

Ohio: Yes. Current policy requires back-up for essential services (see the response to questions 2f and 2i). Current guidelines limit use of gas for boiler fuel when a higher priority group is being curtailed, but this will probably be eliminated due to the repeal of the Fuel Use Act.

Oregon: No.

Pennsylvania: No. The transportation service customer shall agree to sell its natural gas supply to the natural gas distribution utility at the higher of the natural gas utility's average cost of gas or the customer's own cost in the event of a distributor natural gas supply shortage. The PUC has a separate ongoing investigation dealing with issues concerning cogeneration.

Rhode Island: No.

South Carolina: No.

South Dakota: No.

Texas: Not applicable.

Utah: Yes. It must be interruptible service which requires back-up fuel capability.

Virginia: No.

Washington: Yes. It is restricted in one service area for the use of cogeneration.

Wisconsin: Yes. Back-up or alternate fuel for essential services.

Wyoming: No.

7. Does the policy provide for curtailment of transportation service to customers? Yes____ No____. If so, can the policy have the effect of taking transportation gas and converting it into sales gas for high priority users? Yes____ No____. Please describe the policy briefly.

Alabama: Yes, the policy does provide for curtailment of service. No, it cannot have the effect of converting transportation gas to sales gas. There is an interruptible transportation rate similar to a regular interruptible sales rate.

Alaska: Not applicable.

Arizona: Yes, the policy does provide for curtailment of transportation service. No, the policy cannot have the effect of converting transportation gas to sales gas for high priority users.

Arkansas: No.

California: Yes. In the event of an intrastate capacity shortage, the core customers receive priority. Then curtailment occurs in order of priority charges. Customers paying residential priority charges are curtailed pro rata. In the event of a supply shortage, transportation gas can be diverted to core use only if the California PUC decides that core curtailment is imminent.

Connecticut: Yes, per tariff terms and conditions.

Delaware: Yes, the policy does provide for curtailment of transportation service. No, the policy cannot have the effect of converting gas to sales gas for high priority users.

District of Columbia: Yes, the policy does provide for curtailment of transportation service. No, the policy cannot have the effect of converting transportation gas to sales gas for high priority users. It is interruptible at the LDC's option.

Idaho: No, the policy does not provide for curtailment of transportation service to customers. There is a tariff provision that allows for curtailment at the discretion of the company.

Illinois: Yes, the policy does provide for curtailment of transportation service to customers. No, the policy cannot have the effect of taking transportation gas and converting it to sales gas for high priority users. Most tariffs provide for interruption in the event system capacity is limited or if it becomes necessary in the judgment of the company.

Indiana: Most of our rates are interruptible, but we don't have a specific policy.

Iowa: Yes, the policy does provide for curtailment of transportation service to customers. No, the policy cannot have the effect of taking transportation gas and converting it to sales gas for high priority users. Curtailment or interruption due to capacity limitations occurs for transportation customers according to the priority class, subdivision, or category that the end-user would have been if it were purchasing gas from the utility.

Kansas: Not applicable.

Kentucky: Yes, the policy does provide for curtailment of transportation service to customers. No, the policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users. Firm transportation is a higher priority than interruptible sales. Interruptible sales is a higher priority than interruptible transportation. Firm sales is the top priority.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: Yes, the policy does provide for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. See page 12 of Commission Order No. 67583. The Commission did not explicitly address the curtailment of transportation service, but this falls under the heading of restrictions on availability of transportation service. LDCs are free to propose curtailment restrictions but bear the burden of justifying such restrictions.

Massachusetts: Firm transportation service has a priority of service equal to firm sales. If a firm transportation customer's supply fails, the customer is not entitled to receive system supply unless it has contracted for backup service. If the system supply is constrained but the firm transportation customer's deliveries continue unimpaired (a still hypothetical situation), the transportation customer's deliveries may be cut back on a *pro rata* basis under emergency regulations. However, the customer would not be deprived of more than its *pro rata* share.

Michigan: The Commission is currently considering this issue.

Minnesota: Yes, the policy does provide for curtailment of transportation service to customers. No, the policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users. Transportation customers are curtailed exactly as sales customers if curtailment is needed for insufficient delivery capacity. If a lack of supply would curtail sales customers, transportation customers could still receive service.

Mississippi: Not applicable.

Missouri: Yes, the policy does not provide for curtailment of transportation service to customers. Generally, the policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users. However, a special provision dealing with system supply emergency has been incorporated into LDC transportation tariffs. This provision permits the LDC to defer delivery of customer's gas under certain conditions where the unavailability of gas may imperil human life or health. The general policy is that transportation customers should be considered to be within the same priority in the event of capacity limitations or constraints as they would be if they were sales customers.

Montana: Curtailment and interruption are reasons for terminating gas transportation on a short-term basis. The retail rates that a transportation customer could shift to are generally interruptible, but firm general service is also available although at a higher price than interruptible service.

Nevada: Yes. See ST-1 tariff.

New Jersey: Yes, the policy provides for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. One utility's tariff provides that if a customer's take for the month exceeds 130 percent of gas available for transportation, the customer must interrupt the use of transportation gas until the account is balanced. Another utility's tariff provides, after adequate notice to the customer, transportation service can be curtailed as specified in the winter service agreement.

New Mexico: No, the policy does not provide for curtailment of transportation service to customers. No, the policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users.

New York: Yes, the policy does provide for curtailment of transportation service to customers. No, the policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users. Attachment subject to capacity availability after sales service. Transportation service is generally afforded curtailment levels equal to comparable sales service. No provision for utility taking of curtailed customer-owned gas.

North Carolina: Yes, the policy does provide for curtailment of transportation service to customers. No, the policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users.

North Dakota: Yes, the policy does provide for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users--if, by contract, customers agree to this.

Ohio: Yes, the policy provides for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. Curtailment governed by utility-specific curtailment plans. Current guidelines provide for transporters to continue to deliver 50 percent of the production during time of system curtailment with the utility making up volumes to them at a later date.

Oregon: Yes, the policy provides for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. The policy applies during emergency conditions only.

Pennsylvania: Yes, the transportation policy provides for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. See the response to question 6.

Rhode Island: Yes, the transportation policy provides for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. The company solely can decide to discontinue service to transportation customers so that the needs of firms customers can be met.

South Carolina: No, the transportation policy does not provide for curtailment of transportation to customers. No, the policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users.

South Dakota: Yes, the tariffs provide for curtailment of transportation service to customers. Standby service is available for customers of one utility but not all.

Texas: Not applicable.

Utah: Yes, the policy does provide for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. The customer gets a 5 cent discount if MFS and the shipper agree that under specific circumstances MFS will have the right to purchase shippers gas during periods of interruption.

Virginia: Yes, the policy provides for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. Although the Virginia Commission's generic rulemaking did not establish policies governing transportation curtailment, such policies have been reviewed on a case-by-case basis. Curtailment of transportation is discouraged during periods when the LDC experiences supply problems as a result of its contract demand entitlements and the transportation gas continues to be delivered to the LDC's city gas. If the curtailment is a result of distribution system capacity, interruptible transportation is given the same priority as interruptible sales.

Washington: Yes, the policy does provide for curtailment of transportation service to customers. No, the policy cannot have the effect of taking transportation gas and converting it into sales gas for high priority users. Curtailment is determined by sale schedule priority.

Wisconsin: Yes, the policy provides for curtailment of transportation service to customers. Yes, the policy can have the effect of taking transportation gas and converting it into sales gas for high priority users. In the event of capacity constraints, transportation services sold at a discount should be curtailed first. In an emergency supply situation, the LDC should have the right to take transportation gas and fairly compensate the owner for it.

Wyoming: Yes, the policy does provide for curtailment of transportation service to customers. The Commission requires interruption of transportation service when and as it interferes with the utilities' distribution responsibilities, especially to firm customers.

8. Does the policy limit transportation service to dual-fuel customers only? Yes____ No____. Please describe briefly.

Alabama: No.

Alaska: Not applicable.

Arizona: No.

Arkansas: No. For customers whose usage exceeds 500 Mcf/day, automatic qualification for transportation is available. For customers whose usage is at least 100 Mcf/day but does not exceed 500 Mcf/day, less expensive alternative fuel capability or economic distress must be demonstrated.

California: No. The restriction is 250,000 therms/year minimum usage.

Connecticut: For interruptible transportation customers, yes; unless, in one LDC's case, the customer can adequately demonstrate that an alternate supply is not necessary, as in, asphalt plants.

Delaware: No. LDC No. 1 firm transportation customers are not required to have dual-fuel capability. Also, LDC No. 2 grain-dryer customers are not required to have dual-fuel capability.

District of Columbia: Yes. The purpose is to keep dual-fuel users on line.

Idaho: No.

Illinois: No.

Indiana: Most of our rates require dual-fuel capability but, we don't have a specific policy.

Iowa: No.

Kansas: No. Both are receiving service.

Kentucky: No. But the ability to flex transportation rates to meet competition is restricted to those customers with alternate fuels.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No.

Massachussetts: No.

Michigan: The Commission is currently considering this issue.

Minnesota: No. Transportation is available to any customer meeting minimum size requirements (generally 50 MMBTU/day). Flexible rates are available to customers with alternate fuel capability or to those who could readily install such capability.

Mississippi: Not applicable.

Missouri: No.

Montana: No.

Nevada: No.

New Jersey: No. Most of the utilities require dual-fuel capability for transportation service customers.

New Mexico: No.

New York: No.

North Carolina: Yes.

North Dakota: No.

Ohio: No.

Oregon: No.

Pennsylvania: No. Dual-fuel capacity may entitle end-users to interruptible transportation service. The offering of interruptible service is at the utility's discretion since load loss has made the possibility of interruption on certain LDCs remote.

Rhode Island: No.

South Carolina: No.

South Dakota: Some tariffs are restricted, but not all.

Texas: Not applicable.

Utah: Yes. It is limited to interruptible service which requires back-up fuel capability.

Virginia: No. If the end-user does not have dual-fuel capability, it may be required to sign an affidavit stating that its service is subject to curtailment.

Washington: No.

Wisconsin: No.

Wyoming: No.

9. Does the policy require public disclosure of transportation service agreements? Yes____ No____. If so, please describe briefly.

Alabama: No, a standard contract has been approved by the Commission. Only deviations must be filed and become public.

Alaska: Not applicable.

Arizona: No. However, the Commission is advised of customer and rate changes.

Arkansas: No.

California: No. There is a standard form which is public, but the terms and conditions are negotiable. The negotiated contracts are not public.

Connecticut: Yes, all information on file is available to the public.

Delaware: No.

District of Columbia: Yes. The order requires the LDC to file contracts. No protective order has been sought.

Idaho: No.

Illinois: Transportation rates are public documents on file with the Commission. Yearly, volumes transported are available in the Annual Reports filed by each utility with the Commission. The only exception is NI-Gas Rate 17, Contract Service, which was developed to deal with bypass threats.

Indiana: All transportation is by tariff, which are public documents. Contract quantities are not filed unless requested.

Iowa: Yes. The LDC is required to file two copies of each transportation contract entered into within thirty days of execution. The utility is allowed to replace information which identifies the end-user with an identification number.

Kansas: No.

Kentucky: Yes. Although not specifically stated, all records are public unless confidentiality is requested.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No.

Massachusetts: No

Michigan: Yes. State law requires agreements to be filed with the Commission.

Minnesota: No.

Mississippi: Not applicable.

Missouri: No.

Montana: No.

Nevada: No.

New Jersey: No. The transportation service agreements are individually negotiated in accordance with tariff provisions and, therefore, are confidential.

New Mexico: Yes.

New York: No. The form of the service agreement is part of the filed tariff. Specific customer service agreements are not generally filed with the Commission or available to the public.

North Carolina: No.

North Dakota: No.

Ohio: No. At this time the issue of confidentiality is being evaluated. In the meantime, where the utility is reacting to competition, the Commission is permitting the confidential disclosure of rates. All agreements are already filed with the Commission except where transportation is pursuant to an approved tariff.

Oregon: Yes. Public tariff rates are used.

Pennsylvania: No.

Rhode Island: No.

South Carolina: Yes.

South Dakota: No.

Texas: Not applicable.

Utah: No.

Virginia: No.

Washington: No.

Wisconsin: No.

Wyoming: Yes. Transportation tariffs and contracts are made part of the Commission's permanent files and are available for review by the public unless accepted for filing by the Commission on a confidential basis.

10. Are there any other important aspects of your Commission's gas transportation policy? Yes____ No____. If so, please describe.

Alabama: No.

Alaska: Not applicable.

Arizona: Yes. Much effort was expended on developing balancing provisions.

Arkansas: No.

California: No.

Connecticut: Yes. Connecticut is currently capacity-constrained on the interstate pipeline system during the winter peak season. As such, a comprehensive transportation policy consisting of a full menu of services is not possible. When the capacity problem is eliminated, the Commission in all likelihood and predicated on end-user need, may have to formally address a policy.

Delaware: No.

District of Columbia: No.

Idaho: No.

Illinois: Yes. Other aspects generally included in Illinois transport rates are:

- Transported gas is considered the first gas metered.
- An unaccounted for gas factor is applied to transport volumes.
- Customers that wish to return to purchasing system supply gas are treated like new customers.

Indiana: Not applicable.

Iowa: See our current rules.

Kansas: Not applicable.

Kentucky: See Administrative Case No. 297.

Louisiana: Not applicable.

Maine: No.

Maryland: Yes. Smaller LDCs in Maryland are not at present subject to the guidelines, principles, and policies established by the Commission for transportation service. To the extent feasible, smaller LDCs are encouraged, but are not required at this time, to offer transportation services.

Massachusetts: As explained in responses to 2j and 3, the Department's regulations for firm transportation are in transition. The August 7, 1987 order in DPU 85-178 ordered simple-margin pricing as an expedient way to get firm transportation in place within a short time frame, in view of the fact that the Department would not have the opportunity to review an up-to-date cost-of-service study (COSS) for each company to set fully unbundled, cost-based rates. In the first adjudicatory hearing on a firm transportation rate, the Department ordered a cost-based rate (Commonwealth Gas).

Michigan: No.

Minnesota: Yes, rates may not flex to compete with district heating or renewable resources.

Mississippi: Not applicable.

Missouri: Load balancing provisions should be included in transportation tariffs and optional transportation services may be provided by the LDC for transportation customers. (See page 14 of Report and Order in GO-85-264 dated 9/18/86.)

Montana: Don't think so, but it depends on your perspective. Also, flexible pricing proposals, if adopted, may be "unique."

Nevada: Not applicable.

New Jersey: No.

New Mexico: See General Order 44.

New York: No.

North Carolina: No.

North Dakota: No.

Ohio: No, not currently. But that may change when new guidelines are adopted.

Oregon: No.

Pennsylvania: Yes. The provisions of the PUC order recognize that for a rate which provides for a fixed maximum daily quantity, transported gas should be considered last through the meter. However, where a customer's sales service is under an open-ended rate schedule, transported gas may be considered first through the meter. The other important aspect of the Commission's policy has to do with balancing deliveries and withdrawals. A natural gas utility providing transportation service shall reflect in its tariff a three-month time period as a minimum within which the transportation customer shall balance deliveries and withdrawals from the natural gas utility's system.

Rhode Island: No.

South Carolina: No.

South Dakota: Not applicable.

Texas: Not applicable.

Utah: No.

Virginia: No.

Washington: No.

Wisconsin: Yes. "Agency, dedicated gas" and the "shared spot portfolio". LDCs should not steer least-cost gas away from system supply and toward individual users. A spot portfolio of gas may be obtained by the LDC and sold on a best-efforts approach. LDCs not using the spot portfolio approach should offer agency service through a subsidiary or outside their service territory only.

Wyoming: No.

II. The next set of questions deals with the bypass issue and its impact on gas transportation policy.

11. In formulating its gas transportation policies or in deciding not to adopt such policies, did your Commission issue a policy statement or order concerning potential bypass of an LDC by end-users, intrastate pipelines, or interstate pipelines? Yes____ No____. If so, please elaborate.

Alabama: No.

Alaska: Bypass issues will be addressed in proceedings scheduled at a later date.

Arizona: No. Commission staff is analyzing bypass policy options and is considering economic and legal issues.

Arkansas: Yes. The Commission discouraged bypass and placed responsibility of bypass on the LDC, possibly through transportation.

California: No. California has no interstate pipelines. All transmission and distribution is done by the LDCs. LDC bypass for gas service is not a concern. The concern was fuel switching.

Connecticut: No. Although the Commission has entertained the notion of bypass in prior proceedings, nothing has materialized. This is, in fact, a direct result of current interstate capacity problems.

Delaware: No.

District of Columbia: No.

Idaho: No.

Illinois: No. As with transportation rates, the Illinois Commerce Commission has not adopted a formal "policy" on bypass. The Commission has given policy direction in several documents. In a bill review opposing federal House Bill 3445, the Commission noted that the threat of bypass aids the development of cost-based transportation rates by uncovering subsidies in class-average transportation rates. The Commission also indicated its belief that flexibility is needed from class-average rates in charging potential bypassers for transportation. This was evidenced by the Commission's approval of NI-Gas Rate 17, Contract Service.

Indiana: No. Indiana statute requires bypassers to file for a certificate of public convenience and necessity.

Iowa: No.

Kansas: Yes. A policy prohibiting LDC bypass has been stated in several individual orders.

Kentucky: Yes. Any entity, including an interstate pipeline, that proposes to physically bypass an LDC is required to obtain a Certificate of Convenience and Necessity.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No. See page 16 of Order No. 67583.

Massachusetts: No.

Michigan: No.

Minnesota: No.

Mississippi: No, but the Commission is monitoring for bypass.

Missouri: Yes. The Commission issued a Report and Order in GO-85-264 dated 3/20/87 which dealt with some unresolved legal issues relating to transportation. In that order, starting on page 5, the Commission addressed its authority relative to bypass.

Montana: Again, this is the reason MDU proposed flexible pricing in Docket 87.12.77, which goes to hearing in May or June.

Nevada: No.

New Jersey: No. The Commission did indicate its opposition to bypass in a litigated case.

New Mexico: No.

New York: No.

North Carolina: No.

North Dakota: No.

Ohio: No.

Oregon: No.

Pennsylvania: The PUC on February 18, 1988 had initiated an investigation into the bypass of gas utilities. Utilities have until March 19, 1988 to file comments.

Rhode Island: No.

South Carolina: No.

South Dakota: No.

Texas: No.

Utah: No. MFS receives all of its gas through an affiliated pipeline, Questar Pipeline Company. The physical layout eliminates the bypass problem. Utah Gas Service (UGS) might have a potential for bypass but so far we have not had a problem.

Virginia: Yes. Virginia believes that appropriately designed embedded cost-of-service rates should eliminate uneconomic bypass. (See page 25 of the Order.)

Washington: No.

Wisconsin: No.

Wyoming: No.

12. If your Commission issued an order or made a finding on potential bypass, was the potential bypass quantified? Yes____ No____. If so, please explain.

Alabama: No

Alaska: Not applicable.

Arizona: We have established a wide range of potential bypass.

Arkansas: Yes.

California: Not applicable. See answer to number 11.

Connecticut: Not applicable.

Delaware: Not applicable.

District of Columbia: Not applicable.

Idaho: No.

Illinois: No. In a few instances involving specific end-users, both the potential loss of the end-user and the cost of the bypass were estimated. No order has been issued that quantified potential bypass for the state.

Indiana: No.

Iowa: No.

Kansas: No.

Kentucky: No.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No.

Massachusetts: The Department is aware of two instances of proposed bypass (direct hookup to the interstate system) involving municipal electric companies. In one case, the would-be bypasser sought a DPU opinion on the conditions that should govern bypass; later, the customer withdrew its proposal.

Michigan: Not applicable.

Minnesota: Not applicable.

Mississippi: No bypass has been experienced to date.

Missouri: No.

Montana: No.

Nevada: No order of funding.

New Jersey: Yes. See the decision and order In the Matter of the Petition of South Jersey Gas Company Against Sunolin Chemical Company and the B.F. Goodrich Company, BPU Docket No. GO8702-82 (NJBPU, August 18, 1987).

New Mexico: Not applicable.

New York: Not applicable.

North Carolina: No.

North Dakota: Not applicable.

Ohio: Not applicable.

Oregon: No.

Pennsylvania: No. See the response to question 11.

Rhode Island: No.

South Carolina: Not applicable.

South Dakota: Not applicable.

Texas: Not applicable.

Utah: Not applicable.

Virginia: No.

Washington: No.

Wisconsin: Not applicable.

Wyoming: Not applicable.

13. If your Commission has issued an order or made findings about the possibility of bypass, how did the transportation policy reflect this? What types of provisions were included in the policy?

Alabama: Not applicable.

Alaska: Not applicable.

Arizona: Not applicable.

Arkansas: No answer.

California: Not applicable, see number 11.

Connecticut: The Commission is cognizant of the bypass dilemma. However, if bypass were to occur under recent market conditions, it would necessitate expansion of existing capacity-constrained interstate pipeline facilities. Based upon the recent LDC sales service expansion fixed costs (demand charges), bypass of an LDC appears to be an uneconomical alternative.

Delaware: Not applicable.

District of Columbia: Not applicable.

Idaho: Not applicable.

Illinois: The Commission has taken the position that the availability of transportation rates reduces incentives to bypass. The Commission further has stated that it is uneconomic bypass--bypass for the purpose of avoiding rate subsidies--that should be prevented; that is, a situation where it would be cheaper for an end-user to remain on an LDC's system if the end-user were charged based on his cost-of-service. Allowing LDCs flexibility from class-average rates would allow transportation rates to be negotiated with potential bypassers that cover costs yet prevent bypass.

Indiana: Not applicable.

Iowa: Not applicable.

Kansas: Not applicable.

Kentucky: Although there are no published findings, the geographic location of Kentucky makes bypass a possibility because of the location of numerous interstate pipelines crossing the Commonwealth. The Commission has tried to facilitate transportation and to encourage the use of LDC's facilities.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: Not applicable.

Massachusetts: Not applicable.

Michigan: Not applicable.

Minnesota: Not applicable.

Mississippi: Not applicable.

Missouri: Not applicable.

Montana: Not applicable.

Nevada: No order or finding.

New Jersey: Not reflected.

New Mexico: Not applicable.

New York: Not applicable.

North Carolina: Not applicable.

North Dakota: Not applicable.

Ohio: Not applicable.

Oregon: Bypass has not been available yet. The Oregon PUC would authorize discounts to compete with bypass on a case-by-case basis if it arose. See Order 87-402.

Pennsylvania: No. See the response to question 11.

Rhode Island: Not applicable.

South Carolina: Not applicable.

South Dakota: Not applicable.

Texas: Not applicable.

Utah: Not applicable.

Virginia: Bypass policy is reflected in the design of transportation rates. The Virginia Commission did not address the legal questions associated with bypass.

Washington: Not applicable.

Wisconsin: Not applicable.

Wyoming: Not applicable.

14. Have these provisions had the desired effect? Yes____ No____. Please describe.

Alabama: Not applicable.

Alaska: Not applicable.

Arizona: Not applicable.

Arkansas: No answer.

California: Not applicable, see number 11.

Connecticut: Not applicable.

Delaware: Not applicable.

District of Columbia: Not applicable.

Idaho: Not applicable.

Illinois: Yes. Only one case of bypass has occurred in Illinois. The Illinois Commerce Commission was determined not to have authority over bypass as a result of _Mississippi River Fuel Corp. v. Illinois Commerce Commission_, 1 Ill. 2d 509 (1953). In this case, the pipeline was held not to be a public utility nor under the Illinois Commerce Commission's jurisdiction because transmission was not offered for public use.

Indiana: Not applicable.

Iowa: Not applicable.

Kansas: Not applicable.

Kentucky: Unable to answer. No filings have been made for certificates to bypass, the LDCs have been very willing to work with individual end-users.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: Not applicable.

Massachusetts: Not applicable.

Michigan: Not applicable.

Minnesota: Not applicable.

Mississippi: Not applicable.

Missouri: Not applicable.

Montana: Not applicable.

Nevada: Not applicable.

New Jersey: Not applicable.

New Mexico: Not applicable.

New York: Not applicable.

North Carolina: Not applicable.

North Dakota: Not applicable.

Ohio: Not applicable.

Oregon: Not applicable.

Pennsylvania: No. See the response to question 11.

Rhode Island: Not applicable.

South Carolina: Not applicable.

South Dakota: Not applicable.

Texas: Not applicable..

Utah: Not applicable.

Virginia: Yes. Thus far, bypass has been avoided by innovative rate designs.

Washington: Not applicable.

Wisconsin: Not applicable.

Wyoming: Not applicable.

III. The third set of questions is concerned with LDC buying and marketing practices, their effects on gas costs, and potential discriminatory practices.

15. Has any group of LDCs in your state acted collectively to buy gas? Yes____ No____. Does your Commission encourage or discourage such collective buying? Encourage____ Discourage____ Neither____. Please explain.

Alabama: Yes, a group of LDCs has acted collectively. The Commission neither encourages nor discourages this. The group of LDCs who acted collectively were municipal systems not under our jurisdiction. No jurisdictional LDCs have so acted.

Alaska: No, LDCs have not acted collectively. The Commission neither encourages nor discourages such collective buying.

Arizona: No, LDCs have not acted collectively. The Commission neither encourages nor discourages such collective buying.

Arkansas: Yes, a group of LDCs has acted collectively. The Commission neither encourages nor discourages such collective buying.

California: No. Prior to 1987, only two California LDCs purchased gas from non-affiliated out-of-state suppliers. They are the two largest gas LDCs in the country. There would be little reason to encourage them to purchase collectively. There is no explicit policy opposed to such activity, but it does not occur. Currently, one other LDC purchases spot gas from out-of-state for its affiliated electric generation plants.

Connecticut: No, LDCs have not acted collectively. The Commission neither encourages nor discourages such collective buying.

Delaware: No, LDCs have not acted collectively. The Commission neither encourages nor discourages such collective buying.

District of Columbia: No, LDCs have not acted collectively. The Commission neither encourages, nor discourages such collective buying. There is only one LDC.

Idaho: No, LDCs have not acted collectively. The Commission neither encourages nor discourages such collective buying.

Illinois: No, LDCs have not acted collectively. The Commission neither encourages nor discourages such collective buying. Although Section 8-501 of the Public Utilities Act encourages that interconnections be made to ensure availability of natural gas at just and reasonable rates, it does not speak to collective buying. The Illinois Commerce Commission has not been presented with this issue for decision.

Indiana: No, LDCs have not acted collectively. The Commission neither encourages nor discourages such collective buying.

Iowa: No, the LDCs have not acted collectively to buy gas. The Commission does encourage such collective buying. The Board directed the LDCs to meet, to investigate joint purchasing, and to file a report with the Board. The report basically concluded that joint purchasing is not feasible.

Kansas: No, LDCs have not acted collectively.

Kentucky: No, LDCs have not acted collectively. The Commission neither encourages nor discourages such collective buying.

Louisiana: No. This Commission has not addressed this issue.

Maine: No, LDCs have not acted collectively to buy gas. (There is only one LDC.) The Commission neither encourages nor discourages such collective buying.

Maryland: No, LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying. To date, the Commission has not considered the issue of collective purchasing by the state's LDCs.

Massachusetts: Yes, LDCs have acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

Michigan: No, LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

Minnesota: I am not aware of this kind of activity. We do not regulate municipal gas utilities, presumably likely candidates for cooperative purchases.

Mississippi: Not applicable.

Missouri: No, LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying. The concept was never formally discussed by the Commission, staff, or the regulated LDCs.

Montana: No, LDCs have not acted collectively to buy gas, at least not to our knowledge. However, GFG is seeking its own sources of gas, which would require MPC to transport it.

Nevada: No, LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

New Jersey: No collective action yet.

New Mexico: No, LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying. No policy has been established and none is expected.

New York: No, LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

North Carolina: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

North Dakota: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

Ohio: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying. The issue has not been raised to my knowledge.

Oregon: No, groups of LDCs have not acted collectively to buy gas. We encourage each LDC to buy gas separately, but not collectively.

Pennsylvania: No, groups of LDCs have not acted collectively to buy gas. The Commission has not fostered collective buying.

Rhode Island: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

South Carolina: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

South Dakota: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying. There simply has been no deliberation on the issue.

Texas: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

Utah: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying. We have one large and one very small LDC purchasing under different situations.

Virginia: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

Washington: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying.

Wisconsin: No, groups of LDCs have not acted collectively to buy gas. The Commission neither encourages nor discourages such collective buying. This has not been addressed.

Wyoming: No, but a group of affiliated (LDCs and wholesale supply) companies have acted collectively to buy gas--Northern/K N Energy Companies. The Commission encourages any method of obtaining energy that lowers utility costs while maintaining continuity of service.

16. Has the Commission monitored the effects, if any, of collective buying? Yes____ No____. If so, has it resulted in lower gas costs? Yes____ No____.

Alabama: No, the Commission has not monitored.

Alaska: No, the Commission has not monitored.

Arizona: No, the Commission has not monitored.

Arkansas: No, the Commission has not monitored.

California: No.

Connecticut: No, the Commission has not monitored.

Delaware: No, the Commission has not monitored.

District of Columbia: No answer.

Idaho: Not applicable.

Illinois: No, the Commission has not monitored.

Indiana: No, the Commission has not monitored.

Iowa: No, the Commission has not monitored.

Kansas: No, the Commission has not monitored.

Kentucky: No, the Commission has not monitored.

Louisiana: Not applicable.

Maine: No, the Commission has not monitored.

Maryland: No, the Commission has not monitored.

Massachusetts: No, the Commission has not monitored.

Michigan: Not applicable.

Minnesota: Not applicable.

Mississippi: Not applicable.

Missouri: No, the Commission has not monitored.

Montana: No, the Commission has not monitored.

Nevada: No, the Commission has not monitored.

New Jersey: Not applicable.

New Mexico: No, the Commission has not monitored.

New York: Not applicable.

North Carolina: No, the Commission has not monitored the effects.

North Dakota: No, the Commission has not monitored the effects.

Ohio: Not applicable.

Oregon: No, the Commission has not monitored the effects.

Pennsylvania: See the response to question 15.

Rhode Island: Not applicable.

South Carolina: No, the Commission has not monitored the effects.

South Dakota: No, the Commission has not monitored the effects.

Texas: Not applicable..

Utah: No, the Commission has not monitored.

Virginia: No, the Commission has not monitored the effects.

Washington: No, the Commission has not monitored the effects.

Wisconsin: No, the Commission has not monitored the effects.

Wyoming: No.

17. Have any groups of customers acted collectively to buy gas? Yes____ No____. If so, have the antitrust implications of such collective buying been reviewed? Yes____ No____. Please explain.

Alabama: No, antitrust implications have not been reviewed. One LDC bought gas for transportation to a group of customers, acting as agent for the group to keep them on line.

Alaska: No, customers have not acted collectively.

Arizona: Yes, groups of customers acted collectively to buy gas. No, the antitrust implications have not been reviewed. But it was part of an unsuccessful bypass effort.

Arkansas: No, customers have not acted collectively.

California: No. However, gas marketers and brokers are allowed to aggregate supplies.

Connecticut: No, customers have not acted collectively.

Delaware: No, customers have not acted collectively. To date, no gas has actually been transported by LDCs in Delaware.

District of Columbia: Yes, the D.C. Hospital Energy Cooperative, a group of seven hospitals, has acted collectively to buy gas. No, the antitrust implications of such collective buying have not been reviewed. There has been an expressed interest in consumer co-ops.

Idaho: No, customers have not acted collectively.

Illinois: The only collective buying this Commission is aware of is purchases made by the same end-users for different locations. The number of locations range from 2 to 534. No, the antitrust implications of such collective buying have not been reviewed.

Indiana: No, not to our knowledge.

Iowa: Yes. Groups such as colleges, hospitals, and affiliated entities have acted collectively to buy gas. We have no knowledge of the antitrust implications of end-users collectively buying gas. However, some LDCs have investigated the antitrust implications of their joint purchasing.

Kansas: Yes, groups of customers have acted collectively to buy gas. No, the antitrust implications of such collective buying have not been reviewed.

Kentucky: No, customers have not acted collectively.

Louisiana: Not applicable.

Maine: No, groups of customers have not acted collectively to buy gas.

Maryland: No, groups of customers have not acted collectively to buy gas.

Massachusetts: We do not know.

Michigan: Yes, groups of customers have acted collectively to buy gas. No, the antitrust implications of such collective buying have not been reviewed. Schools in the same district have joined together to jointly buy gas for the whole district.

Minnesota: Not to my knowledge.

Mississippi: Not applicable.

Missouri: No, groups of customers have not acted collectively.

Montana: Don't know.

Nevada: No, not that we know of.

New Jersey: Yes, groups of customers have acted collectively to buy gas. No, the antitrust implications of such collective buying have not been reviewed.

New Mexico: No such information is available and no attempt to acquire such information is expected.

New York: Yes, groups of customers have acted collectively to buy gas. No, the antitrust implication of such collective buying have not been reviewed. Customer agreements with producers are not subject to Commission review and, therefore, the Commission has limited official knowledge of collective purchasing.

North Carolina: No, groups of customers have not acted collectively to buy gas.

North Dakota: No, groups of customers have not acted collectively to buy gas.

Ohio: Yes, groups of customers have acted collectively to buy gas. No, the antitrust implications of such collective buying have not been reviewed. Some end-users with multiple delivery points pool their volumes. Also, there are some school consortiums pooling gas. Entries approving transportation arrangements state the Commission approval does not constitute state action for the purpose of antitrust and the party is not insulated from the provisions of any state or federal law.

Oregon: No, groups of customers have not acted collectively to buy gas.

Pennsylvania: No, groups of customers have not acted collectively to buy gas.

Rhode Island: No, groups of customers have not acted collectively to buy gas.

South Carolina: No, groups of customers have not acted collectively to buy gas.

South Dakota: No, groups of customers have not acted collectively to buy gas.

Texas: No, groups of customers have not acted collectively.

Utah: Yes, groups of customers have acted collectively to buy gas. No, the antitrust implications of such collective buying have not been reviewed. We are aware of a group of state-owned universities that are attempting to buy collectively.

Virginia: No, groups of customers have not acted collectively.

Washington: There has been no review of the antitrust implications of collective buying.

Wisconsin: No, groups of customers have not acted collectively that commission staff is aware of.

Wyoming: No, groups of customers have not acted collectively to buy gas. (Two cities, Casper and Laramie, attempted to do so but did not follow through.)

18. Have any of the LDCs in your state established marketing affiliates? Yes____ No____. If so, please list the LDCs and their marketing affiliates.

Alabama: No.

Alaska: No.

Arizona: Yes, Southwest Gas--Santa Fe Gas Marketing.

Arkansas: Yes, ALG--ALG Gas Supply.

California: No.

Connecticut: No.

Delaware: No.

District of Columbia: No.

Idaho: Yes. Intermountain Gas Industries, Inc., the holding company for Intermountain Gas Company (an LDC), has set up IGI Resources, Inc. and Intermountain Transportation Services, Inc. as marketing affiliates. Washington Water Power has set up Development Associates as a marketing affiliate.

Illinois: No.

Indiana: Yes. NIPSCO - NESI
Kokomo Gas & Fuel - KOGAF Enterprises, Inc.
Indiana Energy - Entrade (part owner)

Iowa: Yes.

Holding Company	LDC	Marketing Affiliate(s)
UtiliCorp United, Inc.	Peoples Natural Gas Co.	People Service, Inc. Energroup, Inc.
Midwest Energy	Iowa Public Service Co.	Energy Reserves, Inc.

Kansas: Yes.
Arkla - Arkla Energy Marketing
KPL - Rangeline
Peoples - Peoples Service, Inc.
Williams - Scissortail

Kentucky: Yes.
Delta Resources, a subsidiary of Delta Natural Gas, Inc.

Louisiana: Not applicable.

Maine: No.

Maryland: No.

Massachusetts: Not for the marketing of pipeline gas; three companies have affiliates for the marketing of propane (Berkshire Gas Company owns BerkGas; Colonial Gas Company owns TransGas; and Bay State Gas Company owns Bay State Propane).

Michigan: Yes.
Michigan Consolidated Gas Co. - MichCon Trading
Southeastern Michigan Gas Co. - SEMCO
Consumers Power Company - CMS Brokering

Minnesota: No.

Mississippi: Not applicable.

Missouri: Yes.

LDC	Marketing Subsidiary
The Kansas Power and Light Co. David S. Black Chairman of the Board and CEO 818 South Kansas Ave. Topeka, KS 66612	Rangeline Corporation Ned A. Vahldieck President and CEO Topeka, KS 66612 (913) 296-6300

Montana: Don't know.

Nevada: Yes.
Southwest Gas owns Carson Water which owns Santa Fe Gas Marketing; and Southwest Gas owns Natural Gas Clearinghouse.

New Jersey: Yes.

Elizabethtown Gas Company - EMC
South Jersey Gas Company - South Jersey Marketing

New Mexico: Yes.

Gas Co. of New Mexico (LDC) - Chaparral Gas Marketing (Affiliate)

New York: No.

North Carolina: Yes.

Piedmont Natural Gas Company - Piedmont Natural Energy Company
Public Service Co. of North Carolina - Tar Heel Energy Company
North Carolina Natural Gas Corp. - Cape Fear Energy Company

North Dakota: No.

Ohio: Yes.

Dayton Power & Light Company - Miami Valley Resources
East Ohio Gas & River Gas Companies - CNG Development (formed by parent company)

Oregon: Yes.

Northwest Natural Gas Company - Westar, which is a joint venture with another out-of-state utility affiliate

Pennsylvania: No.

Rhode Island: Yes.

South Carolina: Yes.

Piedmont Natural Gas Company - Piedmont Energy Corporation
United Cities Gas Company - United Cities Energy Corporation

South Dakota: Yes.

Minnegasco - Dyco Petroleum Corporation - "Interlink," a service offered through Minnegasco which provides some market-type functions

Texas: Yes.

Southern Union Gas Company--Mercado
Lone Star Gas Company--Enserch Gas Company
Energas--Enermart

Utah: Yes.

Mountain Fuel Supply Company - Questar Energy Company

Virginia: No.

Washington: Yes. Washington Water Power--Development Associates.

Wisconsin: No.

Wyoming: Yes. (1) No Wyoming utility has established a marketing affiliate to handle transportation of a customer's gas over that utility's system. One utility (Cheyenne Light, Fuel & Power Co.) has worked with its largest industrial customer so that the customer's purchased gas is transported by Colorado Interstate Gas Co. and Cheyenne Light (Cheyenne Light's transportation contract for transportation over its pipeline provides for a rate equal to the former margins from the direct sale that has been displaced). (2) Two utilities have obtained FERC authority to transfer utility gas production and transportation properties to FERC regulated affiliates:

Mountain Fuel Supply Company - Questar Pipeline
Montana-Dakota Utilities Co. - Williston Basin Interstate Pipeline Co.

(The Commission's evidence before the FERC in those cases resulted in substantial rate benefits being granted the affected utility customers over the conditions sought by the applicants.)

19. Are the LDCs or their marketing affiliates helping customers to purchase gas on the spot market? Yes____ No____. Have the LDCs or marketing affiliates that have done so attempted to discriminate against third party brokers or large customers who have bought their own gas, when allocating pipeline capacity? Yes____ No____.
Have any brokers or large customers charged discrimination? Yes____ No____. If they have, what did the Commission do in response.

Alabama: Yes, LDCs are helping customers purchase gas on spot markets. No, LDCs have not attempted to discriminate. No one has charged discrimination. See 17 above.

Alaska: No, LDCs are not helping customers buy spot gas.

Arizona: Yes, LDCs are helping customers purchase gas on the spot market. No, LDCs have not attempted to discriminate. No one has charged discrimination.

Arkansas: Yes, LDCs are helping customers purchase gas on the spot market. No, LDCs have not attempted to discriminate. No one has charged discrimination.

California: No, LDCs are not helping customers purchase gas on the spot market. No, LDCs have not attempted to discriminate. Yes, there have been charges of discrimination. The Commission staff investigated the allegations. The result has been workshops and utility filings concerning the rules of transportation. The discrimination allegations couldn't be documented.

Connecticut: No, LDCs are not helping customers purchase gas on the spot market. No, LDCs have not attempted to discriminate. No one has charged discrimination.

Delaware: No, LDCs are not helping customers purchase gas on the spot market.

District of Columbia: No, LDCs are not helping customers purchase gas on the spot market. No one has charged discrimination.

Idaho: Yes, LDCs are helping customers purchase gas on the spot market. No, the LDCs have not attempted to discriminate. No one has charged discrimination.

Illinois: No, the LDCs are not helping customers purchase gas on the spot market. There have been no charges of discrimination.

Indiana: Yes, LDCs are helping customers purchase gas on the spot market. No, the LDCs have not attempted to discriminate. No one has charged discrimination.

Iowa: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. We have no knowledge of discrimination. The subject has not been investigated.

Kansas: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. Yes, the LDCs or marketing affiliates doing so have discriminated against third party brokers or large customers who have bought their own gas when allocating pipeline capacity. Yes, brokers or large customers have charged discrimination. These cases have not yet been heard.

Kentucky: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs have not attempted to discriminate. No one has charged discrimination.

Louisiana: Not applicable.

Maine: No, the LDC is not helping customers purchase gas on the spot market.

Maryland: No, the LDCs are not helping customers purchase gas on the spot market. No, the LDCs have not attempted to discriminate. No one has charged discrimination.

Massachusetts: No, the LDCs are not helping customers purchase gas on the spot market.

Michigan: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, they have not attempted to discriminate against their-party brokers or large customers. No brokers or large customer have charged discrimination.

Minnesota: Yes, the LDCs are helping customers purchase gas on the spot market. No, they have not attempted to discriminate against third-party brokers or large customers. No brokers or large customers have charged discrimination.

Mississippi: Not applicable.

Missouri: Yes, the LDCs are helping customers purchase gas on the spot market. No, they have not attempted to discriminate against third-party brokers or large customers. No brokers or large customers have charged discrimination.

Montana: Don't know.

Nevada: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. We don't know whether the LDCs or their marketing affiliates have attempted to discriminate against third-party brokers or large customers who have bought their own gas, when allocating pipeline capacity. No brokers or large customers have charged discrimination.

New Jersey: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. There have been some allegations that the LDCs or marketing affiliates discriminate against third-party brokers or large customers who have bought their own gas, when allocating pipeline capacity. Brokers or large customers have charged discrimination. But these have been informal allegations. No complaints have been filed.

New Mexico: No, the LDCs or their affiliates are not helping their customers purchase gas on the spot market. Nor have any brokers or large customers charged discrimination.

New York: No, the LDCs or their marketing affiliates are not helping customers buy gas on the spot market. LDCs are helping to the extent of providing information on pipelines and/or pipeline sources of gas. No, the LDCs have not attempted to discriminate. No, brokers or large customers have not charged discrimination.

North Carolina: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs or their marketing affiliates have not attempted to discriminate. No, brokers and large customers have not charged discrimination.

North Dakota: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs or their marketing affiliates have not attempted to discriminate. No, brokers and large customers have not charged discrimination.

Ohio: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs or their marketing affiliates have not attempted to discriminate. Yes, brokers and large customers have charged discrimination. Columbia Gas of Ohio buys some gas on behalf of some transportation customers as does East Ohio, River Gas and National Gas & Oil, primarily. Allegations against East Ohio Gas are that it provides volumes it serves to customers rather than gas available independently from producers or brokers. The Commission has, so far, permitted this. The customer is generally unharmed but the producer/broker believes it is unfair competition against them.

Oregon: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs or their marketing affiliates have not attempted to discriminate. No, brokers or large customers have not charged discrimination.

Pennsylvania: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs or their marketing affiliates have not attempted to discriminate. No, brokers or large customers have not charged discrimination. Several Pennsylvania LDCs provide agency agreements on an optional basis to their customers.

Rhode Island: No, the LDCs and their marketing are not helping customers purchase gas on the spot market.

South Carolina: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs or their marketing affiliates have not attempted to discriminate. No, brokers or large customers have not charged discrimination.

South Dakota: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs or their marketing affiliates have not attempted to discriminate. No, brokers or large customers have not charged discrimination.

Texas: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. There have been allegations that the LDCs and marketing affiliates are discriminating against third party brokers or large customers, who have bought their own gas, when allocating pipeline capacity. Brokers or large customers have charged such discrimination. The charges of discrimination are currently being investigated. There are five pending dockets.

Utah: Yes, the LDCs or their marketing affiliates are helping customers purchase gas on the spot market. No, the LDCs or their marketing affiliates have not attempted to discriminate. No, brokers or large customers have not charged discrimination.

Virginia: Yes, the LDCs are helping customers purchase gas on the spot market. No they have not attempted to discriminate. No, brokers or large customers have not charged discrimination.

Washington: No, the LDCs or their marketing affiliates are not helping customers purchase gas on the spot market. No, they have not attempted to discriminate. No, brokers or large customers have not charged discrimination. They are not helping all customers or market segments. Excess capacity exists on our transmission system.

Wisconsin: Yes, the LDCs are helping customers purchase gas on the spot market. No they have not attempted to discriminate. Yes, discrimination has been charged; in the generic docket 05-GI-102, brokers were among the intervenors. This raised the possibility of the use of excess market power by the LDCs. However, the Wisconsin PSC has not received any complaints regarding specific instances of discrimination by the LDCs.

Wyoming: No, the LDCs or their marketing affiliates are not helping customers purchase gas on the spot market. No, they have not attempted to discriminate. No, brokers or large customers have not charged discrimination.

IV. A potential side effect of the provision of transportation service by LDCs is the shift of revenue requirements among customer classes.

20. Has your Commission issued a policy statement or order about the possibility of an LDC's transportation rates resulting in a shift of revenue requirements from one class of customers (mainly noncaptive customers) to another class (mainly captive customers)? Yes____ No____.

Alabama: No.

Alaska: Yes, the order only discussed the issue.

Arizona: No.

Arkansas: No.

California: Yes. There will be annual proceedings to allocate costs based on actual usage. This will insulate all classes from cross-subsidy. The basis of the cost allocation is equal cents per therm on cold-year throughput.

Connecticut: No. No dramatic impact as yet.

Delaware: No.

District of Columbia: Yes.

Idaho: No.

Illinois: Yes, See CISCO Docket No. 85-0310, issued July 23, 1986, and NI-Gas Docket No. 85-0053, issued December 11, 1985.

Indiana: No.

Iowa: Yes. In its May 30, 1986 Order Commencing Rulemaking, the Board stated that LDCs may not transfer any costs of released service to any other customers.

Kansas: No.

Kentucky: Yes. In orders concerning flexing of transportation rates, the Commission has set the issue for future rate cases. There have not been any presumptions as to where the difference should be recovered.

Louisiana: No.

Maine: Not applicable.

Maryland: Yes.

Massachusetts: Yes, in the August 7, 1987 order in DPU 85-178.

Michigan: No.

Minnesota: No. See the response to question 3.

Mississippi: Not applicable.

Missouri: Yes.

Montana: No. But the issue will be addressed in at least one ongoing gas transportation docket.

Nevada: No. But the Commission is watching this very closely.

New Jersey: No.

New Mexico: No.

New York: No.

North Carolina: No.

North Dakota: No.

Ohio: Yes. See the response to questions 2c, 3, and 4.

Oregon: No.

Pennsylvania: Yes. The PUC transportation regulations address the issue of revenue shifting.

Rhode Island: No.

South Carolina: The same margin for transportation as regular sale.

South Dakota: No.

Texas: No.

Utah: No. Nor addressing a shift in non-gas cost revenue requirement.

Virginia: Yes.

Washington: Yes. See Cascade Natural Gas, Cause No. U-86-100. Further legislation is pending.

Wisconsin: Yes.

Wyoming: No. Case-by-case orders. The Commission requires any transportation and rate that displaces distribution service to benefit all classes if possible, and strives to make the transportation rate cover the new revenues of the lost distribution service.

21. If your Commission has issued such a policy statement or order about this problem, how did it incorporate the possibility into its transportation policies?

Alabama: Not applicable.

Alaska: Not applicable.

Arizona: Not applicable.

Arkansas: Not applicable.

California: The risk of throughput after the cost allocation is upon the utility. The utility has the authority to discount rates to increase throughput.

Connecticut: Not applicable.

Delaware: Not applicable.

District of Columbia: Set a value-of-service transportation rate with volumetric limitations.

Idaho: Not applicable.

Illinois: Most transportation rates incorporate a lost and unaccounted-for gas factor to prevent the shifting of revenues when a customer transports rather than buys system supply (since this factor was applied via the PGA clause). This was explained in Docket No. 85-0310.

Indiana: Not applicable.

Iowa: By stating in its rules that transportation charges and rates shall be based on the cost of providing the service. The Board may also disallow any costs which the LDC attempts to shift.

Kansas: Not applicable.

Kentucky: Some provisions were incorporated in the transportation policy.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: See pages 17 and 18 of Commission Order No. 67583 for a statement of the interim principle articulated by the Commission with regard to reallocation of revenue requirements between sales and transportation customers.

Massachusetts: The order solicited comments on the proper method of reallocating costs following customer migration. The Department has not taken a final position on this question.

Michigan: Not applicable.

Minnesota: Not applicable.

Mississippi: Not applicable.

Missouri: The Commission's Report and Order in GO-85-264 dated September 18, 1986 contemplates: (1) the existing cost recovery responsibilities among LDC customer classes will be maintained, (2) the LDC is financially indifferent about whether it provides sales or transportation service, and (3) transportation customers are responsible for transportation-related costs.

Montana: Not applicable.

Nevada: Not applicable.

New Jersey: Not applicable.

New Mexico: Not applicable.

New York: Not applicable.

North Carolina: Not applicable.

North Dakota: Not applicable.

Ohio: See the responses to questions 2c, 3, and 4.

Oregon: Not applicable.

Pennsylvania: It is the PUC's opinion to keep non-captive customers on the gas system, albeit at a lower rate, than to lose all contribution to the company's fixed costs. The LDC has the burden of proving costs must be shifted to captive customers.

Rhode Island: Not applicable.

South Carolina: Not applicable.

South Dakota: Not applicable.

Texas: Not applicable..

Utah: Not applicable.

Washington: Not applicable.

Virginia: The Commission's initial policy required that transportation rates be cost-based and that the sales rates be moved, over time, toward equalized returns for each class. This initial policy resulted in a migration of interruptible sales to interruptible transportation. Consequently, the policy resulted in a loss of revenue, which was eventually reallocated to the remaining customer classes. Currently, interruptible sales and transportation move toward parity at the same pace.

Wisconsin: Use of a simple margin approach addresses this problem. There is a presumption that the simple margin approach is cost-based and the parties have the burden in a rate case of showing otherwise. Thus far, no LDCs have attempted to move away from the simple margin approach.

Wyoming: See the response to question 20.

22. Has any shift of revenue requirements among classes occurred as a result of the implementation of gas transportation policies by LDCs? Yes____ No____. If so, how did the Commission respond in the event of such a shift?

Alabama: No study has been made, but such a shift seems likely.

Alaska: No.

Arizona: Commission included transportation service in the last Southwest Gas rate case (September 1987). Difficult to determine impact so far.

Arkansas: No.

California: Not yet known because the implementation date of the policy is May 1, 1988.

Connecticut: No.

Delaware: No. To date, no gas has actually been transported by LDCs in Delaware.

District of Columbia: No.

Idaho: No.

Illinois: No. There has, however, been some shift of demand charges among classes through the PGA mechanism. This depends on the portion of the PGA that is credited to transportation customers.

Indiana: Yes. One utility has a below-cost transportation rate which shifts part of the revenue requirement to the other customers through the gas cost adjustment filing. Otherwise, any shift in revenue requirements has been seen in the cost-of-service studies done in rate cases. Several other LDCs have rates at less than full cost.

Iowa: No.

Kansas: No. Revenue shifts have not occurred because of transportation. Revenue shifts and transportation are both effects of changing market conditions.

Kentucky: Yes. Based on experience in one case, the Commission permitted a small amount of revenue requirements to be shifted from the industrial class to the residential class, although the shift was not as great as proposed by the company.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No.

Massachusetts: Not yet, although this is anticipated. The Department ordered that companies unbundle their service obligations as well as their costs so they will, in effect, shed their obligation to provide to transportation customers such services as backup (replacement of gas) and standby (right to return to the system on a full sales service basis). The costs of providing for reliability of supply and long-run expansion of system capacity under this framework should be allocated only among sales and transportation customers who choose the optional services that impose these costs on the company.

Michigan: No.

Minnesota: No.

Mississippi: Not applicable.

Missouri: No.

Montana: Not applicable.

Nevada: Don't know. The relevant rate case was settled by stipulation.

New Jersey: Yes. Try to minimize the revenue requirements shift.

New Mexico: No.

New York: Yes. In a specific rate case, the Commission reduced firm transportation rates to reflect lower costs related to that service. Revenue impact was imputed to firm sales customer.

North Carolina: No.

North Dakota: No.

Ohio: No, no rate cases have been filed where this has been an issue.

Oregon: No.

Pennsylvania: No.

Rhode Island: No.

South Carolina: A shift of revenue requirements has occurred because of the pressures of alternate fuel prices.

South Dakota: No.

Texas: Yes. The effect of shifts of revenue requirements on rates are addressed in rate hearings.

Utah: No.

Washington: Yes. See the response to question 2.

Virginia: Yes.

Wisconsin: Yes. The only shift in revenues has been between the established system large commercial/industrial/interruptible classes. Use of gross margins (netting out the cost of gas) should result in the same distribution margin going to the LDC whether the therm is system gas or transportation gas. (If the LDC flexes transportation, then the shareholders make up the unrecovered costs.)

Wyoming: No. The Commission has not had to address, in a rate case, transportation rates that would cause shift of revenue requirements. However, cost shifts have occurred when a large industrial customer was lost by an LDC. The Commission has been advised that filings for increased rates based on lost industrial customers will be forthcoming Commission policies. We have required companies to absorb the lost revenue when serving below cost to retain a customer.

V. Increased administrative costs constitute another possible side effect of LDC provision of transportation service.

23. Has the provision of transportation service resulted in any increased administrative costs for the LDCs? Yes____ No____.

Alabama: Probably, but no study made.

Alaska: No.

Arizona: Don't know.

Arkansas: Yes.

California: Not applicable, see the answer to question 22. However, increased costs would be allocated to non-core class, since it alone must transport.

Connecticut: Yes.

Delaware: It is expected that there will be some increase when gas is actually transported.

District of Columbia: No.

Idaho: No.

Illinois: Yes. The Commission stated in its Order in Docket No. 85-0310, "...to the extent costs can be identified and justified, CILCO should do so and recover them in an appropriate customer charge...."

Indiana: Yes.

Iowa: Yes.

Kansas: No, at least nothing significant.

Kentucky: Unknown.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No. No increase in administrative costs has been identified to date.

Massachusetts: Yes.

Michigan: Unknown.

Minnesota: Haven't seen any data.

Mississippi: Not applicable.

Missouri: Yes. These costs have been minor to date.

Montana: An outstanding issue in open dockets.

Nevada: Do not know.

New Jersey: Yes.

New Mexico: Yes.

New York: Yes. Claimed informally--no formal claims, request, or petitions.

North Carolina: Yes.

South Dakota: Yes.

Ohio: Yes. Some utilities have claimed increased administrative costs. An informal study was conducted.

Oregon: Yes.

Pennsylvania: Yes.

Rhode Island: No.

South Carolina: Yes.

South Dakota: Yes.

Texas: No, except one company added one employee.

Utah: Yes.

Virginia: Perhaps. Although general statements have been made to indicate increased administrative costs, these statements have not been supported or quantified.

Washington: I don't know.

Wisconsin: Yes.

Wyoming: No answer.

24. If increased administrative costs have resulted, are they collected? Yes____ No____. If so, how?

Alabama: If so, they are included in cost of service rates.

Alaska: Not applicable.

Arizona: Not applicable.

Arkansas: Yes, through base rates.

California: Not applicable, see question 22.

Connecticut: Yes, through the tariff's "customer charge."

Delaware: No. Possibly they will be included in the next base rate proceeding.

District of Columbia: Not applicable.

Idaho: No.

Illinois: No. Although some utilities have tried to implement a higher customer charge, none has provided the required justification for such an increase to date.

Indiana: Yes. Usually the costs are recovered through special service charges to transporters.

Iowa: Yes, through higher fixed monthly charges.

Kansas: Not applicable.

Kentucky: Not applicable.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: Not applicable.

Massachusetts: Yes, from the customer, through higher customer charges based on cost studies.

Michigan: Not applicable.

Minnesota: Not applicable.

Mississippi: Not applicable.

Missouri: Yes. To the extent that basic transportation service rates reflect certain administrative costs, they are collected. If a customer elects that optional transportation services be performed, the LDC may include cost recovery elements to assess that customer for those services.

Montana: An outstanding issue in open dockets.

Nevada: Not applicable.

New Jersey: Yes, through collection from transportation customers.

New Mexico: Yes. Application fees and other miscellaneous administrative fees.

New York: Not applicable.

North Carolina: No.

North Dakota: No.

Ohio: Yes. Some utilities have included administration fees in their transportation contracts or tariffs.

Oregon: Yes, by a monthly customer charge for transportation.

Pennsylvania: Yes, as part of a base rate proceeding.

Rhode Island: Not applicable.

South Carolina: Yes, in a rate case.

South Dakota: No.

Texas: No. The company will include the salary in its rates.

Utah: Yes, through an $8,000 annual administrative charge for small transporters. For large transportation customers, the cost per unit of sales was considered insignificant.

Virginia: No.

Washington: I don't know.

Wisconsin: Yes. These are established in individual rate cases and range from $75-$150 per month (depending upon which LDC it is). The charge is only assessed during those months when a customer has a contract for supply of spot gas.

Wyoming: No answer.

VI. The potential effects of transportation service on LDC procurement and operations, both generally and with respect to captive customers, and the extent of direct gas purchasing are covered in the next set of questions.

25. How much gas has been bought by customers directly from producers? What are the volumes of gas involved? ______. What percentage of the total market is served by transportation to end users? ______. How much of customers' contracted demand has been converted to transportation service? ______. Please explain.

Alabama: Gas bought by customers from producers:
FY 1985-3.9 Bcf
FY 1986-6.6 Bcf
FY 1987-26.6 Bcf
FY 1988-22.0 Bcf
(FY 1988 estimated through 3/88)

33.6 percent of total market is served by transportation to end-users, as of 2/88.

Alaska: No answer.

Arizona: About 60 million therms of transportation service in 1986 equal to about 10 percent of the 1986 market.

Arkansas: No answer.

California: For the following responses, SoCal refers to Southern California Gas Company, PG&E to Pacific Gas and Electric Company, and SDG&E to San Diego Gas and Electric Company.

(a) SoCal 243.885 MDths
PG&E Not Available
SDG&E 161

(b) SoCal 24%
PG&E Not applicable.
SDG&E 0.1%

(c) Not available until after May 1, 1988.

Connecticut: (a) 5,000 MMcf
(b) less than 5%
(c) 0

Delaware: To date, no gas has been transported by an LDC in Delaware.

District of Columbia: (a) 1.8 Dth
(b) Current 0%
(c) None

Idaho: (a) None
(b) 99%
(c) None. The LDC is not allowed to convert contracted demand to transportation service because of the contract with the pipeline company.

Illinois: 1987 data:
(a) 194 Bcf
(b) 22%
(c) Iowa-Illinois converted 15% of its contract demand to transportation. See the response to question 26 for more information.

Indiana: JANUARY - DECEMBER 1987

Company	Purchased Volume	Purchased Cost	Transported Volume	% Total Vol for End-Use
Citizens Gas & Coke Utility (Dkth)	16,503,152	$32,185,268	8,917,767	35.08%
Fountaintown Gas (MCF)	494,920	1,518,410	452,878	47.78
Hoosier Gas Corp (MCF)	3,659,760	7,187,714	351,903	8.77
Indiana Gas Co. (MCF)	14,860,219	28,552,002	23,614,724	61.38
Kokomo Gas & Fuel (Dkth)	3,499,938	10,131,693	2,192,517	38.52
Lawrenceburg Gas (MCF)	1,518,502	4,740,924	509,836	25.14
Lincoln Natural Gas (Dkth)	136,789	533,096	516,370	79.06
Midwest Natural Gas (incl. Peoples) (MMbtu)	811,890	1,539,653	13,230	1.60
Northern Indiana Fuel & Light (Dkth)	4,227,857	15,770,181	1,907,125	31.09
Northern Indiana Public Service Co. (Dkth)	133,817,688	292,848,819	92,630,204	40.91
Ohio Valley Gas (Dkth)	1,259,570	2,412,310	1,535,665	54.94
Richmond Gas Corp.(Dkth)	2,476,647	8,986,073	916,939	27.02
Southern Indiana Gas & Electric Co. (MCF)	10,415,354	23,055,692	8,626,587	45.30
Terre Haute Gas Co.(MCF)	6,326,257	11,297,165	4,401,322	41.03

Total Volume Handled (Dkth)	Total Dkth Purchased	Total Cost Purchased	Total Volume Transported	% Total for End-User
346,595,610	200,008,543	$440,759,000	146,587,067	41.03%

Iowa: For the eleven months ended July 1987:

(a) 26 Bcf

(b) 13%

(c) Converted contract demand not available in each case

Kansas The information is not available.

Kentucky: Insufficient information on file.

Louisiana: Data not available.

Maine: No Answer.

Maryland: 1987 THROUGHPUT OF MARYLAND LDCS IN MILLIONS OF DEKATHERMS

LDC	Total	LDC Deliveries of Customer-Owned Gas
Maryland Natural Gas/ Frederick Natural Gas[1]	55.6	0
Baltimore Gas and Electric Company	103.0	40.2
Columbia Gas of Maryland	5.6	1.1
Cambridge Gas Company	0.2	0
Citizens Gas Company	0.1	0
Elkton Gas Company	0.3	0
South Penn Gas	NA	0
Chesapeake Utilities	NA	0

[1]Maryland Natural Gas and Frederick Natural Gas are affiliates of Washington Gas Light Company which provide natural gas service in Maryland. Throughput figures are for Maryland only.

Massachusetts: We do not know or monitor these levels. Because of acute regional capacity shortages, companies have not converted any of their sales entitlements to transportation.

Michigan: Approximately 150 Bcf annually, which is about 25 percent of the total utility throughput.

Minnesota: Don't have information on this.

Mississippi: No answer.

Missouri: Based on 1987 data:
(a) 12.9 Bcf
(b) 6.2%
(c) 0

Montana: Data responses pending in outstanding MDU Docket 87.1.8 and 87.12.77.

Nevada:
(a) 164,011,040 therms
(b) approximately 40 percent of throughput
(c) no contract demand on the Southwest Gas System.

New Jersey: Data from all LDCs have not been received.

New Mexico: Such information has not been collected. It probably will be collected in the near future.

New York: (a) 62,000,000 Dth
(b) 10%
(c) End-users do not contract for demand.

North Carolina: (a) 2 MMcf(?)
(b) .557%
(c) 0

South Dakota: We have no records of this. However, to date, these volumes have been small.

Ohio: The table below identifies these data for our eight major gas companies. This information is annual data based on the 12-month period ending mid-1987.

Oregon: (a) 10 Bcf
(b) 20%
(c) 0
Only interim transportation is currently available to Oregon under NGPA section 311.

Pennsylvania: This information is currently not available in this form.

Rhode Island: No answer.

South Carolina: (a) -
(b) 10% or less
(c) -

South Dakota: (a) varies
(b) less than 1%
(c) usually involves picking up a new customer--one that has not recently been consuming gas

Texas: We do not collect this information.

Utah: (a) No history because it is just beginning. Estimated volumes of 19 million Dth/year
(b) 19 MDth will be about 16% of the total market
(c) No contract demand has been converted. The only transportation is for interruptible service.

Virginia: (a) -
(b) approximately 30%
(c) approximately 5%
We have not quantified these numbers on a statewide basis.

Washington: We do not have an open interstate pipeline. It has been open only on an interim basis.

Wisconsin: The Wisconsin PSC does not currently have this information available. We have initiated data requests in upcoming rate cases that should provide this information.

Wyoming: Data is not readily available from Commission reports since direct purchases by industries from natural gas producers is not regulated.

26. How much gas have jurisdictional LDCs bought directly from the producers? ______. What percentage of the LDCs' total markets is so served? ______. How much transportation gas have jurisdictional LDCs bought from pipelines? ______. What percentage of the LDCs' total market is served? ______.

Alabama: Not available.

Alaska: LDCs have bought all their gas directly from producers. One-hundred percent of the LDCs' total markets is so served. LDCs have bought no transportation gas from pipelines.

Arizona: Forty to fifty percent of jurisdictional LDCs' requirements were bought directly from producers.

Arkansas: No answer.

California:

(a)	SoCal	322,325 MDth
	PG&E	124,640 MDth
	SDG&E	49,594 MDth
(b)	SoCal	30%
	PG&E	18%
	SDG&E	46%

(c) and (d) is not easily available. This would require substantial staff time for a complete analysis of the spot market program.

Connecticut:
(a) 15,000 MMcf from producers
(b) 15% of market
(c) 15,000 MMcf from pipeline
(d) 15% of market

Thus making 30% of the total market.

Delaware: LDC No. 1 purchases approximately 50 percent of its gas directly from producers. LDC No. 2 buys all its gas from a wholly-owned subsidiary. The subsidiary's rates are regulated by FERC.

District of Columbia: In the last 12 months, the local LDC has purchased more than 50 percent of its total requirements from the spot market or directly from producers.

Idaho:
(a) 51%
(b) 51%
(c) 49%
(d) 51%

Illinois: 1987 data:
(a) 404 Bcf
(b) 60%
(c) 272 Bcf
(d) 40%

LOCAL DISTRIBUTION COMPANY GAS PURCHASES
(in thousands of Mcf)

	1986			1987		
	Spot	Total	% Spot to Total	Spot	Total	% Spot to Total
CILCO	0	30,968	0%	0	24.759	0.0
CIPS	1,770	25,940	6.8	6,402	21,488	29.8
Consumers	0	914	0.0	395	869	45.5
IL Gas	167	11,989	1.4	474	1,409	33.6
IL Power	28,449	72,915	39.0	24,068	61,358	39.2
Interstate[1]	143	805	17.8	283	737	38.4
II-GE	2,744	12,932	21.2	1,020	11,777	10.2
Kaskaskia	0	2,067	0.0	0	1,985	0.0
Monarch	0	488	0.0	431	468	92.7
Mt. Carmel	102	470	21.7	273	435	62.8
NI Gas	94,609	398,629	24.3	123,922	320,492	38.7
North Shore	5,476	31,915	17.2	13,953	26,472	52.7
Peoples	82,625	236,020	35.0	101,448	193,199	52.5
South Beloit	0	1,010	0.0	0	7,129	0.0
Union Elec	0	2,445	0.0	0	2,368	0.0
United Cities	0	2,404	0.0	0	2.4-0	0.0
Total	216,085	822,911	26.3	272,669	677,355	40.3

Source: FORM 21 Local Distribution Company Annual Reports to the Illinois Commerce Commission, 1986, 1987.

[1]Interstate's purchase information provided directly from the company. Form 21 data did not break Interstate purchased gas information down by state.

Illinois (continued):

END USER TRANSPORTATION AND LOCAL
DISTRIBUTION COMPANY THROUGHPUT
(in thousands of Mcf)

	1986			1987		
	Transportation	Throughput	% Transportation Throughput	Transportation	Throughput	% Transportation Throughput
CILCO	7,201	38,189	18.9%	11,176	35,935	31.1%
CIPS	4,798	30,738	15.6	10,781	32,269	33.4
Consumers	0	914	0.0	0	869	0.0
IL Gas	209	12,198	1.7	298	1,701	17.5
IL Power	25,329	98,244	25.8	32,680	94,038	34.8
Interstate	0	805	0.0	0	737	0.0
II-GE[1]	45	12,977	0.3	340	12,117	2.8
Kaskaskia	0	2,067	0.0	0	1,985	0.0
Monarch	0	488	0.0	0	468	0.0
Mt. Carmel	0	470	0.0	0	435	0.0
NI-Gas	28,898	418,527	6.9	100,719	421,211	23.9
No. Shore	753	32,668	2.3	5,322	31,794	16.7
Peoples	828	236,848	0.3	31,366	224,545	14.0
So. Beloit	75	1,085	6.9	393	7,522	5.2
Union Elec.	0	2,445	0.0	0	2,368	0.0
United Cities	1,203	3,607	33.4	1,286	3,695	34.8
Total	69,339	892,270	7.8	194,361	871,695	22.3

Source: FORM 21 Local Distribution Annual Reports to Illinois Commerce Commission 1986, 1987.

[1] II-GE transportation data based on information provided directly from the company because FORM 21 data did not break its transportation down by state.

Indiana: JANUARY - DECEMBER 1987

Company	Total Volume	Spot Market Volume	Spot Market as % Total
Citizens Gas & Coke Utility	16,503,152	3,506,034	21.24%
Fountaintown Gas	494,920	0	0.0
Hoosier Gas Corp	3,659,760	2,391,944	65.36
Indiana Gas Co.	14,860,219	3,641,442	24.50
Kokomo Gas & Fuel (est. nov-dec 87)	3,499,938	1,015,553	29.02
Lawrenceburg Gas	1,518,502	770,178	50.72
Lincoln Natural Gas	136,789	0	0.0
Midwest Natural Gas (incl. Peoples)	811,890	0	0.0
Northern Indiana Fuel & Light	4,227,857	0	0.0
Northern Indiana Public Service Co. (est. nov-dec 87)	133,817,688	49,921,368	37.31
Ohio Valley Gas	1,259,570	0	0.0
Richmond Gas Corp	2,476,647	489,380	19.76
Southern Indiana Gas & Electric Co.	10,415,354	4,899,462	47.04
Terre Haute Gas Corp	6,326,257	2,960,097	46.79
Totals	200,008,543	69,595,458	34.80

Iowa: For the eleven months ended July 1987:
- (a) 76 Bcf
- (b) 38%
- (c) 99 Bcf
- (d) 49%

Kansas: The information is not available.

Kentucky: Data is incomplete to make the above determination.

Louisiana: Data not available.

Maine: Not applicable.

Maryland: 1987 THROUGHPUT OF MARYLAND LDCS

LDC Sales
(in millions of dekatherms)

LDC	Total	Pipeline Gas	Producer Purchases
Maryland Natural Gas/ Frederick Natural Gas[1]	55.6	25.0	30.6
Baltimore Gas and Electric Company	103.0	36.8[2]	26.0[2]
			(in mcf)
Columbia Gas of Maryland	5.6	3.0	1.5
Cambridge Gas Company	0.2	0.2	0
Citizens Gas Company	0.1	0.1	0
Elkton Gas Company	0.3	0.3	0
South Penn Gas	NA	NA	NA
Chesapeake Utilities	NA	NA	NA

N/A = Not Available

[1]Maryland Natural Gas and Frederick Natural Gas are affiliates of Washington Gas Light Company which provide natural gas service in Maryland. Throughput figures are for Maryland only.

[2]1987 sales for BG&E were broken down into pipeline purchases and producer purchases based on the pipeline/producer mix of purchases for the 12-month period ending October 31, 1987.

Massachusetts: We do not know or monitor these levels. Annual returns indicate that for some companies spot purchases constitute up to 25 percent of annual pipeline throughput; many companies purchase as much spot gas as possible, consistent with contract constraints such as minimum bill requirements.

Michigan: Approximately 220 Bcf is purchased directly, which is 37 percent of total market. Of this, approximately 97 Bcf is bought via the pipeline.

Minnesota: (a) Not applicable.
(b) Not applicable.
(c) None
(d) None

Some LDCs have bought considerable transportation gas; some smaller ones have bought none. Anywhere from 15 percent to 50 percent of system supply in a given month may be transportation gas for larger utilities.

Mississippi: Not applicable.

Missouri: Based on 1987 data: (a) 11.7 Bcf*
(b) 5.6%*
(c) -*
(d) -*

*The data is not easily split between pipeline and producer.

Montana: Don't know.

Nevada: (a) 45%
(b) 27%
(c) Not applicable.

SOUTHWEST GAS CORPORATION-THUNDERBIRD DIVISION
SALES, PURCHASE AND UNACCOUNTED-FOR GAS
TWELVE MONTHS ENDED JANUARY 31, 1988

Description (a)	Total (Therms) (b)
Gas Receipts	
Supplier Gas (El Paso Schedule No.A-1-X)	84,696,970
Spot Market Gas for System Supply:	
Canadian Gas Purchases	12,146,691
Santa Fe	55,652,873
Perry Pipeline	1,836,041
Wellhead Purchases	1,044,195
Total System Supply Purchases	155,376,770
Customer Secured Gas	104,011,040
Total Receipts	259,387,810
Gas Deliveries	
Southwest Customer Sales	
Balancing Account Customers	145,347,852
Small Industrial	1,188,394
Large Industrial	447,831
Electric Generation	2,155,087
Resale	4,901,147
Total Customer Gas	154,040,311
Transportation Deliveries	103,111,070
Total Sales and Transportation	257,151,381
Company Use Gas - Compressor Stations	62,722
Total Sales and Company Use Gas	257,214,103
Unaccounted for Gas (line 18 minus line 8)	(2,183,707)
Percent Unaccounted for Gas (Gain/Loss)	-0.84%
Energy Conversion Factor (Btu's per cf)	1,044

<u>New Jersey</u>: Awaiting data from LDCs.

<u>New Mexico</u>: Such information has not been collected. It will probably be collected in the near future.

<u>New York</u>: Total transportation gas, from producers and pipeline, is approximately 140,000,000 Dth annually, or about 32 percent purchases. Detail between the two categories is not readily available.

<u>North Carolina</u>: (a) 9.4 MMcf
(b) -
(c) 6.2%

<u>North Dakota</u>: We have no record of the volumes. However, we believe that the percentage of LDCs total market is less than 10 percent.

<u>Ohio</u>: The table below identifies these data for our eight major gas companies. I am interpreting direct purchases from producers as purchases of Ohio produced gas and purchases from pipelines as spot gas transported by an interstate. Most of this last category is direct purchases--very little being from pipeline special sales. This information is annual data based on 12-months ended mid-1987.

<u>Oregon</u>: (a) 5 Bcf
(b) 10%
(c) 5 Bcf
(d) 10%

<u>Pennsylvania</u>: This information is currently not available in this form.

<u>Rhode Island</u>: No answer.

<u>South Carolina</u>: (a) 24,537,906 DTS
(b) 49%
(c) 24,128,247 DTS
(d) 66%

<u>South Dakota</u>: The data is not available. All answers would probably be quite small amounts.

<u>Texas</u>: We do not collect this information.

<u>Utah</u>: (a) 360,000 Dth, all by UGS
(b) 30% of UGS, 0.4% of the total market
(c) 0 (see the response to question 11)
(d) 0

<u>Virginia</u>: (a) approximately 60%
(b) -
(c) approximately 40%
(d) -
The 60% includes purchases from brokers and pipeline marketing affiliates. Virginia has prohibited the dedication of certain purchases to specific markets.

Washington: No answer.

Wisconsin: The Wisconsin PSC does not currently have this information available. We have initiated data request in upcoming rate cases that should provide this information.

Wyoming: Data is not readily available. (Most LDC requirements in Wyoming are met by wholesale pipeline purchases.)

27. Has the ability of any of your jurisdictional LDCs to negotiate for long-term gas supplies been impaired by the conversion of high load-factor customers to transportation service only (and the LDC being left with weather-sensitive customers)? Yes____ No____. If so, how does your transportation policy deal with this?

Alabama: No.

Alaska: No.

Arizona: Unknown.

Arkansas: No answer.

California: California's LDCs have not completed negotiations for new long-term gas supplies from suppliers other than interstate pipelines. Sufficient reserves are already held by the interstate pipelines to deliver to the border to cover core needs for the immediate future. Once the FERC finishes its agenda for gas restructuring, the California LDCs may serve long-term supplies from others. There is no consideration of this in the transportation program, but it is relevant to the procurement proceedings underway.

Connecticut: No.

Delaware: No.

District of Columbia: No.

Idaho: No.

Illinois: No.

Indiana: No.

Iowa: We are not aware of any such difficulties. To our knowledge there is not much experience among our LDCs in negotiating for long-term gas supplies.

Kansas: No.

Kentucky: LDCs are still under long-term contracts and have not made the Commission aware of any difficulties to date.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No.

Massachusetts: No, but only because such conversion has not yet occurred.

Michigan: No.

Minnesota: No. There hasn't been a great deal of negotiation for long-term gas supplies. In general, LDC purchases have been on the spot market with interruptible transportation.

Mississippi: Not applicable.

Missouri: To date, it has neither helped nor hindered.

Montana: Do not know.

Nevada: Do not know.

New Jersey: No.

New Mexico: Yes. It does not.

New York: No.

North Carolina: No.

North Dakota: No.

Ohio: Yes. I can only presume this is so. There is no provision in the transportation policy.

Oregon: No.

Pennsylvania: No

Rhode Island: No answer.

South Carolina: Yes. No general transportation policy.

South Dakota: No.

Texas: No.

Utah: Yes. Five cents was added to the transportation rate. Revenues from this are credited to the gas cost balancing account (Account 191) to offset possible adverse impacts on the cost of gas for sales customers.

Virginia: Perhaps. Virginia LDCs have been reluctant to negotiate for long-term supplies from non-traditional sources due to the uncertainty of future transportation policies, price escalation clauses, and gas supply.

Washington: I see a potential problem once an interstate pipeline opens up.

Wisconsin: Uncertain.

Wyoming: Loss of large industry has resulted in LDC long-term gas supply surpluses. No LDC has made a filing based upon such impairment.

28. What has been the effect, if any, of the provision of transportation service on LDC gas procurement and gas operations? Have the cost and complexity of those operations increased or decreased?

Alabama: One would assume complexity has increased. Measurement would be difficult.

Alaska: Not applicable.

Arizona: Unknown.

Arkansas: No answer.

California: The impact upon LDC procurement and system reliability is currently under investigation. Lengthy hearings were completed in April 1988. No decisions or conclusions have yet been made. Comments upon other procurement issues were received on March 31. Some of these may be set for hearing. Gas transportation significantly increases the complexity of LDC gas operations.

Connecticut: Minimal on both counts due to a small number of end-users transporting--approximately four.

Delaware: To date, no gas has been transported by an LDC in Delaware.

District of Columbia: Not enough transportation to matter.

Idaho: Not applicable.

Illinois: The complexity of these operations has increased with the advent of transportation. The LDCs have more decisions to make concerning what supplies to buy over which pipelines and in coordinating system operations.

Indiana: The complexity of an LDC's gas procurement activities has increased because the utility must coordinate with its end-users constantly to assess how much gas each will require from the LDC and how much the end-user will be transporting. Consequently, we would assume that the cost associated with gas operations has also increased.

Iowa: This has not yet been investigated.

Kansas: Certainly, the complexity has increased.

Kentucky: Obviously, it is more complex for the LDC, but the Commission has no information on the costs involved.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: To date, no specific studies have been done concerning the impact of transportation service on LDC gas procurement and gas operations.

Massachusetts: LDC's procurement activities are becoming more complex due to the fragmentation of the market. However, companies report that the increased effort expended on more aggressive procurement results in commodity cost savings which more than offset the costs. In a few instances, companies have been willing to pay minimum bill charges for gas not taken in order to take spot gas instead, as unitized commodity rate savings exceeded unitized minimum bill charges.

Michigan: About the same.

Minnesota: I know there is much greater activity and complexity, I have no knowledge of the cost changes.

Mississippi: Not applicable.

Missouri: This is difficult to assess. Many LDCs are participating in spot market purchasing activities for system supply. They have been successful to a certain extent in temporarily reducing their gas costs. The complexities of gas operations and procurement have certainly increased, especially in the areas of bookkeeping, accounting, billing, and accountability.

Montana: Don't know.

Nevada: No information.

New Jersey: Seems to have varied costs.

New Mexico: Increased take-or-pay payments.

New York: Transportation service, per se, has had limited effect. However, the developing spot market has required utilities to devote more attention to their own purchasing practices.

North Carolina: Decreased.

North Dakota: It appears that the costs and complexity of LDC operation has increased. However, we have no measure of this.

Ohio: LDCs with substantial amounts of transportation have had to reorder their purchasing to maintain throughput and least-cost purchasing for system supply. The specifics of increased or decreased costs vary by utility. Generally, I believe the cost and complexity has increased for most utilities.

Oregon: No difference to date.

Pennsylvania: The complexity of gas procurement has increased.

South Carolina: Increased.

South Dakota: Montana-Dakota Utilities Company - zero effect
Minnegasco - very minor effect
Iowa Public Service Company - very minor effect
Northwestern Public Service Company - small effect

Texas: The complexity of those operations has increased.

Utah: The actual impacts are not known. It is anticipated that the cost of gas operations will increase because the complexity of the operation will increase.

Virginia: The primary effect of transportation has been a result of transportation imbalances. These imbalances have, thus far, been beneficial as a result of declining gas costs. We anticipate the opposite effect as prices go up. The general trend of rate unbundling that has resulted from Virginia transportation is allowing our LDCs to better quantify the price elasticities of the various markets. The enhanced perception of the markets should promote more efficient gas purchasing practices.

Washington: No answer.

Wisconsin: Yes. The LDCs have reallocated and/or added staff for transportation service. These changes have been reflected in the institution of fixed monthly transportation charges. In addition, the LDCs and Wisconsin PSC staff have increased the number of meetings in order to help communications regarding transportation issues.

Wyoming: In the cases where transportation was authorized, the effect was to help the LDC (Cheyenne Light, Fuel & Power) maintain its net revenues with little increase in cost or complexity.

29. Has the provision of transportation service by jurisdictional LDCs had any detrimental (or helpful) effects on the distributors' obligation to buy and transport gas for captive customers?

Alabama: No effect that I know of.

Alaska: Not applicable.

Arizona: Unknown.

Arkansas: No answer.

California: See the answer to question 28.

Connecticut: Minimal, if at all.

Delaware: To date, no gas has been transported by an LDC in Delaware.

District of Columbia: No.

Idaho: Not applicable.

Illinois: The Commission is not aware of any changes in service to captive customers. LDCs retain priority use of their systems for the benefit of system supply customers.

Indiana: No.

Iowa: When ANR Pipeline Company had its minimum bill, some LDCs were precluded from buying spot gas for system supply due, at least in part, to individual customers transporting their own gas for which those customers' requirements were included in the annual table used to figure the minimum bill obligation. Other than this situation, we are not aware of any aspect of the provision of transportation service which would effect the LDC's obligation to buy and transport for captive customers.

Kansas: No answer.

Kentucky: The LDC's obligations have become more difficult to define as a result of transportation, making it more difficult for the LDC to plan its purchase.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No specific beneficial or detrimental effects have been documented.

Massachusetts: We don't know.

Michigan: No effect.

Minnesota: No detrimental or helpful effects that I know of.

Mississippi: Not applicable.

Missouri: No immediate detrimental effects have been noticed.

Montana: The PSC's approval of MDU's proposed transportation rates has, we hope, minimized the shifting of fixed costs to core customers.

Nevada: No.

New Jersey: Still in review.

New Mexico: No.

New York: There has been no known effect as yet.

North Carolina: No.

North Dakota: Not that we are aware of.

Ohio: In general, most utilities are able to continue to follow a least-cost purchasing strategy for system supply while they provide transportation, and the availability of spot market gas has enabled them to lower their weighted average gas costs. Some utilities are having trouble maintaining throughput and fulfilling least-cost due to the share of transportation on their systems.

Oregon: Not to date, but Interstate Pipeline take-or-pay and standby charges may become a problem in the future.

Pennsylvania: Not known at this time.

Rhode Island: No answer.

South Carolina: Detrimental.

South Dakota: No.

Texas: No.

Utah: It probably will have some detrimental effects which should be offset by credits from the 5 cent charge.

Virginia: Only to the extent that upstream transportation capacity is limited. This does not appear to be a current problem in Virginia. Previous limitations resulted in an allocation of the transportation capacity to system supply and to the transportation end users.

Washington: No answer.

Wisconsin: Wisconsin LDCs have been active in purchasing directly from producers, taking advantage of lower prices. They have covered the captive customer's needs with nominations of ACQ at 100 percent of the core customer needs. Most plan to purchase forty to fifty percent of annual needs for the core market or the spot market.

Wyoming: No detrimental effect. Beneficial to the extent set forth in the response to question 28.

30. What provisions does your Commission's transportation policy include to help guarantee continued, reliable LDC service to captive customers? What effects, if any, have those provisions had?

Alabama: None.

Alaska: Not applicable.

Arizona: Not applicable.

Arkansas: No answer.

California: See the response to question number 28. Under California's new gas industry structure, the LDC obligations to serve captive core customers, and the associated ratemaking mechanisms, are unchanged.

Connecticut: Not applicable.

Delaware: LDCs are obligated to serve captive customers. They are requested to structure their gas entitlements to provide continued reliable service.

District of Columbia: A restrictive tariff. There is no transportation.

Idaho: Not applicable.

Illinois: The Commission is aware of one case in which limited capacity required the foreclosure of transportation to end-users so that the LDC might purchase spot supplies to the advantage of system supply customers. The Public Utilities Act (Ill. Rev. Stat. Ch. 111 2/3) requires investigation of these issues as part of the least-cost planning process. There have been no specific effects thus far.

Indiana: Not applicable.

Iowa: Every public utility is required to furnish reasonably adequate service and facilities. (Iowa Code Sec. 476.8). LDCs are required to take all reasonable actions to minimize purchase gas costs consistent with assuring an adequate long-term supply of gas. (Iowa Code Sec. 476.6[15]); Iowa Administrative Code (IAC) 199--19.11). See also Iowa Code Sec. 476.52 regarding management efficiency.

Kansas: A prohibition of LDC bypass is the only relevant matter yet discussed.

Kentucky: The statement that this is the intent of the Commission is overall policy. Transportation is encouraged to the extent these customers are not unduly harmed.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: The Commission does not require an LDC to provide transportation service if LDC capacity is needed to meet the requirements of firm sales customers. The burden is on the LDC to demonstrate that it has insufficient capacity to accommodate transportation services.

Massachusetts: The Department held an exhaustive hearing on companies' practices at the time of a regional gas shortage from December 1980 to January 1981; following this proceeding (DPU 555), the Department ruled that companies may only make interruptible sales or move interruptible volumes of gas when revenues cover or exceed all avoidable costs. All margins earned are to be credited to firm sales customers through the cost of gas adjustment clause. Formerly, companies had retained interruptible margins as a credit toward the cost of service. This revision of policy eliminates the incentive which companies previously had to move interruptible volumes of gas at times of year when such activity could place the security of captive customers' supply in jeopardy. Partly as a result of this change, the state has not seen a recurrence of acute shortages in spite of continued growth in gas markets and constrained supply. With regard to the possible impact of firm transportation on reliability of service to captive customers, transportation is still at such an early stage (there are no firm transportation customers in the state as of today) that it is not possible to gauge the effects of Department policy. Because LDCs show no intention of ceding any of their allocated pipeline capacity, the Department expects that it will be necessary for major new construction to occur before firm transportation can command a significant share of the market.

Michigan: Policy currently being developed.

Minnesota: No specific provisions. We see transportation as a service that provides greater customer choice and lower costs to customers. The enhancement of gas service could increase system use to the benefit of everyone.

Mississippi: Not applicable.

Missouri: The system supply emergency provisions which were discussed in response to question 7 of this survey.

Montana: Captive/core customers have the highest priority of service.

Nevada: No effects.

New Jersey: Least cost strategy; conservation.

New Mexico: None.

New York: The policy provides for mandatory transportation only if the LDC has excess capacity after providing reliable service for its sales customers.

North Carolina: None at this time, except surveillance.

North Dakota: None.

Ohio: See the responses to questions 2f, 2i, and 6. The actual effects of these policies will only be determined when gas supply becomes restricted.

Oregon: None.

Pennsylvania: The PUC regulations require interruption of transportation service in cases where the LDCs have capacity restraints that put captive customers at risk. The regulations also require the sale to the LDC, by the transportation customer, of transportation gas in periods of shortage that place residential customers at risk.

Rhode Island: No answer.

South Carolina: No general policy.

South Dakota: No provisions, but no problems.

Texas: Not applicable..

Utah: None that directly address reliable service.

Virginia: None.

Washington: Statutory requirement to provide service.

Wisconsin: The Wisconsin PSC has no stated policy requiring D-1 and D-2 nomination for captive customers. However, all Wisconsin LDCs have D-1 and D-2 nominated to cover core customer's needs.

Wyoming: On a case-by-case basis, the Commission works to protect and maintain distribution service at the lowest reasonable rate. No application or contract is allowed to jeopardize or unfairly and unnecessarily raise distribution service rates.

VII. The obligation to serve former transportation customers who wish to return to the LDC system as regular customers and the issues of standby and reservation charges are considered next.

31. Because of an "obligation to serve" or some other reasons, does your Commission require an LDC to provide transportation customers, who were formerly firm or interruptible sales customers, traditional utility service (i.e., procurement and transportation service), should these customers wish to return to the LDC system as regular customers? Yes____ No____.

Alabama: No policy, but probably yes.

Alaska: Not applicable.

Arizona: Yes. Implied, not specific in transportation tariffs.

Arkansas: Yes.

California: The conditions under which this will occur are currently under investigation.

Connecticut: Not applicable.

Delaware: Yes. However, interruptible transportation customers that request firm service cannot switch back to interruptible transportation again, and must sign one year contract for service.

District of Columbia: Not applicable. Interruptible tariff only.

Idaho: Yes.

Illinois: Yes

Indiana: This "obligation to serve" issue has not been specifically addressed by this Commission.

Iowa: Yes.

Kansas: Yes, no disputes as yet in this matter.

Kentucky: Yes, only if the LDC has been collecting a reservation charge or stand-by fee. Otherwise, the LDC should collect a reasonable reentry fee.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: Yes.

Massachusetts: No. The right to return must be negotiated as an "extra-cost option" in the transportation service agreement.

Michigan: Policy currently being developed.

Minnesota: Yes.

Mississippi: Not applicable.

Missouri: Yes.

Montana: Yes. But the loads are generally interruptible--low priority!

Nevada: No.

New Jersey: Yes.

New Mexico: No. Only for six months.

New York: No.

North Carolina: No.

North Dakota: Yes, if the company has available gas or can contract for gas to serve.

Ohio: Yes. This issue is being evaluated currently. It is unclear how to deal with the legislative obligation to serve.

Oregon: Yes. For firm service less than 500 therms a day.

Pennsylvania: Transportation customers that decline standby service would receive retail service only if and when the LDC has the capacity to supply them.

Rhode Island: No answer.

South Carolina: Yes.

South Dakota: Yes. However, only to the extent of firm deliveries contracted for from the pipeline.

Texas: No.

Utah: No. However, there is nothing prohibiting the LDC from letting the customer return.

Virginia: No.

Washington: This will be a future issue once the transmission system opens.

Wisconsin: Yes.

Wyoming: Yes.

32. If so, is the LDC allowed to charge the transportation customer a standby or reservation charge? Yes____ No____. If so, how is the charge calculated?

Alabama: No policy, LDCs and Commission staff discussing on informal basis.

Alaska: Not applicable.

Arizona: No. But standby charges are being considered.

Arkansas: No.

California: See the response to question 31.

Connecticut: Not applicable.

Delaware: Yes. Firm transportation customers are charged a standby charge based on the fixed cost of pipeline supply.

District of Columbia: Not applicable.

Idaho: No.

Illinois: No. A customer wishing to return to an LDC's system is treated like a new customer.

Indiana: No. This and other issues are being discussed in a current rate case.

Iowa: The LDC is required by IAC 199-19.13(4)c to impose a reconnection charge when an end-user receiving transportation service without system supply service requests to return to the system supply. System supply reserve service entitles the end-user to return to the system to the extent of the capacity purchased. (IAC 199-19.13[4]a1). All rates and charges for transportation shall be based on the cost of providing the service. (IAC 199-19.13[4]).

Kansas: No, none yet applied for.

Kentucky: Yes. The stand-by or reservation fee is a function of demand charges. The reentry fee would be determined on a case-by-case basis with the Commission's approval and would consider the size of the bypass and the LDC's pipeline supply commitments.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: Yes. LDCs may propose appropriate standby or reservation changes in their transportation tariffs. Such charges are subject to Commission review and approval.

Massachusetts: Yes. The cost is based on the long-run demand cost of the LDC's production facilities, including pipeline demand charges and the level of investment and annual operating expenses related to local supplemental sources.

Michigan: Not applicable.

Minnesota: Yes. Customers who so choose may continue to pay the demand charge for sales.

Mississippi: Not applicable.

Missouri: Yes. See Report and Order in GO-85-264 dated September 18, 1986, page 13, paragraphs E. Backup Service, and F. Status of Transporting Customers Who Do Not Reserve Backup Service.

Montana: No.

Nevada: No. Not in any tariff.

New Jersey: In some instances.

New Mexico: Yes. It is primarily based on take-or-pay risk by utility. (A rate case is now in progress on this issue.)

New York: A firm customer may, at its option, reserve its right to return to firm sales service by paying an additional fee. The fee is equal to the average demand component included in the average cost of purchased gas for resale and is billed on every unit of gas transported.

North Carolina: Not at this time.

North Dakota: No.

Ohio: Yes. Some utilities are charging for standby or back-up by allocating demand costs and crediting these charges back to the gas cost recovery rates to prevent double recovery. The exact allocation method varies by utility. Some indicate to customers that they will also get a portion of any future gas inventory charges assessed by the interstate pipelines.

Oregon: It's currently in the full margin rate as pipeline demand charges.

Pennsylvania: Yes. Standby sales service rates must be cost based and reflect the actual cost of providing that service.

Rhode Island: No answer.

South Carolina: One company has such a charge.

South Dakota: Yes. Montana-Dakota Utilities Company has a standby rate available to transportation customers.

Texas: Not applicable.

Utah: Not applicable.

Virginia: Yes. Although the Commission feels that any customer electing to transport gas should bear the risk of their election, it encourages standby services as an option for customers who desire a gas supply back-up. These charges are generally equivalent to the daily demand charges of the LDC's pipeline supplier. Standby customers must make contractual commitments to their daily back-up requirements.

Washington: This will be a future issue once the transmission system opens.

Wisconsin: Yes. The LDC must continue to charge a system sales customer going to transportation any demand costs that were incurred on that customer's behalf until such time as the LDC may reduce nominations. If, after these changes have been eliminated, a transportation customer wishes to return to system sales, it shall be treated as a new customer.

Wyoming: On a case-by-case basis.

VIII. Finally, a set of questions on transportation service and purchased gas costs.

33. Has the shift of customers to transportation service resulted in increased purchased gas costs (i.e., demand charge related increases) for customers still on the system? Yes____ No____. If so, how are these demand charges handled in the rate to the customers still on the system? Are there changes in rate design?

Alabama: Demand charges are still charged to all firm customers, whether sales or transport.

Alaska: Not applicable.

Arizona: Unknown.

Arkansas: No answer.

California: No.

Connecticut: No. Customers on transportation tariffs have all been incremental loads.

Delaware: To date, no gas has been transported by an LDC in Delaware.

District of Columbia: No.

Idaho: No.

Illinois: These charges are passed through the PGA mechanism so there are no rate design effects.

Indiana: In some cases, the purchased demand costs have increased for other customers. Changes in purchased demand costs are tracked through our gas cost adjustment factors.

Iowa: Whether or not shifting of purchased gas costs has occurred will be the subject of future review. In certain instances, such potential shifts have been identified and disallowed.

Kansas: No. Here again, transportation and cost shifting are both effects of changing market conditions.

Kentucky: No. The companies offering transportation at gross margin are still recovering demand charges through transportation rates. Those transportation rates that are flexible have not as yet been reviewed in a rate case to examine the effect of demand charges.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No.

Massachusetts: No indication as yet that this has occurred.

Michigan: Yes. Demand charges are passed through to sales customers. There have been no changes in rate design.

Minnesota: No.

Mississippi: Not applicable.

Missouri: No.

Montana: Generally no, because with MDU, retail interruptible loads are not allocated demand charges (MDQ or AEQ).

Nevada: No.

New Jersey Yes. To become eligible for transportation service, some of the utilities require that they first become either a firm or an interruptible service customer.

New Mexico: No.

New York: Average cost of gas increased due to constant demand costs recovered over smaller sales volumes. Increases in the average cost of gas were collected through the PGA.

North Carolina: No.

North Dakota: No.

Ohio: Yes. Demand charges remain in the GCR but, as mentioned, where such costs are assessed to specific transportation customers for back-up or standby, these revenues are credited to the GCR.

Oregon: No.

Pennsylvania: Yes. These costs are reviewed via a formal purchased gas cost hearing to determine if the LDC is securing the least expensive gas for its customers.

Rhode Island: No answer.

South Carolina: Yes, collected through purchased gas adjustments.

South Dakota: No. Essentially transportation customers are rejoining the system and provide additional contributions.

Texas: Yes. They are flowed-through in the weighted average cost of gas.

Utah: Yes. Probably has resulted in increased purchased gas costs. The 5 cents additional charge, with the credit to gas costs, is to offset this type of adverse effect on gas costs.

Virginia: No. Virginia's transportation activity has been primarily by interruptible end-users. Consequently, any shifting of gas costs may be associated with competition with alternate fuels.

Washington: Yes. To the extent that these shifts cause take-or-pay liabilities, the recovery of take-or-pay becomes embedded in commodity gas costs.

Wisconsin: No.

Wyoming: Each class rates are being set on the basis of costs as determined by the Commission on a case-by-case basis.

34. Are either firm or interruptible transportation customers required to pay any costs related to the LDC's gas supply? Yes____ No____. If yes, please explain.

Alabama: See 33 above.

Alaska: Not applicable.

Arizona: Yes. Part of charge for transportation service is interstate pipeline's peak and annual fixed charges to LDC.

Arkansas: No.

California: Yes. Certain costs have been identified as transition costs and allocated across all customer classes. These include take-or-pay costs, uneconomic gas supplies, and system commitments made on behalf of all customers prior to the change of the regulatory structure.

Connecticut: Yes. Indirectly, through retained volumes for system unaccounted-for losses.

Delaware: No.

District of Columbia: No.

Idaho: Yes. The transportation rate is set at a level to compensate the LDC for gas supply management.

Illinois: It depends on the transportation rates in effect for a particular LDC. Some transport rates credit back only part of the PGA charges.

Indiana: Yes. Some of the utilities recover purchased demand costs from their transportation customers.

Iowa: Yes, to the extent that system supply reserve service is provided.

Kansas: No.

Kentucky: Yes, to the extent demand charges are incurred by the LDC.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: Yes. To the extent such customers utilize LDC standby service, they must pay standby service rates which are fully compensatory.

Massachusetts: No.

Michigan: In general, transportation customers are not required to pay any costs related to gas supply. However, in the case of one utility, customers without alternate fuel capability are required to pay a portion of the unavoidable pipeline costs.

Minnesota: No.

Mississippi: Not applicable.

Missouri: Customers must pay those costs which represent any unavoidable pipeline charges incurred by the LDC and allocated to that customer class to provide sales service, and to the extent such charges have not been extinguished or modified by the pipeline.

Montana: We only have interruptible gas transportation customers on MDU's system and their sources of gas supply are, to my knowledge, third-party sources. The status quo could change in the next year or so when several gas dockets are closed.

Nevada: Yes. See ST-1 Tariff.

New Jersey: Yes. South Jersey Gas-firm transportation rates include demand, peaking, and storage cost of gas.

New Mexico: No.

New York: No. Only to the extent firm transportation customers who choose to reserve the right to return to firm sales service must pay demand costs.

North Carolina: No.

North Dakota: No.

Ohio: Yes, only the demand costs (so far), as previously mentioned.

Oregon: Yes. Firm margins include storage and pipeline demand charges.

Pennsylvania: No.

Rhode Island: No answer.

South Carolina: Unaccounted for gas.

South Dakota: Yes. Iowa Public Service Company charges new transportation customers for the demand charges applicable to the customer's firm sales capacity displaced by transportation.

Texas: No.

Utah: Yes. The 5-cent increment that goes to reduce gas costs.

Virginia: Yes. If it can be shown and quantified that the transportation customer receives a benefit from a specific gas cost, a portion of this cost may be allocated accordingly. This has been done in one instance with regard to the demand cost-of-service.

Washington: No.

Wisconsin: No, with the exception of the demand charges detailed in the response to question 32.

Wyoming: Yes. Firm or interruptible transportation customer's rates are required to cover gas supply expenses incurred as a result of the transportation.

35. Does your Commission hold customers who shift to transportation service only from firm or interruptible sales service responsible for PGA-related demand charge increases? Yes____ No____. If so, what rate design changes has your Commission made to handle this?

Alabama: Yes, all firm customers pay demand component.

Alaska: Not applicable.

Arizona: Did in case of liquid revenues liability pass-through, direct billed. No general policy.

Arkansas: No answer.

California: See the responses to questions 20 and 22. Such would be an issue in the cost allocation proceeding.

Connecticut: Not addressed by the Commission.

Delaware: No.

District of Columbia: No.

Idaho: Yes. None.

Illinois: Again, the application of demand charges to transportation customers varies by LDC and these charges are handled via the PGA clause.

Indiana: Yes. If PGA-related demand charge increases are included in the demand charges (D1 and D2) billed by the pipelines, these costs are passed on to the appropriate customer classes.

Iowa: Yes. To the extent there is a contract between the LDC and its customer, the Board requires the customer to "buy out." See IAC 199-19.13(4)h.

Kansas: Yes, by means of direct billing if such increases can be adequately identified with a particular customer.

Kentucky: No experience with this yet.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: Yes. LDCs are free to recommend appropriate rate design changes to handle this problem. Such rate design changes are subject to Commission review and approval.

Massachusetts: No.

Michigan: See the response to question 34.

Minnesota: No.

Mississippi: Not applicable.

Missouri: Yes. The same response as in question 34.

Montana: Not applicable.

Nevada: No. This would be examined in each PGA filing.

New Jersey: No. Net yet.

New Mexico: No.

New York: No.

North Carolina: Yes. Because most transportation is within the LDCs contract and, therefore, the transportation customers get the benefit of the CD contract and should pay their share of the cost.

North Dakota: No, no conscious decision has been made on this.

Ohio: No.

Oregon: Yes. Full margin rates pass demand charges through.

Pennsylvania: No.

Rhode Island: No answer.

South Carolina: No.

South Dakota: No.

Texas: No.

Utah: No.

Virginia: Yes. Large sales customers who transport on a short-term basis must enter into contractual commitments for demand service from an LDC. These demand charges would continue regardless of comsumption.

Washington: Yes. At a minimum, the D2 demand charge increases.

Wisconsin: Yes. A simple margin approach, therefore, the PGA for D1 and D2 are the same for both system sales and transportation customers that are being assessed D1 + D2 charges.

Wyoming: Yes. See the response to question 34.

36. If the answer to the previous question was "yes", please describe any applicable charge or surcharge that might be part of your Commission's policy. Specifically, how is it calculated? How long would the transportation customer have to pay the surcharge? Would different transportation customers pay different surcharges or the same amount, depending on, for example, when they shifted to transportation service?

Alabama: See 35 above.

Alaska: Not applicable.

Arizona: Not applicable.

Arkansas: No answer.

California: It would be an issue in the cost allocation proceeding.

Connecticut: Not applicable.

Delaware: Not applicable.

District of Columbia: Not applicable.

Idaho: None.

Illinois: See the response to question 35, above.

Indiana: Policy does not apply. Statute on gas cost adjustment requires pass-through of increases or decreases on a regular basis either every three or four months.

Iowa: See the response to question 35.

Kansas: Such a charge has never yet been applied for.

Kentucky: Not applicable.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: The appropriate changes needed to insulate firm sales customers from cost increased due to utilization of LDC transmission service is currently under investigation in four proceedings concerning individual LDC transportation tariffs.

Massachusetts: Not applicable.

Michigan: Not applicable.

Minnesota: Not applicable.

Missouri: The same response as in question 34.

Montana: Not applicable.

Nevada: None calculated (yet?).

New Jersey: Not applicable.

New Mexico: Not applicable.

New York: Not applicable.

North Carolina: Its tracked through the PGA.

North Dakota: Not applicable.

Ohio: Not applicable.

Oregon: OPUC may surcharge take-or-pay costs if they arise.

Pennsylvania: Not applicable.

Rhode Island: No answer.

South Carolina: Not applicable.

South Dakota: Not applicable.

Texas: Not applicable..

Utah: Not applicable.

Virginia: Large firm sales customers, who occasionally transport, and transportation customers with back-up must enter into a contract demand agreement with the LDC. The customer specifies the desired daily service and is billed a demand charge accordingly. Any customer whose average daily consumption exceeds its contract demand nomination during a peak period is subject to a demand ratchet which would require a higher demand billing for a 12-month period.

Washington: No charge or surcharge is calculated--only the incremental charge in D2 pipeline charges.

Wisconsin: See the response to question 32.

Wyoming: Costs and/or charges determined on a case-by-case basis.

37. Is there any "exit fee" or similar charge for firm or interruptible sales customers who became transportation customers. Yes____ No____ If so, please describe.

Alabama: No.

Alaska: Not applicable.

Arizona: No.

Arkansas: No answer.

California: Yes. If a noncore customer chooses to abandon its contract to purchase gas from the LDC, then it would be required to make up any allocated costs not captured in any new agreement.

Connecticut: Not addressed by the Commission.

Delaware: No.

District of Columbia: No.

Idaho: No.

Illinois: No.

Indiana: No.

Iowa: See the response to question 35.

Kansas: No.

Kentucky: No.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: No.

Massachusetts: No.

Michigan: No.

Minnesota: No.

Mississippi: Not applicable.

Missouri: No. None are currently in place.

Montana: No.

Nevada: No.

New Jersey: No.

New Mexico: No.

New York: No.

North Carolina: No.

North Dakota: No.

Ohio: No.

Oregon: No.

Pennsylvania: No.

Rhode Island: No.

South Carolina: No.

South Dakota: No.

Texas: No.

Utah: No.

Virginia: No.

Washington: No.

Wisconsin: No, except for continued payment of demand charges incurred on their behalf. (See the response to question 32.)

Wyoming: No.

38. If there is a system-wide contract demand reduction, how is this allocated among the remaining customers and stockholders, i.e., case-by-case, by stipulation, or by formula? Please describe.

Alabama: By formula in PGA. Direct pass-through to all firm customers. Not to interruptible or stockholders.

Alaska: Not applicable.

Arizona: No policy.

Arkansas: No answer.

California: Not known or currently an issue--see the response to question 28 and elsewhere--because California's LDCs have no current plans to reduce contract demand on interstate pipelines. Such may result from FERC Section 4 applications by the interstates that deliver gas to the LDCs. If so, it would be an issue in scheduled cost allocation filings by the LDCs before this Commission.

Connecticut: Not addressed by the Commission.

Delaware: Any system-wide contract reduction would be flowed-through to firm customers through the fuel adjustment clause.

District of Columbia: Unknown.

Idaho: Not applicable.

Illinois: Not sure what is meant here. Currently, contract demand levels for Illinois LDCs are set considerably above the level an LDC requires for its system supply customers. These pipeline contracts are set to expire generally within the next couple of years. It is difficult to imagine that an LDC will select a contract demand level that does not contain a reserve margin. It is also difficult to imagine that pipelines would elect to reduce LDC contract demand levels prior to renegotiation of their contracts. If a decision is needed to be made, it probably would be on a case-by-case basis.

Indiana: If demand costs were reduced, the reduced costs would be allocated to the classes in the same manner as before.

Iowa: The Board has a stated policy of requiring system-wide contract demand reductions to be allocated proportionately among customers and/or customer classes based on contract demand prior to the reduction, absent a showing that the reduction was sought for a specific customer(s). There is, however, a case pending before the Board, and another case which may be brought before the Board very shortly, which seek clarification on, and challenge this standard.

Kansas: Such a situation has not yet been brought before the Commission.

Kentucky: No experience to report.

Louisiana: Not applicable.

Maine: Not applicable.

Maryland: In Maryland, pipeline demand charges and commodity charges incurred by an LDC are recovered dollar for dollar through the LDC's purchased gas adjustment charge to its retail customers. PGA charges are imposed on retail sales volumes and are calculated by formulas, subject to Commission review and approval.

Massachusetts: Not applicable.

Michigan: State law requires an annual contested case proceeding (a gas cost recovery plan) to determine the issue.

Minnesota: Case-by-case. Changes in entitlements require Commission approval. Cost changes resulting from entitlements charges are reviewed and determined at that time.

Mississippi: Not applicable.

Missouri: None experienced to date. Commission's order does not address this aspect. In all likelihood, it will be a matter that will be resolved on a case-by-case basis in a rate case.

Montana: Not applicable.

Nevada: None has occurred. This would be in a FERC proceeding for El Paso Natural Gas Co.

New Jersey: There has not been a system-wide contract demand reduction, as demand has been growing.

New Mexico: Case-by-case during a rate proceeding.

New York: There are no demand charges in New York. The impact of customer sales reductions is reflected in individual rate cases, generally impacting firm customer classes.

North Carolina: Yes, benefits to the sales customer.

North Dakota: To date, no such reduction has occurred.

Ohio: Not applicable.

Oregon: Allocated to remaining customers.

Pennsylvania: See the response to question 33.

Rhode Island: No answer.

South Carolina: Demand charges collected through purchase gas adjustment clause.

South Dakota: On a case-by-case basis in the context of a rate proceeding.

Texas: One company said formula, the others said they had no experience of system-wide contract demand a reduction or that they could not answer the question.

Utah: Would be handled on a case-by-case basis.

Virginia: No answer.

Washington: It will be a future issue when the transmission system opens.

Wisconsin: On a case-by-case basis, the Wisconsin PSC examines the intent and use of any replacement (such as firm transportation capacity) for C-D reduction or conversion before determining whether the changed costs should be allocated to commodity or demand.

Wyoming: No case on this specific issue. Would be ruled upon on a case-by-case basis.