NOTICE OF INQUIRY (NOI)

Examining Regulation of Local Distribution Companies

In the Face of Change in the Natural Gas Industry

Docket No. UG-940778
(August 2, 1995)

Following the Federal Energy Regulatory Commission's (FERC's) Order 636 and other industry changes, natural gas local distribution companies (LDCs) now operate in a more competitive environment than ever before. The Commission is undertaking this NOI to consider how it may regulate gas companies so as to balance competitive market realities with state and regional policy goals. The inquiry poses questions to help determine whether the Commission should change how it regulates gas companies to better achieve goals that include securing the benefits of competition for both companies and the customers they serve; protecting customers who do not have competitive options; and carrying out state and regional policy.

By this notice, the Commission initiates an inquiry into, and invites comments about, structural change in the natural gas industry; implications of industry changes for regulation; and recommendations concerning specific rules currently used by the Commission. The Commission will use responses from this inquiry to review and, if necessary, revise regulatory procedures and rules concerning least-cost planning, purchase gas adjustment (PGA) mechanisms, demand side management incentives and finance, and other regulatory issues which may be articulated as a part of this process.

BACKGROUND.

The Commission regulates four local distribution companies (LDCs) that provide retail natural gas service in Washington State. Washington Natural Gas Company (WNG) has approximately 450,000 customers in the Puget Sound region. Cascade Natural Gas Corporation (Cascade) serves about 125,000 customers across the state. The only combined electric and gas utility, The Washington Water Power Company (WWP), provides gas to about 100,000 homes and businesses in the Spokane region. Northwest Natural Gas Company (NNG) serves about 15,000 customers in the Clark County area.

These LDCs, which accept gas at the "city gate" and distribute it to customers to meet their energy needs, are the final component of an international gas industry. Two other important components of this system are pipelines, which move gas from where it is produced to areas of demand; and producers, which collect and process natural gas for delivery to pipelines.

For almost a century, these three industry components (LDCs, pipelines, and producers) have faced an almost constant evolutionary process of regulatory and market changes and institutional responses. In many respects, LDCs and their regulation have been the most stable of these components. However, changes in upstream components have inevitably changed the market environment and opportunities for regulated LDCs, and thus the context in which regulation serves the public interest.

Local distribution companies began in the 19th century as vertically integrated companies which manufactured gas from coal or oil and distributed it, often for use in municipal street lighting (see Richard J. Pierce, Jr., "Reconstituting the natural gas industry from well-head to burnertip", *Energy Law Journal*, v9,n1 (1988), pp 1-57). With large fixed capital costs and significant economies of scale, such companies exhibited characteristics of natural monopolies. Early manufactured gas companies tended to be controlled by municipalities. Monopoly was ensured by issuing sole franchises for use of street rights of way; in turn, city governments required universal, non-discriminatory service terms with rates set by the municipality. Municipal regulation was no longer effective as LDCs grew outside city boundaries to take advantage of economies of scale, so state utility commissions were charged with performing similar regulatory roles.

As the electric industry grew, manufactured gas companies were faced with competition. Natural gas, a by-product of petroleum exploration and production, had clear cost advantages over manufactured gas and could compete with electricity if it could be delivered to customers. Pushed by improvement in construction technology, pipelines began moving gas from areas of production to LDCs in the decades after

World War I. Because pipelines were built by holding-company offshoots of major petroleum producers, they were able to exercise considerable monopoly and monopsony power. Since pipelines crossed several state boundaries, state regulation was not effective.

A 1935 Federal Trade Commission (FTC) study of unregulated pipelines found monopoly abuse and recommended transportation-style regulation of pipelines as common carriers providing non-discriminatory access. However, industry lobbying shaped the regulatory framework actually adopted by Congress in 1938 into utility-style regulation, a major purpose of which was protecting pipelines from competition (see Richard H.K. Vietor, *Contrived Competition: regulation and deregulation in America*; Belknap Press of Harvard University, 1994).

In the 1940s and 50s, the predecessor to FERC attempted to control self-dealing between pipeline purchases from affiliated producers. In response, the US Supreme Court decided in 1955 that purchases from all producers should be regulated by FERC. (*Phillips Petroleum v. Wisconsin*, 347 U.S. 672 (1954)). The resulting economic regulation of a competitive industry created enormous administrative difficulties and price distortions in the next two decades, eventually contributing to acute gas shortages.

The energy crises of the 1970s finally attracted Congressional attention. Its attempt to solve the problem, the Natural Gas Policy Act of 1978 (NGPA), was again a political compromise. Congress attempted regulatory reform only in stages, creating multiple vintages of gas, with some vintages deregulated while others were still subject to price regulation. The market response (a supply "bubble") and the institutional response by producers and pipelines ("take-or-pay" contracts) caused yet another crisis: over ten billion dollars in contract liabilities for gas which pipelines were obligated to pay but unable to sell at commensurate prices.

In response to the take-or-pay crisis, FERC attempted to put the natural gas industry on a sound economic footing through various administrative orders, which in turn impacted state regulation of local distribution companies. Orders 436 and 500 (1985-88) articulated an "open access" policy, which enabled utilities and industrial customers to purchase gas directly from pipelines or upstream suppliers. This changed the nature of the "core" customer base (i.e. residential and small commercial and industrial customers), and led to the development of an independent marketing industry which now competes with LDCs and pipelines to arrange supply and transportation services. FERC's Order 636 (1992) accomplished the regulatory structure recommended by the FTC almost 60 years before: pipelines became common carriers, with the gas supply business separated from pipeline subsidiaries. This placed a much greater responsibility on LDCs to plan, procure, and transport an adequate supply of natural gas. Order 636 also set up a secondary market for releasing pipeline capacity, which increases both the flexibility and the complexity of LDC management of gas supplies.

The natural gas industry is now characterized by competition in many of its segments with some important exceptions such as distribution to core customers. These changes challenge traditional regulatory procedures. For instance:

PGAs. Prior to Orders 436 and 636, LDCs bought gas from pipelines at rates that had to be approved by FERC. This meant that an LDC had a single supplier; gas prices were outside of LDC control; and changes in price were known several months ahead of time during pending FERC proceedings. Under these circumstances, changes in supply costs were considered amenable to automatic pass-through to ratepayers through a purchase gas adjustment mechanism. PGAs were established to reduce regulatory lag for cost increases outside of management control. In contrast, LDCs now have many suppliers and a variety of contract terms available to them; gas supply is under greater LDC management control; and PGAs could become more complex and time-consuming to administer. Thus, several foundation assumptions of PGAs may need to be reexamined.

Price flexibility/contract review. Industrial and large commercial customers may now choose from a number of alternatives to receiving bundled sales services from the LDC. Such customers may have the option of agreeing to have service interrupted during peak usage periods and pay reduced rates as a result; they can purchase gas directly from producers or independent marketers and arrange for the LDC to transport their gas; or they may be able to bypass the LDC and receive service directly from a pipeline. These options may have consequences for other customers, to the extent that large customers have caused investment that may be stranded, or contribute to fixed costs that otherwise would be recovered entirely from core customers.

Another consequence of large customer choice is that LDCs now need greater price flexibility to meet competitive challenges. Washington State has two means of flexible pricing: the banded rates statute (RCW 80.28.075) and the special contract rule (WAC 480-80-335). Because LDCs now exercise greater responsibility for arranging gas supply and negotiating special contracts, regulators may need to conduct prudence reviews to ensure that company management prudently minimizes supply costs for all ratepayers, or that rates and terms of special contracts do not adversely impact core customers. For instance, the Commission has noted that a decision to enter a contract with a large industrial customer, priced under the banded rate statute, would be subject to prudence review in the next revenue requirement case (Third Supplemental Order, Docket No. UG-901459, March 9, 1992), and recently set a similar requirement for special contracts (Fourth Supplemental Order Approving Special Contract, Docket No. UG-930511, April 29, 1994). In both cases, the Commission noted that a review of management prudence was necessary to prevent shifting any revenue shortfall to core customers, since customers without competitive alternatives should not be responsible for enabling the company to compete.

Risk. Some parties have suggested that financial markets may perceive changing circumstances in the gas industry as changing the risk profile of regulated utilities, possibly impacting the cost of capital for these companies. However, LDCs still retain monopoly rights to serve a particular region so do not face many of the risks of competitive firms, such as the risk of losing core customer market share to a competitor.

At least for the short term, several LDC functions (e.g. distributing gas to core customers) seem likely to remain a monopoly and hence appropriate for economic regulation. Regulation and competition may be inconsistent in several important ways. For instance, a firm may be tempted to shift costs away from its competitive ventures onto core customers. A firm's competitiveness may be constrained by requirements to charge tariffed rates. Changes in the gas industry may raise fundamental questions about which services or functions of a gas company should be subject to economic regulation, and which might be best provided by unregulated enterprise.

During this period of change in the natural gas industry, state and regional policy has been consistent: energy efficiency should be evaluated on an equivalent basis with supply side investments, and companies should invest in energy efficiency when that is the lowest-cost way of meeting demand. Examples of this policy direction are enactments by the Washington State Legislature and the State Energy Strategy prepared by the Washington State Energy Office (WSEO). Congress has articulated national policy favoring energy efficiency. The Energy Policy Act of 1992 (EPACT) amended the Public Utility Regulatory Policies Act (PURPA) to require states to consider the adoption of new standards pertaining to integrated resource planning and utility investment in conservation and demand management. Section 115 of EPACT also requires that states adopting the proposed standards implement the standards in a way that does not give utilities unfair advantage over small businesses in the development of energy efficiency. (The text of EPACT Section 115 is included as an attachment).

Over the past decade, the Commission has adopted a number of rules, policies, and procedures to align its regulatory role with these state, regional, and national policy objectives. In 1987, the Commission adopted its least-cost planning rule (WAC 480-90-191) that requires jurisdictional natural gas companies to develop least-cost plans for Commission review every two years. Under the process set in this rule, LDCs must produce plans to meet expected load with a least-cost mix of supply resources and improvements in the efficient use of gas. Such plans consider a range of future natural gas demand; the cost of available demand- and supply-side resources to meet the expected demand; an integrated plan to meet load at lowest cost to the utility and its ratepayers over 20 years; and an action plan for implementing and revising the plan's direction over each two year period. Plans are to be developed considering input from the public. The Commission has accepted demand side management (DSM) programs for several gas companies, and has reviewed several proposals for alternative ratemaking.

REGULATORY CHALLENGE. Traditional regulation of gas companies operated on the premise of "command and control" techniques which require a Commission's prior approval of virtually all services, rates, and terms. Such tools for natural gas distribution companies include rate cases, purchased gas adjustment mechanisms, and requirements to prepare least cost plans. Recent Commission responses to competition include banded rates, approval of special contracts, and changes to PGA mechanisms.

Given the competitive aspects of the gas industry, and policy directives favoring energy efficiency, the Commission is faced with a challenge in its regulatory mission: how to capitalize on the benefits of competition, for both companies and their ratepayers, while protecting those ratepayers who do not have competitive options and promoting broader public interest goals. We need to consider what level of regulatory scrutiny is necessary to protect monopoly customers, and whether companies competing for customers and market share should be expected to disclose all details of business and resource plans if such disclosure will cause competitive disadvantage. How might the Commission ensure that companies, their customers, and other industry players participate beneficially in a competitive marketplace?

A competitive marketplace is not the only objective of public oversight of natural gas utilities, given the vital role that energy plays in our society. How should the Commission balance the various objectives society has placed on the gas industry, including the obligation of providing safe, reliable, affordable energy supply and demand resources for all customer classes, with a competitive marketplace? If some customers choose to leave the system, adversely impacting the costs and service of others, or causing plant to become not "used and useful", how should the Commission strike a fair balance?

PURPOSE OF THE INQUIRY. This Inquiry is intended to solicit opinions and analysis about implications of industry conditions that affect natural gas utilities and the consequent role of regulation. This process will sharpen the Commission's ability to assess whether existing regulatory tools and procedures can be expected to serve well in the future; whether these tools and mechanisms require adaptation or modification; or whether a new regulatory framework using new tools and mechanisms should be fashioned. The intent is for the Inquiry to help frame a regulatory role that is consistent with both the Commission's statutory mission and the realities of the natural gas industry.

Specifically, this Inquiry will provide a basis for determining whether the Commission's least-cost planning rule (WAC 480-90-191) will continue to be a constructive tool, and whether adapting or modifying the rule is appropriate. In addition, the Inquiry will provide a basis for determining whether alternatives to current purchase gas adjustment mechanisms would be appropriate responses to industry change, and what principles should guide such alternative mechanisms. The Inquiry will also provide a basis for deciding what types of DSM program cost recovery mechanisms are most appropriate for the industry. Finally, this proceeding will serve to meet the requirement placed on state Commissions by Section 115 of EPACT.

Written responses to this NOI constitute the first phase of our Inquiry. Additional opportunities for input, as necessary, will be announced upon completion of the first phase. We intend to observe the following approximate timetable:

August 2, 1995	-	Commission issues Notice of Inquiry.
September 30, 1995	-	Interested persons file comments.
Winter 1995-96	-	Commission issues summary of Inquiry and initiates rule-makings, workshops or other proceedings as appropriate.

Respondents to the Inquiry are invited to provide detailed discussion and recommendations on the following topics and questions.

A. Supply-side issues

1. Should the Commission keep the current PGA mechanism, abandon the automatic pass-through approach, or change the PGA process in response to changes in the gas industry? If so, how might such a mechanism operate?

2. Are there incentive mechanisms that would encourage more efficient supply-side acquisitions by LDCs? If so, how would that mechanism work?

3. When should prudence of gas supply and transportation acquisitions be addressed: *ex post*, during a PGA process or rate case, or through some *ex ante* procedure? If the latter applies, how would such a review and approval process work?

4. Are changes in line extension policies called for in the new environment? If so, what changes are necessary?

B. Customer choice and competitive bypass issues

1. Should the Commission adopt an exit fee policy for customers that wish to change from sales to transportation service, or bypass existing distribution systems? If so, how would an exit fee be determined, and how would the fee be handled in rates?

2. Should the obligation to serve extend to customers who have become transportation customers or have chosen to bypass in the past; *i.e.* should those customers be allowed freedom to return as sales customers? If so, should customers

who wish to return to the utility's merchant function be charged an entry fee? If so, how should that process work?

3. Currently, special contracts and banded rates are available to address bypass of the LDC. Are there other mechanisms that could be used to help address this issue?

4. If an LDC is bypassed, who should bear the burden of lost revenue and stranded investment: all ratepayers, ratepayers in the same class, shareholders, or some combination?

C. Unbundling

1. Given the competitive nature of many gas functions, should the Commission direct LDCs to provide unbundled services? If so, should unbundling include a core/non-core distinction? Should unbundling allow core aggregation?

2. If the Commission should adopt some form of core/non-core unbundling, what specific services should be provided on an unbundled basis, and which services, if any, should remain bundled?

3. If the Commission should adopt some form of unbundling, how should rates for each of the services be set?

4. If substantial unbundling is called for, should utilities' obligation to serve be reinterpreted?

D. Least cost planning

1. Should the Commission adopt rules to align least-cost planning more closely with other LDC business planning?

2. Should the Commission consider changes to the least-cost planning rule to allow gas utilities to protect commercially sensitive information in the planning process?

3. What impact, if any, does utility funded DSM have on a gas utility's ability to compete both as a merchant for sales customers, and as a distributor of natural gas? What changes, if any, are needed in the least-cost planning rule to address these concerns?

4. Should the Commission consider any other changes to the gas least-cost planning rule to adapt to industry changes?

E. Demand side management and conservation

1. How should DSM programs be provided and evaluated in a competitive gas industry?

2. Who should pay for DSM programs under increasing competition, and how should DSM costs be recovered?

3. What forms of benefit-cost and avoided cost tests are most appropriate for evaluating DSM programs by Washington LDCs?

4. Should non-energy benefits be considered in evaluating supply and energy efficiency options? If so, how should such non-energy benefits be quantified and incorporated?

5. Is there a risk of DSM plant being a threat to future competitiveness, or DSM assets being stranded? If so, what solutions are appropriate to mitigate these risks?

F. <u>EPACT issues</u>

1. Should the Commission adopt the integrated resource planning standard proposed and defined in EPACT Section 115? (See attachment for proposed standard and definition.)

2. Should the Commission adopt the standard pertaining to utility investment in conservation and demand-side management proposed in EPACT Section 115?

3. If the Commission adopts the EPACT standards, how should these be implemented so utilities would not have an unfair competitive advantage over small businesses engaged in design, sale, supply, installation, or servicing of energy conservation, energy efficiency, or other demand-side management measures?

G. <u>Missed questions</u>

Have we asked the right questions? Are there other inquiries we should undertake? Are there ways that the Commission's regulatory practices can be changed to provide more efficient regulation, for the benefit of both ratepayers and utilities, not covered in the above questions?

Written comments, bearing the above caption and docket number, should be addressed to Steve McLellan, Commission Secretary, postmarked no later than Sept 30, 1995. The Commission requests that commentors file an original and ten (10) copies of written comments. We also request that comments be provided on a 3 1/2 inch, high density "floppy" diskette with the software indicated on the disk's label. Please number and organize responses by the above corresponding outline. To make comments easier to post to electronic bulletin boards and the Commission's internet FTP site, please use end notes instead of footnotes.

For more information regarding this Inquiry, please contact Jeffrey Showman of the Commission's Policy section by telephone at 360-586-1196, or by E-mail at jeffrey@wutc.wa.gov. After evaluating comments, the Commission will schedule further proceedings in this docket.

DATED at Olympia, Washington, and effective this day of August, 1995.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

SHARON L. NELSON, Chairman

RICHARD HEMSTAD, Commissioner

WILLIAM R. GILLIS, Commissioner

Attachment: EPAct Standards.

The Energy Policy Act of 1992 (EPAct) set two new federal standards for gas utilities and required state utility commissions to consider adopting these standards:

> 1. **Integrated Resource Planning** -- Each gas utility shall employ integrated resource planning in order to provide adequate and reliable service to its gas customers at the lowest system cost. All plans . . . shall (A) be updated on a regular basis, (B) provide the opportunity for public participation and comment, (C) provide for methods of validating predicted performance, and (D) contain a statement that the plan be implemented after approval of the State regulatory authority . . . .
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> 2. **Investment in Conservation and Demand Management** -- The rates charged by any State regulated gas utility shall be such that the utility's prudent investments in, and expenditures for, energy conservation and load shifting programs and for other demand-side management measures which are consistent with the findings and purposes of the Energy Policy Act of 1992 are at least as profitable (taking into account the income lost due to reduced sales resulting from such programs) as prudent investments in, and expenditures for, the acquisition or construction of supplies and facilities. This objective requires that (A) regulators link the utility's net revenues, at least in part, to the utility's performance in implementing cost-effective programs promoted by this section; and (B) regulators ensure that, for purposes of recovering fixed costs, including its authorized return, the utility's performance is not affected by reductions in its retail sales volumes. (Section 115 of EPAct (Pub.L. 102-486, Title I, § 115; 106 Stat. 2803, 2804) amended Sections 302 and 303 of the Public Utility Regulatory Policies Act of 1978 (PURPA) (15 U.S.C. 3202, 3203).

The Commission must also consider the impact that implementing these standards would have on small businesses engaged in the design, sale, supply, installation, or servicing of energy conservation, energy efficiency, or other demand-side management measures, and must implement such standards so utilities would not have an unfair competitive advantage over such businesses (EPACT Section 115 (c); 15 U.S.C. 3203(d)).